BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2002-223-E - ORDER NO. 2003-38

JANUARY 31, 2003

IN RE:	Application of South Carolina Electric & Gas Company for an Increase in its Electric Rates and Charges	)))	ORDER APPROVING ELECTRIC RATES AND CHARGES

I.

INTRODUCTION

This matter is before the Public Service Commission of South Carolina ("Commission") on the Application of South Carolina Electric & Gas Company ("SCE&G" or the "Company"), filed August 6, 2002, for adjustments in the Company's electric rates and tariffs, and for certain changes in the Company's General Terms and Conditions for service. The Application was filed pursuant to *S.C. Code Ann.* §§ 58-27-820, 870 (1976, as amended) and *S.C. Code Regs.* 103-834 (as amended) (South Carolina Public Service Commission Rules of Practice and Procedure).

The Company's rates and tariffs were approved by the Commission in Order No. 96-15, issued January 9, 1996, in Docket No. 95-1000-E. Subsequently, the Commission ordered a prospective rate reduction for the Company of $22.699 million annually, in Commission Order No. 98-987, Docket No. 98-623-E. The rates and tariffs as requested in the Company's Application in the present docket would produce an increase in annual revenues of approximately $104.7 million and provide a return on common equity of 12.5%, according to the Company's calculations.

By letter, the Commission's Executive Director instructed the Company to cause to be published a Notice of Filing and Hearing in newspapers of general circulation in the area affected by the Company's Application. The Notice of Filing and Hearing indicated the nature of the Company's Application and advised all interested parties desiring participation in the scheduled proceeding of the manner and time in which to file appropriate pleadings. The Company was also required to directly notify all customers affected by the proposed rates and tariffs. The Company furnished affidavits demonstrating that the Notice was duly published in accordance with the Executive Director's instructions and certified that a copy of the Notice was mailed to each affected customer.

Petitions to intervene were received from the Consumer Advocate for the State of South Carolina ("Consumer Advocate"), the United States Department of the Navy ("Navy"), John D. Ruoff, Ph.D., *pro se* ("Dr. Ruoff"), South Carolina Merchants Association ("SCMA"), S.M.I. Steel-South Carolina ("SMI"), South Carolina Energy Users Committee ("SCEUC"), South Carolina Small Business Chamber of Commerce ("SCSBCC"), and Wal-Mart Stores, Inc. ("Wal-Mart").

The Commission Staff made on-site investigations of the Company's facilities, audited the Company's books and records, and gathered other detailed information concerning the Company's electric operations. The Consumer Advocate, Navy, Dr.

Ruoff, SCMA, SMI, and SCEUC likewise conducted extensive discovery. SMI withdrew its intervention prior to the commencement of the hearing in this matter.

A public hearing was held in the offices of the Commission from November 18 through November 22, 2002. The Honorable Mignon L. Clyburn presided. SCE&G was represented by Catherine D. Taylor, Esquire, Belton T. Zeigler, Esquire, and Francis P. Mood, Esquire. The Consumer Advocate was represented by Hana Pokorna-Williamson, Esquire, and Elliott F. Elam, Jr., Esquire. The Navy was represented by Audrey J. Van Dyke, Esquire, and Marilyn Johnson, Esquire. SCMA was represented by Robert E. Tyson, Esquire. SCEUC was represented by Scott Elliott, Esquire. SCSBCC was represented by Joseph M. Epting, Esquire, and Joseph M. Epting, Jr., Esquire. Frank R. Ellerbe, III, Esquire, represented Wal-Mart. Dr. Ruoff appeared *pro se*. The Commission Staff was represented by F. David Butler, General Counsel.

The Company presented the direct and rebuttal testimony of Neville O. Lorick, its President and Chief Operating Officer; Kevin Marsh, its Senior Vice President and Chief Financial Officer; Carlette L. Walker, Assistant Controller of SCANA Corporation's regulated subsidiaries, including SCE&G; John R. Hendrix, Supervisor of Electric Pricing and Rate Administration, SCANA Services, Inc.; Julius A. Wright, Ph.D., President of J. A. Wright & Associates, Inc.; Thomas R. Osborne, Managing Director Global Energy and Power Group, Investment Banking Department, UBS Warburg, LLC; and Burton G. Malkiel, Ph.D., Chemical Bank Chairman's Professor of Economics at Princeton University. The Company presented direct testimony only of James M. Landreth, its Vice-President of Fossil and Hydro Generation.

The Consumer Advocate presented the testimony of Glenn A. Watkins, Vice President and Senior Economist of Technical Associates, Inc., and David C. Parcell, Executive Vice-President and Senior Economist, Technical Associates, Inc. Mr. Parcell's testimony was jointly sponsored with SCMA. SCMA, in addition to Mr. Parcell, presented the direct and surrebuttal testimony of Kevin C. Higgins, a principal in the firm of Energy Strategies, LLC, and James M. Herritage, President of Energy Auditors, Inc. SCMA also presented the direct testimony of Chris Schell, Manager of Construction, Energy and Environmental Services for BI-LO Stores, Inc. SCEUC presented the testimony of Nicholas Phillips, Jr., a principal in the firm of Brubaker & Associates, Inc., and Michael Gorman, a consultant with the same firm. SCSBCC presented the testimony of Timothy C. Wilkes, CPA, Chairman of the Board of Directors of that organization. Wal-Mart presented the testimony of James W. Stanway, Director of Project Development for that company. The Navy presented the direct and surrebuttal testimony of Donald B. Coates, a public utility specialist with the Navy's Rate Intervention Office. The Commission Staff presented the testimony of Thomas L. Ellison, PSC Audit Manager I; A. R. Watts, Chief of Electric, PSC Utilities Department; Eddie Coates, Rates Analyst, PSC Utilities Department; and James E. Spearman, Ph.D., the Commission's Research and Planning Administrator. Dr. Ruoff presented no witnesses.

The Commission also heard from four public witnesses: Robert L. Slimp, Ralph Lewis, John W. Casey, and Reginald Troutman Miller.

II.

FINDINGS OF FACT

Based upon the Application, the testimony, and exhibits received into evidence at the hearing and the entire record of these proceedings, the Commission makes the following findings of fact:

1. SCE&G is an electric utility operating in 24 counties in the central and southern areas of South Carolina, where it is engaged in the generation, transmission, distribution and sale of electricity to the public for compensation. SCE&G's retail electric operations in South Carolina are subject to the jurisdiction of the Commission pursuant to *S.C. Code Ann.* § 58-27-10, *et seq.* (1976, as amended). SCE&G's wholesale electric operations are subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). In addition to its electric operations, SCE&G also provides natural gas services, subject to the jurisdiction of the Commission pursuant to *S.C. Code Ann.* § 58-5-10, *et seq.* (1976, as amended).

2. The appropriate test year period for the purposes of this proceeding is the twelve-month period ending March 31, 2002.

3. The Company sought at the onset of the hearing, an increase in annual revenues of $104.7 million.

4. The appropriate operating revenues for the Company's retail operations for the test year under present rates and after accounting and *pro forma* adjustments are $1,228,169,000.

5. The appropriate operating revenues for SCE&G's retail operations under the approved rates are $1,298,873,000 which reflect a net authorized increase in operating revenues of $70,704,000.

6. The appropriate operating expenses for the Company's retail operations for the test year under its present rates and after accounting and *pro forma* adjustments are $964,541,000.

7. The appropriate operating expenses for the Company's retail operations under the approved rates are $986,796,000.

8. The Company's reasonable and appropriate federal and state income tax expense should be based on the use of a 35% federal tax rate and a 5.0% South Carolina tax rate, respectively.

9. The Company's appropriate level of net operating income for return for the test year under present rates, and after accounting and *pro forma* adjustments is $266,396,000 for SCE&G's retail operations, including customer growth of $2,768,000.

10. The appropriate net income for return under the rates approved and after all accounting and *pro forma* adjustments is $315,354,000 for retail operations, including customer growth of $3,277,000.

11. A year-end original cost rate base of $3,174,083,000 for retail operations consisting of the components set forth in Table B of this Order shall be adopted.

12. The capital structure utilized by the Commission in this proceeding for the determination of the fair overall rate of return is the capital structure of South Carolina Electric & Gas, updated to September 30, 2002, and adjusted to include $150,000,000 in

equity securities issued on October 16, 2002. This consists of 43.41% long-term debt, 4.41% preferred stock, and 52.18% common equity.

13. The embedded cost rate for long-term debt of 7.23% and the embedded cost rate for preferred stock of 6.81% as of September 30, 2002 have been used in the determination of the fair overall rate of return approved herein.

14. The fair rate of return on common equity which SCE&G should be allowed the reasonable opportunity to earn is 12.45%, which is the rate of return adopted by the Commission for this proceeding. The capital structure and cost of capital which the Commission has approved herein produce an overall rate of return of 9.94% for SCE&G retail electric operations as depicted in the following table:

TABLE A

COMPONENT OF CAPITAL STRUCTURE	RATIO %	EMBEDDED COST/RATE %	OVERALL COST/RATE %
Long Term Debt	43.41	7.23	3.14
Preferred Stock	4.41	6.81	.30
Common Equity	52.18	12.45	6.50
	100.00		9.94

15. The rate designs and rate schedules approved by the Commission and the modifications thereto as described herein are appropriate and should be adopted.

16. The proposed changes in the Company's General Terms and Conditions for service, including proposed reconnection charges, are unreasonable, and as discussed hereinafter, should be denied at this time.

17. By its Order No. 1999-655 in Docket No. 1999-389-E, the Commission has allowed the Company to accelerate depreciation of its Cope Generating Station, at its

discretion, when revenue or expense levels warrant. This mechanism will expire on December 31, 2002, unless extended by the Commission. The Company has requested such an extension until December 31, 2005. The Commission finds that the justifications for its decision in Order No. 1999-655 are still reasonable and prudent and such extension should be allowed.

III.

EVIDENCE AND CONCLUSIONS

The evidence and conclusions supporting the findings of the Commission in this matter are as follows:

A. EVIDENCE AND CONCLUSIONS CONCERNING THE COMPANY'S BUSINESS AND LEGAL STATUS

(FINDING OF FACT NO. 1)

The evidence supporting the finding concerning the Company's business and legal status is contained in the Company's Application and in prior Commission Orders and docket files of which the Commission takes judicial notice. This finding of fact is essentially informational, procedural, and jurisdictional in nature, and the matters it involves are uncontested.

B. EVIDENCE AND CONCLUSIONS CONCERNING THE TEST PERIOD (FINDING OF FACT NO. 2)

The evidence for this finding concerning the test period is contained in the Application of the Company and the testimony and exhibits of Company witness Carlette L. Walker (Tr., Vol. II, Walker, at.361) and Staff witness Thomas L. Ellison (Tr., Vol. V, Ellison, at 1455). A fundamental principle of the ratemaking process is the establishment of a test-year period. Reliance upon the test year concept, however, is not designed to preclude the recognition and use of other historical data which may precede or post date the selected twelve month period where it is appropriate to do so.

Integral to the use of a test year is the necessity to make normalizing adjustments to the historic test-year figures. Only those adjustments which have reasonable and definite characteristics and which tend to influence reflected operating expenses are made in order to give proper consideration to revenues, expenses, and investments. *Parker v. South Carolina Public Service Commission*, 280 S.C. 310, 313 S.E.2d 290 (1984). Adjustments may be allowed for items occurring in the historic test year but which will not recur in the future, or to give effect to items of an extraordinary nature by either normalizing or annualizing such items to reflect more accurately their annual impact, or to give effect to any other item which should have been included or excluded during the historic test year. The Commission finds the twelve months ending March 31, 2002, to be the reasonable period on which to make its ratemaking determinations.

C. EVIDENCE AND CONCLUSIONS CONCERNING REVENUES, EXPENSES AND INCOME

(FINDINGS OF FACT NOS. 3-10)

1. DEPRECIATION

We deny the new depreciation rates proposed by SCE&G, which were based on a new depreciation study submitted by SCE&G. Company witness Walker, who sponsored the new depreciation study, was not familiar with the details of the study, and could not answer relevant questions related to the study's preparation, portions of the study related to plant investment, account retirement patterns, or other methodologies contained therein. *See* Tr., Vol. II, Walker, at 430-432. Indeed, the witness stated specifically that she was not familiar with the specifics and details of the study, which was why the Company had hired a consultant. Id. at 431. The Company did proffer the consultant's testimony. However, this does not constitute evidence in this case. Accordingly, although we decline to strike the study from the evidence of this case, we will not give it any weight, and we therefore deny the new depreciation rates proposed by the Company. We will consider such matters as this on a case-by-case basis in future proceedings.

2. CHARLESTON AND COLUMBIA FRANCHISE AGREEMENTS

(a) FACTS

In 1996 and 2002, the Company successfully negotiated 30-year franchises for the provision of electric and gas services within the cities of Charleston and Columbia, respectively. By the testimony of Mr. Lorick (Tr., Vol. I, Lorick at 40-44; Vol. V at

1655) and Dr. Wright (Tr., Vol. IV, Wright, at 993-97; Vol. V, at 1720), the Company established the essential nature of these two service areas to its system and to all of its customers. The population of these two municipalities accounts for approximately 17% of the system's customer base. (Tr., Vol. I, Lorick, at 43). Charleston and Columbia are the two largest and most densely populated cities in SCE&G's service area and, also, represent areas of growth in the service area. (*Id.*). As these witnesses testified, it is self-evident that the loss of significant service rights in either of these municipalities would have a devastating effect on the system. (*Id.*). Both of these franchises were sufficiently at risk to justify the negotiation of the new agreements. (Tr., Vol. I, Lorick, at 43-45; Vol. IV, Wright, at 994-5).

As to the City of Charleston, SCE&G, or its predecessors, have provided utility services for over one hundred years. The existing franchise with that city had expired, necessitating the negotiation of a new agreement. After several extensions of the old agreement, the new, thirty-year agreement was entered into in 1996. (Tr., Vol. I, Lorick, at 44).

As to the City of Columbia, the Company, and its predecessors, have provided utility services for decades as reflected in the opinion of the South Carolina Supreme Court in *State ex rel. Daniel, Attorney General v. Broad River Power Co.,* 157 S.C. 1, 153 S.E. 537 (1929). (*Id.* at 41). In recent years, the relationship between the City and the Company had deteriorated to the extent that the City was seriously considering municipalization of the electric system and retained a consultant for this purpose. (*Id.* at 44).

Integral components of the franchise relationships in both cities were the public transit systems owned and operated by the Company. (*Id.* at 41). As a part of the new agreements, the Company was able to cease public transit operations and divest itself of these utility functions. (*Id.* at 45). In Docket Nos. 96-281-E and 2002-145-E, respectively, the Commission approved the conveyance of the Company's transit and other assets to the cities of Charleston and Columbia and the cessation of transit operations in those cities by the Company.

Since these transit transfers were integral to the Company's obtaining the thirty-year franchise agreements and attendant franchise rights, the Company took the position in its application that the costs of such franchises should be borne by the Company's electric ratepayers. Historically, however, the operating losses resulting from the transit systems have been absorbed by the Company's shareholders. (*Id.* at 90). The protracted efforts of the Company to address transit rates, routes, and earnings (or lack thereof) were referenced by Dr. Ruoff, and the Commission has taken judicial notice of those proceedings. (*Id.* at 107-108). These proceedings need not be addressed in more detail here. Suffice it to say that the issue between the Company, on the one hand, and Intervenors addressing this issue, on the other, is the appropriate determination of the costs of these franchises to the Company. Since the hearing in this matter, Dr. Ruoff and the Consumer Advocate have negotiated with the Company a compromise proposal for the Commission's consideration, in which there is a sharing of the franchise costs in a way that recognizes the benefits of the franchises to the customers system-wide, while, at the same time, acknowledges the historic treatment of transit operating losses. The specifics of the proposal are set forth hereinafter. The testimony of Company witnesses Mr. Lorick and Dr. Wright amply support the findings of the Commission on this issue. (Tr., Vol. V, Wright, at 1735-37).

(b) CHARLESTON AND COLUMBIA FRANCHISES STIPULATION

The Commission has always encouraged the discussion and possible settlement of issues among parties, subject to the Commission's review and approval of such settlements as comporting with sound regulatory principles and being reasonable and prudent in their terms. Following the hearing in the matter, discussions were held by and among counsel for the Company, counsel for the Consumer Advocate and Dr. Ruoff. It was Dr. Ruoff who addressed in detail in these proceedings the issue of recovery of costs related to the Company's thirty-year franchise agreements with Charleston and Columbia. As a result of these discussions, a Stipulation was entered into by and among these parties as a recommendation to the Commission. The relevant language is as follows:

> The Company's proposed rate increase in Docket No. 2002-223-E reflected the inclusion of $45.2 million in rate base and $1.9 million in amortization expense related to 30-year electric franchises in the cities of Columbia and Charleston. The total retail revenue requirement associated with the franchises, which provides both a return of and a return on the amount in rate base, is approximately $8.0 million annually.
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> The parties agree that the Company should be allowed to amortize the franchises at the rate of $4.0 million annually while foregoing a return on the unamortized balance. In this manner, the retail revenue requirement is reduced by approximately $4.0 million. The amortization will be applied proportionately to the remaining balance of each franchise and shall remain in effect until all amounts related to the franchises have been written off. The amount of the franchise for the City of Columbia will

> include cash payments that will be made to the City through 2009 under the terms of the Conveyance Agreement, amounts necessary to match Federal grants for new buses, the net book value of various assets transferred to the City and costs to be incurred in the future for improvements and modifications to the Columbia Canal Hydroelectric Project required by the Federal Energy Regulatory Commission pursuant to the renewal of the project's operating license. The amount of (the) franchise for the City of Charleston will be as currently reflected on the Company's books and records.
>
> As approved in Docket Nos. 96-281-E and 2002-145-E, the Company has accounted for the costs of the franchises in Electric Plant in Service, Account 302 - Franchises and Consents. In light of the proposed cost recovery treatment, it is more appropriate that the balances be transferred to Account 182.3 - Other Regulatory Assets. The parties agree that the Commission should allow the Company to account for the balances related to the Columbia and Charleston franchises in Account 182.3.

The Commission finds the stipulated proposal to be a reasonable, fair, and equitable treatment of the costs associated with the Charleston and Columbia franchise agreements. Accordingly, the stipulation is hereby approved.

3. GRIDSOUTH RTO COSTS

The testimony of Company witnesses Mr. Lorick and Dr. Wright recount a history of the actions of FERC as it pertains to the creation and ultimate suspension/termination of GridSouth Regional Transmission Organization ("RTO"). (Tr., Vol. I, Lorick, at 46-50; Vol. V, Wright, at 1707-15). For purposes of this Order, the relevant facts are briefly summarized as follows.

On December 20, 1999, FERC issued its Order No. 2000 which required utilities regulated by that agency to file a plan to join or form an RTO that would be operational by December 15, 2001, or provide an explanation as to why this could not be accomplished. (Tr., Vol. I, Lorick, at 46; Vol. V, Wright, at 1707). FERC clearly signaled that companies not joining an RTO would be subject to substantial penalties, including possible loss of their ability to sell power at market rates in the wholesale markets. (Tr., Vol. V, Wright, at 1707-08). At the time of its Order 2000, FERC's approach to RTO's allowed for variation in their structure and function to meet local concerns and interests. (*Id.* at 1708). As a result of that order, a number of utilities undertook complying efforts, among them, SCE&G, Duke Power, and Carolina Power & Light Company (CP&L), who joined efforts to form GridSouth RTO. (Tr., Vol. I, Lorick, at 47). Their objective, in addition to FERC compliance, was to develop an RTO focused on the customer and system needs of the Carolinas. (*Id.*). The companies made their GridSouth filing with FERC on October 16, 2000, and FERC gave conditional approval for the RTO in March, 2001. *Carolina Power & Light Co.,* 94 FERC ¶ 61,273 (March 14, 2001 Order). (Id. at 48; Vol. V, Wright, at 1709). In this order, FERC provisionally approved GridSouth as a for-profit RTO, operating in North and South Carolina, which could eventually own its transmission assets. FERC also provisionally approved organizational documents under which the participating utilities would manage the formation of GridSouth. The "provisional approval" indicated the fact that FERC was requiring that the original GridSouth documents be refiled with limited changes to reflect matters decided in the March 14, 2001 Order. (Tr., Vol. V, Wright, at 1709-11).

During the summer of 2001, a leadership change at FERC resulted in a dramatic change in that agency's RTO regulatory objectives. *See e.g. Regional Transmission Organizations, Order Initiating Mediation*, FERC ¶ 61,066 (2001), *n.b.* the concurring opinion of Commissioner Massey. As a consequence of this change in policy, the formation of GridSouth was no longer consistent with FERC regional transmission objectives, and, on June 18, 2002, the three participating utilities suspended this project. (Tr., Vol. I, Lorick, at 48-9; Vol. V, Wright, at 1711-15). However, the utilities' action could also be interpreted as a termination. It is unclear at this juncture. Although FERC issued an Order provisionally accepting the formation of the RTO as a "good first step," there remained the question of the independence of the RTO from its founders, SCE&G, Duke Energy, and Carolina Power & Light. Pursuant to various notices from FERC, GridSouth represented that it would limit its spending prior to the seating of an independent board for the RTO, which never took place.

In the present docket, the Company claims to have spent in excess of $13 million in activities associated with its share of the formation of the RTO. SCE&G is proposing to amortize the $13 million over 5 years. The annual retail revenue requirement impact under the Company's proposal is $3.35 million. See Tr., Vol. IV, Watkins, at 1058. We reject the Company's proposal.

First, most of the costs were incurred before the test year. Second, booked assets of GridSouth amounted to some $73.9 million as of July 31, 2002. Unfortunately, not much detail was provided by the Company as to the nature of its investment in the project. In fact, we believe that the Company has not met its burden for cost recovery at this time. See Tr., *Id.* at 1060; Tr., Vol. II, Coates, at 334. The Commission Staff agreed with this position in its Brief. See Post-Hearing Brief of the Commission Staff at 10. Further, the Staff testified that, since GridSouth was not operational during the test year, it should not have been considered used and useful during that time, although it might have been considered property held for future use. See Tr., Vol. V, Ellison, at 1490.

It should also be noted that FERC has made no determination as to how it will treat GridSouth expenditures at the wholesale level. Further, the costs involved were imposed as the result of FERC mandates. Accordingly, we agree with the position of the Staff in its Brief, which argues that it is premature to allow recovery of GridSouth costs at the retail level at this time. See Post-Hearing Brief of the Commission Staff at 10.

Finally, we agree with Staff that the door should remain open on this issue, and that allowance of GridSouth costs should be deferred until such time as the Company can meet its burden of proof, and/or until FERC rules on the allowance of the expenditures at the wholesale level. Id. at 10-11. It is understood that FERC could not consider the allowance of GridSouth expenditures at the wholesale level until this Commission has approved the transfer of functional control of transmission assets. At present, however, we reject the Company's proposal on GridSouth costs, for the reasons enumerated above.

4. BUY/RESELL TRANSACTIONS

The Company and Staff have proposed a *pro forma* adjustment to reduce test-year retail electric revenue and expenses to eliminate amounts related to certain wholesale power transactions. The transactions in question involved power traders working as agents for the Company who purchased power generated by third parties and then resold that power to third parties ("Buy/Resell Transactions"). (Tr., Vol. II, Walker, at 366). By Order effective October 1, 2001, the Commission had approved booking these revenues and expenses to non-regulated accounts. *See* Order No. 2002-74. The adjustment proposed by the Company and Staff here concerns amounts that were booked to regulated accounts before the effective date of that order. (*Id.*). No party to the proceeding has objected to this *pro forma* adjustment as such, and it is granted for the reason set forth in the testimony of Mrs. Walker. (Tr., Vol. II, Walker, at 366).

Instead, the Consumer Advocate's witness, Mr. Watkins, proposed that the Commission should allocate the net margins generated by these Buy/Resell Transactions 75% to ratepayers and 25% to the Company's unregulated accounts. He asserts that this is comparable to the treatment of certain transactions involving Piedmont Natural Gas Company authorized in Docket No. 2002-63-G.

The Commission, however, reaffirms its finding in Order No. 2002-74 and holds that Buy/Resell Transactions are indeed activities that are properly booked to unregulated accounts. The Commission finds that these transactions do not involve power generated by the Company's regulated utility plants. (Tr., Vol. II, Walker, at 391, 418). Accordingly, the revenues and expenses related to these transactions are not properly considered part of the Company's regulated activities or part of its provision of service to retail electric customers in South Carolina.

The Consumer Advocate's witness, Mr. Watkins, asserts that administrative costs related to these sales have been improperly billed to regulated accounts. (Tr., Vol. IV, Watkins, at 1082). His testimony is not based on a review of the actual accounts to which the costs were or were not billed but is based on a supposition based on his review of certain accounting orders. (*Id.* at 1055). In fact, Mrs. Walker, the Assistant Controller for SCE&G, testified that no such costs had been billed to regulated accounts. (Tr., Vol.

II, Walker, at 420). The Commission does not find credible evidence in the record to support the assertion that administrative or other costs related to these transactions have been improperly left booked in regulated accounts.

Mr. Watkins further asserts that recent precedent involving Piedmont Natural Gas Company requires that revenues and costs related to the Buy/Resell Transactions be "shared" between regulated and unregulated accounts. *See generally*, *In re Application of Piedmont Natural Gas Company*, Order No. 2002-671, November 1, 2002, at p. 77. The Commission, however, does not find the situation with Piedmont Natural Gas in Docket No. 2002-63-G to be analogous to the situation here.

Integrated electric utilities like SCE&G build and operate electric generating plants that serve most of their customers' needs. When they make opportunity sales from the output of those plants, this Commission typically has required 100% of the costs and revenues from those transactions to be booked to regulated operations.

Gas utilities, like Piedmont, do not produce their own gas, but instead purchase gas supply and gas transportation capacity on upstream pipelines. These "upstream assets" are purchased and held primarily to serve the utility's regulated customers. The cost of buying and holding these assets are paid by those customers. At times natural gas utilities like Piedmont may be able to resell some unused portion of these upstream assets in the open market. These sales are typically made on a limited term or recallable ("capacity release") basis with the underlying contracts remaining dedicated to serving retail customers.

The Commission is aware from its long history of regulating Piedmont that the sale of upstream assets involved in Docket No. 2002-63-G were sales such as described above. Because the assets underlying such sales were held to serve retail customers, a sharing of the risks and rewards related to their remarketing was appropriate.

The Buy/Resell Transactions at issue here are not analogous to the assets involved in Docket No. 2002-63-G. They are not part of a long-term portfolio of supply assets for which SCE&G's regulated customers bear the cost nor do they involve regulated generating assets in any way. (Tr., Vol. II, Walker, at. 391, 418). These are not transactions that are properly considered part of the Company's regulated activities or part of its provision of service to retail electric customers in South Carolina. Accordingly, the Commission finds that the costs and revenues related to these transactions are properly booked to unregulated accounts.

5. EMPLOYEE CLUBS

Through a *pro forma* adjustment, SCE&G has deducted from test year expenses and investment amounts related to its employee clubs.[1] (*Id.* at 367). It has done so by *pro forma* adjustments that have (a) removed operating and maintenance costs related to these clubs from retail electric O&M expenses and (b) removed the capital investments related to these clubs from retail electric plant in service accounts.

The Consumer Advocate's witness, Mr. Watkins, notes that in removing these costs the Company deducted 89.94% of the capital cost of the clubs from retail electric

[1] The Company has also agreed with the Staff that certain investment in Construction Work in Progress related to the clubs is properly removed from rates. That adjustment is one of the uncontested Staff adjustments referenced at the conclusion of this section of the order.

plant accounts and deducted 55.11% of the O&M expenses related to the clubs from retail electric operating and maintenance expense. (Tr., Vol. IV, Watkins, at 1057). Having noted this disparity, he proposes to apply the 89.94% allocation factor to both capital investment and O&M expenses. (*Id.*).

The Commission finds that in making adjustments to remove nonallowables, it is proper to remove the amounts initially allocated to regulated accounts, nothing more or less. Mr. Watkins provides no information to indicate that 89.94% of the O&M expenses related to employee clubs were initially allocated to retail electric expense, rather than the 55.11% that Mrs. Walker proposed to remove.

In this regard, the Commission does not find the fact of the disparity in allocation factors (89.94% vs. 55.11%) to be at all unusual. With a utility like SCE&G, it is not unusual that capital related items would be allocated at a proportionally greater rate to electric operations than would labor-related items, like employee benefits. The disparity in allocation reflects the fact that the capital investments for an electric and gas utility like SCE&G is disproportionately weighted to the electric side of the business where high-value generation investments, like the V. C. Summer Nuclear Station, are held. Employee headcounts, however, are typically more evenly divided between electric and non-electric activities. These facts would explain the difference in allocations.

The Commission notes that the Staff has audited the *pro forma* adjustments proposed by the Company and made revisions where required. (Tr., Vol. V, Ellison, at 1463). No revisions were proposed with relation to these allocations. For all these reasons, the Commission finds no credible basis in the record to deduct 89.94% of gross expenses related to employee clubs from allowable retail electric expenses, rather than the 55.11% that the Company proposed.

6. AT-RISK COMPENSATION PAY

The pay package SCE&G offers its employees includes both base pay and at-risk compensation. (Tr., Vol. II, Walker, at 368-69). As structured today, SCE&G's incentive pay program is based 50% on the achievement of company-wide financial goals and 50% on the achievement of annual business objectives. These business objectives concern such things as efficiency, quality of service, customer satisfaction, and progress towards strategic objectives. (Tr., Vol. V, Marsh, at 1682). Under this structure, incentive payouts vary from year to year depending on success in achieving these goals. The issue concerning incentive pay arises in this proceeding because there was no payout related to at-risk compensation during the test year. The record shows that at-risk compensation plans were in force during the entire test year. (Tr., Vol. II, Walker, at 368-69). But these plans contained minimum financial targets which SCANA was required to meet for there to be any payout. SCANA did not meet those minimum financial targets for 2001, and as a result, there was no pay out of at-risk compensation during the test year. (Tr., Vol. II, Walker, at 369).[2]

In its Application, the Company proposed a *pro forma* adjustment to include an amount equal to 50% of the target 2002 incentive pay in retail electric expenses. The

[2] Because the decision not to pay incentives for 2001 was made during the test year, the Company reversed the accrual of the incentive by booking a credit equal to the entire amount of 2001 calendar year accruals. (Tr., Vol. II, Walker, at 369). The reversals made during the test year included January, February and March, 2001, which are periods prior to the test year. Both the Company and the Staff proposed to remove the reversals associated with those periods prior to the test year. The Commission finds that this adjustment is clearly appropriate as a means of returning test year incentive expenses to zero, and we approve the Staff's adjustment. (*See* Tr., Vol. V, Ellison, at 1466).

50% amount reflects the potential payout for 2002 that is not tied to Company financial performance. Instead, as the plan is now configured, 50% may be paid out based solely on the achievement of non-financial goals, and meeting financial goals is not a condition of the pay out. The record also shows that the Company, in fact, is accruing funds to pay incentive compensation for calendar year 2002 and "anticipates achieving these [incentive] goals and paying out 50% of the at-risk compensation." (*Id*).

The Commission Staff based a proposed disallowance of this adjustment on the fact that no incentive compensation was paid during the test year. (Tr., Vol. V, Ellison at 1465). The fact that no payout was made during the test year demonstrates that such expense is possibly non-recurring in future years. We disallow the Company's adjustment for at-risk compensation pay accordingly.

7. ADJUSTMENT FOR ANNUALIZING DEPRECIATION EXPENSE AND ACCUMULATED DEPRECIATION

As indicated above, it commonly occurs that the Commission must make *pro forma* adjustments to depreciation expenses in the process of setting rates. It has been the Commission's practice when making *pro forma* adjustments in depreciation expense also to make an adjustment to the level of accumulated depreciation on the Company's books. The past practice of the Commission has been to take 100% of the amount of the annualized *pro forma* adjustment to depreciation expense as a credit to depreciation reserves. This credit to depreciation reserves reduces the Company's rate base and lowers the amount of net plant on which the Company earns a return.

In her testimony, the Company's witness Mrs. Walker disagreed with this increase in depreciation reserves. (Tr., Vol. II, Walker, at 391-92). In the opinion of Mrs. Walker, this practice artificially increases the amount of depreciation reserves, thereby overstating the amount of depreciation the Company has actually recovered.

The booking of depreciation expense is the means by which utilities are allowed to recover the value of their investment in utility assets. As depreciation expenses are recovered, they are booked to depreciation reserves and reduce rate base by the amount of the original investment that has been recovered through rates.

In this case, the Commission accepts the Staff's adjustment of $296,000 to annualize depreciation expense on a retail basis. The offsetting adjustment to the depreciation reserve of $294,000 on a retail basis as proposed by Staff is also approved. The Commission agrees with the Staff that the proper accounting entry to record depreciation expense is to debit the expense account and credit the reserve account in the same amount. The Commission finds that a full rate base offset is proper since that represents the amount being recovered above the line in cost of service in this case.

8. URQUHART REPOWERING PROJECT

SCE&G completed the project to re-power two of its three Urquhart Station generating units in June of 2002 after the close of the test year. (*Id.* at 373). The Company's accounting witness, Mrs. Walker proposed several *pro forma* adjustments necessary to reflect this known and measurable out of period event. (*Id.* at 373-75).

(a) MISCELLANEOUS URQUHART PROJECT *PRO FORMA* ADJUSTMENTS

Concerning the Urquhart plant adjustments, there has been no opposition to the Company's proposed adjustments related to (a) plant in service and CWIP accounts, (b) depreciation and property tax expenses, and (c) maintenance related O&M expenses. (*Id.* at 373-74). However, the Commission Staff's witness, Mr. Ellison, has proposed certain revisions in the amounts of these *pro forma* adjustments, which the Company has not opposed. (Tr. Vol. V, Ellison, at 1471-72). The Commission finds that the completion of the Urquhart Station Repowering Project is a known and measurable event and that the above mentioned *pro forma* adjustments are appropriate to reflect this event in rates for the reasons stated in the testimony of Mrs. Walker and Mr. Ellison. The Commission further accepts Mr. Ellison's proposed changes in those adjustments as appropriate for the reasons stated in his testimony. (*Id.*).

(b) ADJUSTMENT TO INCLUDE FIXED PIPELINE CAPACITY CHARGES IN BASE RATES

As a result of the recent Urquhart Re-Powering Project, the two re-powered units now are fueled by natural gas. To provide gas supply to those units, SCE&G has entered into long-term, fixed-charge contracts with its interstate and intrastate suppliers for the right to have gas delivered to the plant. (Tr., Vol. II, Walker, at 375). As the evidence indicates, these fixed capacity related charges do not vary according to the consumption of natural gas by the plant. (*Id.*)

The Company proposes an adjustment to include in base rates, rather than in fuel costs, the fixed capacity charges that SCE&G must pay for upstream natural gas transportation capacity to serve Plant Urquhart. Based on the fixed nature of these obligations, the Commission finds that it is appropriate that these charges be included in base rates. Doing so, the Commission finds, will help to properly segregate the fixed charges of the plant from the variable charges that are related to the intensity of its use. (Tr. Vol. II, Walker, at 375). Doing so should also lead to greater stability in annual fuel factors computed under *S.C. Code Ann.* §58-27-865 (Supp. 2002) and will allow the Company to better match the true variable cost of operating the plant with system economics and opportunities for market sales.

The fixed capacity related charges in question total $8,510,386 per year. (Tr. Vol. II, Walker, at 374). The Commission orders that this amount be reflected in electric operating expenses for rate making purposes and that the retail portion of this amount ($8,081,000) shall be deducted from the fuel cost recovery under *S.C. Code Ann.* §58-27-865. As the actual retail-related capacity charges vary from year to year and are added to the fuel cost calculation, they will be netted against the fixed deduction, such that variations, positive or negative, will be reflected in the fuel costs calculated under *S.C. Code Ann.* §58-27-865.

To account for this change in the method of recovery of these costs, the Company is further ordered to reduce the fuel cost recovery factor established in Order No. 2002-347 by $0.00044/kwh. This reduction shall take effect on the effective date of the rates approved herein. The amount of the reduction reflects the per kilowatt hour effect of deducting $8,081,000 in expenses from the fuel cost approved in Order No. 2002-347.

9. JASPER PROJECT CWIP

SCE&G is currently constructing a new 875-MW natural gas fired generating plant in Jasper County South Carolina. (Tr., Vol. I, Lorick, at 39). Construction has been underway since the Spring of 2002, pursuant to Order No. 2002-19, issued by this Commission in Docket 2001-420-E, approving the siting of the plant. (*Id.*).

Construction of the Jasper plant is proceeding under a fixed-price, turn-key contract between SCE&G and Duke/Fluor Daniel. (Tr., Vol. II, Walker, at 271-72). This contract contains schedule and performance guarantees, and fixed, milestone-based payment schedules, that are fully comparable to the contracts under which Duke/Fluor Daniel recently built the Cope Generating Station for SCE&G. (*Id*; Vol. V, Marsh, at 1673-74).

(a) THE COMPANY'S PROPOSED TREATMENT OF CWIP

The Company has asked the Commission to allow it to include in rates the Construction Work in Progress (CWIP) related to the Jasper Project through December 31, 2002. At that time, payments under the Duke/Fluor Daniel contract, and related carrying costs and internal Company costs, will have increased the total Jasper Project CWIP from the $148,142,435 on the books as of June 30, 2002, to $276,224,951. (Tr., Vol. II, Walker, at 376). The Company proposes that the Staff will audit the CWIP balances after that date and that new rates will not go into effect until Staff determines that the full $276,224,951 has been properly expended on the project. (Tr., Vol. V, Marsh, at 1674).

The Commission agrees that the amount of $276,224,951 of Jasper Project CWIP should be included in rates in this proceeding, subject to audit by the Commission Staff as set forth above. This decision is in keeping with the Commission's decisions concerning CWIP related to the Cope Generating Station, as reflected in orders in Docket Nos. 92-619-E and 95-1000-E. Specifically, in Order No. 93-465, issued in Docket No. 92-619-E, the Commission discussed the benefits of such an approach to CWIP in great detail.[3] The reasons given there still have force, and the Commission reaffirms the findings of that order. (*See* Tr., Vol. V, Marsh, at 1675-76).

(b) BENEFITS OF THE COMPANY'S CWIP PROPOSAL

The Commission finds that allowing this additional CWIP into rates will stop the accrual of carrying costs on the full $276,224,951 of investment at issue. (Tr., Vol. V, Ellison, at 1473). These carrying costs, which accrue as Allowance for Funds Used During Construction (AFUDC), would otherwise be capitalized as additional costs of the facility. These costs would then become part of the Company's rate base and revenue requirements until fully depreciated over the life of the project.

Allowing this CWIP to be reflected in rates now will reduce the ultimate cost of the plant by the full amount of the carrying costs at issue. This reduction in the cost of

[3] The assertion by the Consumer Advocate's witness, Mr. Watkins, that established precedent required the CWIP to be cut off by September 30, 2002 is not correct. (Tr., Vol. IV, Watkins, at 1057). The orders sited indicate that the level of expenditures included in rates were levels reached only after the hearing in the case and within a matter of weeks of the effective dates of the rates in question. Order No. 93-465 at 43; Order No. 96-15 at 11.

the plant will reduce the amount of revenue that the Company will need to recover to support its investment in the plant. Accordingly, customers will benefit by lower rates during the full useful life of the plant.

In addition, the Commission finds that allowing $276,224,951 of Jasper Project CWIP to be placed into rates in this proceeding does several other important things:

First, allowing this investment into rates now will improve the quality of the Company's earnings at a time when earnings quality is very important to the financial health of utility companies. AFUDC represents non-cash "paper" earnings. Analysts historically have not favored such paper earnings in their analysis of the financial health of regulated utilities. In today's markets, the Commission believes that investors will be particularly sensitive to the quality of a company's earnings and allowing this additional CWIP into rates will improve the quality of SCE&G's earnings.

Second, allowing this CWIP into rates at this time will spread the rate impact of revenue requirement related to the new plant more evenly over the plant's construction period. The Commission finds that the alternative would be to defer the CWIP and the related carrying costs for inclusion in rates in future proceedings. This deferral, the Commission finds, would result in higher future rate increases and less opportunity for customers to adjust to additional costs of supplying their growing demands.

Third, allowing this investment into rates now sends a constructive message to investors concerning the eventual inclusion of the project into rates. The Commission finds that sending such a signal will assist the Company in maintaining access to capital on reasonable terms during a period when the Company will be raising substantial capital in national markets. The Commission finds that allowing the Company to access reasonably priced capital during this time will reduce the cost of serving customers over the entire period that the new bonds and shares are outstanding.

The Commission specifically finds that because of the nature of the contracts under which the plant is being constructed, and because of the Staff audit of actual expenditures the Commission is requiring as staff witness Ellison testified, the amounts of CWIP to be included in rates under this Order are fully known and measurable for ratemaking purposes. (*Id.*).

Accordingly, the Commission rules that $276,224,951 of Jasper Project CWIP should be included in rates in this proceeding, subject to Staff audit.

(c) THE SCEUC ARGUMENTS

The witness for the SCEUC, Mr. Phillips, argued in his testimony that the additional CWIP related to Jasper should not be included in rates in this proceeding for reasons related to (a) the nature of the plant as a combined-cycle gas plant, (b) the present economic conditions of the nation, (c) the size of the plant, and (d) his assertion that the plant is not used and useful at present. We address each of these arguments in turn.

<u>The Nature of the Plant</u> – Mr. Phillips notes that combined cycle natural gas generation plants have relatively low capital costs. (Tr., Vol. IV, Phillips, at 1227). However, the record shows that the Jasper Plant will in fact cost more in nominal dollars

than did the Cope Plant for which this treatment for CWIP was initially granted.[4] The Commission finds that the relative capital costs are not a basis for treating the Jasper CWIP differently from CWIP related to other plants.

In addition, Mr. Phillips notes the relatively short construction cycle of the Jasper Plant as a reason to treat its CWIP differently from other plants. The record shows that, the Jasper Plant will have a 38 month planning and construction cycle. (Tr., Vol. V, Lorick, at 1644). While this time period is shorter than that of a coal-fired generating station, the Commission determines that it is still a significant period of time over which to accrue carrying costs on project expenditures.

The Commission finds that given this 38 month construction cycle, there are substantial benefits to the CWIP treatment requested here. In fact, the Company's CFO calculated that the effect of not adding any of the Jasper CWIP to rates would be to increase the ultimate cost of the plant by $64 million and increase by $9 million the annual revenue requirement of the plant that would be charged to customers. (Tr., Vol. V, Marsh, at 1701). The Commission finds this testimony to be credible and probative of the benefits of the CWIP treatment the Company is proposing.

<u>Present Financial Conditions</u> – Mr. Phillips points to difficult financial conditions as a reason not to allow the proposed treatment of CWIP. (Tr., Vol. IV, Phillips, at 1227). However, these conditions must be viewed in light of the long-term interest of all parties. The Commission believes that it is of great importance, in light of the adverse conditions in financial markets today, that the Company preserve its access to capital on

[4] <u>Compare</u> Tr., Vol. I, Lorick, at 39 (total Jasper Plant cost is $478 million) with Order No. 95-15 at p. 10 (total Cope Plant cost was $436 million).

reasonable terms. Such access will allow it to maintain a reliable, efficient electric system on which all business in its service territory depends. Including the additional CWIP for Jasper in rates at this time is in the best interest of the Company and its customers for that reason.

The Size of the Jasper Plant – The final point Mr. Phillips raises is his assertion that the Jasper plant is sized larger than currently needed. However, the record shows that even with all CWIP through December 31, 2002, in rates, only 58% of the total cost of the plant will be borne by customers. (Tr., Vol. V, Lorick, at 1644). Moreover, the Commission finds that the plant was properly designed to take advantage of valuable economies of scale in its construction. The record shows that building the third Jasper unit at this time has reduced the cost of the plant by $111 million, compared to the cost of building two units presently and adding a third later. (*Id.* at 1645). Moreover, the record shows that the third unit will be needed to serve retail demand in 2006 and that the procurement of equipment for it would have had to have begun before the present construction was complete. (*Id.*). Finally, the Company has been able to sell 250 MW of system capacity to third parties based on the reserves Jasper will represent when it comes on line. (*Id.*). Customers will be credited 100% of the value of this sale. (*Id.* at 1645, 1654, 1698).

Accordingly, the Commission reaffirms its finding in the Jasper siting order that the Jasper Plant is properly sized and that customers will receive substantial benefits from the decision to build all three units at this time. Order No. 2002-19 at pp. 4-5, 14. The

Commission does not find that the size of the Jasper Plant provides a justification for not allowing the Company's requested CWIP treatment.

The Used and Useful Nature of the Plant – Mr. Phillips also suggests that the Company's investment in the Jasper Plant is not used and useful and so should not be included in rates. Under South Carolina law, property that is prudently acquired for future utility use is properly included in rate base. *See Southern Bell Tel. & Tel. Co. v. Public Service Commission*, 244 S.E.2d 278, 282 (S.C., 1978). In addition, the Commission has consistently held that CWIP related to projects prudently undertaken and managed to provide utility service is indeed used and useful and properly included in rate base. Such is the case with the Jasper Project.

The issue is well settled in South Carolina that CWIP is properly included in rate base. The only question here is whether the full amount of the known and measurable investment in the Jasper Project should be included in rates in this proceeding. The Commission finds that sound regulatory policy, existing precedent, and the evidence on the record all supports inclusion of CWIP in the amount of $276,224,951 in rates subject to Staff audit.

10. CASH WORKING CAPITAL

Part of the capital required to operate a utility or other business is the capital needed to meet the business's cash requirements. As the record shows, there are two principal methods recognized by regulatory commissions for measuring the amount of cash working capital needed to operate regulated utilities. The one-eighth method calculates cash working capital by taking one-eighth of the utility's designated Operating and Maintenance expenses. The Commission has employed the one-eighth method pursuant to a directive to regulated utilities, dated November 13, 1974. That directive sets forth both the one-eighth method as the required method of calculating working capital and sets forth the categories of O&M expenses to which it applies.

The alternative method to the one-eighth formula is the use of lead-lag studies. Lead-lag studies are studies which attempt to measure the utility's working capital needs by measuring the lead times between receipt of goods and services by the utility and payment for them, and by measuring the lag between utility's provision of service and payment of the resulting bills by the customer. (Tr. Vol. II, Walker, at 387-88). Lead-lag studies for enterprises as complex as electric utilities are time consuming and expensive. (*Id.*; Vol. V, Ellison, at 1459). In addition, such studies require many subjective decisions to be made concerning how to characterize revenues and expenses and how to correlate costs with revenues. (Tr., Vol. II, Walker, at 387-88). The result is that such studies are rarely conclusive and tend to reflect the bias of the experts who produce them.

(a) REQUEST TO ORDER A LEAD-LAG STUDY FOR THE NEXT RATE PROCEEDING

No party has objected to the use of the one-eighth formula in this proceeding. The Consumer Advocate's witness, Mr. Watkins, however, has requested that the Commission order the Company to undertake a lead-lag study for determining cash working capital in its next rate proceeding. (Tr., Vol. IV, Watkins, at 1062-63).

In 1989, the Commission reviewed the results of a lead lag study that it had ordered SCE&G to perform along with all other electric and gas utilities under its jurisdiction. In that proceeding, the Commission found that the one-eighth formula provided comparable results to a properly conducted lead lag study and that "the expense and effort to prepare such a [lead-lag] study did not justify its utilization." Order No. 89-588, p. 39.

The Commission addressed the issue again in Order No. 93-465 (p. 36-37), where it ruled as follows:

> [T]he one eighth formula is a proper means to determine cash working capital. One reason is practicality. The lead-lag study is extremely complex and expensive. A utility company, like SCE&G, generates millions of bills for services each year and pays thousands of bills from suppliers. If the Commission were to order lead-lag studies, SCE&G's customers would ultimately pay the cost of them. Moreover, the outcome of the studies is very much dependent on the assumptions used in labeling and tracking expenditures. . . .[U]tility companies are uniquely well-suited for application of a standard formula for cash-working capital purposes.

In this proceeding, the expert accounting witness for the Company, Mrs. Walker, testified that "[t]he justifications for not conducting such [lead-lag] studies are equally applicable today as they were in past cases." (Tr., Vol. II, Walker, at 388).

The record here does not contain any evidence indicating that the conclusions reached in the prior orders no longer apply. The record provides the Commission with no reliable, credible or probative evidence on which to conclude that new lead-lag studies would, in fact, produce benefits that outweigh the simplicity, clarity and efficiency gained by continuing to rely on the one-eighth formula. In this regard, the Commission finds that the citation to magazine articles concerning cash conversion analyses by the Navy's witness, Mr. Coates, does not provide a credible basis for drawing conclusions concerning matters as complex, subjective and sensitive as cash working capital requirements. (Tr., Vol. II, Coates, at 335, 342). The Commission declines to order such a study and reaffirms its ruling in Order No. 93-465.

(b) APPLICATION OF THE ONE-EIGHTH FORMULA TO *PRO FORMA* ADJUSTMENTS

In employing the one-eighth formula, the Company applied it initially to its per books statement of test year O&M expenses. Then, as it made *pro forma* adjustments to those per books expenses, the Company computed related revisions to its cash working capital requirements to reflect the impact of those *pro forma* changes on cash working capital needs. (Tr., Vol. II, Walker, at 389). This process ultimately produced a calculation of cash working capital that took into account the elimination of unallowable, non-recurring or atypical test year expenses. The calculation also took into account known and measurable changes to test year expenses. Consistent with recent Commission precedent, however, the Staff applied the formula on a per books basis and to adjustments that corrected the Company's books. Staff's calculations had the effect of keeping cash working capital on a per book basis. (Tr., Vol. V, Ellison, at 1476).

The Commission agrees with the method employed by the Staff because per book amounts represent actual expenditures for the test period. The Staff's method is more representative of the actual cash requirements of the utility during the test period.

(c) CHANGES TO THE ONE-EIGHTH FORMULA

The Witness for the Navy, Donald Coates, testified that the Commission should change the universe of O&M expenses to which the one-eighth formula should apply. He specifically suggested that the Commission exclude from the one-eighth calculation fossil fuel costs and related costs, and costs related to uncollectible accounts. (Tr., Vol. II, Coates, at 335-36).

However, for the reasons set forth in the testimony of the Company's witness, Mrs. Walker, the Commission finds that these expenses are indeed expenses to which cash working capital is required and should be part of the cash working capital calculation. (Tr., Vol. II, Walker, at 383-86). In addition, the Commission finds that the method of applying the cash working capital formula it has used in past cases, and has determined to be accurate through its resulting experience, requires inclusion of the expenses Mr. Coates would exclude in the calculation. To exclude these expenses, the Commission finds, would call into question the accuracy of the proven formula that it has historically used and uses properly in the present case.

In addition, Mr. Coates bases his proposal on the working capital calculation as applied by FERC. The Commission finds, as Mrs. Walker testified, that the FERC approach involves a number of other differences in how working capital is calculated. (Tr., Vol. II, Walker, at 454). These other differences would increase the level of working capital the Company would be allowed, where the elements Mr. Coates chose to suggest would all decrease it. The Commission concludes that it would not be proper to appropriate parts of the FERC approach without regard to the other elements that may well make the approach, in total, produce a reasonable result. (*Id.* at 454-55).

11. NUCLEAR DECOMMISSIONING COST

Neither the Consumer Advocate, Dr. Ruoff, nor any of the other witnesses presented any testimony concerning an adjustment to the Company's nuclear decommissioning costs. Accordingly, no proposed adjustment was placed before the Commission and parties for discussion, comment or rebuttal at the hearing.

However, the Consumer Advocate and Dr. Ruoff propose that the Company terminate collection from ratepayers for nuclear decommissioning expenses, taking into account inflation in costs and earnings from the investment of the decommissioning trust fund. *See* Joint Brief of the Consumer Advocate and Dr. John C. Ruoff at 4. This is based on those two parties' conclusion that the Company has already collected adequate money to fund its future decommissioning expenses, taking into account inflation in costs and earnings from the investment of the decommissioning trust fund. We reject the adjustment and the propounded reasoning, since there is no basis in the record to support this finding. Although the Consumer Advocate attempted to bolster the record with documentation on decommissioning expenses, he did not demonstrate that the Company collected adequate funds for its future decommissioning expenses.

12. ADJUSTMENT TO PENSION INCOME

As the record indicates, the return on the Company's pension plan assets in the last several years has exceeded the cost of accruing future pension benefits for employees. (Tr., Vol. II, Walker, at 370). This level of return has allowed the Company to recognize income from the plan rather than expense. (*Id.*). As a result, the Company recorded $16,292,735 in pension income for the test period. (*Id.* at. 371). However, due to recent downturns in the stock market, the Company will be able to record only $5,350,032 in pension income in calendar year 2002. (*Id.*). The Company has proposed a *pro forma* adjustment to test year expenses to reflect this decrease in pension income of $10,942,703. (*Id.* at 370).

The Navy's witness, Donald Coates, argued against this adjustment on the basis that the Company's "proposal is no better predictor of future Pension (Income) Expense than what was actually recorded in the test year." (Tr., Vol. II, Coates, at 337). The Commission, however, finds that the pension income reflected in the Company's proposed adjustment is not a "proposal" but reflects the amount that the Company is, in fact, required to book during 2002 based on Financial Accounting Standard No. 87 ("FAS 87"). (Tr., Vol. V, Marsh, at 1670-71). Under FAS 87, companies are required to book pension expense or income based on actuarial studies conducted by certified actuaries. (*Id.* at 1671). These studies measure anticipated future pension liabilities, present plan asset levels, and likely levels of future plan income. (*Id.*).

The Commission finds that the Company's proposed adjustment to pension income of $10,942,703 is based on the current actuarial study under which the Company is operating, conducted by the firm of Towers Perrin. (*Id.*). The Commission finds that this actuarial study is based on reasonable assumptions, which if in error at all, underestimate the erosion in the plan's long-term value. (*Id.* at 1671-72).

The Commission further finds that under FAS 87, pension income or expense is never based on "actual experience." Instead, pension expense is always based on the best available actuarial measurement of anticipated future expenses and anticipated future assets. Accordingly, the most accurate measure of pension income or expense is the most current, validly-conducted actuarial study. The Commission therefore reaffirms its ruling in Order No. 93-465 that "the test year pension expense should be based on the latest actuarial study. . . . [T]his annualization is appropriate and is also consistent with the treatment of pension expense by other regulatory commissions." Order No. 93-465 at 14.

Based on this ruling, the Commission finds that the adjustment to pension income proposed by the Company is proper.

13. RATE BASE TREATMENT OF STORM DAMAGE RESERVE FUNDS

In Order No. 96-15 at pp. 61-66, the Commission authorized the Company to establish a storm damage reserve as an alternative to acquiring insurance for distribution and transmission facilities not otherwise covered under standard casualty insurance policies. The storm damage reserve was authorized as an alternative to the expensive, inadequate or risky insurance coverage available against such losses on the market. Order No. 96-15 at 61-62. In this proceeding, no party has challenged the propriety of the storm damage reserve itself. The accounting witness for the Consumer Advocate, however, has proposed a change in the way that the storm damage funds are accounted for on the books of the Company. (Tr., Vol. IV, Watkins, at 1064).

It is long-standing policy that the Company's shareholders should not earn a return on capital they have not supplied. Accordingly, the Commission generally requires the Company to deduct from rate base any customer-supplied funds it may hold, including customer deposits, contributions in aid of construction, customer pre-payments and the like. In many cases, customer-supplied funds are subject to State and Federal income tax. Accordingly, the Commission has required the funds held net of the related tax payments to be deducted from rate base to reflect the actual amount of customer-supplied funds held by the Company.

Under the State and Federal tax laws, funds collected from customers for the storm damage reserve are taxable income to the Company when received. As it requires with other customer-provided funds, the Commission requires the Company to credit against rate base the net amount of the storm damage funds collected after taxes. (Tr., Vol. 2, Walker, at 393).

The Consumer Advocate's witness, Mr. Watkins, proposes that the Company credit the pre-tax amount of the storm damage funds collected from customers against rate base. (Tr., Vol. IV, Watkins, at 1064). Mr. Watkins does not dispute that the funds collected are in fact subject to tax, nor does he dispute the amount of funds actually available for credit against rate base is $16.8 million (gross collections of $27.2 million net of taxes of $10.4 million). (Tr., Vol. II, Walker, at 393). However, Mr. Watkins asks the Commission to order the Company to credit the full amount of $27.2 million against rate base. (Tr., Vol. IV, Watkins, at 1064-65).

For the reasons set forth in the testimony of the Company's witness, Mrs. Walker, the Commission finds that this proposal violates the fundamental principle that deductions from rate base to reflect customer contributed capital should reflect the actual net amount of capital received by the Company from customers. (Tr., Vol. II, Walker, at 393-94).

In addition, the Commission rejects Mr. Watkins' argument that the Company is unfairly insulated from all storm damages. The Company is, in fact, liable for the first $2.5 million in storm damages in any given year. Moreover, the Commission has historically allowed utilities to accrue the prudent and necessary costs of major storms as regulatory assets and to amortize them in future rates. The storm damage reserve established in Order No. 96-15 changes the timing for recovery of such costs by allowing those costs to be collected over time in advance of a storm. The mechanism thereby protects customers and the Company from unexpected and potentially disruptive rate increases that might otherwise be necessary to cover catastrophic storm damage. The Commission, however, cannot agree with the Consumer Advocate that the benefits to all parties that this mechanism provides somehow constitute a justification for denying the Company's shareholders a return on part of their investment in the Company.

The Commission Staff is proposing to allocate all of the storm damage reserve to the Company's retail operations. Staff's adjustment is a reduction to rate base of $264,000. Further Staff proposes to true-up the storm damage reserve to reflect the actual amount of the reserve at the end of the test period. Staff's adjustment reduces rate base by $76,000. Staff's proposals are consistent with Order No. 96-15, and we therefore approve Staff's adjustments. *See* Tr., Vol. V, Ellison, at 1479.

14. NON-ALLOWABLES

The Commission Staff, the Consumer Advocate and the Navy have all proposed the removal of various non-allowables from the cost of service, such as institutional and good will advertising, civic club dues, donations, service awards, employee newsletters, and other miscellaneous items that are not considered necessary expenses for ratemaking purposes. The Commission has reviewed the testimony of all parties and finds that the Staff's proposed total company adjustment of $762,000 is the appropriate adjustment for these non-allowable items. (Tr., Vol. V, Ellison, at 1478). This amount includes a civil penalty of $101,000. We believe that the Staff's proposal most accurately identifies the proper amount of non-allowables removable from cost of service. The Commission notes that in keeping with established precedent, the Staff has proposed removal of one-half of the dues associated with the Company's membership in the Chamber of Commerce. (*Id.*). The Commission finds that the Chamber of Commerce is an organization useful for recruiting industry into South Carolina, and so benefits the State to the extent that one-half of the dues for the Chamber are properly recognized for rate-making purposes in this proceeding as well.

15. SALUDA DAM REMEDIATION

SCE&G is in the early stages of a project to strengthen the Saluda Dam against the danger of failure due to earthquakes. This project is being undertaken pursuant to orders of the FERC which regulates dam safety for hydroelectric projects of such size.

Owing to the early stages of the Saluda Dam Remediation Project, the Company is not seeking to include related construction work in progress in rates at this time. Instead, it has proposed an adjustment to remove the initial amounts of CWIP related to this project from rate base for the purposes of this proceeding. (Tr., Vol. II, Walker, at 377). However, the Company is careful to point out that it does intend to include project-related investments and expenses in Quarterly Reports to the Commission and does not waive the right to seek rate recovery of these amounts in future proceedings. (*Id.*).

No party has objected to these adjustments or requests. The Commission finds them to be appropriate and hereby grants them without prejudice to the Applicant or to any party as to the issues that may be raised in future proceedings concerning this project and the investments related to it.

16. MISCELLANEOUS *PRO FORMA* ADJUSTMENTS PROPOSED BY THE APPLICANT

The Applicant has proposed *pro forma* adjustments, in addition to those discussed more specifically above, as follows:

a. Annualizing the effect on retail operations of its new sale-for-resale contract with the City of Greenwood (Tr., Vol. II, Walker, at 366);

b. Decreasing test year expenses to remove expenses related to capacity purchases that are no longer required (*Id.*);

c. Adjusting the level of uncollectible accounts to reflect unusual levels of write-offs during the test year (*Id.* at 367);

d. Removing costs and investments related to Employee Clubs (*Id.*);

e. Annualizing changes in Service Company cost allocations (*Id.*);

f. Annualizing nuclear plant security and maintenance expenses (*Id.* at 368);

g. Annualizing base salary expense and related taxes (*Id.*);

h. Annualizing OPEB expense and related adjustments to rate base (*Id.* at 370);

i. Updating plant in service to reflect additions and retirements up to June 30, 2002 (*Id.* at 371);

j. Updating depreciation reserves to June 30, 2002 (*Id.*);

k. Annualizing current depreciation rates (*Id.*);

l. Adjusting amortization expense to reflect items fully written off during the test period (*Id.* at 372);

m. Annualizing the impact of plant additions on property taxes (*Id.* at 373);

n. Updating CWIP balances to June 30, 2002 (*Id.*);

o. Placing the full amount of the Urquhart Project plant in service into rate base to reflect commercial operation of the plant, along with adding depreciation, property taxes and maintenance related O&M expenses into expenses (*Id.* at 373-74);

p. Reducing rate base by the value of synthetic fuel tax credits earned as of June 30, 2002 (*Id.* at 380); and

q. Decreasing income tax expense by the reduction in income taxes associated with the *pro forma* adjustments allowed to rate base. (*Id.* at 381).

The Commission finds these *pro forma* adjustments to be proper for the reasons stated in the testimony of the Company's accounting witness that is referenced above. The Commission further finds that, in calculating final rates under this Order, these proposed adjustments should be revised to reflect the Commission's specific rulings contained elsewhere in this Order and to reflect the other corrections to these adjustments proposed by the Staff and not contested by the Applicant.

17. STAFF AND OTHER ADJUSTMENTS

The Commission Staff has proposed a number of other adjustments to which the Company consents or did not oppose. Those included:

a. An adjustment to reduce property, plant and equipment balances related to the investment in the Urquhart Repowering Project (Tr.,Vol. V, Ellison, at 1467-71);

b. An adjustment to reflect the 12 month average of material and supplies in rate base (*Id.*);

c. An adjustment to reduce O&M expense related to property taxes which produces a net adjustment to the Company's figures of $1,477,000 (*Id.* at 1471, Vol. II, Walker, at 394);

d. An adjustment related to OPEB true ups (Tr., Vol. V, Ellison, at. 1480); and

e. An adjustment for customer growth using Staff's growth factor of 1.05% (Hearing Exhibit 45, Audit Exhibit A-2).

The Commission finds these *pro forma* adjustments to be proper for the reasons stated in the testimony of Mr. Ellison that is referenced above and as limited and modified by specific rulings contained elsewhere in this Order.

The Commission holds that all other accounting and *pro forma* adjustments proposed by the Commission Staff, and not objected to by other parties, are approved. Further, all other adjustments proposed by other parties, which are not specifically addressed herein, have been considered by the Commission and are denied.

D. EVIDENCE AND CONCLUSIONS REGARDING YEAR END ORIGINAL COST RATE BASE

(FINDING OF FACT NO. 11)

Pursuant to *S.C. Code Ann.* Sec. 58-27-180 (1976), the Commission has the authority after hearing to "ascertain and fix" the value of the property of an electric utility. In the context of a ratemaking proceeding, such authority is exercised in the determination of the electric utility's rate base.

For ratemaking purposes, the rate base is the total net value of the electric utility's tangible and intangible capital or property value on which the utility is entitled to earn a fair and reasonable rate of return. The rate base, as allocated or assigned directly to SCE&G's retail electric operations, is composed of the value of SCE&G's property, used and useful in providing retail electric service to the public, plus net nuclear fuel, construction work in progress, materials and supplies, and allowance for cash working capital. The rate base computation incorporates reductions for the reserve for depreciation and amortization, accumulated deferred income tax and customer deposits. In accordance with its standard practice, the Audit Department of the Commission Staff conducted an audit and examination of SCE&G's books and verified all account balances from SCE&G's General Ledger, including rate base items, with plant additions and retirements. (Tr., Vol. V, Ellison, at 1451; Hearing Ex. 45). On the basis of this audit, pertinent hearing exhibits, and testimony contained in the record of the hearing, the Commission can determine and find proper balances for the components of SCE&G's rate base, as well as the propriety of related accounting adjustments.

For ratemaking purposes, the Commission has traditionally determined the appropriate rate base at the end of the test period. This Commission's practice of determining a utility's rate base on a "year end" basis serves to enhance the timeliness of the effect of such action and preserves the reliance on historic and verifiable accounts without resort to speculative or projected figures. Consequently, the Commission finds it most reasonable to continue to adhere to this regulatory practice and evaluate the issues of this proceeding using a rate base for SCE&G's retail electric operations as of March 31, 2002.

When the rate base has been established, SCE&G's total operating income for return is applied to the rate base to determine what adjustments, if any, to the present rate structure are necessary to generate earnings sufficient to produce a fair rate of return. The rate base should reflect the actual investment made by investors in SCE&G's property and the value upon which stockholders will receive a return on their investment.

With respect to the record in the instant proceeding, only certain rate base issues were contested by the parties of record. Those issues related to plant in service and construction projects and to the methodology for computation of working capital and are each discussed separately in the previous section of this Order. The Commission hereby adopts the following as the Company's rate base:

TABLE B
ORIGINAL COST RATE BASE
RETAIL ELECTRIC
MARCH 31, 2002
(000'S)

	$
Gross Plant in Service	4,730,816
Accumulated Depreciation	(1,586,439)
Net Plant	3,144,377
CWIP	474,438
Accumulated Deferred Income Taxes	(461,697)
Materials & Supplies Inventory	136,762
Total Working Capital	1,822
Deferred Debits/Credits	(121,619)
Total Original Cost Rate Base	3,174,083

E. EVIDENCE AND CONCLUSIONS REGARDING COST OF CAPITAL (FINDINGS OF FACT NOS. 12, 13, 14)

1. COST OF EQUITY

(a) LEGAL STANDARDS

In setting rates, the Commission must determine a fair rate of return that the utility should be allowed the opportunity to earn after recovery of the expenses of utility operations. The legal standards applicable to this determination are set forth in *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591, 602-03 (1944) and *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679, 692-73 (1923). These standards were adopted by the South Carolina Supreme Court in *Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission*, 244 S.E. 2d. 278, 281 (S.C. 1978).

Specifically, *Bluefield* holds that:

> What annual rate will constitute just compensation depends upon many circumstances, and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting the opportunities for investment, the money market and business conditions generally.

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. at 692-73, as quoted in *Southern Bell Telephone and Telegraph co. v. South Carolina Public Service Commission*, 244 S.E. 2d. at 281. In addition, these cases establish that the process of determining rates of return requires the exercise of informed judgment by the Commission. As the South Carolina Supreme Court has held, quoting *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. at 602-03:

> the Commission was not bound to the use of any single formula or combination of formulae in determining rates. Its ratemaking function, moreover, involves the making of 'pragmatic adjustments'. . . . Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. . . . The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates, involves the balancing of the investor and the consumer interests.

Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission, 244 S.E. 2d. at 281. This is in keeping with the general rule that "[r]atemaking is not an exact science, but a legislative function involving many questions of judgment and discretion." *Parker v. South Carolina Pub. Service Commission*, 313 S.E.2d 290, 291 (S.C. 1984).

These principals have been employed by the Commission and the Courts of this State consistently since their adoption in 1978. They continue to provide the appropriate standards to guide the Commission's determination of rates of return in proceedings such as this one. From these authorities, the Commission derives the following specific points to guide its evaluation of the evidence in this case:

1) The rate of return should be sufficient to allow SCE&G the opportunity to earn a return equal to firms facing similar risks;
2) The rate of return should be adequate to assure investors of the financial soundness of the utility and to support the utility's credit and ability to raise capital needed for on-going utility operations at reasonable cost;
3) The rate of return should be determined with due regard for the present business and capital market conditions facing the utility;
4) The rate of return is not formula-based but requires an informed expert judgment by the Commission balancing the interests of shareholders and customers.

Finally, the Commission notes that "[t]he determination of a fair rate of return must be documented fully in its findings of fact and based exclusively on reliable, probative, and substantial evidence on the whole record." *Porter v. South Carolina Public Service Commission,* 504 S.E.2d 320, 323 (S.C. 1998) citing *S.C. Code Ann.* § 58-5-240 (Supp. 2002); accord S.C. Ann. § 58-27-870(G) (Supp. 2002).

(b) OVERVIEW OF THE TESTIMONY

The starting point for the determination of SCE&G's cost of capital is a review of the testimony of the witnesses who used financial models to measure required equity returns numerically. In all, four witnesses testified as to the appropriate cost of capital for SCE&G based on the use of financial models. Those witnesses were

- Burton G. Malkiel, Ph.D., the Chemical Bank Chairman's Professor of Economics at Princeton University who testified on behalf of SCE&G. Dr. Malkiel is former Chairman of the Economics Department of Princeton, former Dean of the Yale Business School, and a former member of the President's Council of Economic Advisors. He is a member of the Board of Directors and Chairman of the Investment Committee of Prudential Securities Company and is a Member of the Board of Directors of Vanguard Group of Investment Companies. (The latter companies have a combined investment portfolio of $1 trillion.) Dr. Malkiel has published extensively on finance issues both in the academic and popular press;
- David C. Parcell, MBA, Executive Vice-President and Senior Economist, with Technical Associates, Inc. who testified on behalf of both the Consumer Advocate and the South Carolina Merchant's Association;
- Michael Gorman, MBA, a consultant with Brubaker & Associates, Inc. who testified on behalf of the South Carolina Energy Users Committee; and
- James E. Spearman, Ph.D., the Commission Staff's Research and Planning Administrator.

In addition, Thomas R. Osborne, Managing Director in the Global Energy and Power Group of UBS Warburg, LLC's Investment Banking Department, testified on behalf of SCE&G concerning conditions in national capital markets and the group of comparable companies he selected and provided to Dr. Malkiel as an input to Dr. Malkiel's calculations. Finally, Kevin Marsh, SCE&G's Senior Vice President and Chief Financial Officer, testified on the present business and market conditions that the Company is facing and concerning the flotation costs the Company has incurred in issuing new capital.

Summary results of the financial analyses conducted by the four witnesses who offered opinions regarding SCE&G's equity capital are as follows:

RESULTS	**WITNESS**			
	Dr. Malkiel	**Mr. Parcell**	**Mr. Gorman**	**Dr. Spearman**
DCF	12.3%[5]	10.5%-11.0%[6]	11.2%[7]	7.74%-12.65%[8]
Risk Premium	Not accepted but as high as 13.5%[9]	Not Used	9.9%-11.4%[10]	8.4% -12.4%[11]
CAPM	Rejected[12]	10%-10.5%[13]	9.4%[14]	8.06% – 10.61%[15]
Comp. Earnings	Not used	11.0%[16]	Not used	Not used
Flotation Adjustment	0.20%[17]	Not Included	Not Included	0.20%[18]
Recommendation	**12.5%**[19]	**10.5%**[20]	**10.5%**[21]	**11.95 - 12.45%**[22]

[5] Tr., Vol. III, Malkiel, at 803.
[6] Tr., Vol. IV, Parcell, at 1107.
[7] Tr., Vol. IV, Gorman, at 1177.
[8] Tr., Vol. V, Spearman, at 1585.
[9] Tr., Vol. III, Malkiel, at 820 (when adjusted for company size).
[10] Tr., Vol. IV, Gorman, at 1172-73.
[11] Tr., Vol. V, Spearman, at 1585.
[12] Tr., Vol. III, Malkiel, at 814-17.
[13] Tr., Vol. IV, Parcell, at 1107.
[14] Tr., Vol. IV, Gorman, at 1177.
[15] Tr., Vol. V., Spearman, at 1585.
[16] Tr., Vol. IV, Parcell, at 1107.
[17] Tr., Vol. III, Malkiel, at 805-06.
[18] Tr., Vol. V, Spearman, at 1587.
[19] Tr., Vol. III, Malkiel, at 808.
[20] Tr., Vol. IV, Parcell, at 1107.
[21] Tr., Vol. IV, Gorman, at 1177
[22] Tr., Vol. V, Spearman, at 1587.

(c) REVIEW OF THE METHODOLOGIES

(i) CAPITAL ASSET PRICING MODEL ("CAPM")

Three of the four witnesses, Mr. Parcell, Mr. Gorman and Dr. Spearman, performed a CAPM analysis as one of several tools to measure the Company's cost of equity capital. As the chart above shows, the CAPM model consistently produced the lowest rates of return of any of the models. Mr. Parcell's CAPM analysis produced a return of 10.0% to 10.5% while Mr. Gorman's produced a return of only 9.4%. Dr. Spearman's produced a range of 8.06% – 10.61%.

The Commission finds that the reliable, probative and substantial evidence on the record demonstrates that, in the present economic conditions, the CAPM model does not accurately measure the required rates of return for companies like SCE&G. Dr. Spearman rejected a rate of return for SCE&G in the range produced by the CAPM model (8.06% to 10.61%) because he did not believe that investors would invest in SCE&G if its returns were set in that range. (Tr., Vol. V, Spearman, at 1606). As discussed more fully below, the Commission agrees with Dr. Spearman's conclusion: reasonable expectations of returns in the markets are indeed greater than those indicated by the CAPM model. (*Id.*).

In addition, the Commission finds reliable and probative Dr. Malkiel's conclusion that an absolute floor for investor expectations of returns for a company of the size and risk profile of SCE&G in today's market is above 11.8%. (Tr., Vol. III, Malkiel, at 802-03). Dr. Malkiel arrived at this conclusion by measuring the market returns on a group of utilities with market capitalizations approximately five times that of SCE&G. (*Id.* at 802). He found that the value that the market actually placed on their shares created an

11.8% return on equity for these companies. (*Id.*). The Commission finds, as discussed more fully below, that comparable larger companies are perceived to be less risky, not more risky, than comparable but smaller companies and therefore such larger companies may enjoy lower costs of capital than smaller companies. (*Id.* at 824).

Accordingly, the Commission finds that the reliable, probative and substantial evidence on the record establishes that a minimum return for SCE&G must be higher than 11.8% in present market conditions. (Tr., Vol. III, Malkiel, at 802). The Commission also finds that the results of the CAPM model, when measured against present economic conditions and investor's expectations, does not produce credible results.

The Commission also finds credible the testimony of Dr. Malkiel that the empirical evidence and research raises questions concerning the theoretical assumptions underlying the CAPM model. (*Id.* at 839-41). The CAPM model employs a measure of a stock's volatility relative to the broader market, called beta. On the basis of the beta, the CAPM model attempts to calculate the company's risk and market's required return for taking on that risk. The validity of beta as an indicator of required return is at the heart of the CAPM model. (*Id.* at 839). Recent research, however, has shown that betas are not stable, and they cannot be accurately measured. (*Id.* at 815). More importantly, a number of recent and important studies in the finance literature have shown that beta and return are essentially uncorrelated. (*Id.* at 815-17, 839-41; Vol. IV, Malkiel at 917-18). These later findings are unchallenged in the record here.

Based on this evidence, the Commission finds that CAPM is not a reliable basis for measuring return in this proceeding. The Commission notes that this decision is based on the record before it in this proceeding, and does not foreclose parties from advancing testimony using CAPM in future cases, or from addressing the concerns raised about this analytical tool in future dockets.

(ii) COMPARABLE EARNINGS

The Consumer Advocate's witness, Mr. Parcell, utilized a method called Comparable Earnings to measure SCE&G's earnings. (Tr., Vol. IV, Parcell at 1136). This method attempts to correlate rates of return with book-to-market ratios. (*Id.*). The record shows that there are several reasons to doubt both the accuracy of the method and the conclusions drawn from it.

First, the reliable, probative and substantial evidence on the record indicates that analyses based on book values are inherently questionable. As Dr. Malkiel testified, book values depend on an individual company's policies with respect to depreciation, with respect to write-offs, and with respect to other accounting practices. (Tr., Vol. III, Malkiel, at 829). These policies are not comparable from company to company. (*Id.*). The Commission finds this testimony to be persuasive and credible.

Second, the Commission finds that Mr. Parcell's Comparable Earnings analysis does not sufficiently support his conclusion that 11% is the appropriate rate of return for SCE&G. Mr. Parcell begins his analysis by determining the earnings of the companies that he has selected as being comparable to SCE&G in terms of book to market ratios.

His analysis indicates that these comparable companies have experienced "historical returns of 11.8-13.2 percent" and "projected returns on equity for 2002, 2003 and 2005-2007 are within a range of 11.5 percent to 14.3 percent for the comparison groups." (Tr., Vol. IV, Parcell, at 1138-39).

Mr. Parcell justifies his 11.0% return recommendation by assuming that any return that would allow a stock to trade above book value is a fair rate of return under the standard of *Hope* and *Bluefield, supra.* (Tr., Vol. IV, Parcell, at 1137). However, the *Hope* and *Bluefield* opinions do not concern themselves with book values. Instead, they require that rates of return for utilities be comparable to those of businesses facing similar risks. Mr. Parcell's own analysis shows that the group of comparable companies he has chosen (a) enjoys book-to-market value ratios substantially greater than 100% and (b) enjoys rates of return in a range from 11.5% to 14.3%. (Tr., Vol. IV, Parcell, at 1138-39). Moreover, his analysis also indicates that an 11% return on equity for SCE&G would lead to an immediate and substantial drop in market value, since it would serve to bring the historical 155% to 166% market-to-book ratio to a level "of at least 100%." (Tr., Parcell, Vol. IV, at 1138, 1140; Vol. III, Malkiel, at 829).

For the reasons stated above, the Commission finds that Mr. Parcell's Comparable Earning analysis does not support the 11% return recommendation he derives from it. If the analysis has any meaning, it would appear to support a range of returns from 11.5% to 14.3%. Mr. Parcell's analysis affirmatively demonstrates that a return of 11% or less would result in a substantial and disruptive drop in the company's stock values. The

Commission finds that this analysis contradicts his recommendation, and that of Mr. Gorman, that a 10.5% return would be a fair return under *Hope* and *Bluefield, supra.*

(iii) RISK PREMIUM

Mr. Gorman and Dr. Spearman conducted risk premium analyses as part of their review of SCE&G's cost of capital. Dr. Spearman's analysis produced results in the range of 8.4% to 12.4%, before flotation adjustment. (Tr., Vol. V, Spearman, at 1584-85). Mr. Gorman's analysis produced results in the range of 9.9% to 11.4%. (Tr., Vol. IV, Gorman, at 1172-73).

Dr. Malkiel testified that he had considered, but rejected, the use of a risk premium analysis as an appropriate means of measuring SCE&G cost of equity capital. (Tr., Vol. III, Malkiel, at 819). However, he further testified that if such an analysis were to be conducted, he would not employ beta as an adjusting factor in light of the demonstrated lack of validity of betas as indicators of required returns. (*Id.* at 819-20).

In addition, Dr. Malkiel testified that a risk premium analysis concerning SCE&G would need to account for the small size of SCE&G in comparison to the market generally and the resulting perceived increase in risk. (*Id.*). Recent studies in the finance field and long-term data concerning actual market returns show that there is a very strong correlation between company size and required return, with smaller companies requiring substantially higher returns than larger ones. (Tr., Vol. III, Malkiel at 819-20; Vol. IV, Malkiel, at 885-88, 917-18).

Dr. Malkiel then demonstrated that a standard risk premium analysis, relying on long term market data, and not adjusting for beta, would produce an indicated return of approximately 12% before flotation adjustment, a figure substantially greater than Mr. Gorman's point estimate of 10.8% based on his risk premium method. (Tr., Vol. III, Malkiel, at 819-20). Further, adjusting the 12% return number for the small size of SCE&G relative to the market would produce a return of approximately 13.5%, which is much greater than the 12.3% return recommended by Dr. Malkiel based on his DCF methodology. (*Id.*).

A review of Mr. Gorman's testimony establishes that Mr. Gorman's analysis does not account for the impact of company size on market perception of risk and required return. (Tr., Vol. IV, Gorman, at 1171-73). In addition, Mr. Gorman's analysis is based on a relatively short time frame (15 years) while Drs. Spearman and Malkiel present calculations based on a full 75 years of market data. (*Compare* Tr., Vol. IV, Gorman, at 1172 with Tr. Vol. III, Malkiel, at 819-20; Vol. V, Spearman, at 1584-85; Exhibit 48 (JES-10)). Mr. Gorman provides no explanation as to why he chose to use only data from 1986 forward or why it would not be preferable and more accurate to use the much larger data set that is readily available.

Furthermore, Mr. Gorman's calculation of returns specific to the utility sector does not consider actual reported utility returns, but instead is based exclusively on a compilation of the average returns authorized by utility commissions for the years in question. (Tr., Vol. IV, Gorman, at 1172; Exhibit 40, Schedule 5). There is no evidence showing why use of authorized return data is preferable to the actual returns markets have required. Nor is their any evidence to correlate those authorized returns with the returns that capital markets have, in fact, required or to compare these rates to market returns of companies facing similar risks. Under *Hope* and *Bluefield*, it is the reasonable return requirements of capital markets that this Commission is directed to consider as a principal factor in setting returns.

For these reasons, the Commission does not believe that Mr. Gorman's analysis and the 10.8% return conclusion that he draws from it represent a reliable basis on which to establish a rate of return for SCE&G. The Commission further notes that the upper end of the risk premium range of returns calculated by Dr. Spearman's analysis (12.4%) is based on an analysis that (a) uses long-term data, (b) uses actual return information, and (c) does reflect the higher return requirement associated with smaller companies. (Tr., Vol. V, Spearman, at 1584-85; Exhibit 48 (JES-10)). Dr. Spearman's analysis does, however, adjust its results downward substantially for beta. (Tr., Vol. V, Spearman, at. 1171-1172; Exhibit 48 (JES-10)). Without the beta adjustment, Dr. Spearman's analysis could support a return much higher than 12.4%.

Based on this evidence, the Commission finds that risk premium analyses does indeed support a cost of equity capital, before flotation adjustment, in the range of 12% or higher.

(iv) DISCOUNTED CASH FLOW MODEL ("DCF")

The DCF model ("DCF" or "Gordon Model") measures investors' return requirements by correlating a Company's stock price with the present value of its anticipated earnings stream and through this analysis, to determine the rate of return assumptions embedded in that relationship. (Tr., Vol. III, Malkiel, at 794-95). As the testimony indicates, the Gordon model works particularly well for determining the required rates of return for public utilities, particularly in economic circumstances like those at present. (*Id.* at 798).

All four cost of capital witnesses used the DCF model to estimate SCE&G's cost of equity capital. By design, Dr. Spearman's results covered the broadest range (7.74%-12.65% before flotation adjustment), since he included the broadest range of alternative calculations in his analysis. Dr. Malkiel employed a single DCF calculation based on the assumptions that he found most reasonable and accurate. His calculation showed a tight grouping of returns around a 12.3% return on equity before flotation adjustment. (*Id.* at 801). Mr. Gorman conducted a somewhat similar analysis with a different group of comparable companies from those used by Dr. Malkiel. He concluded that the DCF model indicated 11.2% as an appropriate cost of capital for SCE&G. (Tr., Vol. IV, Gorman, at 1177). Much of the difference between Mr. Gorman's return and Dr. Malkiel's return can be attributed to the different earnings growth rates used in their DCF models. Mr. Gorman used an average earnings growth rate of 5.25% compared to Dr. Malkiel's average earning growth rate of 6.6%. Mr. Parcell conducted a DCF analysis using a different group of comparable companies and a very different measurement of anticipated future growth rates. Mr. Parcell averaged a number of different growth rates to derive the 4.3% growth rate used in his DCF model. His DCF analysis indicated a return in the range of 10.5% to 11% would be appropriate for SCE&G. (Tr., Vol. IV, Parcell, at 1131).

Earnings Growth vs. Dividend Growth – A key input in the DCF analysis is the estimated future earnings stream of the company. One way of measuring future earnings is to use analysts' estimates of the company's future growth in earnings per share. These estimates are provided in publications by financial services firms like I/B/E/S, First Call and others. (Tr., Vol. III, Malkiel, at 797, 802-03). This is the approach Dr. Malkiel and Mr. Gorman used, and which Dr. Spearman used for that part of his DCF analysis he found to be most credible.

Another approach is to use estimates of future dividend growth as the growth rate in the DCF analysis. (Tr., Vol. V, Spearman, at 1577-78). As one of his alternative calculations, Dr. Spearman performed a DCF calculation for SCE&G using anticipated dividend growth as his growth factor. The results showed a cost of equity for SCE&G of between 7.75 - 9.01%. (*Id.* at 1585). No party supported a cost of equity for SCE&G in such an extremely low range. Dr. Spearman did not base his recommendations on the results of this analysis, testifying that analysts' predictions of earnings growth are the principal data on which investors rely and include dividend growth to the extent relevant. (*Id.* at 1615). In addition, Dr. Spearman rejected as unrealistic returns in the range produced by this analysis. (*Id.* at 1621).

The Commission finds that the reliable, probative and substantial evidence on the record establishes that in present economic circumstances a DCF analysis based exclusively on dividend growth rates does not provide a reliable basis on which to measure SCE&G's equity capital costs. Again, the Commission notes that this decision is based on the record before it in this proceeding, and does not foreclose parties from advancing testimony using dividend growth DCF in future cases, or from addressing the concerns raised about this analytical tool in future dockets.

Historical and Constructed Growth Rates – Mr. Parcell used an average of various historical, prospective, and constructed growth rates, including earnings retention growth, book value growth, dividend growth, and earnings growth as the growth factor in his DCF analysis. (Tr. Vol. IV, Parcell, at 1130). The problems arising from the use of dividend growth have been discussed. Book values may not be comparable across companies as previously discussed. Also, there is no theoretical foundation for using book value growth as the growth factor in the DCF model. The use of retention earnings growth as the DCF growth rate has more validity as it is a means of measuring earnings growth. Analysts may, in fact, consider all of these factors when forecasting future returns. However, there is no basis for merely aggregating these factors and averaging them to derive a growth rate for the DCF model.

The Commission also finds persuasive the testimony of Dr. Malkiel concerning the most appropriate growth rate for the DCF analysis for purposes of this proceeding. He testified that his own work

> and the work of Fama-French and Myron Gordon confirm that growth rates projected by securities analysts are the most reliable tool for estimating the cost of equity capital using a DCF analysis. Further, my own work and Dr. Gordon's work have demonstrated that a DCF analysis using analysts' growth rates is the most direct, most widely used and accepted, and most reliable model in use in corporate finance today to estimate a company's cost of equity capital.

(*Id.* at 830). Drs. Malkiel and Spearman concur that investors rely heavily on analysts' forecasts of earnings growth when making investment decisions. For these reasons, the

Commission finds that the most reliable DCF model in this proceeding is the earnings growth DCF model.

Comparable Companies – Because SCE&G stock is not publicly traded, each witness selected a comparison group of companies. Dr. Malkiel used a group of electric utility companies selected by Mr. Osborne as comparable to SCE&G. Mr. Gorman selected a group of six utility companies that he considered comparable to SCE&G. Mr. Parcell selected a group of five companies that he considered comparable to SCE&G. Dr. Spearman selected seventeen companies comprising the Moody's Electric Utility Index as his comparison group. The differing return-on-equity recommendations of the witnesses appeared to be the result of the model inputs and not the comparison groups. Specifically, the different results occurred primarily from the different growth rates used in the DCF analyses. The return-on-equity estimates produced by the DCF analyses would be very close to each other if the same growth rates were used by each witness. Since the choice of comparison group seemed to have little impact on the return-on-equity recommendations of the witnesses, the Commission sees no need to favor one comparison group over another in this case.

Conclusions Concerning the Numerical Analyses – The Commission finds that the reliable, probative and substantial evidence on the record demonstrates that the earnings growth DCF analyses performed by Drs. Malkiel and Spearman are appropriate and reliable numerical analyses to use in evaluating required market returns for SCE&G in this proceeding. Dr. Malkiel's analysis produced a return of 12.3% while Dr. Spearman's analysis produced returns in the range of 10.61% to 12.65%.

The Commission further finds that the results of these DCF analyses are confirmed by risk premium analyses based on long-term data, actual return data, and similar sized companies. According to Dr. Malkiel, the risk premium analysis produced a 12% return which should be adjusted to 13.5% to reflect the small size of SCE&G. The corresponding risk premium analysis performed by Dr. Spearman produced a return as high as 12.4%.

Weighing the results of the reliable and probative numerical analyses, the Commission finds that the substantial evidence on the record of this proceeding supports a return on equity for SCE&G, before flotation adjustment, in the upper end of the range calculated by Dr. Spearman of 10.61% to 12.65% derived from his DCF analysis using earnings growth. This range encompasses the upper end of Dr. Spearman's return derived from his risk premium analysis and Dr. Malkiel's recommended return of 12.3%. (Tr., Vol. V, Spearman, at 1579-80, 84-85).

(d) ESTABLISHMENT OF A COST OF EQUITY CAPITAL (BEFORE FLOTATION ADJUSTMENT)

Having reviewed the financial modeling data provided by the witnesses, the Commission now reviews the other factors established by *Hope* and *Bluefield* to be relevant to its determination of an appropriate cost of capital for SCE&G. Specifically, those cases require:

1) That the rate of return should be adequate to assure investors of the financial soundness of the utility and support the utility's credit and ability to raise capital needed for on-going utility operations; and

2) That the rate of return should be set with due regard to current business and capital market conditions affecting the utility.

Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. at 692-73, as quoted in *Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission*, 244 S.E. 2d, at 281.

Capital Markets – The Commission finds that the reliable, probative and substantial evidence on the record shows that the capital market conditions facing SCE&G are difficult and tumultuous. (Tr., Vol. III, Osborne at 732, 736, 753, 780; Vol. IV, Malkiel, at 894-96; Vol. V, Spearman, at 1586-87). In the wake of recent high profile business bankruptcies and near failures--several of which are in the energy sector--stock markets have become, in Dr. Malkiel words, "incredibly volatile." (Tr., Vol. III, Malkiel at 894).

Regulated utility companies that were once seen as a group as safe, secure investments are now viewed with skepticism by investors. (Tr., Vol. I, Marsh, at 166-67). As Dr. Spearman testified, lingering uncertainty about the pace and course of regulatory change is seen as a major risk for electric utility companies in today's markets. (Tr., Vol. V, Spearman, at 1612). As Mr. Osborne further testified:

> Unfortunately, the entire power sector, and not only those companies engaged in unregulated energy activities, is now being viewed by investors as entailing more risk. Consequently, the power sector as a whole, and each individual company, must provide sufficiently high returns to continue to attract investor capital.

(Tr., Vol. III, Osborne, at 753).

Based on the evidence in the record in this regard, which is more extensive than that quoted here, the Commission finds that the market conditions support the choice of a rate of return for the Company at the higher end of the range established above.

Business Conditions – The Commission finds that SCE&G is facing business conditions that make it particularly sensitive to conditions in financial markets and investors' concerns about the risks of the energy sector. The record shows that SCE&G must spend $961 million during the next two years to add new generating capacity to its system, to provide environmental and safety upgrades to existing facilities, and to make other improvements or additions to its facilities. (Tr., Vol. I, Marsh at 161, 170). SCE&G has recently issued $550 million from the capital markets over the current three year period. (*Id.*).

The Commission finds that the Company has historically sought to maintain a single-A bond rating and that rating is presently in jeopardy. (*Id.* at 179). The Commission finds to be credible and persuasive the testimony of SCE&G's CFO, Mr. Marsh, that as a result of several major business failures, rating agencies have become more stringent in their expectations and unyielding in applications of their rating standards. (*Id.* at 164-65, 179). The evidence shows that SCE&G does not fully meet the financial targets for its single-A status at present and will lose that rating if the rates approved under this order do not generate earnings sufficient to improve its debt coverage ratios. (*Id.* at 163-65, 179).

Accordingly, in assessing the business conditions facing the Company, the Commission finds that the reliable, probative and substantial evidence on the record shows that SCE&G's credit ratings are in jeopardy and that the Company's ability to raise money on reasonable terms to support the proper discharge of its public duties may be at risk. These facts support a cost of equity capital at the high end of the range discussed above.

Balancing of Interests – The South Carolina courts have held that the setting of rates of return "involves the balancing of the investor and the consumer interests." *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. at 602-03, quoted in *Southern Bell Telephone and Telegraph Co. v. South Carolina Public Service Commission*, 244 S.E. 2d. at 281. The evidence on the record here shows that were SCE&G's debt rating to drop to BBB the result would be to add substantially to the cost of the $550 million in new financing SCE&G must raise over the next two years. (TR at vol. I, pp. 165, 170). Specifically, over the life of a 30 year bond such a rating drop would add $1.05 in additional financing costs to each $10.00 financed, or $58 million of additional financing costs to $550 million in new bonds. (*Id.* at 165, 170). Clearly, shareholders and customers share an interest in maintaining SCE&G's access to capital on reasonable terms during this period of high capital needs for the Company and volatile and unyielding conditions in financial markets. To do otherwise could substantially increase the Company's debt service costs for decades and could substantially increase costs to customers for an equal length of time.

Conclusion – Determining the appropriate return on equity is more than a numerical calculation. Many factors must be considered when deriving the appropriate return. In the end, the Commission is convinced that the most prudent, just and reasonable response to the financial evidence, to present business and market conditions, and to the interrelated interests of the Company and its customers, is to set a rate of return for the utility at high end of the return-on-equity range (11.75% - 12.25%) proposed by Dr. Spearman. (Tr., Vol. V, Spearman, at 1585-87). A return of 12.25% before flotation adjustment is well within the 12.65% upper end of Dr. Spearman's DCF analysis and the 12.4% upper end of his risk premium analysis. It also fits well within Dr. Malkiel's analysis showing that much larger companies are earning average returns of 11.8% and SCE&G's proper return must be substantially higher than 11.8%. Dr. Spearman's recommended return is only slightly lower than the 12.3% return recommended by Dr. Malkiel. (Tr., Vol. III, Malkiel, at 802).

The Commission also finds that this return on equity should provide the Company an opportunity, with sound management, to retain its access to capital on reasonable terms and to support and maintain its credit. Setting a return on equity capital at this level should indicate to investors and potential investors in SCE&G that their continued investment in the electric and gas infrastructure on which this State depends will be treated fairly by this Commission, and that their reasonable return expectations will be respected. The Commission believes that this rate of return properly balances the interests of investors and customers and furthers the long term interests of both groups by helping the Company maintain its debt rating and thereby reduce its long term cost of debt service.

(e) FLOTATION ADJUSTMENT

A flotation adjustment is an upward adjustment to the cost of capital to reflect the cost of issuing, or "floating," new capital. The adjustment reflects (a) the fact that flotation of new capital incurs substantial cost and (b) as an accounting matter, those costs are not otherwise recovered in rates. It has been the practice of the Commission in past cases to allow applicants to recover a flotation adjustment where a flotation of new equity has taken place in the recent past or is planned during the next three years. (Tr., Vol. V, Spearman, at 1587). Both Drs. Malkiel and Spearman and the Applicant's CFO, Mr. Marsh, testified in support of the need for an acquisition adjustment for SCE&G in this proceeding. Mr. Marsh further established, through reliable and probative testimony, that these costs are held on the Company's balance sheet as a permanent deduction from the balance of capital received from investors and are not treated as expenses, amortized or otherwise included in rates. (Tr., Vol. V, Marsh, at 1702-03). Dr. Spearman noted that when a Company issues equity, the issuance negatively impacts the stockholders of the Company. The issuance drives down the price of the stock and lowers the earnings per share, which makes it more difficult for the Company to increase dividends. In order to compensate for this decline to the stockholders, a flotation adjustment is made. (Tr., Vol. V, Spearman, at 1633). Drs. Malkiel and Spearman both quantified the amount of the adjustment for SCE&G as an additional 20 basis points (0.20%). (Tr., Vol. III, Malkiel at 807-09; Tr., Vol. V, Spearman, at 1587).

The Commission makes the following specific determinations concerning flotation costs:

The On-Going Nature of Flotation Cost – The Consumer Advocate suggested, in its cross-examination of Dr. Malkiel, that allowing a flotation cost adjustment to be included in the Company's cost of capital would result in over-recovery of flotation costs. He suggests that the full value of the flotation costs would be recovered in the first year, and a duplicative recovery would result for every succeeding year thereafter. (*Id.* at 865).

The Commission finds that this line of argument misconstrues the nature of a flotation adjustment. As the reliable, probative and substantial evidence on the record shows, flotation costs are not an expense to be recovered during a particular period. Instead, they represent a difference in the amount of funds that investors have invested in the Company compared to the amount the Company actually receives. In other words, if flotation costs equal 4.25% percent of the capital raised, then for every $1.00 contributed by an investor, the Company receives $0.9575 in capital. For investors to earn a given return on their $1.00 investment, the company must earn a higher return on the $0.9575 held in rate base.

Upon cross examination by Commissioner Atkins, Dr. Spearman explained that existing stockholders, unlike bondholders, are penalized when new common stock is issued. Stockholders give a company money in return for dividends and common stock. The stockholder expects both the dividend and the price of the stock to increase over time. When new stock is issued, the stock price decreases and earnings per share decreases. Both of these are detrimental to existing stockholders. A decrease in stock price lowers the value of the existing stockholders investment. A reduction in earnings per share puts downward pressure on future dividend payouts as more earnings are required to pay dividends. The reduction in earnings per share also hinders future stock appreciation. (Tr. Vol.V, Spearman, at 1632-1634). The negative impact of stock dilution resulting from the issuance of new common stock continues until the number of shares outstanding returns to its pre-issuance level. A stock flotation adjustment is required to compensate existing stockholders for this dilution.

Amount of the Flotation Adjustment – Both Drs. Malkiel and Spearman recommended a 20 basis point flotation adjustment. The Commission is encouraged that the differing methodologies used by Dr. Malkiel and Dr. Spearman produced identical results. Dr. Malkiel's methodology determines the stock flotation adjustment based on the percentage of the sales revenue of the common stock that is actually received by the company. Dr. Spearman's methodology determines the stock flotation adjustment based on DCF returns before and after the new stock was issued. His methodology measures the actual market reaction to the stock issuance. The Commission finds the methodology used by Dr. Spearman and his recommended 20 basis point adjustment to be appropriate in this case.

Accordingly, the Commission finds that the reliable, probative and substantial evidence on the record establishes that flotation adjustments are indeed appropriate in this case to reflect SCE&G's recent issuance of new equity and the fact that these costs are not otherwise recovered in setting rates. The Commission finds that an adjustment of 20 basis points is in fact appropriate to ensure that the return investors actually receive for the funds invested in the Company equals the return that the Commission establishes with reference to the Company's rate base.

(f) TOTAL GRANTED RATE OF RETURN ON EQUITY

The addition of the approved rate of return on equity without flotation costs of 12.25% and the 20 basis points flotation cost yields a total approved rate of return on equity of 12.45%.

2. CAPITAL STRUCTURE

In keeping with established Commission practice, the Staff has updated the Company's capital structure and cost of debt and preferred stock, to reflect the figures current at the time of the Staff's recent audit and included the October 16, 2002, issuance of $150,000,000 of common stock. (Tr., Vol. V, Spearman, at 1460). These underlying figures are not in dispute. Witnesses Malkiel, Gorman, and Spearman recommended capital structures consisting of long-term debt, preferred stock, and common equity.

The Consumer Advocate's witness Mr. Parcell, however, has argued that the Commission should depart from its long-standing practice of setting cost of capital based on long-term obligations, and has proposed that the Commission insert into the cost of capital analysis consideration of the Company's short-term debt.

The Commission, however, finds persuasive the testimony of Dr. Malkiel who testified that the rates and levels of short-term debt fluctuate significantly due to multiple, short-term factors, such as the impending maturities of long-term debt, and current levels of accounts receivables. Dr. Malkiel further testified that "[t]o include short-term debt [in cost of capital calculations] will tend to distort the company's true cost of financing its business operations since capital projects are financed through either equity or long-term debt." (Tr., Vol. III, Malkiel, at 832). The Commission finds this testimony to be reliable and probative and finds that the substantial evidence on the record support using long-term debt and equity as the basis for computing the Company's capital costs.

3. EMBEDDED COST RATE OF LONG-TERM DEBT AND PREFERRED STOCK

The Commission's determination concerning the amount and cost of long-term debt and preferred stock is based on the embedded rates of those instruments as shown in the Company's books and records. The rates used are the actual rates in force on September 30, 2002, determined subject to the Staff audit of the Company's books and records. The values are as shown in Finding of Fact No. 13.

F. EVIDENCE AND CONCLUSIONS CONCERNING RATE DESIGN (FINDINGS OF FACT NO. 15, 16)

1. GENERAL PRINCIPLES

Upon the identification of revenue requirements, the Commission is responsible for determining specific rates and developing a rate structure that will yield required revenues. It is generally accepted that proper utility regulation requires the exercise of control over the rate structure to insure that equitable treatment is afforded each class of customer.

The Commission's statutory responsibility to fix "just and reasonable rates" [*S.C. Code Ann.* §§ 58-3-140, 58-27-810 (1976)] has been exercised by the recognition of the objective to provide a utility a fair opportunity to earn a reasonable return, which meets the established revenue requirement and equitably apportions the revenue responsibility among classes of service. In discharging the Commission's responsibility to fix "just and reasonable rates," we have traditionally adhered to the following criteria:

> ...(a) the revenue-requirement or financial-need objective, which takes the form of a fair-return standard with respect to private utility companies; (b) the fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed fairly among the beneficiaries of the service; and (c) the optimum-use or customer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between cost incurred and benefits received.

Bonbright, *Principles of Public Utility Rates* (1961), p. 292.

These criteria have been consistently observed by this Commission and again are utilized here.

The cost of supplying electricity to different customer classes is a function of many factors and variables. The allocation of these costs among the different classes of customers represents a complex task. The procedure generally used by this Commission in analyzing utility costs in the context of the review of rate design provides for the distribution of total costs among three major categories: (1) costs that are a function of the total number of customers, (2) costs that are a function of the volume of the service supplied (energy costs), and (3) costs that are a function of the service capacity of plant and equipment in terms of their capability to carry hourly or daily peak loads (demand costs).

In concluding that rates should be based on cost of service principles, the Commission espouses the economic theory that regulation is intended to act as a surrogate for competition by insuring that each rate that is charged for electricity is fair and reasonable. That is, that utility rates are maintained at the level of costs, including a fair return on capital. By incorporating cost of service principles, the Commission provides for rates and charges which are designed to promote equity, engineering efficiency (cost-minimization), conservation and stability.

Company witness, John Hendrix, discussed the Company's adherence to the foregoing principles in its processes for developing rates. His testimony consisted of three major subject areas: cost of service, rate design, and general terms and conditions. Mr. Hendrix sponsored the utility's cost study and supported the resultant rates and charges. (Hearing Ex. 17 [JRH-2]); (Tr., Vol. II, Hendrix, at 464).

2. COST OF SERVICE STUDY

The foundation for an equitable and efficient, cost-based rate structure is a cost of service study, which accounts for the variables and factors from which are derived the costs of supplying electricity to different classes of customers. The cost of service study not only identifies the total cost of service and thereby measures the profitability of the utility, but also identifies cost by function and class of service, and so measures the compensability of service to any one customer class. Furthermore, the cost of service study is used to assess the propriety of any one particular rate structure in the design of rates. In a sense, a cost of service study functions as a regulatory guide by which the ratemaker can determine the existing rate of return of each class and the manner and extent to which it should be adjusted to achieve cost-based rates.

The principal steps in developing the cost of service study are the functionalization of costs, classification of cost, and allocation of costs. (*Id.* at 465). Functions include production, transmission, and distribution. Classifications are identified as customer, demand, and energy. The final step in the process is the allocation of costs to classes of service. (*Id.* at 466).

Customer costs, which vary with the number and size of customers, are direct costs which customers place on the system simply by being connected with a service drop, meter, account, and monthly bill. (*Id.*). Accordingly, the Company developed factors used for allocating billing expenses between customer classes by weighing the average number of customers in the class by the average time to read a typical meter for customers in that class and the average time required to develop billing determinants for customers in that class.

Demand costs are the fixed costs of building and operating the system required to serve the Company's customer base. The cost of service study utilizes two basic demand allocators. The coincident peak allocator was developed based on the system territorial four-hour peak demand. The non-coincident peak allocator was developed by combining the non-coincident peak demands of each class of customers when they were incurred during the test year. (*Id.* at 467; Tr., Vol. V, Watts, at 1509).

The energy allocator was developed from the annual kilowatt hour-sales by class of customer adjusted for system losses. The Company collected data on energy usage by customer class and used actual test period data in making this allocation. (Tr., Vol. II, Hendrix at 468).

Following classification, the revenue, expense and rate base items were allocated according to function or purpose. (*Id.* at 466; Tr., Vol. V, Watts, at 1509). This process is essential to a fair allocation of revenue requirements for the utility system, which requires the separation of costs associated with each customer class and with the utility's jurisdictional operations.

The Company's cost of service study, utilized in the design of the proposed rates and charges, was founded on embedded costs and is based on the cost of service study recommended by the Staff's Utilities Department. (Tr., Vol. II, Hendrix, at 511; Vol. V, Ellison, at 1457). The Commission has consistently relied upon the concept of embedded costs as the starting point in the implementation of ratemaking precepts. There is no evidence in the record of this proceeding to cause the Commission to abandon our well-founded reliance upon the principle of embedded cost as a starting point for determining just and reasonable rates. The Commission hereby reaffirms the Four Hour Band Coincident Peak Methodology for ratemaking purposes, adopted in its Order No. 96-15.

No Intervenor challenged the validity of the Company's cost of service study. (Tr., Vol. II, Hendrix, at 494). The cost of service study presented provides a proper foundation for distributing costs among classes since it recognizes cost causation and distributes costs accordingly. This study also provides a proper basis for determining cost-based rates and is a major component of fair and equitable rate design. The cost of service study also provides a reasonably accurate measure of profitability among classes of customers. (*Id.* at 469). *See* Hearing Ex. 17 (JRH-1 & 2). Accordingly, the Commission hereby approves the Company's proposed cost of service study.

3. ALLOCATIONS AND REVENUE REQUESTS

This Commission has considered it axiomatic that retail rates should produce rates of return among classes which bear a reasonable relationship to the Company's overall rate of return. Further, there should be movement towards equal rates of return among the classes. PSC Order 96-15 (January 9, 1996), Docket No. 95-1000-E, at p. 70. It has been the allocations and revenue requests proposed by the Company which have caused the most concern among the Intervenors.

(a) THE COMPANY'S POSITION

The revenue requested by the Company is based on the rate of return information contained in Exhibit D-11, page 2 of 3 of the Company's Application. This information indicates a need for a net revenue increase of $104,716,000 to compensate the Company adequately for its electric service. As testified by the Company's accounting witness Mrs. Walker, the Company proposes to include in retail rates, and eliminate from the fuel cost recovery calculation, $8,079,000 in annual pipeline fixed capacity charges related to natural gas service to the recently repowered turbines at Plant Urquhart. To reflect this, rates have been created to reflect a total revenue increase from base electric rates of $112,795,000. The matching reduction in fuel cost recovery accomplished by reducing the base fuel rate in the proposed rates from $0.01722 per KWH to $0.01678 per KWH, will create a net increase from the rate adjustments proposed on Ex. 17 of $104,716,000. (The Commission Staff report calculates this amount as $104,714,153. *See* Hearing

Exhibit 45.) The Company requested that, if the Commission approves the fixed capacity charges for inclusion in base rates, the base fuel rate requested be approved also.

In addition to cost of service, other factors guided the Company in designing its rates. These factors were value of service, rate history, revenue stability, improvement of system load factor, and optimum use of natural resources. (*Id.* at 470). Mr. Hendrix acknowledged on cross-examination that his consideration of these factors necessitates the exercise of experienced, subjective judgment. (*Id.* at 512, 526).

The result of the application of the factors utilized by the Company, objective and subjective, was the rate of return relationships set forth in Hearing Exhibit No.17 (JRH-3):

SOUTH CAROLINA ELECTRIC & GAS
CLASS RATE OF RETURN RELATIONSHIPS

	BEFORE INCREASE			AFTER INCREASE	
	RATE OF RETURN	% OF RETAIL ROR	% INCREASE	RATE OF RETURN	RELATIONSHIP
RESIDENTIAL	7.78%	100%	7.06%	9.50%	96%
SMALL	7.12%	92%	13.81%	10.13%	102%
MEDIUM	7.82%	101%	11.94%	10.87%	109%
LARGE	8.50%	109%	5.38%	10.12%	102%
LIGHTING	7.50%	96%	12.82%	10.17%	102%
TOTAL RETAIL	7.78%	100%	8.70%	9.93%	100%

Mr. Hendrix testified that these relationships reflected cost causation and were significant in order to adhere to the Commission's objective of moving toward equal rates of return among classes of customers. Since the Company's last rate case, the peak demand for Medium General Service and Small General Service grew at a faster pace than the overall peak demand. These two classes are adding costs to the system at a higher rate than the other classes. Tr., Vol. II, Hendrix, at 488.

As to shifts in rate of return ratios, since the Company's last rate case, the Residential class had gone from 92% to 100%, Small General Service went from 108% to 92%, Medium General Service went from 106% to 101%, Large General Service stayed the same at 109%, and Lighting went from 100% to 96%. Assuming reasonably that these trends in shifts will continue, the returns in this case are set so that each of the customer classes can move toward 100% until the next time rates are revisited. It would be inappropriate to set them in a way which would permit disparities to grow during the intervening time frame. The Company has historically considered a "reasonable" relationship to be within 10% plus or minus of the overall return. This basic principle has been used by the Company and approved by the Commission for many years, and the principle is appropriate for use in the present proceeding as well. The proposed revenue spread puts all classes of customers within this band of reasonableness. *Id.* at 488-489.

(b) THE INTERVENORS' POSITION

The arguments of the Intervenors essentially challenged the subjective factors relied on by the Company and contended that rates for every customer class should be cost-based. Any subsidies provided by one class to another as a result of rates being set above costs should be eliminated, according to Intervenor witness Higgins. (Tr., Vol. IV, Higgins, at 1202); Vol. V, Higgins, at 1262). Revenues from rates for each particular class of customer should equal the cost of serving that particular class. (Tr., Vol. IV, Higgins, at 1204). SCE&G's proposed rates place a disproportionate and unreasonable burden on customers in the Medium General Service (Tr., Vol. V, Higgins, at 1262) and

Small General Service classes, (Tr., Vol. V, Wilkes, at 1396), according to the Intervenor witnesses. In order to achieve cost minimization (the customer's efficient use of electricity), rates must send appropriate price signals. Deviation from cost-based pricing distorts the signals sent. (Tr., Vol. IV, Phillips, at 1205). Such distortions could adversely affect the state's base of industrial customers and affect the state's ability to attract new industry. (*Id.* at 1224-25). In the alternative, the Intervenor witnesses state that if strictly cost-based rates are not implemented, a new rate spread should be adopted or the Company's proposed spread should be reduced, utilizing any reductions which the Commission might make to the Company's revenue requirement. (Tr., Vol. V, Higgins, at 1267-1275). There was substantial concern voiced by all classes of customers regarding the implementation of any rate increase given the present state of the economy generally.

(c) PSC STAFF POSITION

While making no recommendation as to the amount of revenue to be allowed in this proceeding, the Staff concluded that the methodology applied in constructing the cost of service study continued to provide reasonable apportionment and allocation of the Company's revenues, operating expenses and rate base. (Tr., Vol. V, Watts, at 1517).

(d) CONCLUSION

The Commission is mindful of the implications of a rate increase on any class of customers and, indeed, on any customer. The Commission is also mindful of the requirements of the utilities which it regulates and the need for decisions which strategically balance the needs of a utility and its customers.

SCE&G in this application sought $104,714,153 in additional revenues per the Staff's report. Our rate of return, capital structure, and accounting and pro forma adjustments as described heretofore produce $70,704,000 in additional annual retail revenue, or a reduction of $34,010,153 from the amount proposed. In deciding where to allocate the approved rate increase across SCE&G's various customer classes, we believe that the small and medium general service customers should receive the greatest share of the $34,010,153 reduction. This is somewhat consistent with Intervenor witness Higgins' proposal to earmark the first $4.2 million of any revenue requirements reduction for the Medium customer class. Under Higgins' plan, any reduction beyond that amount should then be spread to all classes of customers in such a manner as to retain the relative return ratios as described in his testimony. *See* Tr., Vol. V, Higgins, at 1274. Further, we believe that this reduction moves the rate of return for the rate classes back towards the 100% benchmark for rate of return among the various classes. Accordingly, we have determined that the rate increase should be distributed across customer classes as follows:

Rate Class	Requested	Approved
Residential	7.06%	5.11%
Small General Service	13.81%	8.00%
Medium General Service	11.94%	8.00%
Large General Service	5.40%	3.89%
Lighting	12.82%	12.82%

Even though the Small General Service and Medium General Service customers are still receiving the largest increases of any of the classes of customers, we would note that our holding results in substantial reductions to these classes from what was originally proposed by the Company. Also, we would state that, since the Company's last rate case, the peak demand for these two classes grew at a faster pace than the overall peak demand, which means that these two classes are adding costs to the system at a higher rate than the other classes. Tr., Vol. II, Hendrix, at 488. Thus, the greater percentage increase to these two classes is justified in this case.

4. BASIC FACILITIES CHARGE

The Company proposes that the Basic Facilities Charge (BFC) for all rates be increased. In his testimony and exhibits, Company Witness John Hendrix demonstrated, without contradiction, that the actual and continuous expenditures necessary to provide customers with the ability to use electricity substantially exceed the proposed BFC. (*See* Hearing Ex. 17 [JRH-4]). We, therefore, find and conclude that the BFC proposed for each customer class is reasonable and approve same.

5. ADJUSTMENT TO RATE 9

The Company has proposed an adjustment to its Rate 9 (General Service) allowing the Company to eliminate the hourly component of the summer demand charge. A demand charge would still apply but would be based on a peak demand greater than 250 KVA set at any point during the day. As explained by Company Witness John

Hendrix, the Company's experience, since the demand charge was previously approved and imposed, reflects that the time-specific demand component of this rate has been difficult to administer because Rate 9 applies to a large, diverse group of customers and also includes a large number of smaller customers. Consequently, it has been difficult to find metering for measuring peaks at certain hours which fit the pricing of the rate and providing useful customer data. No parties have questioned the legitimacy of the Company's request and the Commission finds and concludes that this request is reasonable and hereby approves same.

6. RATES 20, 21, AND 21(A) (STIPULATION)

The Company and the South Carolina Merchants Association (SCMA) have entered into a Stipulation in this case, which involves Rate 20, Rate 21, and a new experimental rate, Rate 21(A). The Stipulation notes that, based on the Commission's determination and approval of the Company's revenue requirement in this case and the amount of increases to be allocated to each customer class to achieve the approved revenue requirement, the Company will revise the design of its filed rates as set forth below in order to achieve the approved revenue requirement by class of customer, based on the Company's test-year billing determinants.

Rate 20 will be re-designed to include a declining tailblock based on the following criteria:

a) The rate will contain two (2) energy blocks as to which energy charges shall apply. The first energy block will apply to all customers with an energy requirement of up to and including 75,000 KWH. The second block (Declining Block) will apply to all customers with an energy requirement in excess of 75,000 KWH.

b) The second energy block (Declining Block) will be designed so that it is equal to 1.035 times the Company's Rate 23 energy margin as approved by the Commission in this docket, plus the Commission-approved fuel rate, plus the storm damage adder for the Medium General Service Class.

c) The first energy block (75,000 KWH and under) will be designed to recover the remaining revenue requirement of this customer class reduced by the revenue received from the Basic Facility Charge, applicable Demand Charge and the Declining Block Energy Charge.

d) The Company will attempt to put as much as possible of any revenue increase approved by the Commission in this docket for the Medium General Service customer class in the Rate 20 demand charge.

The Company's Rate 21 will remain as proposed in the Company's Application. (The Company makes its Rate 21 available to any customer using the Company's standard service for power and light requirements and having a contract demand of 50 KVA and a maximum demand of less than 1,000 KVA.) SCMA witnesses Kevin C. Higgins (Tr., Vol. V, Higgins, at 1278-79) and James Herritage (Tr., Vol. V, at 1366-67) criticized this rate as not sufficiently rewarding high load-factor customers. As explained by Company witness John Hendrix, the rate is not designed to reward customers regardless of their usage, but is designed to provide an incentive by encouraging customers to shift their usage from on-peak to off-peak periods of use thereby reducing system peak demand. Those customers who do not or cannot shift their usage do not benefit under this rate. Generally, since high-load customers are utilizing their demand at or near its full potential, it is difficult for them to shift load to off-peak periods. (Tr., Hendrix, Vol. II, at 484.) The Commission therefore approves Rate 21 as proposed by the Company.

Under the terms of the Stipulation, the Company will develop an experimental Rate 21(A) incorporating the following terms and conditions:

a) Purpose. The purpose of Rate 21(A) is to determine if a discount will encourage medium general service customers to make operational changes resulting in a shifting of peak loads to off peak periods and/or the shedding of peak loads; to determine the extent of these changes in usage; and to determine what, if any, discount is appropriate as a result of reduction of peak load.

b) Eligibility for Participation. This experimental rate is open to any qualifying (as defined below) Rate 21 customer and the first 250 qualifying Rate 20 customers to register, which will comprise the Initial Participating Group.

c) Qualification for Participation. To qualify for participation in this rate experiment, an eligible customer must have recorded a monthly peak demand of 200 KVA or greater at least once during the twelve (12) months preceding that customer's registration for participation.

d) Notice. The Company will notify eligible customers of the rate experiment in the manner prescribed by the Commission. Such notice shall define the registration period for participation and the procedure for registration. Notice shall be given to eligible customers at least 30 days prior to the opening of the registration period.

e) Registration Period. The period for registration will be 30 days, specified in the Notice required above. At the end of the 30 day registration period, the participating group will be closed and no new participants will be allowed, except for a limited number of new facilities as provided for below. Registration may be accomplished through various means, including e-mail, as prescribed by the Commission, or, in the absence of Commission requirements, as agreed upon by the Company and Commission Staff.

f) Expansion of Participating Group. The parties recognize that participating customers may open new facilities during the experiment period and agree that the participating group may be expanded to accommodate at least some of such new facilities. They also recognize that restrictions on new participants, even though affiliated with existing participants, are necessary in order to effectively manage the proposed rate experiment. To accommodate such customer growth, entities in the Initial Participating Group may, in the aggregate, add up to a maximum of 25 new facilities to the experimental rate after the close of the registration period. New facilities will be accommodated on a first come, first served basis, based on the date upon which such added facility can take service under the rate.

g) Term of Rate 21(A) Experiment. The term period for which the Rate 21(A) experiment shall exist is 48 months, calculated as set forth herein. Because of necessary preparations for participation, such as metering, each participating customer will come on the experimental rate at staggered times. Therefore, the term period of the Rate 21(A) experiment will end 48 months after the final customer in the Initial Participating Group receives service under the experimental rate. The parties recognize that this may mean that some participants participate for longer than 48 months, but none will participate less. The term of the Rate 21(A) experiment is unaffected, however, by the entry of participants under the expansion provisions, in paragraph f) above. Expansion participants will only be involved in the experiment for the remaining period of the term as calculated based on the Initial Participating Group. The Company will make a good faith effort to ensure that all customers which register for Rate 21(A) will begin being billed on that rate within six (6) months of the end of the registration period.

h) Obligation to Complete Experiment. A participating customer must agree in writing to remain on Rate 21(A) for the entire term of the experiment, except that a customer which has been on the rate for twelve (12) months and determines that the rate is not beneficial may change to another rate for which the customer qualifies. In the event of such transfer, there will be no refund of excess charges between the new rate and Rate 21(A), if any. Rate 21(A) is non-transferable. If a customer moves to another location, the rate will not follow such customer nor will it apply to that customer's old location or facility.

i) No Guarantee of Results. The parties understand and agree that Rate 21(A) is an experiment, and the Company guarantees no savings to any customer participating in the experiment. Customer-requested comparisons of Rate 21(A) vs. Rate 20 absent actual on and off peak billing determinants will require estimates by the

Company. The Company will use its best efforts to make such comparisons but makes no guarantee of such comparisons or the results of a customer's participation in Rate 21(A).

j) Analysis of Experiment; Report. After the expiration of 48 months of the Rate 21(A) term period, as defined in paragraph g), above, the Company will prepare an analysis of the experiment and file a report with the Commission with recommendations concerning the future of the experimental rate, including whether it should be made permanent, terminated, modified, expanded or continued as an experiment. Rate 21(A) will remain in force until the Commission takes action on the rate following its review of the Report. After final Commission action on the Report, customers participating in the Rate 21(A) experiment may choose any Company rate for which they qualify.

k) Criteria and Guidelines for Designing Rate 21(A). A Profile Customer load will be used to establish a benchmark to measure the amount of savings to be realized from switching to Rate 21(A) from Rate 20. This profile is as follows:

i) 70% annual load factor – annual KWH equals 2,606,100

ii) 500 KVA peak load

iii) 85% Power Factor which would equal 425 KW

iv) 75% Load Factor during on peak periods – summer KWH equals 215,794; winter KWH equals 512,869

v) Off-peak KWH falls out from there – KWH equals 1,877,438

vi) No incremental off-peak KVA

vii) Rate 21(A) will be designed in a way that the Profile Customer above will realize an estimated savings of 4% by moving from the newly-designed declining-tailblock Rate 20 to Rate 21(A).

viii) Based on the final decision of the Commission and the allocation of the revenue increase to classes, the Company will not be obligated to design Rate 21(A) in a manner that would allow any migration from Rate 24.

Further, under the Stipulation, SCMA withdraws all opposition to the Company's request for a 12.5% return on common equity. SCMA also acknowledges that as a consequence of this stipulation and the rate designs discussed above, the Company may experience a loss of revenue.

We have examined the terms of the Stipulation between the Company and SCMA and find them fair and reasonable. Further, we approve the terms of the Stipulation as we find that the rate proposals contained therein appear to be potentially advantageous to the rate classes of customers who are members of SCMA and other businesses as well.

7. TARIFFS AND TERMS AND CONDITIONS OF SERVICE

In its Application, the Company requested a number of changes in its tariffs and terms and conditions of service. The proposals are discussed below.

(a) RECONNECTION CHARGE

The Company proposes to increase the reconnection charge from $15.00 to $25.00 for reconnections scheduled during normal working hours, with an additional charge of $10.00 when the reconnection is requested after normal working hours. (*Id.* at 473-74).

As indicated in the testimony of Commission Staff Witness Mr. Watts (Tr., Vol. V, Watts, at 1512) and Company Witness Mr. Hendrix (Tr., Vol. II, Hendrix, at 474-75), the Company's actual cost in performing reconnections may justify the proposed charges. However, we deny the proposal. We find that, in today's economic conditions, the residential customer would be burdened by such an increase. Clearly, those customers who already have difficulty paying their electric bill would have even greater difficulty with paying an increased reconnection fee to have their electric service reconnected. The proposal for an increase in the reconnection fee is therefore denied.

(b) SECURITY DEPOSITS FROM NONRESIDENTIAL CUSTOMERS

SCE&G requested an amendment to its General Terms and Conditions (Section IV(D)(5)-"Billing and Payment Terms: Deposit") to provide:

> In addition to the above conditions, new or existing non-residential customers may be required to provide a deposit if their credit standing has deteriorated to the extent that, in the judgment of Company, a condition of insecurity is created with regard to present and future payment(s) owed to the Company.

The effect of this amendment is to allow the Company to collect deposits from a non-residential customer whose credit standing has declined to the extent that it creates a condition of insecurity as to that customer's ability to pay for electric service.

We deny the proposal without prejudice. The difficulty with this proposal is the lack of guidelines as to how it would be determined if the credit standing of the non-residential customer has declined to the extent that it creates a condition of insecurity as to a customer's ability to pay for electric service. At present, this non-specificity troubles us greatly. Accordingly, although we deny the proposal at present, we will consider the matter once again when, and if, the Company provides more specific guidelines as to how the deposit would be applied.

(c) DENIAL OR DISCONTINUANCE OF SERVICE

In Sec. III (j) of its General Terms and Conditions, the Company proposes to delete the provisions of paragraph 10 in its entirety and substitute the following language.

> The Company shall not furnish its service to any premises where, at the time of application any person residing at the premises is indebted or any member of the household is indebted under an undisputed bill for service, previously furnished such person or furnished any other member of the person's household or business.

Following paragraph 13, the Company proposes to add

> Failure of the Company to terminate or suspend service at any time after the occurrence of grounds therefore or to resort to any other legal remedy or to exercise any one or more of such alternative remedies, shall not waive or in any manner affect the Company's right to later resort to any or more of such rights or remedies on account of any such ground then existing or which may subsequently occur.

Company witness, John Hendrix, explained that the requested amendment would allow the Company to refuse to provide new service to a premise where members of the household or business have not paid an undisputed bill. Under the present Terms and Conditions, the Company cannot act on the non-payment if the individual applying for the new service to the premises (who may be a landlord or other non-resident) is not the individual listed on the unpaid bill or a member of that individual's household. (*Id.* at 477).

However, as discussed by Staff witness, A. R. Watts, the difficulty with the Company's proposal is developing language which avoids unintended adverse effects on good credit customers. This would arise when a landlord, homeowner, or other third party not residing in the premises is denied service due to the payment record of a renter or other individual living in the premises. Mr. Watts contended that the proposed modification is inconsistent with the Commission's current regulations. (Tr., Vol. V, Watts, at 1511-12). The Commission agrees with Mr. Watts and denies the proposed amendment.

(d) MISCELLANEOUS CHANGES TO GENERAL TERMS AND CONDITIONS

The Company has proposed miscellaneous other changes to its General Terms and Conditions set forth in Exhibits C1 and C2, attached to the Application.

Based on the testimony of Company witness John R. Hendrix and Staff Witness A. R. Watts, there is ample evidence in the record justifying the need and reasonableness of these proposed changes to the General Terms and Conditions, and they are accordingly hereby approved.

G. EVIDENCE AND CONCLUSIONS REGARDING ACCELERATED DEPRECIATION MECHANISM

(FINDING OF FACT NO. 17)

In our Order No. 1999-655 in Docket No. 1999-389-E, the Commission allowed the Company to accelerate depreciation of its Cope Generating Station when revenue and expense levels warranted. When invoked, the Company records additional depreciation related to the Cope facility, which increases expenses and thereby reduces earnings. The mechanism enables the Company to respond to short-term levels of expenses or revenues, without adjustments in rates which would have long-term implications. The Commission maintains at all times the ability to initiate a rate reduction proceeding if it believes that the Company's earnings will be higher than approved levels on a sustained basis. The Company has requested that the Commission extend until December 31, 2005, the period over which it would be able to apply the accelerated capital recovery mechanism, which would otherwise expire on December 31, 2002. Based on the testimony of Company witness Kevin Marsh, the Commission believes this request is in the best interest of the Company and its customers. (Tr., Vol. I, Marsh, at 169). SCE&G ratepayers obtain benefits in that downward pressure is placed on electric rates over the long term: (a) the depreciated book value of the generation rate base used to serve native load customers is reduced and (b) the Company preserves the ability to make ongoing investments in rate base to meet customer and Company needs, without necessarily having to increase rates to recover such investments. In this way, customers obtain the benefit of a reduction in the depreciated book value of the generation rate base used to serve them, the utility becomes more cost-competitive because of the reduction in the net book value of its generating assets, and shareholders and bondholders receive a return on their investment in those assets. Such a mechanism also sustains a stable regulatory environment during the time when the Company experiences an increased level of earnings. (Tr., Vol. V, Marsh, at 1679-80). The Commission agrees with Mr. Marsh, that the reasons supporting the Commission's initial decision regarding this mechanism are still valid today, and the requested extension is hereby granted. The Commission is not persuaded by the testimony of Consumer Advocate witness Watkins that this accounting treatment is "improper" and allows the Company to "misrepresent" its financial results. The Commission will maintain regulatory oversight of this process and finds no basis for these assertions by the Consumer Advocate's witness.

IV.

DECREE

WHEREFORE, it is ordered:

1. That South Carolina Electric & Gas Company shall implement the rate schedules that conform to the finding of this Order for service rendered on or after February 1, 2003, or at such later time that the Staff of this Commission shall verify in writing to this Commission that $276,224,951 of allowable Jasper Project CWIP has been expended.

2. That South Carolina Electric & Gas Company shall within (10) days from its receipt of this Order file with the Commission rate schedules and terms and conditions of service that incorporate the findings in this Order.

3. That this Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Mignon L. Clyburn, Chairman

ATTEST:

Gary E. Walsh, Executive Director

(SEAL)

Flotation Cost Allowance in Rate of Return Regulation: Comment

Cleveland S. Patterson

The Journal of Finance, Vol. 38, No. 4. (Sep., 1983), pp. 1335-1338.

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Flotation Cost Allowance in Rate of Return Regulation: Comment

CLEVELAND S. PATTERSON*

WHEN A PUBLIC UTILITY sells new equity securities, it incurs "flotation costs." In most regulatory jurisdictions, these costs are not considered to be expenses for purposes of computing revenue requirements and must therefore be accounted for in some other manner.[1] There are two consistent approaches to accounting for flotation costs which have been advocated in regulatory hearings. The first consists in reimbursing the utility in each period for flotation costs actually incurred during that period. The second approach increases the allowed return on equity in all future periods to compensate the equity investor for the erosion of his initial equity contribution due to flotation costs.

Arzac and Marcus (A-M), in the December 1981 issue of this journal, have analyzed the effect of an allowance for flotation costs on the allowed rate of return on equity and argued that in order to avoid dilution of the initial shareholders' equity the allowed rate of return, r, should be equal to

$$r = \frac{k}{1 - \dfrac{fh}{1-f}} \tag{1}$$

where

k = the investors' required rate of return;
f = flotation costs, expressed as a fraction of the value of the issue; and
h = external equity financing rate, expressed as a fraction of earnings

The authors also argue, based on Equation (1), that r increases with the rate of external financing.

An alternative approach to that proposed by A-M, which I refer to as the "conventional approach," is to set the allowed rate of return equal to[2]

$$r' = \frac{D_t}{P_{t-1}(1-f)} + g \tag{2}$$

* Department of Finance, Concordia University, Montreal.

[1] Flotation costs may take the form of temporary "price pressure" due to the increased supply of shares and/or out-of-pocket expenses. The latter are generally deducted directly from retained earnings and thus reduce book value per share unless they are recovered in some manner. Price pressure, if it exists, causes book value per share after the stock issue to be lower than it would have been if the new shares could have been sold at the pre-pressure price. This type of flotation cost, being an opportunity cost, is not accounted for at all in the firm's financial statements.

[2] The derivation of Equation (2) can be found in most standard corporate finance textbooks. Its use in regulatory hearings by financial witnesses is widespread. For a recent example, see testimony by Irwin Friend and David Kosh in FCC Docket No. CC79-63 re American Telephone and Telegraph Company (May 1981).

where D_t/P_{t-1} is the dividend yield in year t and g is the perpetual dividend growth rate expected by investors. Substituting k for $(D_t/P_{t-1}) + g$ gives

$$r' = k + \frac{D_t}{P_{t-1}}\left[\frac{f}{1-f}\right] \tag{3}$$

In this approach, r' is independent of the rate of external financing and is applied to the equity base in every year whether new financing is contemplated or not.

In this comment, we compare the properties of Expression (1) with those of Expression (2). It is shown that if the allowed rate of return is determined consistently according to Expression (1), as recommended by A-M, the utility is reimbursed its flotation costs in each year as they are incurred. For this reason, the allowed rate of return in each year is a function of the external equity financing rate in the A-M model. If the allowed rate of return is determined by Expression (2), the present value of flotation cost adjustments received by the utility is the same as in the previous case. However, the two methods generally differ in their intergenerational allocation of those costs since application of Expression (2) amortizes them over an infinite horizon while application of Expression (1) effectively expenses them.

To show that determination of the allowed rate of return according to Expression (1) is equivalent to expensing issue costs in each period when a stock issue occurs, let $s = hr$ be the amount of new equity financing required each year, N_t, expressed as a fraction of existing equity, K_{t-1}. Then Equation (1) becomes

$$r = \frac{k}{1 - \dfrac{fs}{r(1-f)}} \tag{4}$$

Solving for r and substituting $s = N_t/K_{t-1}$ we obtain

$$r = k + \frac{N_t}{K_{t-1}}\left[\frac{f}{1-f}\right] \tag{5}$$

Let P_t be the value of the new issue before flotation costs so that $N_t = P_t(1-f)$. Then by multiplying Equation (5) through by K_{t-1}, we obtain

$$rK_{t-1} = kK_{t-1} + fP_t \tag{6}$$

In other words, the regulatory process implied by Expression (1) permits investors to receive in each year t their required return on existing equity, kK_{t-1}, plus a full recovery of the flotation expenses, fP_t, incurred in that year.

We now show that the conventional approach also provides for adjustments whose present value is fP_t in each year in which there is a stock issue. Assume a single stock issue in year t which adds an amount N_t to the book value of the firm's equity. The conventional approach applies an incremental return on equity which, from Equation (3), is equal to $D_t/P_{t-1}[f/(1-f)]$ to N_t, and to all future earnings on N_t which are retained at the rate b and reinvested at r', in perpetuity. The present value of this perpetual future stream of return increments at time t,

V_t, is equal to

$$V_t = \sum_{T=t}^{\infty} \frac{N_t(1 + br')^{T-t}}{(1 + k)^{T-t+1}} \cdot \frac{D_t}{P_{t-1}} \left[\frac{f}{1 - f}\right] \tag{7}$$

Since $N_t = P_t(1 - f)$ and, under the assumptions of the model, $g = br'$ so that $k = (D_t/P_{t-1}) + br'$, Equation (7) can be restated as[3]

$$\begin{aligned} V_t &= \frac{P_t(1 - f)}{k - br'} \cdot (k - br')\left[\frac{f}{1 - f}\right] \\ &= fP_t \end{aligned} \tag{8}$$

Comparison of Equation (6) with Equation (8) shows that consistent application of either method will serve to recover the costs of every stock issue, fP_t, $t = 1 \cdots \infty$, and thus avoid dilution of existing shareholders' investment. However, the models differ in that the flotation costs are recovered immediately under the A-M proposal but are amortized over an infinite period under the conventional approach.

It is important to note that the present value of the cost adjustments under the conventional method will only amount to fP_t if r' is applied to cumulative retained earnings as well as issued common stock and if it is applied in every future year whether or not there is a stock issue in that year. In the extreme case where a company had only one initial stock issue in year 1, for example, the costs of the issue would only be recovered if r' were applied consistently to total equity, including retained earnings, in all future years even though no future financing was contemplated. Under the conventional approach, in other words, the flotation cost adjustment is not made to reflect current or future financing costs, as in the A-M model; it is made to compensate investors for costs incurred in *preceding* stock issues.[4]

In summary, we have shown that the present value of the adjustment for flotation costs is the same whether Expression (1) is used or whether Expression (2) is used. Where the two methods differ is in the intergenerational allocation of the costs. Expression (1) effectively expenses issue costs as incurred, while Expression (2) effectively amortizes them over an assumed infinite equity life.[5]

[3] Since the purpose of the flotation cost adjustment is to avoid dilution of existing investors' equity by maintaining the market value, net of flotation costs, equal to book value, there is no additional contribution to g from the issue of new stock whose net proceeds exceed book value. Under the same conditions, the present value of the flotation cost adjustment is independent of b and therefore the assumption made in the derivation of Equation (8) that b is the same in every period is sufficient but not necessary for the equality of V_t and fP_t.

[4] Confusion over the purpose of the adjustment in the conventional approach can lead to inappropriate "strawman" criticisms of its application. See for example A-M's footnote 4.

It is perhaps troubling that current investors should receive compensation for expenses incurred by previous investors. However, the treatment is analogous to the conventional inclusion of amortized bond issue expenses in the current embedded cost of debt.

[5] It can be seen from a comparison of Equations (3) and (5) that sufficient conditions for the two methods to result in identical adjustments in each year, as well as identical present values, are that market price be equal to book value and s be equal to $r'(1 - b)$. For other equity growth rates, the adjustments in any year t will in general be different.

Which is "correct" is a policy decision with respect to intergenerational fairness and the smoothing of revenue requirements over time. The principal policy constraint is that, whichever method is chosen, it must be used consistently over the life of the utility. If a switch from the use of Expression (2) to the use of Expression (1) is made, then investors will never fully recover the flotation costs incurred in acquiring equity capital prior to the switchover. Conversely, if a switch is made in the other direction and Expression (2) is applied to all equity, rather than being restricted to new equity and its associated retained earnings added after the switchover, then investors will be compensated twice for pre-switchover flotation costs.

REFERENCES

1. E. R. Arzac and M. Marcus. "Flotation Cost Allowance in Rate of Return Regulation: A Note." *Journal of Finance* 36 (December 1981), 1199–1202.

DIRECT TESTIMONY

OF

JANIS FREETLY

Senior Financial Analyst
Finance Department
Financial Analysis Division
Illinois Commerce Commission

Central Illinois Light Company, d/b/a/ AmerenCILCO

Central Illinois Public Service Company, d/b/a/ AmerenCIPS

and

Illinois Power Company, d/b/a AmerenIP

Proposed General Increase in Electric Rates
and
Proposed General Increase in Gas Rates

Docket Nos. 09-0306 – 09-0311 (Cons.)

September 28, 2009

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Witness Identification

Q. Please state your name and business address.

A. My name is Janis Freetly. My business address is 527 East Capitol Avenue, Springfield, Illinois 62701.

Q. What is your current position with the Illinois Commerce Commission ("Commission")?

A. I am currently employed as a Senior Financial Analyst in the Finance Department of the Financial Analysis Division.

Q. Please describe your qualifications and background.

A. In May of 1995, I earned a Bachelor of Business degree from Western Illinois University. I received a Master of Business Administration degree, with a concentration in Finance, from Western Illinois University in May of 1998. I have been employed by the Commission in my present position since September of 1998. I was promoted to Senior Financial Analyst on August 31, 2001.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony and the accompanying schedules is to present my analysis of the cost of common equity of the electric delivery services and natural gas distribution operations of Central Illinois Light Company d/b/a AmerenCILCO ("CILCO"), Central Illinois Public Service Company d/b/a/ AmerenCIPS ("CIPS"), and Illinois Power Company d/b/a AmerenIP ("IP") (collectively referred to as the

"Ameren Illinois Utilities," "AIU" or "Companies"). In addition, I will respond to the direct testimony of Ameren witness Kathleen C. McShane.[1]

Cost of Common Equity

Q. What is your estimate of the Companies' costs of common equity for natural gas distribution operations?

A. My analysis indicates that the costs of common equity for natural gas distribution operations are 9.83% for CILCO, 9.41% for CIPS and 9.83% for IP.

Q. What is your estimate of the Companies' costs of common equity for electric delivery service operations?

A. My analysis indicates that the costs of common equity for electric delivery service operations are 10.31% for CILCO, 10.23% for CIPS and 10.35% for IP.

Q. How did you measure the investor-required rates of return on common equity for the Companies?

A. I measured the investor-required rates of return on common equity for the Companies' electric delivery service and natural gas distribution operations with the non-constant discounted cash flow ("NCDCF") and risk premium models. Since the Companies do not have market-traded common stock, NCDCF and risk premium models cannot be applied directly to the Companies; therefore, I applied both models to samples of public utilities comparable in risk to the electric delivery service and natural gas distribution operations of the Companies.

[1] AmerenCILCO Ex. 12.0E (Revised), AmerenCILCO Ex. 12.0G (Revised), AmerenCIPS Ex. 12.0E (Revised), AmerenCIPS Ex. 12.0G (Revised), AmerenIP Ex. 12.0E (Revised), and AmerenIP Ex. 12.0G (Revised).

Sample Selection

Q. How did you select your Gas sample?

A. My Gas sample comprises the same nine local gas distribution companies utilized by Ms. McShane, namely, AGL Resources, Inc., Atmos Energy Corp., New Jersey Resources Corp., Nicor Inc., Northwest Natural Gas Company, Piedmont Natural Gas Company, South Jersey Industries, Inc., Southwest Gas Corp., and WGL Holdings, Inc, as shown on Schedule 6.01-G.

Q. How did you select your Electric sample?

A. I began with Ms. McShane's list of electric utilities categorized by the Edison Electric Institute ("EEI") as Regulated or Mostly Regulated. I then eliminated the electric companies in the Mostly Regulated category since my return on common equity recommendation is for the regulated electric operations of the Ameren Illinois Utilities. From the list of electric utilities categorized as Regulated by EEI, I eliminated the companies that were not assigned an industry classification code of 4911 (Electric Services) or 4931 (Electric and Other Services Combined) within Standard & Poor's ("S&P") Utility Compustat. Next, I removed companies that are or recently have been involved in mergers, acquisitions, or divestures. I also removed companies that lacked growth rate estimates from Zacks Investment Research, Inc. ("Zacks") or 60 months of data necessary to calculate beta. The sixteen remaining regulated electric utilities that compose my Electric sample are ALLETE, Ameren Corp., American Electric Power Company, Inc., Avista Corp., Cleco Corp., CMS Energy Group, Great Plains Energy Corp., IDACORP, Inc., Northeast Utilities, PG&E Corp., Pinnacle West Capital Corp., Progress Energy, TECO Energy, Westar Energy, Inc., Wisconsin Energy Corp., and Xcel Energy Inc, as shown on Schedule 6.01-E.

Discounted Cash Flow ("DCF") Analysis

Q. Please describe DCF analysis.

A. For a utility to attract common equity capital, investors must expect it to provide a rate of return on common equity sufficient to meet their requirements. DCF analysis establishes a rate of return directly from investor requirements. Implementation of a DCF analysis does not require a comprehensive analysis of a utility's operating and financial risks since the market price of a utility's stock already embodies the market consensus of those risks.

According to DCF theory, a security price equals the present value of the cash flow investors expect it to generate. Specifically, the market value of common stock equals the cumulative value of the expected stream of future dividends after each dividend is discounted by the investor-required rate of return.

Q. Please describe the DCF model with which you measured the investor-required rate of return on common equity.

A. As it applies to common stocks, DCF analysis is generally employed to determine appropriate stock prices given a specified discount rate. Since a DCF model incorporates time-sensitive valuation factors, it must correctly reflect the timing of the dividend payments that stock prices embody. As such, incorporating stock prices that the financial market sets on the basis of quarterly dividend payments into a model that ignores the time value of quarterly cash flows constitutes a misapplication of DCF analysis. The companies in the Gas and Electric samples pay dividends quarterly; therefore, I applied a multi-stage non-constant-growth quarterly DCF model to measure the annual required rate of return on common equity.

Q. In past proceedings, Staff has typically employed a constant growth, or single-stage, DCF model. Why did you apply a non-constant growth DCF model in this proceeding?

A. Staff did not typically use a non-constant growth DCF model in past proceedings because it is a more elaborate model with additional unobservable growth rate variables that are *likely* subject to greater measurement error than the analyst growth rate estimates Staff uses in constant-growth DCF analyses. Specifically, no observable estimates of investor "transitional" and "steady-state" growth rate expectations for individual companies exist.[2] Nevertheless, under certain circumstances, measurement error associated with a constant-growth DCF analysis exceeds that associated with a non-constant growth DCF model, making the latter model preferable.

A single-stage, constant growth DCF model employs a single growth rate estimate, which is assumed to be sustainable infinitely. Thus, the cost of common equity calculation derived from a constant growth estimate is correct if the near-term growth rate forecast for each company in the sample is expected

[2] The "steady-state" is defined as a period of long, indefinite length during which a company's expected rate of return on new investment does not vary. (A constant growth DCF model assumes a company is already in the "steady-state;" that is, the growth rate is the "steady-state" growth rate). The "transitional" phase is a bridge between the current, near-term period and the "steady-state" level during which the company's rate of return on new investment adjusts from the current level to the "steady-state" level.

to equal its average long-term dividend growth. However, the level of growth indicated by the average 3-5 year growth rates for my Gas and Electric samples are not sustainable over the long-term. Therefore, I implemented a multi-stage, non-constant growth DCF model.

Q. Why did you conclude that the 3-5 year growth rates for your Gas and Electric samples are not sustainable over the long-term?

A. The average Zacks growth rate is 6.33% for my Gas sample and 6.53% for my Electric sample. As I will discuss later, the current expectations of growth for the economy, as measured by gross domestic product ("GDP"), is only approximately 4.70%. In theory, no company could sustain into infinity a growth rate any greater than that of the overall economy, or it would eventually grow to become the entire economy. Moreover, since utilities in particular are generally below-average growth companies, the sustainability of an above average growth rate is particularly dubious. Given the difference between the growth rates for my Gas and Electric sample companies and the overall growth of the economy, the continuous sustainability of the Zacks growth rates for my Gas and Electric samples is highly unlikely. Thus, I used a non-constant growth DCF model that employs distinct growth rate estimates for each of three discrete time periods.

Q. Please describe how you modeled your non-constant growth DCF analysis.

A. I modeled three stages of dividend growth. The first, a near-term growth stage, is assumed to last five years. The second stage is a transitional growth period lasting from the end of the fifth year to the end of the tenth year. Finally, the third, or "steady-state," growth stage is assumed to begin after the tenth year and continue into perpetuity. An expected stream of dividends is estimated by applying these stages of growth to the current dividend. The discount rate that equates the present value of this expected stream of cash flows to the company's current stock price equals the market-required return on common equity. Schedule 6.02 mathematically presents the relationship between the cash flow stream, stock price, and market required rate of return on common equity.

Q. How did you estimate the growth rate parameter?

A. Determining the market-required rate of return with the DCF methodology requires a growth rate that reflects the expectations of investors. Although the current market price reflects aggregate investor expectations, market-consensus expected growth rates cannot be observed directly.

For the first stage, which is assumed to last five years, I used Zacks growth rate estimates as of August 18, 2009. Zacks summarizes and publishes the earnings growth expectations of financial analysts employed by the research departments of investment brokerage firms. Zacks provides 3-5 year forward-looking estimates of earnings growth.

To estimate the long-term growth expectations for the third, steady-state stage, I utilized the implied 20-year forward U.S. Treasury rate in ten years, which reflects current expectations of the long-term overall economic growth during the steady-state growth stage of my non-constant DCF model.[3] An implied 20-year forward U.S. Treasury rate in ten years of 4.83% was derived from the 3.51% 10- and 4.35% 30-year U.S. Treasury rates as of August 18, 2009 using the following formula: [4]

$${}_{20}f_{10} = [(1+{}_{30}r_0)^{30} / (1+{}_{10}r_0)^{10}]^{1/20} - 1$$

Where ${}_{20}f_{10}$ = the implied 20-year forward U.S. Treasury rate in ten years;
${}_{30}r_0$ = the current 30-year U.S. Treasury rate; and
${}_{10}r_0$ = the current 10-year U.S. Treasury rate

The growth rate employed in the intervening, five-year transitional stage equals the average of the Zacks growth rate and the steady-state stage growth rate. Schedule 6.03-G presents the growth rate estimates for the companies in the Gas sample. Schedule 6.03-E presents the growth rate estimates for the companies in the Electric sample.

Q. Is an estimate of the long-term overall economic growth rate a reasonable estimate for the steady-state stage growth for your Gas and Electric samples?

A. Ideally, company-specific steady-state growth rate estimates are preferable. Unfortunately, company specific steady-state growth rate forecasts are not available. Further, for the reasons presented above, it is evident that investors

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[3] Excepting a small premium for interest rate risk, the implied 20-year forward U.S. Treasury rate in ten years represents the risk-free rate of return during the 20-year period beginning in 10 years and ending 30 years from today, as implied by current 10- and 30-year U.S. Treasury rates. As I explain later, the overall economic growth rate and the risk-free rate of return should be similar since both are a function of production opportunities and consumption preferences.

[4] Global Insight forecasts indicate a 4.5% nominal GDP growth rate for the 2019-2039 period. (Global Insight, *The U.S. Economy: The 30-Year Focus, First Quarter 2009*, Table 1.)

cannot reasonably expect utilities to sustain growth over the very long term equal to analysts' current 3-5 growth rate estimates. Thus, while the overall economic growth rate might be biased upward for generally low-growth companies such as utilities, it is much closer to the growth rate that investors could reasonably expect utilities to sustain over the long term.

Q. How did you measure the stock price?

A. A current stock price reflects all information that is available and relevant to the market; thus, it represents the market's assessment of the common stock's current value. I measured each company's current stock price with its closing market price from August 18, 2009. Those stock prices for the companies in the Gas sample appear on Schedule 6.04-G. Those stock prices for the companies in the Electric sample appear on Schedule 6.04-E.

Since stock prices reflect the market's concurrent expectation of the cash flows the securities will produce and the rate at which those cash flows are discounted, an observed change in the market price does not necessarily indicate a change in the required rate of return on common equity. Rather, a price change may reflect investors' re-evaluation of the expected dividend growth rate. In addition, stock prices change with the approach of dividend payment dates. Consequently, when estimating the required return on common equity with the DCF model, one should measure the expected dividend yield and the corresponding expected growth rate concurrently. Using a historical stock price along with current growth expectations or combining an updated stock price with past growth expectations would likely produce an inaccurate estimate of the market-required rate of return on common equity.

Q. Please explain the significance of the column titled "Next Dividend Payment Date" shown on Schedules 6.04-G and 6.04-E.

A. Estimating year-end dividend values requires measuring the length of time between each dividend payment date and the first anniversary of the stock observation date. For the first dividend payment, that length of time is measured from the "Next Dividend Payment Date." Subsequent dividend payments occur in quarterly intervals.

Q. How did you estimate the expected future quarterly dividends?

A. Most utilities declare and pay the same dividend per share for four consecutive quarters before adjusting the rate. Consequently, I assumed the current declared dividend rate will remain in effect for a minimum of four quarters and then adjust during the same quarter it changed during the preceding year; if the utility did not change its dividend during the last year, I assumed the rate would change during the next quarter. The average expected growth rate was applied to the current declared dividend rate to estimate the expected dividend rate. For the Gas sample, Schedule 6.04-G presents the current quarterly dividends for the prior year and Schedule 6.05-G presents the expected quarterly dividends for the coming year. For the Electric sample, Schedule 6.04-E presents the current quarterly dividends for the prior year and Schedule 6.05-E presents the expected quarterly dividends for the coming year. This technique was applied to produce dividend projections for the next 11 years, substituting the appropriate growth rate estimate for each of the three stages of my non-constant growth DCF analysis.

Q. Based on your DCF analysis, what are the estimated required rates of return on common equity for the Gas and Electric samples?

A. My non-constant growth DCF analysis estimates a required rate of return on common equity of 9.79% for the Gas sample, as shown on Schedule 6.06-G. The DCF estimates for the Gas sample are derived from the growth rates presented on Schedule 6.03-G, the stock price and dividend payment dates presented on Schedule 6.04-G, and the expected quarterly dividends presented on Schedule 6.05-G.

My non-constant growth DCF analysis estimates a required rate of return on common equity of 10.49% for the Electric sample, as shown on Schedule 6.06-E. The DCF estimates for the Electric sample are derived from the growth rates presented on Schedule 6.03-E, the stock price and dividend payment dates presented on Schedule 6.04-E, and the expected quarterly dividends presented on Schedule 6.05-E.

Risk Premium Analysis

Q. Please describe the risk premium model.

A. The risk premium model is based on the theory that the market-required rate of return for a given security equals the risk-free rate of return plus a risk premium associated with that security. A risk premium represents the additional return investors expect in exchange for assuming the risk inherent in an investment. Mathematically, a risk premium equals the difference between the expected rate of return on a risk factor and the risk-free rate. If the risk of a security is measured relative to a portfolio, then multiplying that relative measure of risk and the portfolio's risk premium produces a security-specific risk premium for that risk factor.

The risk premium methodology is consistent with the theory that investors are risk-averse. That is, investors require higher returns to accept greater exposure to risk. Thus, if investors had an opportunity to purchase one of two securities with equal expected returns, they would purchase the security with less risk. Conversely, if investors had an opportunity to purchase one of two securities with equal risk, they would purchase the security with the higher expected return. In equilibrium, two securities with equal quantities of risk have equal required rates of return.

The Capital Asset Pricing Model ("CAPM") is a one-factor risk premium model that mathematically depicts the relationship between risk and return as:

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

where R_j $\equiv$ the required rate of return for security j;

R_f $\equiv$ the risk-free rate;

R_m $\equiv$ the expected rate of return for the market portfolio; and

β_j $\equiv$ the measure of market risk for security j.

In the CAPM, the risk factor is market risk, which is defined as risk that cannot be eliminated through portfolio diversification. To implement the CAPM, one must estimate the risk-free rate of return, the expected rate of return on the market portfolio, and a security or portfolio-specific measure of market risk.

Q. How did you estimate the risk-free rate of return?

A. I examined the suitability of the yields on four-week U.S. Treasury bills and thirty-year U.S. Treasury bonds as estimates of the risk-free rate of return.

Q. Why did you examine the yields on U.S. Treasury bills and bonds as measures of the risk-free rate?

A. The proxy for the nominal risk-free rate should contain no risk premium and reflect similar inflation and real risk-free rate expectations to the security being analyzed through the risk premium methodology.[5] The yields of fixed income securities include premiums for default and interest rate risk. Default risk pertains to the possibility of default on principal or interest payments. Securities of the United States Treasury are virtually free of default risk by virtue of the federal government's fiscal and monetary authority. Interest rate risk pertains to the effect of unexpected interest rate fluctuations on the value of securities.

Since common equity theoretically has an infinite life, its market-required rate of return reflects the inflation and real risk-free rates anticipated to prevail over the long run. U.S. Treasury bonds, the longest term Treasury securities, are issued with terms to maturity of thirty years;[6] U.S. Treasury notes are issued with terms to maturity ranging from two to ten years; U.S. Treasury bills are issued with

[5] Real risk-free rate and inflation expectations comprise the non-risk portion of a security's rate of return.

[6] On February 9, 2006, the U.S. Treasury resumed issuing 30-year Treasury bonds.

terms to maturity ranging from four weeks to six months. Therefore, U.S. Treasury bonds are more likely to incorporate within their yields the inflation and real risk-free rate expectations that drive, in part, the prices of common stocks than either U.S. Treasury notes or Treasury bills.

However, due to relatively long terms to maturity, U.S. Treasury bond yields also contain an interest rate risk premium that diminishes their usefulness as measures of the risk-free rate. U.S. Treasury bill yields contain a smaller premium for interest rate risk. Thus, in terms of interest rate risk, U.S. Treasury bill yields more accurately measure the risk-free rate.

Q. Given that the inflation and real risk-free rate expectations reflected in the yields on U.S. Treasury bonds and the prices of common stocks are similar, does it necessarily follow that the inflation and real risk-free rate expectations that are reflected in the yields on U.S. Treasury bills and the prices of common stocks are dissimilar?

A. No. To the contrary, short and long-term inflation and real risk-free rate expectations, including those that are reflected in the yields on U.S. Treasury bills, U.S. Treasury bonds, and the prices of common stocks, should equal over time. Any other assumption implausibly implies that the real risk-free rate and inflation is expected to systematically and continuously rise or fall.

Although expectations for short and long-term real risk-free rates and inflation should equal over time, in finite time periods, short and long-term expectations may differ. Short-term interest rates tend to be more volatile than long-term interest rates.[7] Consequently, over time U.S. Treasury bill yields are less biased (i.e., more accurate) but less reliable (i.e., more volatile) estimators of the long-term risk-free rate than U.S. Treasury bond yields. In comparison, U.S. Treasury bond yields are more biased (i.e., less accurate) but more reliable (i.e., less volatile) estimators of the long-term risk-free rate. Therefore, an estimator of the long-term nominal risk-free rate should not be chosen mechanistically. Rather, the similarity in current short and long-term nominal risk-free rates should be evaluated. If those risk-free rates are similar, then U.S. Treasury bill yields should be used to measure the long-term nominal risk-free rate. If not, some other proxy or combination of proxies should be used.

Q. What are the current yields on four-week U.S. Treasury bills and thirty-year U.S. Treasury bonds?

A. Four-week U.S. Treasury bills are currently yielding 0.14%. Thirty-year U.S. Treasury bonds are currently yielding 4.40%. Both estimates are derived from quotes for August 18, 2009.[8] Schedule 6.07 presents the published quotes and effective yields.

Q. Of the U.S. Treasury bill and bond yields, which is currently a better proxy for the long-term risk-free rate?

A. In terms of the GDP price index, the Energy Information Administration ("EIA") forecasts the annual inflation rate will average 1.6% during the 2009-2030

[7] Fabozzi and Pollack, ed., *The Handbook of Fixed Income Securities*, Fourth Edition, Irwin, p. 789.

[8] The Federal Reserve Board, *Federal Reserve Statistical Release: Selected Interest Rates, H.15 Daily Update*, http://www.federalreserve.gov/releases/H15/update/, August 19, 2009.

period.[9] In comparison, Global Insight forecasts that annual GDP price inflation will average 1.8% during the 2009-2039 period.[10] In terms of the Consumer Price Index ("CPI"), the *Survey of Professional Forecasters* ("*Survey*") forecasts that inflation rate will average 2.6% during the next ten years.[11] Although EIA, Global Insight and the *Survey* do not forecast the real risk-free rate, they do forecast real GDP growth, which is a proxy for the real risk-free rate. EIA forecasts real GDP growth will average 2.7% during the 2009-2030 period.[12] Global Insight forecasts real GDP growth will average 2.7% during the 2009-2039 period.[13] The *Survey* forecasts real GDP growth will average 2.6% during the next ten years.[14] Those forecasts imply a long-term, nominal risk-free rate between 4.3% and 5.2%.[15] Therefore, EIA, Global Insight, and *Survey* forecasts of inflation and real GDP growth expectations suggest that, currently, the U.S. Treasury bond yield of 4.40% more closely approximates the long-term risk-free rate. It should be noted, however, that the U.S. Treasury bond yield is an upwardly biased

[9] Energy Information Administration*, Annual Energy Outlook 2009,* Table A20. Macroeconomic Indicators, www.eia.doe.gov/oiaf/aeo/, March 2009.

[10] Global Insight, *The U.S. Economy: The 30-Year Focus, First Quarter 2009*, Table 1: Summary of the U.S. Economy.

[11] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, www.phil.frb.org/files/spf/survq403.html, August 14, 2009. The *Survey* aggregates the forecasts of approximately fifty forecasters.

[12] Energy Information Administration*, Annual Energy Outlook 2009,* Table A20. Macroeconomic Indicators, www.eia.doe.gov/oiaf/aeo/, March 2009.

[13] Global Insight, *The U.S. Economy: The 30-Year Focus, First Quarter 2009*, Table 1: Summary of the U.S. Economy.

[14] Federal Reserve Bank of Philadelphia, *Survey of Professional Forecasters*, www.phil.frb.org/files/spf/survq403.html, February 13, 2009.

[15] Nominal interest rates are calculated as follows:

$$r = (1 + R) \times (1 + i) - 1.$$

where r ≡ nominal interest rate;
R ≡ real interest rate; and
i ≡ inflation rate.

estimator of the long-term risk-free rate due to the inclusion of an interest rate risk premium associated with its relatively long term to maturity.

Q. Please explain why the real risk-free rate and the GDP growth rate should be similar.

A. Risk-free securities provide a rate of return sufficient to compensate investors for the time value of money, which is a function of production opportunities, time preferences for consumption, and inflation.[16] The real risk-free rate does not include premiums for inflation; therefore, only production opportunities and consumption preferences affect it. The real GDP growth rate measures output of goods and services excluding inflation and, as such, also reflects both production and consumers' consumption preferences. Therefore, both the real GDP growth rate and the real risk-free rate of return should be similar since both are a function of production opportunities and consumption preferences without the effects of a risk premium or an inflation premium.

Q. How was the expected rate of return on the market portfolio estimated?

A. The expected rate of return on the market was estimated by conducting a DCF analysis on the firms composing the S&P 500 Index ("S&P 500") as of June 30, 2009. That analysis used dividend information and closing market prices reported by Zacks Research Wizard and in the July 2009 edition of *S&P Security Owner's Stock Guide*. July 1, 2009 growth rate estimates were also obtained primarily from Zacks and secondarily from Yahoo! Finance.[17] Firms not paying a

[16] Brigham and Houston, Fundamentals of Financial Management, 8th edition.
[17] Growth rates were obtained from Yahoo! Finance only if unavailable from Zacks.

dividend as of June 30, 2009, or for which neither Zacks nor Yahoo! Finance growth rates were available were eliminated from the analysis. The resulting company-specific estimates of the expected rate of return on common equity were then weighted using market value data from Zacks Research Wizard. The estimated weighted average expected rate of return for the remaining 356 firms, composing 82.27% of the market capitalization of the S&P 500, equals 12.70%.

Q. How did you measure market risk on a security-specific basis?

A. Beta measures risk in a portfolio context. When multiplied by the market risk premium, a security's beta produces a market risk premium specific to that security. I used Value Line's betas, Zacks betas, and regression analysis to estimate the betas of the Gas and Electric samples.

I used published Value Line beta estimates for each company in the Gas and Electric samples. Value Line estimates beta for a security with the following model using an ordinary least-squares technique:[18]

$$R_{j,t} = a_j + \beta_j \times R_{m,t} + e_{j,t}$$

where $R_{j,t}$ $\equiv$ the return on security j in period t;

$R_{m,t}$ $\equiv$ the return on the market portfolio in period t;

a_j $\equiv$ the intercept term for security j;

β_j $\equiv$ beta, the measure of market risk for security j; and

$e_{j,t}$ $\equiv$ the residual term in period t for security j.

[18] Statman, Meir, "Betas Compared: Merrill Lynch vs. Value Line", *The Journal of Portfolio Management*, Winter 1981.

A beta can be calculated for firms with market-traded common stock. Value Line calculates its betas in two steps. First, the returns of each company are regressed against the returns of the New York Stock Exchange Composite Index ("NYSE Index") to estimate a raw beta. The regression analysis employs 260 weekly observations of stock return data. Then, an adjusted beta is estimated through the following equation:

$$\beta_{adjusted} = 0.35 + 0.67 \times \beta_{raw}.$$

The regression analysis estimate of beta for a security or portfolio of securities is estimated with the following model using an ordinary least-squares technique:

$$R_{j,t} - R_{f,t} = a_j + \beta_j \times (R_{m,t} - R_{f,t}) + e_{j,t}$$

where $R_{j,t}$ $\equiv$ the return on security *j* in period *t*;

$R_{f,t}$ $\equiv$ the risk-free rate of return in period *t*;

$R_{m,t}$ $\equiv$ the return on the market portfolio in period *t*;

a_j $\equiv$ the intercept term for security *j*;

β_j $\equiv$ beta, the measure of market risk for security *j*; and

$e_{j,t}$ $\equiv$ the residual term in period *t* for security *j*.

The regression analysis beta estimates for the Gas and Electric samples were calculated in three steps. First, the U.S. Treasury bill return is subtracted from both the average percentage change in the sample's stock prices and the percentage change in the NYSE Index to estimate each portfolio's return in excess of the risk-free rate. Second, the excess returns of the sample are regressed against the excess returns of the NYSE Index to estimate a raw beta. The regression analysis employs sixty monthly observations of stock and U.S. Treasury bill return data. Third, the beta is adjusted through the following equation:

$$\beta_{adjusted} = 0.33743 + 0.66257 \times \beta_{raw}.$$

Like Staff's regression beta, Zacks employs 60 monthly observations in its beta estimation. However, Zacks betas regress stock returns against the S&P 500 Index rather than the NYSE Index. Further, the beta estimates Zacks publishes are not adjusted (i.e., raw). Thus, I adjusted them using the same formula used to adjust the regression beta.

Q. Why do you use an adjusted beta estimate?

A. Some empirical tests of the CAPM suggest that the linear relationship between risk, as measured by raw beta, and return is flatter than the CAPM predicts. That is, securities with raw betas less than one tend to realize higher returns than the CAPM predicts. Conversely, securities with raw betas greater than one tend to realize lower returns than the CAPM predicts. Adjusting the raw beta estimate towards the market mean value of 1.0 results in a linear relationship between the beta estimate and realized return that more closely conforms to the CAPM prediction.[19] Securities with betas less than one are adjusted upwards thereby increasing the predicted required rate of return towards observed realized rates of return. Conversely, securities with betas greater than one are adjusted

[19] Litzenberger, Ramaswamy and Sosin, "On the CAPM Approach to the Estimation of a Public Utility's Cost of Equity Capital," *Journal of Finance*, May 1980, pp. 375-376.

downwards thereby decreasing the predicted required rate of return towards observed realized rates of return.

Q. What are the beta estimates for the Gas and Electric samples?

A. Since both the Zacks beta estimates and the regression beta estimates are calculated using monthly data rather than weekly data (as Value Line uses), I averaged those results to avoid over-weighting that approach. I then averaged that result with the Value Line beta to obtain a single estimate of beta for each sample.

For the Gas sample, the regression beta estimate is 0.51 and the Value Line beta and Zacks beta average 0.68 and 0.56, respectively, as shown in Table 1 below.[20]

Table 1

Company	Value Line Estimate	Zacks Estimate*
AGL RESOURCES	0.75	0.61
ATMOS ENERGY CORP	0.65	0.68
NEW JERSEY RESOURCES	0.65	0.44
NICOR INC	0.75	0.57
NORTHWEST NATURAL GAS	0.60	0.52
PIEDMONT NATURAL GAS	0.65	0.46
SOUTH JERSEY INDUSTRIES	0.65	0.50
SOUTHWEST GAS	0.75	0.80
WGL HOLDINGS INC	0.65	0.48
Average	0.68	0.56

* after adjustment

[20] The Value Line Investment Survey, "Summary and Index," August 14, 2009, pp. 2-22; Zacks Research Wizard, August 18, 2009.

The average of the Zacks and regression betas is 0.54. Averaging this monthly beta with the weekly Value Line beta (0.68), produces a beta for the Gas sample of 0.61.

For the Electric sample, the regression beta estimate is 0.66 and the Value Line beta and Zacks beta average 0.71 and 0.72, respectively, as shown in Table 2 below.[21]

Table 2

Company	Value Line Estimate	Zacks Estimate*
Allete Inc.	0.70	0.77
American Electric Power	0.75	0.71
Ameren Corp.	0.80	0.82
Avista Corp.	0.70	0.83
Cleco Corp.	0.70	0.70
CMS Energy	0.80	0.73
Great Plains Energy	0.75	0.85
Idacorp Inc.	0.70	0.61
Northeast Utilities	0.70	0.66
PG&E Corp.	0.55	0.56
Pinnacle West Capital	0.75	0.75
Progress Energy	0.65	0.61
Teco Energy	0.80	0.93
Westar Energy	0.75	0.76
Wisconsin Energy Corp.	0.65	0.58
Xcel Energy Inc.	0.65	0.64
Average	0.71	0.72

* after adjustment

[21] The Value Line Investment Survey, "Summary and Index," August 14, 2009, pp. 2-22; Zacks Research Wizard, August 18, 2009.

The average of the Zacks and regression betas estimates is 0.69. Averaging this monthly beta with the weekly Value Line beta (0.71), produces a beta for the Electric sample of 0.70.

Q. What required rate of return on common equity does the risk premium model estimate for the sample?

A. For the Gas sample, the risk premium model estimates a required rate of return on common equity of 9.46%. For the Electric sample, the risk premium model estimates a required rate of return on common equity of 10.21%. The computations of these estimates appear on Schedule 6.07.

Cost of Common Equity Recommendation

Q. Based on your entire analysis, what is your estimate of the required rate of return on the common equity for the Companies?

A. A thorough analysis of the required rate of return on common equity requires both the application of financial models and the analyst's informed judgment. An estimate of the required rate of return on common equity based solely on judgment is inappropriate. Nevertheless, because techniques to measure the required rate of return on common equity necessarily employ proxies for investor expectations, judgment remains necessary to evaluate the results of such analyses. Along with DCF and risk premium analyses, I have considered the observable 5.70% rate of return the market currently requires on less risky A-rated utility long-term debt.[22] Based on my analysis, in my judgment, the investor-required rate of return on common equity for natural gas distribution operations equals 9.83% for CILCO, 9.41% for CIPS and 9.83% for IP and the investor-required rate of return on common equity for electric delivery service operations equals 10.31% for CILCO, 10.23% for CIPS and 10.35% for IP.

Q. Please summarize how you estimated the investor-required rate of return on common equity for the natural gas distribution operations of the Companies.

A. First, for the natural gas distribution operations of the Companies, I estimated the investor required rate of return on common equity for the Gas sample of 9.63% by taking the simple average of the DCF-derived results (9.79%) and the risk-premium-derived results (9.46%) for the Gas sample.

Second, I adjusted the Gas sample's investor required rate of return downward by 12 basis points for CIPS to reflect the lower financial risk of CIPS relative to the Gas sample. I adjusted the Gas sample's investor required rate of return upward by 30 basis points for CILCO and IP to reflect the higher financial risk of CILCO and IP relative to the Gas sample.

Third, I adjusted the Companies' cost of common equity downward by 10 basis points to reflect the reduction in risk associated with the recovery of a greater

[22] Value Line Investment Survey, *Selection & Opinion,* August 14, 2009, p. 3377, http://www.valueline.com.

portion of fixed delivery services costs through the monthly customer charge, which was authorized in the Companies' last rate cases.[23]

Thus, for the natural gas distribution operations of the Companies, the investor-required rate of return on common equity is 9.83% for CILCO, 9.41% for CIPS, and 9.83% for IP.

Q. Please summarize how you estimated the investor-required rate of return on common equity for the electric delivery service operations of the Companies.

A. First, for the electric delivery service operations of the Companies, I estimated the investor required rate of return on common equity for the Electric sample, which is a simple average of the DCF-derived results (10.49%) and the risk premium-derived results (10.21%) for the Electric sample, or 10.35%. Second, I adjusted the Electric sample's investor required rate of return downward to reflect the lower financial risk of CILCO and CIPS relative to the Electric sample. I adjusted the Electric sample's investor required rate of return downward by 4 basis points for CILCO and 12 basis points for CIPS. Thus, for the electric delivery service operations of the Companies, the investor-required rate of return on common equity is 10.31% for CILCO, 10.23% for CIPS, and 10.35% for IP.

Q. How did you minimize measurement error in your cost of common equity analyses?

[23] In Docket Nos. 07-0585 – 07-0590 Cons., the Commission authorized the AIUs to recover 80% of the fixed delivery services costs of the natural gas operations through the monthly customer charge. (Order, Docket Nos. 07-0585 – 07-0590 Cons., September 24, 2008, pp. 215 and 236-238.)

A. The models from which the individual company estimates were derived are correctly specified and thus contain no source of bias. Moreover, excepting the use of U.S. Treasury bond yields as proxies for the long-term risk-free rate and overall economic growth, I am unaware of bias in my proxy for investor expectations. In addition, measurement error has been minimized through the use of a sample, since estimates for a sample as a whole are subject to less measurement error than individual company estimates.

Q. Why did you adjust your estimate of the investor-required rate of return on common equity for the Gas and Electric samples to estimate the Companies' cost of common equity?

A. The Gas sample serves as a proxy for the natural gas distribution operations of the target companies, CILCO, CIPS and IP, and the Electric sample serves as a proxy for the electric operations of the target companies and should therefore reflect the risks of the Companies. If the proxy does not accurately reflect the risk level of the target company, an adjustment should be made. Since the operating risks of the Gas and Electric samples are similar to the gas and electric operations of the Companies, a review of the relative financial risks of the Gas and Electric samples and the Companies is required. To estimate the financial risk of the Companies going forward, I compared the financial strength implicit in the revenue requirement Staff recommends for each company's gas and electric operations to utility benchmarks.

Q. How did you compare the financial strength implicit in the revenue requirement Staff recommends for each of the AIU gas utilities to utility benchmarks?

A. I compared the values for the financial guideline ratios that result from Staff's proposed revenue requirement for the AIU gas utilities to Moody's guidelines for the regulated gas distribution industry. Although no formula exists for determining an assigned credit rating, Moody's provides broad guidelines on the ratio ranges that may generally be seen at different rating levels for regulated utilities. Moody's focuses on four ratios to assess the financial strength of local gas distribution companies: (1) earnings before interest and taxes ("EBIT") to interest coverage; (2) retained cash flow ("RCF") to total debt coverage; (3) debt to capitalization; and (4) free cash flow ("FCF") to funds from operations ("FFO") coverage.[24]

For CILCO Gas, Staff's recommended revenue requirement results in an EBIT to interest coverage ratio of 3.22x, which falls within the benchmark range of an A credit rating. Staff's recommended revenue requirement for CILCO Gas results in an RCF to total debt coverage ratio of 12.24%, which falls within the benchmark range of a Baa credit rating. Staff's debt to capitalization ratio of 53.09% for CILCO Gas also falls within the benchmark range of a Baa credit rating.[25] Together, the three ratios I calculated for CILCO Gas are consistent with a Baa1 credit rating.

[24] Moody's Investors Service, *Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies)*, October 2006, p. 16.
[25] I did not include the FCF to FFO ratio in my analysis since that ratio cannot be calculated for gas distribution operations alone.

For CIPS Gas Staff's recommended revenue requirement results in an EBIT to interest coverage ratio of 4.06x, which falls within the benchmark range of an A credit rating. Staff's recommended revenue requirement for CIPS Gas results in an RCF to total debt coverage ratio of 21.26%, which falls within the benchmark range of an Aa credit rating. Staff's debt to capitalization ratio of 46.35% for CIPS Gas falls within the benchmark range of an A credit rating. Together, the three ratios I calculated for CIPS Gas are consistent with an A1 credit rating.

For IP Gas Staff's recommended revenue requirement results in an EBIT to interest coverage ratio of 2.70x and an RCF to total debt coverage ratio of 12.38%, which fall within the benchmark range of a Baa credit rating. Staff's debt to capitalization ratio of 54.56% for IP Gas also falls within the benchmark range of a Baa credit rating. Together, the three ratios I calculated for IP Gas are consistent with a Baa1 credit rating.

The Moody's financial guidelines for gas distribution companies, along with AIU gas utilities' scores on those financial ratios are shown below in Table 3. In summary, I conclude that Staff's revenue requirement recommendations, including my cost of common equity recommendations, are indicative of levels of financial strength that are commensurate with an Baa1 credit rating for CILCO Gas, an A1 credit rating for CIPS Gas, and a Baa1 credit rating for IP Gas.

Table 3 – Moody's Guideline Ratios for Gas Utilities

	Aa (3)	A (6)	Baa (9)	Ba (12)
Financial Guideline Ratios				
EBIT / Interest	5.0 – 7.0X	3.0 - 5.0X	2.0 - 3.0X	1.0 – 2.0X
RCF / Debt	21- 26%	15 - 21%	10 - 15%	5 - 10%
Debt / Capitalization	30 – 40%	40 - 50%	50 - 65%	65 – 85%
Gas sample				
EBIT / Interest		4.21X		
RCF / Debt		15.31%		
Debt / Capitalization			53.37%	
Staff Proposal – CILCO G				
EBIT / Interest		3.22X		
RCF / Debt			12.24%	
Debt / Capitalization			53.09%	
Staff Proposal – CIPS G				
EBIT / Interest		4.06X		
RCF / Debt	21.26%			
Debt / Capitalization		46.35%		
Staff Proposal – IP G				
EBIT / Interest			2.70X	
RCF / Debt			12.38%	
Debt / Capitalization			54.56%	

In contrast, the Gas sample's average financial ratios for 2006-2008, shown in Table 3 above, are indicative of a level of financial strength that is commensurate with a credit rating of A3, which is consistent with the current average credit ratings Moody's has assigned the Gas sample. The Gas sample's level of financial strength indicates that it has more financial risk than CIPS and less financial risk than CILCO and IP. Financial theory posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. Thus, in my judgment, given the difference between the credit rating commensurate with the forward-looking financial strength of each Company's gas distribution operations and the credit rating commensurate with the financial strength of the

Gas sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of each Company's costs of common equity.

Q. How are the financial ratios for gas utilities calculated?

A. The EBIT to interest coverage ratio equals interest divided into the product of the before tax weighted average cost of capital and rate base. The RCF to debt coverage ratio equals total debt divided into the sum of the funds available to shareholders and non-cash items (i.e., depreciation, amortization, deferred taxes and investment tax credits) minus cash dividends. The debt to capitalization ratio equals total debt divided by the sum of total capital. Definitions for those ratios are presented on Schedule 6.08 and Schedule 6.09.

Q. How did you estimate the components of the above financial ratios?

A. Each component was based on its contribution to Staff's recommended revenue requirement for the gas operations of CILCO, CIPS and IP. "Funds available to shareholders" equals Staff's recommendations for the Companies' weighted cost of preferred stock and common equity times its rate base.[26] Depreciation, amortization, and investment tax credits equal Staff's recommended amounts for those items.[27] Deferred taxes equal the amounts reported by the Companies.[28] The interest component equals the product of Staff's recommendations for the

[26] Staff's recommended common equity ratio for each of the Companies can be found in ICC Staff Exhibit 5.0, Schedule 5.01; Staff's recommended rate base can be found in ICC Staff Exhibit 1.0, Schedule 1.03 CILCO-G, Schedule 1.03 CILCO-E, Schedule 1.03 CIPS-G, Schedule 1.03 CIPS-E, Schedule 1.03 IP-G, and Schedule 1.03 IP-E.

[27] ICC Staff Exhibit 1.0, Schedule 1.01 CILCO-G, Schedule 1.01 CILCO-E, Schedule 1.01 CIPS-G, Schedule 1.01 CIPS-E, Schedule 1.01 IP-G, and Schedule 1.01 IP-E.

[28] AmerenCILCO Gas and Electric Schedule C-5.2, AmerenCIPS Gas and Electric Schedule C-5.2, and AmerenIP Gas and Electric Schedule C-5.2.

weighted cost of short-term and long-term debt and rate base.[29] Total debt equals the product of Staff's recommendations for percentage of short-term and long-term debt in the capital structure and rate base. The cash preferred dividend for each of the companies equals the product of the weighted cost of preferred stock times rate base.[30] Cash common dividends are zero for CILCO and CIPS given the Company's 0% dividend payout in 2008.[31] Cash common dividends for IP are based on 50% dividend payout and are derived by taking 50% of the funds available to shareholders.[32]

Q. How did you estimate the adjustments to the cost of common equity of the Gas sample?

A. First, I calculated the yield spreads between the credit ratings implied by the financial ratios for CILCO, CIPS and IP and those of the Gas sample. As noted above, the financial ratios for CILCO, CIPS and IP are commensurate with Baa1, A1 and Baa1 credit ratings, while the Gas sample's financial ratios are commensurate with an A3 credit rating. This produced yield spreads of 50 basis points for CILCO and IP and 20 basis points for CIPS.[33] The spreads for 30-year utility debt yields as of August 31, 2009, are presented on Schedule 6.10. Next, to determine my cost of common equity adjustment, I multiplied those yield

[29] Staff's recommended cost of debt and debt ratio for each of the Companies can be found in ICC Staff Exhibit 5.0, Schedule 5.01.

[30] Normally, cash preferred dividends would exclude non-cash amortization of issuance expense; however, I omitted this adjustment due to immateriality.

[31] CILCO Schedule WPD-7, p. 15; CIPS Schedule WPD-7, p. 13; Companies' Response to Staff Data Request ("DR") JF 3.01.

[32] I assumed a 50% common dividend payout for IP because IP pays dividends to Ameren Corp., which then invests funds back into IP. IP's actual dividend payout ratio for 2008 was 2242%. (IP Schedule WPD-7, p. 17)

[33] Reuters Corporate Spreads for Utilities, www.bondsonline.com, August 31, 2009.

spreads by 60%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios. Thus, my cost of common equity adjustment for the natural gas distribution operations was 30 basis points higher for CILCO and IP and 12 basis points lower for CIPS.

Q. Why did you adjust your cost of common equity recommendations for the natural gas distribution operations to reflect the recovery of a greater portion of fixed delivery services costs through the monthly customer charge?

A. The Commission authorized the AIU gas utilities to recover 80% of the fixed delivery service costs through the monthly customer charge in the last rate cases. This cost recovery method will remain in effect when the rates set in this proceeding go into effect. In the AIU's last rate cases, the Commission recognized that this move toward more fixed cost recovery through the fixed monthly charge provides AIU more assurance of recovering its fixed costs of service for gas operations. Hence, this cost recovery reduces risk and provides the utilities greater assurance that the authorized rate of return will be earned. Therefore, a downward adjustment to the AIU gas utilities' rate of return on common equity is appropriate to reflect this reduction in risk.

Q. How should the cost of common equity for the natural gas distribution operations of the Companies be adjusted to reflect the lower risk associated with increasing the fixed customer charge to account for a greater portion of fixed costs?

A. I recommend the Commission adopt the same 10 basis point adjustment to the cost of common equity for the AIU gas companies that the Commission found appropriate in the last rate cases.[34]

Q. How did you compare the financial strength implicit in the revenue requirement Staff recommends for each of the AIU electric utilities to utility benchmarks?

A. I compared the values for the financial guideline ratios that result from Staff's proposed revenue requirement for the AIU electric utilities to Moody's guidelines for electric utilities with low business risk. To assess the financial strength of electric utilities, Moody's focuses on four ratios: (1) funds from operations ("FFO") to interest coverage; (2) FFO to total debt; (3) retained cash flow ("RCF") to total debt coverage; and (4) debt to capitalization.[35]

For CILCO Electric, Staff's recommended revenue requirement results in a FFO to interest coverage ratio of 4.25X and a FFO to total debt coverage ratio of 20.17%, which fall within the benchmark range of an A credit rating. Staff's recommended revenue requirement for CILCO Electric results in an RCF to total debt coverage ratio of 19.89% which falls at the upper end of the benchmark range of an A credit rating. Staff's recommended debt to capitalization ratio of 53.09% falls within the benchmark range of an A credit rating. Together, those ratios are consistent with an A1 credit rating for CILCO Electric.

[34] Order, Docket Nos. 07-0585 – 07-0590 (Cons.), September 24, 2008, p. 215.
[35] Moody's Investors Service, *Rating Methodology: Global Regulated Electric Utilities*, March 2005, p. 8.

For CIPS Electric, Staff's recommended revenue requirement results in a FFO to interest coverage ratio of 7.07X, a FFO to total debt coverage ratio of 35.55%, and an RCF to total debt coverage ratio of 34.99%, which lie within the guideline range for an Aa credit rating. Staff's debt to capitalization ratio of 46.35% for CIPS Electric also falls within the benchmark range of an Aa credit rating. Together, those ratios are consistent with an Aa2 credit rating for CIPS Electric.

For IP Electric, Staff's recommended revenue requirement results in a FFO to interest coverage ratio of 3.57X, a FFO to total debt coverage ratio of 20.06%, and an RCF to total debt coverage ratio of 15.67%, which fall within the guideline range of an A credit rating. Staff's debt to capitalization ratio of 54.56% also falls within the benchmark range of an A credit rating. Together, those ratios are consistent with an A2 credit rating for IP Electric.

The financial guideline ratios from Moody's for electric utilities with low levels of business risk are shown below in Table 4. In summary, I conclude that Staff's revenue requirement recommendations, including my cost of common equity recommendations, are indicative of a level of financial strength that is commensurate with an A1 credit rating for CILCO Electric, an Aa2 credit rating for CIPS Electric, and an A2 credit rating for IP Electric.

Table 4 – Moody's Guideline Ratios for Electric Utilities

	Aa	A	Baa	Ba
Financial Guideline Ratios				
FFO/IC	> 5.0X	3.0-5.7X	2.0-4.0X	< 2.0x
FFO/Debt	> 22%	12-22%	5-13%	< 5%
RCF/Debt	> 20%	9-20%	3-10%	< 3%
Debt / Capitalization	< 50%	50-75%	60-75%	> 70%
Electric Sample				
FFOIC		4.1X		
FFO/Debt		20.3%		
RCF/Debt		14.95%		
Debt / Capitalization		54.82%		
Staff Proposal – CILCO E				
FFOIC		4.25X		
FFO/Debt		20.17%		
RCF/Debt		19.89%		
Debt / Capitalization		53.09%		
Staff Proposal – CIPS E				
FFOIC	7.07X			
FFO/Debt	35.55%			
RCF/Debt	34.99%			
Debt / Capitalization	46.35%			
Staff Proposal – IP E				
FFOIC		3.57X		
FFO/Debt		20.06%		
RCF/Debt		15.67%		
Debt / Capitalization		54.56%		

The Electric sample's lower implied average credit rating indicates that its risk is higher than that of the CILCO's and CIPS' electric delivery service operations. Financial theory posits that investors require higher returns to accept greater exposure to risk. Conversely, the investor-required rate of return is lower for investments with less exposure to risk. Thus, in my judgment, given the difference between the implied forward-looking credit ratings for the Companies and the implied average credit rating of the Electric sample, the sample's average cost of common equity needs to be adjusted to determine the final estimate of the Companies' costs of common equity.

Q. How are the financial ratios for electric utilities calculated?

A. The FFO to interest coverage ratio equals interest divided into the sum of the funds available to shareholders, non-cash items (i.e., depreciation, amortization, deferred taxes and investment tax credits), and interest. The FFO to debt coverage ratio equals the sum of the funds available to shareholders and non-cash items divided by total debt. The RCF to debt coverage ratio equals total debt divided into the sum of the funds available to shareholders and non-cash items (i.e., depreciation, amortization, deferred taxes, and investment tax credits) minus cash dividends. The debt to capitalization ratio equals total debt divided by the sum of total capital. The calculation of those ratios is presented on Schedule 6.08 and Schedules 6.09.

Q. How did you estimate the adjustments to the cost of common equity of the Electric sample?

A. First, I calculated the yield spreads between the credit ratings implied by the financial ratios for the CILCO, CIPS and IP and the credit rating implied by the average financial ratios for the Electric sample. As noted above, the financial ratios are commensurate with credit ratings of A1 for CILCO, Aa2 for CIPS and A2 for IP, while the Electric sample's financial ratios are commensurate with an A2 credit rating. This produced yield spreads of 10 basis points for CILCO and

30 basis points for CIPS.[36] The spreads for 30-year utility debt yields as of August 31, 2009, are presented on Schedule 6.10. Next, to determine my cost of common equity adjustment, I multiplied those yield spreads by 40%, which is the percent of the overall credit rating that Moody's assigns to the financial ratios for electric utilities. Thus, my cost of common equity adjustment for the electric operations is 4 basis points for CILCO and 12 basis points for CIPS. I did not adjust the Electric sample cost of common equity for IP because the financial ratios for IP are commensurate with the same level of financial risk (A2) as the Electric sample.

Q. Do your cost of common equity recommendations take into account the new uncollectibles riders that the Companies are proposing in Docket No. 09-0399?

A. No. My cost of common equity recommendations do not take into account for any change in risk associated with the new uncollectibles riders the Companies are proposing in Docket No. 09-0399. Thus, a further adjustment to the applicable cost of common equity recommendation is appropriate for the uncollectibles riders when authorized by the Commission.

Q. What new riders are the Companies proposing in Docket No. 09-0399?

A. Pursuant to Illinois Public Act 96-0033, the AIUs filed a petition for approval of uncollectible riders on August 31, 2009 (Docket No. 09-0399). The proposed riders would be applicable to both gas ("Rider GUA" – Gas Uncollectible Adjustment) and electric ("Rider EUA" – Electric Uncollectible Adjustment)

[36] Reuters Corporate Spreads for Utilities, www.bondsonline.com, August 31, 2009.

customers. According to the direct testimony of Ameren witness Robert J. Mill in Docket No. 09-0399, the purpose of these riders is to allow the Companies to recover actual uncollectibles amounts, through an automatic adjustment clause, which are not otherwise recovered through base delivery service charges or via supply charges. Specifically, he states "Section 16-111.8a of the law states that the uncollectible recovery for a utility is based on '…the incremental difference between its actual uncollectible amount as set forth in Account 904 in the utility's most recent annual FERC Form 1 and the uncollectible amount included in the utility's rates for the period reported in such annual FERC Form 1.'"[37]

Q. How would the uncollectibles riders affect the Companies' risks and costs of capital?

A. The uncollectibles riders authorized by Public Act 96-0033 would ensure more timely and certain collection of bad debt expense. This cost recovery mechanism provides greater assurance that the Companies will earn their authorized rates of return. Since the uncollectible riders would reduce uncertainty of cash flows, it would reduce the Companies' risk. Therefore, downward adjustments to the Companies' rates of return on common equity would be appropriate to recognize the reduction in risk associated with the use of the uncollectibles riders when authorized by the Commission.

[37] Docket No. 09-0399, Ameren Exhibit 1.0, Direct Testimony of Robert J. Mill, p. 3. (filed August 31, 2009)

Moody's Investors Service recently upgraded the ratings of the AIUs to investment grade.[38] The upgrade reflects positive developments in Illinois, including the recently passed legislation providing Illinois utilities with a bad debt rider. Moody's acknowledges that such riders would reduce the risk of the utilities by providing greater assurance of bad debt cost recovery and factored that into the decision to upgrade the AIUs to investment grade.

Q. How should the cost of common equity for the Ameren Illinois Utilities be adjusted when the Commission authorizes the uncollectibles riders?

A. I am unaware of any established approach for precisely gauging the effect the adoption of the uncollectibles riders would have on investors' perceptions of the Companies' risk levels and the resulting costs of equity. Thus, any adjustment will inevitably be inexact. Therefore, my proposed adjustments for Riders GUA and EUA reflect a range of alternatives using two distinct approaches.

In the first approach, I estimated the effect the adoption of Riders GUA and EUA would have on the Companies' Moody's credit ratings and based my adjustment on the resulting change in implied yield spreads. Moody's analysis of gas utilities focuses on four core rating factors: sustainable profitability, regulatory support, ring fencing, and financial strength and flexibility. These four factors are measured using a set of "sub-factors" weighted by relative importance. Each sub-factor is then assigned to a Moody's rating category (i.e., Aaa, Aa, A, Baa,

[38] Moody's Investors Service, Rating Action: *Moody's Upgrades Ameren Illinois Utilities to Investment Grade*, August 13, 2009.

Ba, B, Caa), which is converted into a numeric value[39] and multiplied by its assigned weight. The weighted average of the sub-factor ratings is then translated into the overall rating.[40]

Of the four rating factors, the adoption of an uncollectibles rider would most affect sustainable profitability and regulatory support. The sustainable profitability factor assesses a firm's ability to remain profitable and efficient despite the inherent volatility associated with the gas sector. Thus, a rider designed to reduce uncertainty in cash flows would positively affect the sustainable profitability factor. Moody's assigns the profitability factor a total weight of 20% in determining the overall credit rating score.

Regulatory support considers the strength of the utility's relationship with its regulatory commission(s). Moody's states that a utility's ability to recover allowed expenses in a timely manner and earn its authorized rate of return is a very important component of the utility's relationship with its regulator. A utility's score on this factor would improve with approval of a mechanism that allows it to timely adjust rates to cover all costs of service since its ability to earn its authorized rate of return would be enhanced. Moody's assigns a 10% weight to the regulatory support factor when determining the overall credit rating score.

Although Moody's does not identify the precise impact that an uncollectibles rider would have on these two factors, enhancing the utility's ability to earn its

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[39] Aaa = 1, Aa = 3, A = 6, Baa = 9, Ba = 12, B = 15 and Caa =18.

[40] The overall rating might differ from the actual, assigned rating due to the utilities being in a state of transition. (Moody's Investors Service, *Special Comment - Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector*, June 2005, p. 19).

authorized rate of return would be viewed favorably and could increase the scores assigned to the sustainable profitability and regulatory support factors. Hence, I assumed that the credit ratings assigned to each of these factors would improve by one credit rating (i.e., 3 points on the numeric scale) with the uncollectibles rider. Since these two factors comprise 30% of the overall weighting, raising the scores for these two factors by 3 rating points, as described above, would result in an improvement to the Companies' overall credit ratings of approximately one credit rating notch (i.e., 3 x 30% = 0.9). For example, if the overall credit rating for a company is Baa1 before the rider, then the same company would likely improve to A3 after the rider.

For the natural gas distribution operations, my analysis indicates that the going forward level of financial strength is consistent with credit ratings of Baa1 for CILCO and IP and A1 for CIPS. This analysis indicates that the ratings would go up to A3 for CILCO and IP and Aa3 for CIPS due to Rider GUA. Hence, the returns on common equity would be reduced by the 50 basis points spread between credit ratings of Baa1 and A3 for CILCO and IP, and by the 10 basis point spread between credit ratings of A1 and Aa3 for CIPS.

For the electric delivery service operations, my analysis indicates that the going forward level of financial strength is consistent with credit ratings of A1 for CILCO, Aa2 for CIPS and A2 for IP. This analysis indicates that the ratings would go up to Aa3 for CILCO, Aa1 for CIPS and A1 for IP due to Rider EUA. Hence the returns on common equity would be reduced by the 10 basis point spread between credit ratings of A1 and Aa3 for CILCO, the 10 basis point spread between credit ratings of Aa2 and Aa1 for CIPS, and the 10 basis point spread between credit ratings of A2 and A1 for IP.

The second approach is an iterative process of adjusting my cost of common equity estimate downward to offset the increased operating income resulting from the adoption of Rider GUA as proposed by the Companies in Docket No. 09-0399 (hereafter, "Operating Income Analysis"). Based on Staff's pre-adjustment rate of return recommendations of 9.83% for CILCO Gas and IP Gas and 9.41% for CIPS Gas and Staff's rate base recommendations of $222,479,000 for CILCO Gas, $212,602,000 for CIPS Gas and $555,438,000 for IP Gas, I calculated pro forma operating incomes without Rider GUA (Staff's rate base x rate of return recommendations) of $17,768,187 for CILCO Gas, $16,367,551 for CIPS Gas and $48,767,456 for IP Gas. To estimate the effect Rider GUA would have on the pro forma operating income of each of the AIU gas utilities, I subtracted the Companies' estimates of uncollectibles recovery via base rates from the Account 904 balances for the years 1999-2008.[41] I then divided the average difference between the Companies' estimates of uncollectibles recovery via base rates and Account 904 balances over the last ten years by the pro forma operating income without Rider GUA. If Rider GUA had been in effect during the last ten years, my analysis indicates that the pro forma operating incomes for the gas operations of CILCO, CIPS and IP would have been approximately 8.18%, 9.41% and 5.11% higher, on average. Thus, I multiplied the pro forma operating incomes for the gas operations of CILCO, CIPS and IP by those respective amounts to estimate

[41] Companies' Responses to Staff DRs JF 2.06 and JF 4.02.

the effective pro forma operating incomes if Rider GUA were adopted but no adjustments were made. I then adjusted my cost of common equity downward until the pro forma operating incomes under Rider GUA equaled the original pro forma operating incomes I calculated for the Companies without Rider GUA. This process produced downward adjustments to the costs of equity for the gas operations of CILCO, CIPS and IP of approximately 139, 137 and 100 basis points, respectively, to reflect the risk reduction associated with Rider GUA.

Q. Did you apply the same Operating Income Analysis directly to the Companies' electric delivery service operations to determine the reduced risk that will result from the adoption of Rider EUA?

A. No. The Companies were not able to provide an estimate of uncollectibles recovery via base rates for the electric delivery service operations. Therefore, I was not able to directly estimate the incremental recovery of uncollectibles expense had Rider EUA been in effect for the past ten years. The Companies did provide the Account 904 balances for each of the past ten years for the electric operations of CILCO, CIPS and IP.[42] Consequently, I compared the uncollectibles for the electric operations of the Companies to the uncollectibles for the gas operations of the Companies by computing the ratio of average Account 904 balances to the pro forma operating income without Rider s GUA and EUA for both the gas and electric operations of CILCO, CIPS and IP. [43]

[42] Companies Supplemental Response to Staff DR JF 4.02.
[43] The pro forma operating income before Riders GUA and EUA is equal to Staff's recommended Rate Base multiplied by Staff's recommended rate of return for the gas and electric operations of each AIU.

Based on Staff's pre-adjustment rate of return recommendations of 10.31% for CILCO Electric, 10.23% for CIPS Electric and 10.35% for IP Electric, and Staff's rate base recommendations of $324,782,000 for CILCO Electric, $517,903,000 for CIPS Electric and $1,462,880,000 for IP Electric, I calculated pro forma operating incomes without Rider EUA (Staff's rate base x rate of return recommendations) of $26,618,381 for CILCO Electric, $41,938,649 for CIPS Electric and $131,842,266 for IP Electric.

For CILCO Gas, the ratio of average Account 904 balances to pro forma operating income is 15.28%. For CILCO Electric, the ratio of average Account 904 balances to pro forma operating income is 7.42%. I then divided the ratio for the electric operations by the ratio for the gas operations (7.42% ÷ 15.28% = 48.58%) and applied 48.58% of the operating income adjustment for the gas operations to the electric operations. Thus, I estimate the operating income for CILCO Electric would have been approximately 3.97% (48.58% x 8.18% = 3.97%) higher, on average, if Rider EUA had been in effect during the last ten years.

For CIPS Gas, the ratio of average Account 904 balances to pro forma operating income is 14.49%. The ratio of average Account 904 balances to operating income for the CILCO Electric is 12.20%. The ratio for the electric operations divided by the ratio for the gas operations (12.20% ÷ 14.49% = 84.19%) Thus, I estimate the operating income for CIPS Electric would have been approximately 7.92% (84.19% x 9.41% = 7.92%) higher, on average, if Rider EUA had been in effect during the last ten years.

For IP Gas, the ratio of average Account 904 balances to pro forma operating income is 11.39%. The ratio of average Account 904 balances to operating income for the IP Electric is 5.28%. The ratio for the electric operations divided by the ratio for the gas operations is 46.34% (5.28% ÷ 11.39% = 46.34%). Thus, I estimate the operating income for IP Electric would have been approximately 2.37% (46.34% x 5.11% = 2.37%) higher, on average, if Rider EUA had been in effect during the last ten years.

I then multiplied the pro forma operating incomes for the electric operations of CILCO, CIPS and IP by 3.97%, 7.92% and 2.37%, respectively, to estimate the effective pro forma operating incomes if Rider EUA were adopted but no adjustments were made. I then adjusted my cost of common equity downward until the pro forma operating incomes under Rider EUA equaled the original pro forma operating incomes I calculated for the Companies without Rider EUA. This process produced downward adjustments to the costs of common equity for the electric operations of CILCO, CIPS and IP of approximately 72, 123 and 48 basis points, respectively, to reflect the risk reduction associated with Rider EUA.

Q. Please summarize the results of the two approaches that you used to estimate the downward adjustments to the required costs of common equity that would result from the adoption of Riders GUA and EUA.

A. Table 5 below summarizes the results of the two approaches I used to estimate the downward adjustments to the required costs of common equity for the gas operations of CILCO, CIPS and IP necessary to reflect the reduced risk that would result from the adoption of Rider GUA.

Table 5

Approach	CILCO Gas	CIPS Gas	IP Gas
Implied Moody's ratings adjustment	50 basis points	10 basis points	50 basis points
Operating income adjustment	139 basis points	137 basis points	100 basis points

Those results range from 50 to 139 basis points for CILCO Gas, 10 to 137 basis points for CIPS Gas and 50 to 100 basis points for IP Gas. Based on the midpoints of those ranges, I recommend adjustments to the costs of common equity for the gas operations of CILCO, CIPS and IP of 94.5, 73.5 and 75 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider GUA.

Table 6 below summarizes the results of the two approaches I used to estimate the downward adjustments to the required costs of common equity for the electric operations of CILCO, CIPS and IP necessary to reflect the reduced risk that would result from the adoption of Rider EUA.

Table 6

Approach	CILCO Electric	CIPS Electric	IP Electric
Implied Moody's ratings adjustment	10 basis points	10 basis points	10 basis points
Operating income adjustment	72 basis points	123 basis points	48 basis points

Those results range from 10 to 72 basis points for CILCO Electric, 10 to 123 basis points for CIPS Electric and 10 to 48 basis points for IP Electric. Based on the midpoints of those ranges, I recommend adjustments to the costs of common equity for the electric operations of CILCO, CIPS and IP of 41, 66.5 and 29 basis points, respectively, to reflect the reduced risk that will result from the adoption of Rider EUA.

A summary of my cost of common equity recommendations, including my estimates of the downward adjustments to the required costs of common equity of CILCO, CIPS and IP necessary to reflect the reduced risk that would result from the adoption of Riders GUA and EUA is on Schedule 6.11.

Q. Is the Companies' estimate of uncollectibles recovery via base rates the proper starting point for determining the incremental recovery of uncollectibles expense had Rider GUA and EUA been in effect for the past ten years?

A. No. The Companies' estimate of uncollectibles recovery via base rates represents what the Companies were allowed to recover based on factors set in rate cases, not what the Companies actually recovered through rates for bad debt expense. Company responses to Staff discovery requests regarding the actual revenue associated with the uncollectibles recorded for each of the Ameren Illinois Utilities is pending.[44] In rebuttal testimony, I intend to revise my analysis using the amounts actually recovered to determine the incremental recovery of uncollectibles expense had Rider GUA been in effect for the past ten years. Hence, my proposed adjustments to reflect the reduced risk that will result from the adoption of Riders GUA and EUA will most likely change in my rebuttal testimony, depending on the Companies' response to Staff DR JF 5.01.

[44] Staff DR JF 5.01.

Response to Ms. McShane

Q. Please evaluate Ms. McShane's analysis of the Companies' costs of common equity.

A. Ms. McShane's analysis contains significant errors:

1. She utilizes historical data in her DCF and risk premium analyses.
2. She inappropriately adjusts her DCF and risk premium results to compensate for the alleged difference between market value and book value.
3. She uses the Comparable Earnings approach as a check on her recommended rate of return on common equity for the Companies' electric and gas operations, although that model ignores investor return requirements.

Historical Data

Q. What historical data did Ms. McShane use in her cost of common equity analysis?

A. Ms. McShane used historical data, in part, to estimate the dividend yields in her DCF analysis, the market risk premiums in her equity risk premium analyses, and the earned returns on book common equity for the sample of industrial companies used in her comparable earnings analysis.

Q. Why is Ms. McShane's use of historical data in her analyses improper?

A. The use of historical data is problematic. First, historical data favors outdated information that the market no longer considers relevant over the most-recently available information. Second, historical data reflects conditions that may not continue in the future. In other words, use of average historical data implies that securities data will revert to a mean. Even if securities data were mean reverting, there is no method for determining the true value of that mean let alone the length of time over which mean reversion will occur. Consequently, sample means, which depend upon the measurement period used, are used. Thus, any measurement period chosen is arbitrary, rendering the results uninformative.

Q. Please provide an example of how the use of historical data can distort cost of common equity analyses.

A. First, consider Ms. McShane's use of historical data in determining the dividend yield (dividend ÷ stock price) in her DCF model.[45] Since stock prices reflect all current information, only the most recent stock price can reflect the most recently available information. Historical stock prices <u>must</u> include observations that cannot reflect the most current information available to the market. For example, if the actual earnings for a company were much higher than anticipated, the market would react to that news and bid up its stock price. Consequently, the pre-earnings announcement stock prices would reflect obsolete information and understate the value of that company's stock.

Ms. McShane implies that her use of historical data to estimate the dividend yield is an attempt to reduce measurement error when she states that "the use of an average price ensures that the estimated cost of equity is not attributable to any

[45] Ms. McShane used the average of daily closing stock prices for the period February 26 to March 26, 2009. (AmerenCILCO Exhibits 12.0E.4, 12E.5 and 12E.6; AmerenCILCO Exhibits12.0G.4, 12G.5 and 12G.6).

capital market anomalies that may arise due to transitory investor behavior."[46] However, while it is true that measurement error is a problem inherent in cost of common equity analysis and should be reduced whenever possible, introducing old stock prices into an analysis simply substitutes one alleged source of measurement error, volatile stock prices, for another, irrelevant stock prices. Stock prices can be influenced by temporary imbalances in supply and demand; however, any distortions such imbalances might have on the measured cost of common equity can be reduced through the use of samples, a technique which Ms. McShane already applies.

Next, consider Ms. McShane's equity risk premium analysis, which calls for an estimate of the investor-required rate of return on the market portfolio. To compute the achieved equity risk premium for her sample, she first calculated the achieved equity risk premium for the S&P 500 Common Stock Index for two historic periods (1926-2008 and 1947-2008) relative to the 20-year U.S. Treasury bond income return.[47] Next, she calculated the achieved equity risk premium for the S&P/Moody's Electric Utility Index and the S&P/Moody's Gas Distribution Utility Index relative to the 20-year U.S. Treasury bond income return.[48] She also estimated the historic equity risk premium relative to the total return on Moody's long-term A-rated public utility bonds.[49] To compute the DCF-based

[46] AmerenCILCO Ex. 12.0E (Revised), p. 37; AmerenCILCO Ex. 12.0G (Revised), p. 38.
[47] AmerenCILCO Exhibit 12.0E (Revised), pp. 48-50 and AmerenCILCO Exhibit 12E.7.1; AmerenCILCO Exhibit 12.0G (Revised), pp. 51-52 and AmerenCILCO Exhibit 12G.7.1.
[48] AmerenCILCO Exhibit 12.0E (Revised), pp. 53-54 and AmerenCILCO Exhibit 12E.7.1; AmerenCILCO Ex. 12.0G (Revised), pp. 55-56 and AmerenCILCO Ex. 12G.7.1.
[49] AmerenCILCO Exhibit 12.0E (Revised), pp. 54-55 and AmerenCILCO Exhibit 12E.7.2; AmerenCILCO Ex. 12.0G (Revised), pp. 56-57 and AmerenCILCO Ex. 12G.7.2.

equity risk premium for her Electric and Gas samples, Ms. McShane used the period from August 2007 to March 2009.[50]

Consequently, Ms. McShane estimates the required rate of return on the market using, in part, historical earned rates of return. As proxies for current required rates of return, historical earned returns possess several shortcomings. First, the returns an investment generates are unlikely to have equaled investor return requirements due to unpredictable economic, industry-related, or company-specific events. Second, even if an investment's return equaled investor requirements in a given period, both the price of, and the investment's sensitivity to, each source of risk changes over time. Consequently, the past relationship between two investments, such as common equity and debt, is unlikely to remain constant. Third, the magnitude of the historical risk premium depends upon the measurement period used. Unfortunately, no proven method exists for determining the appropriate measurement period. Thus, historical earned rates of return are questionable estimates of the required rate of return that are susceptible to manipulation and whose use could distort the estimate of a company's cost of common equity.

Q. Has the Commission previously rejected the use of historical data in determining a company's cost of capital?

A. Yes. The Commission rejected use of historical dividend yields in the Docket No. 03-0403 Order (Aqua, then CIWC, rate proceeding), which stated:

[50] AmerenCILCO Exhibit 12.0E (Revised), pp. 55-58 and AmerenCILCO Exhibit 12E.8; AmerenCILCO Ex. 12.0G (Revised), pp. 56-57 and AmerenCILCO Ex. 12G.8.

> The Commission is aware that historical data has a place in many cost of capital analyses. The instant objective, however, is to estimate the forward-looking cost of common equity. For this reason, the Commission has consistently rejected the use of average common stock prices, and has accepted the use of spot common stock prices when implementing the DCF model. The Commission continues to believe that the use of spot common stock prices in the DCF model is superior to the use of average prices.[51]

In addition, the Commission rejected Ms. McShane's use of historical data in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), a previous rate proceeding of the Companies.[52] Referring to Ms. McShane's estimate of the market risk premium, the Commission stated:

> The Commission observes that earned returns on equity are different than expected returns on equity and that the former can not be used to estimate the latter. Additionally, the Commission believes that it would be all too easy to select a historical period that produces a biased result, whether upwardly biased or downwardly biased. As it has done in numerous previous rate cases, the Commission rejects this type of approach to estimating the forward looking cost of common equity. [53]

Ms. McShane's use of historical data in her cost of common equity analysis should also be rejected in this proceeding.

Market to Book Adjustment

Q. Please summarize Ms. McShane's rationale for the market to book adjustment that she applied to her DCF and risk premium cost of common equity estimates.

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[51] Order, Docket No. 03-0403, April 13, 2004, p. 42.

[52] In the Companies' last rate proceeding, Docket Nos. 07-0585 – 07-0590 (Cons.), Ameren accepted Staff's cost of common equity recommendation in its Initial Brief. Hence the Commission did not address Ms. McShane's analysis in the Final Order. (Order, Docket Nos. 07-0585 – 07-0590 (Cons.), Sept. 24, 2008, p. 180)

[53] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, pp.142-143.

A. Ms. McShane argues that if the market value differs from book value, a cost of common equity estimate derived from market values needs to be adjusted when applied to book values of common equity to determine utility rates. She states “when the market value common equity ratio is higher (lower) than the book value common equity ratio, the market is attributing less (more) financial risk to the firm than is ‘on the books’ as measured by the book value capital structure. Higher financial risk leads to a higher cost of common equity, all other things equal.”[54] Ms. McShane claims that an adjustment is warranted for her DCF and risk premium derived cost of common equity estimates in the instant docket because: 1) both methodologies produce market-based cost of common equity estimates; 2) the Commission applies its cost of common equity estimate to book value rate base; and 3) application of the market-derived cost of common equity for a sample with an average 51% (electric) or 60% (gas) market value common equity ratio to CILCO’s 43.6%, CIPS’ 48.7%, or IP’s 44.1% book value common equity ratio would fail to recognize the higher financial risk of the latter.[55] Hence, she argues that the estimated cost of common equity for the comparable utilities needs to be increased when applied to the Companies’ book value common equity ratio to recognize the higher financial risk of the Companies’ common book equity.

Q. What is the fundamental error with market to book adjustments?

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[54] AmerenCILCO Ex. 12.0E (Revised), pp. 59-60 and AmerenCILCO Ex. 12.0G (Revised), pp. 61-62.

[55] AmerenCILCO Ex. 12.0E (Revised), p. 65, AmerenCILCO Ex. 12.0G (Revised), p. 67, AmerenCIPS Ex. 12.0E (Revised), pp. 65-66, AmerenCIPS Ex. 12.0G (Revised), p.67, AmerenIP Ex. 12.0E (Revised), p.65, and AmerenIP Ex. 12.0G (Revised), p.67.

A. Market to book adjustments such as Ms. McShane’s are based on the flawed argument that a market-derived required rate of return does not produce a “fair” return when applied to a book value rate base if the market to book ratio differs from one. The crucial flaw in that argument is that it equates secondary investing (i.e., the purchase of existing shares of stock from other investors) with primary investing (i.e., the purchase of new shares of stock directly from the company or the retention of earnings for reinvestment). The former does not affect the amount of money available to the company to buy assets because the proceeds from the sale go to the previous stockholder, not to the company. Thus, a rise in the price of existing common stock traded in secondary markets does not increase the amount of capital actually serving customers. It only reveals that investors’ expectations for the future cash flows of the company have risen or that their required rate of return has fallen. In contrast, primary investment directly contributes capital to the company that is available to buy assets to serve customers. Under original cost ratemaking, ratepayers provide a return only on the amount of capital that is invested in assets that serve ratepayers. Inflating that return to compensate investors for capital not invested in plant and equipment is neither fair nor appropriate; moreover, such an adjustment would render the establishment of original cost rate base a pointless exercise.

A fair rate of return is determined exogenously from the ratemaking process. That is, the investor required rate of return is determined entirely by the market price investors are willing to pay based on the perceived riskiness of cash flows. Thus, investors, not the Commission, determine the required rate of return. As the Commission stated in Docket No. 92-0448/93-0239 (Cons.), "The Commission, in authorizing a rate of return, makes an estimate of what the investor is demanding. It is the Commission that reacts to the investor, not vice-versa."[56] The Commission does not control what investors pay for a share of stock, nor does it control investors' expectations for dividends and growth; the Commission simply evaluates investors' behavior to ascertain investors' rate of return requirements. The Commission then applies that market-determined rate of return to the amount of equity capital determined to be serving customers.

The erroneous equation of primary and secondary investing also leads to Ms. McShane's incorrect comparison of book values and market values. As indicated above, the amount of money contributed to the company for the purchase of assets that serve ratepayers is not necessarily equal to the market value of the company's stock. This is because the market value of a company's stock is based on the <u>cash flows</u> expected to be generated by all of its assets discounted by the investor-required rate of return.

If a utility's services were entirely subject to original cost-based, rate of return regulation[57] and its rates perfectly and instantaneously reflected changes in its costs, then the market value of the firm would equal the book value whenever the expected rate of return matches the investor required rate of return. However, if the expected rate of return exceeds the investor required rate of return, then

[56] Order, Docket No. 92-0448/93-0239 (Cons.), October 11, 1994, p. 172.

[57] For the purpose of this discussion, the phrase "entirely subject to original cost-based, rate of return regulation" means that a utility's revenues perfectly match its costs including taxes and cost of capital.

demand for the company's stock will increase as investors seek a share in those abnormally high returns. This increased demand for the company's stock will cause the stock's market value to rise until the expected rate of return on market value equals the required rate of return. Such a scenario would explain why market values of utilities have grown to exceed their book values. Utilities frequently have other sources of cash flows in addition to the operating income component of the revenue requirement set by the Commission. For example, many utility companies own non-regulated assets that generate cash flows for investors. Also, investment tax credits, deferred taxes, and positive working capital balances contribute to utilities' cash flows. Thus, some utilities may be able to earn more than their ratemaking operating income, which, as explained above, would drive the market values of utilities above their book values. Clearly, the Commission should not further increase allowed rates of return when the benefits that utilities receive from other sources of earnings not recognized by the rate setting process increase stock prices above book value. To do so would compensate utilities twice for the same sources of cash flow.

Finally, allowing upward adjustments to the allowed rate of return based on a market to book value ratio greater than one, when taken to its logical conclusion, would require the Commission to continually make upward adjustments to the allowed rate of return, since such an upward adjustment would tend to again increase the market to book value ratio, thereby warranting another increase, resulting in a never ending upward movement in the allowed rate of return. To establish utility rates, regulators generally apply a market-based rate of return to a book value rate base. If that process provided a return that did not meet investor requirements, market prices would fall towards book value. Yet, the market prices of utility stocks continue to exceed book value.

Q. Do you agree with Ms. McShane's position that lower book value common equity ratios of the Companies relative to the Gas and Electric samples indicate that the Companies possess higher financial risk than the Gas and Electric samples?

A. No. The intrinsic financial risk of a given company does not change simply because the manner in which it is measured has changed. Such an assertion is akin to claiming that the ambient temperature changes when the measurement scale is switched from Fahrenheit to Celsius. Specifically, capital structure ratios are merely indicators of financial risk; they are not sources of financial risk. Financial risk arises from contractually required debt service payments. Changing capital structure ratios from a market to book value basis does not affect a company's debt service requirements.

Q. Has the Commission addressed this argument before?

A. Yes. Ms. McShane made the same adjustment to her market-derived cost of common equity estimates in Docket Nos. 02-0798/03-0008/03-0009 (Cons.). The Commission Order rejected her proposed market-to book adjustment stating:

> the Commission has a long history of applying its estimated market required rate of return on common equity to its book value, net original cost rate base for Illinois jurisdictional utilities…. There is no evidence that this practice has ever

> served as an impediment to a utility's ability to raise capital or maintain its financial integrity.[58]

Further, in Docket Nos. 06-0070/06-0071/06-0072 (Cons.), the Commission once again rejected Ms. McShane's proposed market to book adjustment stating:

> the Commission observes that it has repeatedly rejected arguments in favor of using market-to-book ratios as the basis for establishing cost of common equity. The Commission rejects both of the contradictory arguments that market-to-book ratios should be directly used in establishing CILCO's, CIPS', and IP's cost of common equity in this proceeding.[59]

Q. Are there any significant differences between the market to book arguments rejected by the Commission in past cases and those presented by Ms. McShane?

A. No. Both are based on the false argument that an adjustment to a cost of common equity estimate derived from market values of equity is necessary when that estimate is to be applied to book values of equity to determine utility rates. Thus, the Commission should disregard Ms. McShane's market to book adjustments.

Comparable Earnings Model

Q. Please describe Ms. McShane's comparable earnings model.

A. Ms. McShane's comparable earnings model uses the average historical earned return on book value of common equity for a proxy group of 81 U.S. industrial

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[58] Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, p. 87.
[59] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, p. 141.

companies over the period 1991-2007.[60] The average achieved return for those 81 companies was 15.9%. She claims that her comparable earnings test indicates that competitive firms of similar risk to her samples of electric and gas utilities may be expected to earn average returns of approximately 15.0% - 16.0%.

Q. Is the comparable earnings methodology appropriate for determining the cost of common equity?

A. No. The comparable earnings methodology is based on the erroneous assumption that earned or expected returns on book equity are acceptable substitutes for investor-required returns. Investor return requirements are a function of risk and manifested in the market prices of securities. In contrast, Ms. McShane's comparable earnings analysis is based on accounting returns, which are largely unresponsive to market forces. The return on book value of common equity is entirely unaffected by changes in the investor required rate of return. For example, in response to a decline in risk, risk premiums, or the time value of money, investors would bid up the price of a stock, thereby reducing the implied required rate of return, but the anticipated return on book equity would not change.

Q. Has the Commission rejected use of the comparable earnings analysis to measure a utility's cost of common equity?

A. Yes. The Commission has consistently and repeatedly rejected the comparable earnings methodology. Ms McShane presented a comparable earnings model in

[60] AmerenCILCO Ex. 12.0E (Revised), pp. 68-75; AmerenCILCO Ex. 12.0G (Revised), pp. 71-78.

Docket Nos. 02-0798/03-0008/03-0009 (Cons.) and the Commission discarded it.[61] Ms. McShane again offered a comparable earnings test as part of her cost of common equity analysis in one of Ameren's prior rate proceeding, Docket Nos. 06-0070/06-0071/06-0072 (Cons.). The Commission rejected the comparable earnings test in that proceeding and stated:

> Among other things, the Commission believes that the comparable earnings test is faulty because it incorrectly assumes the earned returns on book common equity are the same as, or representative of, investor-required returns on common equity.[62]

The Commission also rejected use of the comparable earnings methodology in Docket Nos. 03-0676/03-0677 (Cons.), Docket Nos. 01-0528/01-0628/01-0629 (Cons.), Docket Nos. 99-0121, 92-0448/93-0239 (Cons.), and Docket No. 89-0033.[63]

Q. Are there any significant differences between the comparable earnings models rejected by the Commission in past cases and the one presented by Ms. McShane?

A. No. Both are based on earned returns on book equity as substitutes for investor required returns. In this proceeding, Ms. McShane claims that the results of the comparable earnings test should be relied on as an indicator of whether her market-based test results (the DCF and equity risk premium), as adjusted for the

[61] Order, Docket Nos. 02-0798/03-0008/03-0009 (Cons.), October 22, 2003, p. 88.
[62] Order, Docket Nos. 06-0070/06-0071/06-0072 (Cons.), November 21, 2006, pp. 141-142.
[63] Order, Docket Nos. 03-0676/03-0677 (Cons.), October 6, 2004, p. 40; Order, Docket Nos. 01-528/01-0628/01-0629 (Cons.), March 28, 2002, p. 13; Order, Docket No. 99-0121, August 25, 1999, p. 68; Order, Docket Nos. 92-0448/93-0239 (Cons.), October 11, 1994, p. 173; Order on Remand, Docket No. 89-0033, November 4, 1991, p. 15.

market/book ratio are reasonable. The Commission should once again disregard Ms. McShane's comparable earnings analysis.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.01-G

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Gas Sample

	Company	Ticker	Moody's Credit Rating	Common Equity Ratio
1	AGL Resources	atg	Baa1	39.10%
2	Atmos Energy	ato	Baa2	45.37%
3	New Jersey Resources	njr	Aa3	51.18%
4	Nicor Inc.	gas	Baa2	44.00%
5	Northwest Natural Gas	nwn	A3	45.26%
6	Piedmont Natural Gas	pny	A3	41.89%
7	South Jersey Industries	sji	Baa1	47.41%
8	Southwest Gas	swx	Baa3	43.49%
9	WGL Holdings	wgl	A2	51.70%
	Average		A3	45.49%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.01-E

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Electric Sample

	Company	Ticker	Moody's Credit Rating	Common Equity Ratio
1	Allete	ale	Baa1	57.37%
2	Ameren Corp.	aee	Baa3	45.55%
3	American Electric Power	aep	Baa2	36.82%
4	Avista Corp.	ava	Baa3	45.54%
5	Cleco Corp.	cnl	Baa3	47.50%
6	CMS Energy	cms	Ba1	25.75%
7	Great Plains Energy	gxp	Baa3	43.97%
8	Idacorp Inc.	ida	Baa2	47.82%
9	Northeast Utilities	nu	Baa2	35.12%
10	PG&E Corp.	pcg	Baa1	43.78%
11	Pinnacle West Capital	pnw	Baa3	47.04%
12	Progress Energy	pgn	Baa2	41.91%
13	Teco Energy	te	Baa3	37.78%
14	Westar Energy	wr	Baa3	45.17%
15	Wisconsin Energy Corp.	wec	A3	41.17%
16	Xcel Energy Inc.	xel	Baa1	44.03%
	Average		Baa2	42.90%

Docket Nos. 09-0306 – 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.02

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

The Non-Constant Growth Discounted Cash Flow Model

The formula for measuring the cost of common equity, *k*, when growth, *g*, does not become constant until period φ, is as follows:

$$k = \left[\frac{D_{1,1}(1+k)^{\varphi-0.25} + D_{1,2}(1+k)^{\varphi-0.50} + D_{1,3}(1+k)^{\varphi-0.75} + \ldots + D_{\varphi,4} + P_{\varphi,4}}{P} \right]^{\left(\frac{1}{x+\varphi-0.25}\right)} - 1$$

where: P ≡ the current market value;

$D_{\varphi,q}$ ≡ the expected dividend at the end of quarter q in year φ, where q = 1 to 4 and φ = the number of periods until the steady-state growth period;

k ≡ the cost of common equity;

x ≡ the elapsed time between the stock observation and first dividend payment dates, in years; and

$P_{\varphi,4}$, the market value at the beginning of the steady-state growth stage, is calculated from the following equation:

$$P_{\varphi,4} = \frac{\sum_{q=1}^{4} D_{\varphi,q}(1+g_l)(1+k)^{1-[x+0.25(q-1)]}}{k - g_l}$$

where: $D_{\varphi,q}$ ≡ the dividend paid in quarter q during the last year of the transitional growth stage; and

g_l ≡ the steady-state growth rate.

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.03-G

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Gas Sample

	Growth Rates		
Company	Stage 1[1]	Stage 2[2]	Stage 3[3]
AGL Resources	5.25%	5.04%	4.83%
Atmos Energy	5.00%	4.92%	4.83%
New Jersey Resources	7.00%	5.92%	4.83%
Nicor Inc.	4.15%	4.49%	4.83%
Northwest Natural Gas	6.75%	5.79%	4.83%
Piedmont Natural Gas	6.63%	5.73%	4.83%
South Jersey Industries	9.50%	7.17%	4.83%
Southwest Gas	6.00%	5.42%	4.83%
WGL Holdings	6.67%	5.75%	4.83%

[1] Zacks 3-5 year earnings per share growth rate estimate (Zacks Investment Research, Inc.)
[2] Equals the average of Stage 1 and Stage 3 growth rates.
[3] The implied 20-year forward U.S. Treasury rate in ten years ($_{20}f_{10}$), based on the 10- and 30-year U.S. Treasury rates as of August 18, 2009. (The Federal Reserve Board, Federal Reserve Statistical Release: Selected Interest Rates, H.15 Daily Update, http://www.federalreserve.gov/releases/H15/update/, August 19, 2009.)

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.03-E

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Electric Sample

	Growth Rates		
Company	Stage 1[1]	Stage 2[2]	Stage 3[3]
Allete	4.00%	4.42%	4.83%
Ameren Corp.	3.67%	4.25%	4.83%
American Electric Power	3.80%	4.32%	4.83%
Avista Corp.	8.67%	6.75%	4.83%
Cleco Corp.	14.50%	9.67%	4.83%
CMS Energy	6.25%	5.54%	4.83%
Great Plains Energy	3.00%	3.92%	4.83%
Idacorp Inc.	5.00%	4.92%	4.83%
Northeast Utilities	7.67%	6.25%	4.83%
PG&E Corp.	7.25%	6.04%	4.83%
Pinnacle West Capital	6.50%	5.67%	4.83%
Progress Energy	4.60%	4.72%	4.83%
Teco Energy	10.25%	7.54%	4.83%
Westar Energy	5.67%	5.25%	4.83%
Wisconsin Energy Corp.	8.43%	6.63%	4.83%
Xcel Energy Inc.	5.20%	5.02%	4.83%

[1] Zacks 3-5 year earnings per share growth rate estimate (Zacks Investment Research, Inc.)
[2] Equals the average of Stage 1 and Stage 3 growth rates.
[3] The implied 20-year forward U.S. Treasury rate in ten years (${}_{20}f_{10}$), based on the 10- and 30-year U.S. Treasury rates as of August 18, 2009. (The Federal Reserve Board, Federal Reserve Statistical Release: Selected Interest Rates, H.15 Daily Update, http://www.federalreserve.gov/releases/H15/update/, August 19, 2009.)

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.04-G

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Gas Sample

Prices and Dividends

	Company	Current Dividend $D_{0,1}$	$D_{0,2}$	$D_{0,3}$	$D_{0,4}$	Next Dividend (D1) Payment Date	8/18/2009 Stock Price
1	AGL Resources	$ 0.420	$ 0.430	$ 0.430	$ 0.430	12/1/2009	$ 34.18
2	Atmos Energy	0.325	0.330	0.330	0.330	9/10/2009	$ 27.63
4	New Jersey Resources	0.280	0.310	0.310	0.310	10/1/2009	$ 36.32
3	Nicor Inc.	0.465	0.465	0.465	0.465	11/1/2009	$ 36.39
5	Northwest Natural Gas	0.395	0.395	0.395	0.395	11/13/2009	$ 42.56
6	Piedmont Natural Gas	0.260	0.260	0.270	0.270	10/15/2009	$ 24.42
7	South Jersey Industries	0.270	0.298	0.298	0.298	10/2/2009	$ 34.86
8	Southwest Gas	0.225	0.225	0.238	0.238	12/1/2009	$ 24.99
9	WGL Holdings	0.355	0.355	0.368	0.368	11/1/2009	$ 33.01

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.04-E

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Electric Sample

Prices and Dividends

	Company	Current Dividend $D_{0,1}$	$D_{0,2}$	$D_{0,3}$	$D_{0,4}$	Next Dividend (D1) Payment Date	8/18/2009 Stock Price
1	Allete	$ 0.430	$ 0.440	$ 0.440	$ 0.440	12/1/2009	$ 33.07
2	Ameren Corp.	0.635	0.635	0.385	0.385	9/30/2009	$ 26.21
3	American Electric Power	0.410	0.410	0.410	0.410	12/10/2009	$ 30.68
4	Avista Corp.	0.180	0.180	0.180	0.210	9/15/2009	$ 19.77
5	Cleco Corp.	0.225	0.225	0.225	0.225	11/17/2009	$ 24.24
6	CMS Energy	0.090	0.125	0.125	0.125	11/30/2009	$ 13.05
7	Great Plains Energy	0.415	0.415	0.208	0.208	9/21/2009	$ 17.71
8	Idacorp Inc.	0.300	0.300	0.300	0.300	11/30/2009	$ 28.22
9	Northeast Utilities	0.213	0.213	0.238	0.238	9/30/2009	$ 23.55
10	PG&E Corp.	0.390	0.390	0.420	0.420	10/15/2009	$ 39.86
11	Pinnacle West Capital	0.525	0.525	0.525	0.525	12/1/2009	$ 32.33
12	Progress Energy	0.615	0.620	0.620	0.620	11/3/2009	$ 38.92
13	Teco Energy	0.200	0.200	0.200	0.200	11/25/2009	$ 12.98
14	Westar Energy	0.290	0.290	0.300	0.300	10/1/2009	$ 20.25
15	Wisconsin Energy Corp.	0.270	0.338	0.338	0.338	12/1/2009	$ 44.36
16	Xcel Energy Inc.	0.238	0.238	0.238	0.245	10/20/2009	$ 19.30

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.05-G

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Gas Sample

Expected Quarterly Dividends

Company	$D_{1,1}$	$D_{1,2}$	$D_{1,3}$	$D_{1,4}$
AGL Resources	$ 0.430	$ 0.453	$ 0.453	$ 0.453
Atmos Energy	0.330	0.347	0.347	0.347
New Jersey Resources	0.310	0.332	0.332	0.332
Nicor Inc.	0.465	0.484	0.484	0.484
Northwest Natural Gas	0.422	0.422	0.422	0.422
Piedmont Natural Gas	0.270	0.270	0.288	0.288
South Jersey Industries	0.298	0.326	0.326	0.326
Southwest Gas	0.238	0.238	0.252	0.252
WGL Holdings	0.368	0.368	0.392	0.392

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.05-E

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Electric Sample

Expected Quarterly Dividends

Allete	$ 0.440	$ 0.458	$ 0.458	$ 0.458
Ameren Corp.	0.385	0.385	0.399	0.399
American Electric Power	0.426	0.426	0.426	0.426
Avista Corp.	0.210	0.210	0.210	0.228
Cleco Corp.	0.258	0.258	0.258	0.258
CMS Energy	0.125	0.133	0.133	0.133
Great Plains Energy	0.208	0.208	0.214	0.214
Idacorp Inc.	0.315	0.315	0.315	0.315
Northeast Utilities	0.238	0.238	0.256	0.256
PG&E Corp.	0.420	0.420	0.450	0.450
Pinnacle West Capital	0.559	0.559	0.559	0.559
Progress Energy	0.620	0.665	0.665	0.665
Teco Energy	0.221	0.221	0.221	0.221
Westar Energy	0.300	0.300	0.317	0.317
Wisconsin Energy Corp.	0.338	0.366	0.366	0.366
Xcel Energy Inc.	0.245	0.245	0.245	0.258

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.06-G

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Gas Sample

Non-Constant DCF Cost of Common Equity Estimates

Company	Estimate
AGL Resources	10.36%
Atmos Energy	10.11%
New Jersey Resources	9.05%
Nicor Inc.	10.19%
Northwest Natural Gas	9.37%
Piedmont Natural Gas	10.09%
South Jersey Industries	9.73%
Southwest Gas	9.13%
WGL Holdings	10.12%
Average	9.79%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.06-E

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Electric Sample

Non-Constant DCF Cost of Common Equity Estimates

Company	Estimate
Allete	10.26%
Ameren Corp.	9.07%
American Electric Power	10.26%
Avista Corp.	10.49%
Cleco Corp.	11.87%
CMS Energy	9.29%
Great Plains Energy	8.14%
Idacorp Inc.	9.48%
Northeast Utilities	9.96%
PG&E Corp.	10.03%
Pinnacle West Capital	12.62%
Progress Energy	11.65%
Teco Energy	13.91%
Westar Energy	11.55%
Wisconsin Energy Corp.	8.88%
Xcel Energy Inc.	10.32%
Average	10.49%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.07

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Risk Premium Analysis

Interest Rates as of August 18, 2009

U.S. Treasury Bills		U.S. Treasury Bonds	
Discount Rate	Effective Yield	Equivalent Yield	Effective Yield
0.14%	0.14%	4.35%	4.40%

Risk Premium Cost of Equity Estimates*
Gas Sample

Risk-Free Rate		Beta		Risk Premium		Cost of Common Equity
4.40%	+	0.61	*	(12.70% - 4.40%)	=	9.46%

Risk Premium Cost of Equity Estimates*
Electric Sample

Risk-Free Rate		Beta		Risk Premium		Cost of Common Equity
4.40%	+	0.70	*	(12.70% - 4.40%)	=	10.21%

*Risk-Free Rate Proxy is the U.S. Treasury Bond Yield.

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.08

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Ratios

Components

Before Tax Weighted Average Cost of Capital = Weighted Cost of Short-Term Debt + Weighted Cost of Long-Term Debt + (Weighted Cost of Preferred Stock ÷ (1 - Composite Tax Rate)) + (Weighted Cost of Equity ÷ (1 - Composite Tax Rate))

Funds Available to Shareholders = (Weighted Cost of Equity + Weighted Cost of Preferred Stock) x Rate Base

Non-Cash Items = Depreciation & Amortization + Deferred Taxes and Investment Tax Credits

Funds From Operations = Funds Available to Shareholders + Non-Cash Items

Cash Dividends = (Weighted Cost of Preferred Stock x Rate Base) + (Payout Ratio x Funds Available to Shareholders)

Interest = (Weighted Cost of Short-term Debt + Weighted Cost of Long-term Debt) x Rate Base

Total Debt = (Short-term Debt Ratio + Long-term Debt Ratio) x Rate Base

Ratios

Funds From Operations / Interest Coverage = (Funds From Operations + Interest) ÷ Interest

Funds From Operations / Debt = Funds From Operations ÷ Total Debt

EBIT / Interest Coverage = (Before Tax Weighted Average Cost of Capital x Rate Base) ÷ Interest

RCF /Debt = (Funds From Operations - Cash Dividends) ÷ Total Debt

Debt/ Capitalization = Short-term Debt Ratio + Long-term Debt Ratio

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.09-CILCO-G

Central Illinois Light Company

Components

Before Tax Weighted Average Cost of Capital = 0.12% + 3.18% +(0.15% ÷ (1-0.39745)) + (4.20% ÷ (1-0.39745)) = 10.61%

Funds Available to Shareholders = (4.20% + 0.15%) x $222,479,000 = $9,681,370

Non-Cash Items = $7,250,000 + -$2,133,450 = $5,116,550

Funds From Operations = $9,681,370 + $5,116,550 = $14,797,920

Cash Dividends = 0.15% x $222,479,000 = $338,731

Interest = (0.12% + 3.18%) x $222,479,000 = $7,336,588

Total Debt = (5.60% + 47.49%) x $222,479,000 = $118,115,273

Ratios

EBIT / Interest Coverage = (10.61% x $222,479,000) ÷ $7,336,588 = 3.22X

RCF /Debt = ($14,797,920 - $338,731) ÷ $118,115,273 = 12.24%

Debt/ Captialization = 5.60% + 47.49% = 53.09%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.09-CIPS-G

Central Illinois Public Service Company

Components

Before Tax Weighted Average Cost of Capital = 0.09% + 2.62% +(0.26% ÷ (1-0.39745)) + (4.69% ÷ (1-0.39745)) = 11.01%

Funds Available to Shareholders = (4.69% + 0.26%) x $212,602,000 = $10,507,717

Non-Cash Items = $8,064,000 + $2,918,867 = $10,982,867

Funds From Operations = $10,507,717 + $10,982,867 = $21,490,584

Cash Dividends = 0.26% x $212,602,000 = $543,105

Interest = (0.09% + 2.62%) x $212,602,000 = $5,768,575

Total Debt = (5.91% + 40.44%) x $212,602,000 = $98,540,474

Ratios

EBIT / Interest Coverage = (11.01% x $212,602,000) ÷ $5,768,575 = 4.06X

RCF /Debt = ($21,490,584 - $543,105) ÷ $98,540,474= 21.26%

Debt/ Captialization = 5.91% + 40.44% = 46.35%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.09-IP-G

Illinois Power Company

Components

Before Tax Weighted Average Cost of Capital = 0.01% + 4.24% +(0.09% ÷ (1-0.39745)) + (4.19% ÷ (1-0.39745)) = 11.47%

Funds Available to Shareholders = (4.19% + 0.09%) x $555,438,000 = $23,820,242

Non-Cash Items = $20,833,000 + $5,292,697 = $26,125,697

Funds From Operations = $23,820,242 + $26,125,697 = $49,945,939

Cash Dividends = (0.09% x $555,438,000) + (50% x $23,820,242) = $12,437,233

Interest = (0.01% + 4.24%) x $555,438,000 = $23,608,437

Total Debt = (0.45% + 54.11%) x $555,438,000 = $303,035,911

Ratios

EBIT / Interest Coverage = (11.47% x $555,438,000) ÷ $23,608,437 = 2.70X

RCF /Debt = ($49,945,939 - $12,437,233) ÷ $303,035,911 = 12.38%

Debt/ Captialization = 0.45% + 54.11% = 54.56%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.09-CILCO-E

Central Illinois Light Company

Components

Funds Available to Shareholders = (4.51% + 0.15%) x $324,782,000 = $15,152,889

Non-Cash Items = $20,682,000 + -$1,051,825 = $19,630,175

Funds From Operations = $15,152,889 + $19,630,175 = $34,783,064

Cash Dividends = 0.15% x $324,782,000 = $494,491

Interest = (0.12% + 3.18%) x $324,782,000 = $10,710,187

Total Debt = (5.60% + 47.49%) x $324,782,000 = $172,428,474

Ratios

Funds From Operations / Interest Coverage = ($34,783,064 + $10,710,187) ÷ $10,710,187 = 4.25X

Funds From Operations / Debt = $34,783,064 ÷ $172,428,474 = 20.17%

RCF /Debt = ($34,783,064 - $494,491) ÷ $172,428,474 = 19.89%

Debt/ Captialization = 5.60% + 47.49% = 53.09%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.09-CIPS-E

Central Illinois Public Service Company

Components

Funds Available to Shareholders = (5.04% + 0.26%) x $517,903,000 = $27,411,902

Non-Cash Items = $51,505,000 + $6,409,504 = $57,914,504

Funds From Operations = $27,411,902 + $57,914,504 = $85,326,406

Cash Dividends = 0.26% x $517,903,000 = $1,323,015

Interest = (0.09% + 2.62%) x $517,903,000 = $14,052,373

Total Debt = (5.91% + 40.44%) x $517,903,000 = $240,046,694

Ratios

Funds From Operations / Interest Coverage = ($85,326,406 + $14,052,373) ÷ $14,052,373 = 7.07X

Funds From Operations / Debt = $85,326,406 ÷ $240,046,694 = 35.55%

RCF /Debt = ($85,326,406 - $1,323,015) ÷ $240,046,694 = 34.99%

Debt/ Captialization = 5.91% + 40.44% = 46.35%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.09-IP-E

Illinois Power Company

Components

Funds Available to Shareholders = (4.51% + 0.09%) x $1,462,880,000 = $67,323,140

Non-Cash Items = $76,361,000 + $16,392,508 = $92,753,508

Funds From Operations = $67,323,140+ $92,753,508 = $160,076,648

Cash Dividends = (0.09% x $1,462,880,000) + (50% x $67,323,140) = $35,049,846

Interest = (0.01% + 4.24%) x $1,462,880,000 = $62,178,518

Total Debt = (0.45% + 54.11%) x $1,462,880,000 = $798,118,070

Ratios

Funds From Operations / Interest Coverage = ($160,076,648 + $62,178,518) ÷ $62,178,518 = 3.57X

Funds From Operations / Debt = $160,076,648 ÷ $798,118,070 = 20.06%

RCF /Debt = ($160,076,648 - $35,049,846) ÷ $798,118,070 = 15.67%

Debt/ Captialization = 0.45% + 54.11% = 54.56%

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.10

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Reuters Corporate Spreads for Utilities

Ratings	30-year
Aaa/AAA	95
Aa1/AA+	145
Aa2/AA	155
Aa3/AA-	165
A1/A+	175
A2/A	185
A3/A-	195
Baa1/BBB+	245
Baa2/BBB	265
Baa3/BBB-	280
Ba1/BB+	395
Ba2/BB	595
Ba3/BB-	695
B1/B+	795
B2/B	1400
B3/B-	1600
Caa/CCC+	1700

Docket Nos. 09-0306 - 0311 (Cons.)
ICC Staff Exhibit 6.0
Schedule 6.11

Central Illinois Light Company
Central Illinois Public Service Company
Illinois Power Company

Summary of Cost of Common Equity Adjustments

	CILCO		CIPS		IP	
	Gas	Electric	Gas	Electric	Gas	Electric
Sample DCF	9.79%	10.49%	9.79%	10.49%	9.79%	10.49%
Sample CAPM	9.46%	10.21%	9.46%	10.21%	9.46%	10.21%
Sample Average	9.63%	10.35%	9.63%	10.35%	9.63%	10.35%
Adjustments						
Financial Risk	0.30%	-0.04%	-0.12%	-0.12%	0.30%	0.00%
Fixed Customer Charge	-0.10%	0.00%	-0.10%	0.00%	-0.10%	0.00%
Recommended Cost of Common Equity						
Before Uncollectibles Rider Adjustment	**9.83%**	**10.31%**	**9.41%**	**10.23%**	**9.83%**	**10.35%**
Uncollectibles Rider Adjustment	-0.95%	-0.41%	-0.74%	-0.67%	-0.75%	-0.29%
Including Uncollectibles Rider Adjustment	8.89%	9.90%	8.68%	9.57%	9.08%	10.06%

MOODY'S
INVESTORS SERVICE

Rating Action: **Moody's Upgrades Ameren Illinois Utilities to Investment Grade**

Global Credit Research - 13 Aug 2009

Approximately $2.5 billion of Debt Securities Upgraded

New York, August 13, 2009 -- Moody's Investors Service upgraded the ratings of Central Illinois Public Service Company (AmerenCIPS; Issuer Rating to Baa3 from Ba1); Central Illinois Light Company (AmerenCILCO, Issuer Rating to Baa3 from Ba1); Illinois Power Company (AmerenIP, Issuer Rating to Baa3 from Ba1) and CILCORP Inc. (senior unsecured to Ba1 from Ba2). The Corporate Family Rating, Probability of Default rating and all loss given default ratings of the CILCORP have been withdrawn. Moody's affirmed the ratings of Ameren Corporation (Ameren, Baa3 senior unsecured), Union Electric Company (AmerenUE, Baa2 Issuer Rating), and AmerenEnergy Generating Company (Genco, Baa3 senior unsecured). The rating outlook of Ameren and all of its subsidiaries is stable.

"The upgrade of Ameren's Illinois utilities is prompted by the recent execution of new bank credit facilities and the improved political and regulatory environment for utilities in Illinois," said Michael G. Haggarty, Vice President and Senior Credit Officer. The new two year bank facility provides $800 million of credit and liquidity support for Ameren, AmerenCIPS, AmerenCILCO, and AmerenIP. Although it replaces $1 billion of credit facilities with a longer tenor, bank and credit market conditions have made it more difficult and expensive for utilities to enter into facilities at previous amounts and with longer maturities. Moody's believes this new facility provides adequate liquidity support considering lower usage of the facility in 2009 and going forward, Ameren's anticipated continued ability to access the capital markets for long-term debt financings. Moody's notes that CILCORP is not a borrower under the new facility and will rely on Ameren's money pool or other arrangements to maintain adequate liquidity.

Moreover, the upgrade also reflects positive developments in Illinois since rate freeze legislation was passed by the Illinois House of Representatives in 2007. Following a comprehensive settlement agreement on electric rates and power procurement issues reached in the state in August 2007, Ameren's Illinois utilities received a reasonably supportive delivery service rate case outcome in September 2008 in their first rate proceeding after the settlement. The newly created Illinois Power Agency's first power procurement RFP process during the first half of 2009 was executed successfully and resulted in somewhat lower electric rates for residential customers. In addition, legislation was recently passed providing Illinois utilities with a bad debt rider. Although the southern Illinois economy continues to face recessionary conditions, which could make future regulatory proceedings more challenging, Moody's believes the utilities should be able to obtain sufficient regulatory relief to maintain their investment grade credit quality.

Ratings upgraded and assigned a stable outlook include:

Central Illinois Public Service Company's senior secured debt to Baa1 from Baa2, Issuer Rating to Baa3 from Ba1, and preferred stock to Ba2 from Ba3;

CILCORP Inc.'s senior unsecured debt to Ba1 from Ba2;

Central Illinois Light Company's senior secured debt to Baa1 from Baa2; and Issuer Rating to Baa3 from Ba1;

Illinois Power Company's senior secured debt to Baa1 from Baa2, Issuer Rating to Baa3 from Ba1, and preferred stock to Ba2 from Ba3.

Ratings affirmed with a stable outlook include:

Ameren's Baa3 Issuer Rating and Prime-3 short-term rating for commercial paper;

Union Electric Company's A3 senior secured, Baa2 Issuer Rating, Baa3 subordinated, Ba1 preferred stock, and Prime-3 short-term rating for commercial paper;

Ameren Energy Generating Company's Baa3 senior unsecured debt.

Ratings withdrawn:

CILCORP's Corporate Family Rating and Probability of Default Rating.

The last rating action on Central Illinois Public Service Company, Illinois Power Company and Union Electric Company was on August 3, 2009, when their senior secured debt ratings were upgraded one notch. The last rating action on CILCORP was on January 29, 2009, when its rating was affirmed and its rating outlook was changed to stable from positive, as was also the case for Central Illinois Public Service Company, Central Illinois Light Company, and Illinois Power Company. The last rating action on Ameren was on February 16, 2009 when its rating was affirmed. The last rating action on Ameren Energy Generating Company was on August 13, 2008, when its rating was downgraded. The principal methodology used in rating these issuers was Regulated Electric and Gas Utilities, which can be found at www.moodys.com in the Credit Policy & Methodologies directory, in the Ratings Methodologies subdirectory. Other methodologies and factors that have been considered in the process of rating these issuers can also be found in the Credit Policy & Methodologies directory.

Ameren Corporation is a public utility holding company headquartered in St. Louis, Missouri. It is the parent company of Union Electric Company (AmerenUE), Central Illinois Public Service Company (AmerenCIPS), CILCORP Inc., Central Illinois Light Company (AmerenCILCO); Illinois Power Company (AmerenIP), and AmerenEnergy Generating Company.

New York
Michael G. Haggarty
VP - Senior Credit Officer
Infrastructure Finance Group
Moody's Investors Service

JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

New York
William L. Hess
Managing Director
Infrastructure Finance Group
Moody's Investors Service
JOURNALISTS: 212-553-0376
SUBSCRIBERS: 212-553-1653

Deutsche Bank

23 February 2010

DTE Energy

Reuters: **DTE.N** Bloomberg: **DTE US** Exchange: **NYS** Ticker: **DTE**

Upping estimates on electric rate base re-calc and P&I

Jonathan Arnold
Research Analyst
(+1) 212 250-3182
jonathan.arnold@db.com

Lauren Duke
Research Associate
(+1) 212 250-8204
lauren.duke@db.com

Strong 2010 guidance issued, still looks fairly valued
DTE introduced formal 2010 EPS guidance today of $3.35-$3.75, higher than the level implied in their previous 2010 early outlook from the October 2009 analyst meeting. Key drivers behind the increase were higher MichCon earnings and higher utilization at the Power & Industrial segment. We believe that to earn at the high end of the range, DTE would need to overearn at its utilities and/or surprise at the non-utility segments. Despite the strong 2010 guidance, we continue to rate DTE a Hold as the stock looks fairly valued to us versus peers.

2009 results in line with expectations, guidance midpoint above our estimate
DTE reported 4Q09 operating EPS of $0.72, in line with consensus and $0.02 above our estimate. For the full year, DTE reported operating EPS of $3.30, in line with our estimate and consensus. Overall, results were largely as expected, with the exception of some costs being shifted from MichCon to Parent. DTE's 2010 guidance surprised to the upside based largely on a slight increase in expectations for MichCon and higher Power & Industrial earnings. We had already increased our P&I estimates above DTE's previous 2010 early outlook based on higher steel utilization, but we did not anticipate the magnitude of the impact.

Boosting estimates by $0.10 across the board
We are increasing our 2010, 2011, and 2012 EPS estimates by $0.10 to $3.55, $3.60, and $3.90. We attribute roughly half of this increase to higher estimates at Power & Industrial and the other half to a recalculation of our Detroit Edison rate base estimates. We had previously used a higher estimate to depreciate the rate base over time, in line with our D&A forecast. We have now adjusted that estimate to exclude certain amortization items that do not impact rate base.

Increasing price target by $2 to $44 on higher estimates; risks
Our $44 price target is based on a sum-of-the-parts analysis. We apply an 11x P/E multiple, in line with the regulated utility peer average, to our 2012 EPS estimates for Detroit Edison and MichCon. We apply a 7.5x EV/EBITDA multiple to Gas Midstream, a 6x multiple to P&I, and a 5x multiple to Energy Trading. We add in $2-$3 per share for DTE's Barnett Shale assets. Upside risks include higher earned ROEs and the sale of assets to offset equity needs. Downside risks include underearning at the utilities and a continued economic decline. See p. 4.

Forecasts and ratios

Year End Dec 31	2009A	**2010E**	2011E
FY EPS (USD)	3.30	**3.55**	3.70
OLD FY EPS (USD)	3.30	**3.45**	3.60
% Change	-0.0%	**2.9%**	2.8%
P/E (x)	10.2	**12.4**	11.9
DPS (USD)	2.12	**2.12**	2.16
Dividend yield (%)	6.3	**4.8**	4.9

Source: Deutsche Bank estimates, company data

[1] Includes the impact of FAS123R requiring the expensing of stock options.

Results

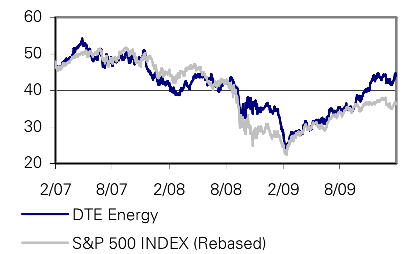
Hold

Price at 23 Feb 2010 (USD)	**43.99**
Price target	**44.00**
52-week range	**44.64 - 23.61**

Key changes

Price target	42.00 to 44.00 ↑	**4.8%**
EPS (USD)	3.45 to 3.55 ↑	**2.9%**
Revenue (USDm)	8,586.6 to 8,491.9 ↓	**-1.1%**

Price/price relative

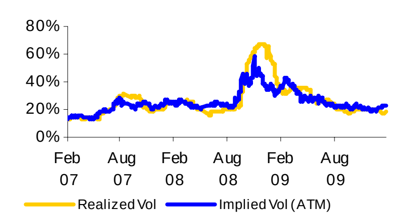


Performance (%)	1m	3m	12m
Absolute	*4.6*	*9.6*	*53.3*
S&P 500 INDEX	*0.3*	*-1.1*	*47.3*

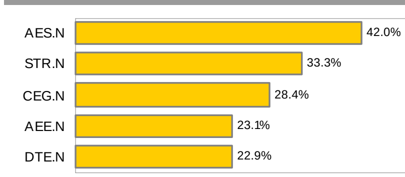
Stock & option liquidity data

Market cap (USDm)	7,417.7
Shares outstanding (m)	168.6
Free float (%)	100
Volume (23 Feb 2010)	647,400
Option volume (und. shrs., 1M avg.)	11,830
Short interest (m)	–
Short interest (%)	–
Institutional ownership (%)	–
DPS (USD)	2.12

Implied & Realized Volatility (3M)



Implied Volatility (3M, ATM) vs. Peers



*Weighted-avg. of index components
Data as of 16-Feb-10

Deutsche Bank Securities Inc.

Model updated:24 February 2010

Running the numbers

North America

United States

Utilities and Power

DTE Energy

Reuters: DTE.N Bloomberg: DTE US

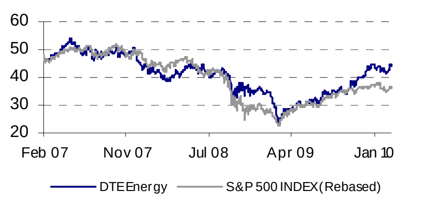
Hold

Price (23 Feb 10)	USD 43.99
Target price	USD 44.00
52-week Range	USD 23.61 - 44.64
Market Cap (m)	USDm 7,418 EURm 5,466

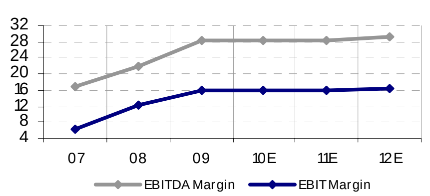
Company Profile

DTE Energy is a holding company that owns 2 Michigan utilities (Detroit Edison and MichCon) and 4 non-utility subsidiaries. Detroit Edison is an electric distribution and generation utility with 2.2M customers. MichCon is a gas distribution, transmission, and storage utility with 1.2M customers. Gas Midstream owns interests in 2 gas pipelines and 2 storage fields. Unconventional Gas Production owns E&P assets in the western Barnett Shale in Texas. Power and Industrial provides energy and utility services to industrial customers, provides coal transportation and marketing, and develops biomass projects.

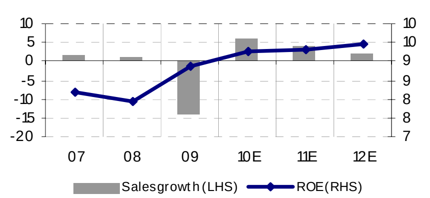
Price Performance



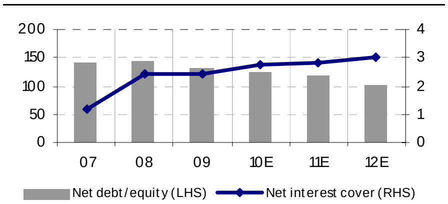
Margin Trends



Growth & Profitability



Solvency



Jonathan Arnold
+1 212 250-3182 jonathan.arnold@db.com

Fiscal year end 31-Dec	2007	2008	2009	2010E	2011E	2012E
Financial Summary						
DB EPS (USD)	2.82	2.90	3.30	3.55	3.70	3.90
Reported EPS (USD)	2.82	2.89	3.31	3.55	3.70	3.90
DPS (USD)	2.12	2.12	2.12	2.12	2.16	2.20
BVPS (USD)	34.63	37.01	38.28	39.25	40.55	43.00
Valuation Metrics						
Price/Sales (x)	0.9	0.7	0.7	0.9	0.9	0.9
P/E (DB) (x)	17.3	13.9	10.2	12.4	11.9	11.3
P/E (Reported) (x)	17.3	14.0	10.2	12.4	11.9	11.3
P/BV (x)	1.3	1.0	1.1	1.1	1.1	1.0
FCF yield (%)	nm	3.0	14.2	2.0	4.0	4.3
Dividend yield (%)	4.4	5.3	6.3	4.8	4.9	5.0
EV/Sales	1.7	1.5	1.6	1.7	1.6	1.6
EV/EBITDA	10.0	6.8	5.5	5.9	5.7	5.4
EV/EBIT	25.7	12.1	9.8	10.5	10.0	9.4
Income Statement (USDm)						
Sales	9,229	9,350	8,022	8,492	8,826	9,023
EBITDA	1,535	2,064	2,271	2,414	2,512	2,624
EBIT	599	1,163	1,268	1,364	1,426	1,500
Pre-tax profit	320	732	804	920	973	1,056
Net income	**480**	**471**	**543**	**598**	**632**	**687**
Cash Flow (USDm)						
Cash flow from operations	**1,114**	**1,570**	**1,819**	**1,548**	**1,818**	**1,911**
Net Capex	-1,299	-1,373	-1,035	-1,400	-1,520	-1,575
Free cash flow	**-185**	**197**	**784**	**148**	**298**	**336**
Equity raised/(bought back)	-708	-16	35	100	50	350
Dividends paid	-364	-344	-348	-357	-369	-388
Net inc/(dec) in borrowings	-390	286	-476	100	24	-245
Other investing/financing cash flows	1,623	-160	-29	0	0	0
Net cash flow	**-24**	**-37**	**-34**	**-9**	**3**	**53**
Change in working capital	*196*	*-87*	*69*	*0*	*0*	*0*
Balance Sheet (USDm)						
Cash and cash equivalents	123	86	52	42	45	98
Property, plant & equipment	11,408	12,231	12,431	12,781	13,215	13,666
Goodwill	2,037	2,037	2,024	2,024	2,024	2,024
Other assets	10,186	10,236	9,688	9,688	9,688	9,688
Total assets	**23,754**	**24,590**	**24,195**	**24,535**	**24,972**	**25,476**
Debt	8,509	8,847	8,368	8,338	8,232	7,857
Other liabilities	9,344	9,705	9,511	9,541	9,771	10,001
Total liabilities	**17,853**	**18,552**	**17,879**	**17,879**	**18,003**	**17,858**
Total shareholders' equity	**5,901**	**6,038**	**6,316**	**6,656**	**6,970**	**7,618**
Net debt	*8,386*	*8,761*	*8,316*	*8,296*	*8,187*	*7,759*
Key Company Metrics						
Sales growth (%)	1.6	1.3	-14.2	5.9	3.9	2.2
DB EPS growth (%)	-2.5	2.8	13.8	7.4	4.3	5.3
Payout ratio (%)	74.7	72.9	64.0	59.8	58.4	56.5
EBITDA Margin (%)	16.6	22.1	28.3	28.4	28.5	29.1
EBIT Margin (%)	6.5	12.4	15.8	16.1	16.2	16.6
ROE (%)	8.2	8.0	8.8	9.3	9.3	9.5
Net debt/equity (%)	142.1	145.1	131.7	124.6	117.5	101.8
Net interest cover (x)	1.2	2.4	2.4	2.7	2.8	3.0
DuPont Analysis						
EBIT margin (%)	6.5	12.4	15.8	16.1	16.2	16.6
x Asset turnover (x)	0.4	0.4	0.3	0.3	0.4	0.4
x Financial cost ratio (x)	0.2	0.6	0.6	0.6	0.6	0.7
x Tax and other effects (x)	4.9	0.7	0.7	0.7	0.7	0.7
= ROA (post tax) (%)	**2.0**	**1.9**	**2.2**	**2.5**	**2.6**	**2.7**
x Financial leverage (x)	4.1	4.1	4.0	3.8	3.7	3.5
= ROE (%)	**8.2**	**8.0**	**8.8**	**9.3**	**9.3**	**9.5**
annual growth (%)	*-6.9*	*-3.0*	*11.3*	*4.8*	*0.7*	*1.4*
x NTA/share (avg) (x)	34.4	36.3	37.4	38.2	39.6	41.2
= Reported EPS	**2.82**	**2.89**	**3.31**	**3.55**	**3.70**	**3.90**
annual growth (%)	*-2.5*	*2.4*	*14.6*	*7.1*	*4.3*	*5.3*

Source: Company data, Deutsche Bank estimates

Expecting strong 2010

2010 guidance implies higher growth rate than long-term target

DTE issued 2010 guidance of $3.35-$3.75 versus our estimate of $3.45 and consensus of $3.41. The midpoint implies a 7.6% EPS growth rate, higher than DTE's long-term target of 5%-6% annual EPS growth. DTE's guidance was also higher than its 2010 early outlook initially provided at its October 2009 analyst meeting and reaffirmed in late January after the Detroit Edison rate decision was issued. The main driver behind the increase was higher expectations at the Power & Industrial segment. DTE's original forecast assumed ~60% utilization of its coke batteries (important for steel production). Since then, DTE has fully contracted its 2010 capacity (and 90% of 2011 capacity) through 5-7 year contracts that have increased the earnings expectations. We had increased our estimates by $0.05 per year in early January to account for higher steel production expectations, but with DTE contracting its full capacity, we are now increasing our estimates by another $0.05 at P&I.

No market equity issuances planned for 2010, but offset by pension funding

We had assumed that DTE would issue $200M of equity in 2010, with $50M at the DRIP and the remainder in a market issuance. While DTE did announce that they do not need to do any market issuances this year, they do expect to issue $200M of new equity. Of this, $50M will be for the DRIP program, as expected, and another $50M will be used to fund employee benefit programs. The remaining $100M will be issued directly into the pension plan to meet funding needs. The share count impact is the same, but DTE will only receive $50M of the cash. DTE did not change its 2010-2012 equity needs of $600M-$800M (which could be offset by asset sales). We assume they issue $100M per year in DRIP and employee benefit plans and $300M of market equity in 2012.

Adjusting estimates on recalculation of Detroit Edison rate base

We are increasing our estimates by another $0.05 (beyond the $0.05 for P&I) to account for higher rate base expectations at Detroit Edison. We had previously used our full Detroit Edison depreciation and amortization (excluding the securitization amortization) to depreciate rate base over time. We are now using a lower estimate that adjusts for additional amortization items that do not affect rate base. On average, this adjustment has increased our rate base by $200M, driving our Detroit Edison estimate increase. We estimate 2012 year-end rate base at $11.1B, at the low end of DTE's forecast. We continue to assume that DTE's utilities will be able to earn their authorized returns over the next few years, given its ability to file annual rate cases and self-implement new rates six months after filing, decoupling, and uncollectibles trackers.

Reaffirmed 5%-6% long-term EPS growth target; stock looks fairly valued

DTE reaffirmed its long-term EPS growth forecast of 5%-6%. DTE expects the utilities to largely drive this growth, based on the renewables and energy optimization riders and Detroit Edison's environmental capital requirements. Our estimates imply a ~7.5% growth rate for 2010, 4.3% for 2011, and 5.4% for 2012. Despite the increase in our earnings estimates, we continue to view DTE as fairly valued. On our now well above consensus 2012 EPS estimate, DTE trades roughly at a slight premium to its mostly regulated peers on a P/E basis. We believe that DTE should trade in line with peers given its business mix, economic environment, growth prospects, and regulatory construct.

Valuation

We are increasing our price target to $44 from $42 on our increased EPS estimates. We value DTE on a sum-of-the-parts basis. We value Detroit Edison and MichCon at $36-$37 by applying an average regulated utility P/E multiple of 11x to our 2012 EPS estimates. We view a peer average multiple as appropriate despite the favorable Michigan regulatory construct because of the risks associated with the Michigan economic environment. Even with decoupling, a continued economic decline could affect DTE by limiting capital spending opportunities and increasing rate sensitivity among customers, regulators and politicians. We value DTE's non-utility businesses at $7-$8. We apply a 7.5x EV/EBITDA multiple to the Gas Midstream segment, which is a premium to the average regulated utility multiple. In our view, this premium is justified given the segment's FERC-regulated gas pipeline and storage assets that are allowed a higher ROE than the average utility. We apply a 6x multiple to the Power and Industrial segment and 5x to Energy Trading. Lastly, we value DTE's western Barnett Shale E&P assets at $2-$3 per share by applying a $2/Mcfe value to 2009 proved reserves of 234 Bcfe.

Figure 1: DTE Sum-of-the-Parts Valuation

Business Segment	Valuation Metric	2012E	Multiple	Value
Detroit Edison	P/E	$2.70	11.00x	5,234
MichCon	P/E	$0.61	11.00x	1,189
Utility Equity Value				**6,423**
Gas Midstream	EV/EBITDA	96	7.50x	719
Power & Industrial	EV/EBITDA	105	6.00x	628
Energy Trading	EV/EBITDA	98	5.00x	489
Unconventional Gas Production	$/Mcfe	234	$2.00	468
Total Non-Utility Enterprise Value				2,304
Less: Non-Utility Net Debt (2012E)				(988)
Non-Utility Equity Value				**1,316**
Total Equity Value				**7,739**
Diluted Average Shares Outstanding (2012E)				176
Equity Value Per Share				**$44**

Source: Deutsche Bank and DTE Energy

Risks

Upside risks include more favorable rate case outcomes at Detroit Edison and MichCon than we assume and a stronger economic recovery, which could increase capital spending opportunities. Asset sales, particularly the Barnett Shale assets, would offset some of our expected equity issuance assumptions. Downside risks include less favorable rate case outcomes than we assume, especially if they disallow capital spending. A continued decline in the economy and an inability to refinance upcoming debt maturities or to renew expiring credit facilities would also be downside risks.

Figure 2: DTE Energy Income Statement ($ in Millions)

DTE Energy (NYSE: DTE) Income Statement	2007A	1Q08A	2Q08A	3Q08A	4Q08A	2008A	1Q09A	2Q09A	3Q09E	4Q09E	2009E	2010E	2011E	2012E
Operating Revenue	9,229	2,579	2,249	2,341	2,181	9,350	2,257	1,688	1,961	2,121	8,022	8,492	8,826	9,023
Fuel & Purchased Power	(3,553)	(1,266)	(1,032)	(1,034)	(974)	(4,306)	(960)	(577)	(735)	(846)	(3,118)	(3,443)	(3,620)	(3,637)
Gross Margin	**5,676**	**1,313**	**1,217**	**1,307**	**1,207**	**5,044**	**1,297**	**1,111**	**1,226**	**1,275**	**4,904**	**5,049**	**5,206**	**5,385**
O&M Expense	(3,781)	(698)	(754)	(624)	(600)	(2,676)	(591)	(581)	(554)	(632)	(2,358)	(2,325)	(2,381)	(2,438)
Taxes & Other	(360)	(80)	(78)	(71)	(75)	(304)	(80)	(61)	(63)	(71)	(275)	(309)	(313)	(324)
EBITDA	**1,535**	**535**	**385**	**612**	**532**	**2,064**	**626**	**469**	**609**	**572**	**2,271**	**2,414**	**2,512**	**2,624**
EBITDA / Gross Margin	27.0%	40.7%	31.6%	46.8%	44.1%	40.9%	48.3%	42.2%	49.7%	44.9%	46.3%	47.8%	48.3%	48.7%
Depreciation & Amortization	(936)	(226)	(216)	(235)	(224)	(901)	(232)	(240)	(266)	(265)	(1,003)	(1,050)	(1,086)	(1,124)
EBIT	**599**	**309**	**169**	**377**	**308**	**1,163**	**394**	**229**	**343**	**307**	**1,268**	**1,364**	**1,426**	**1,500**
Interest Income / (Expense)	(501)	(120)	(118)	(120)	(126)	(484)	(129)	(131)	(132)	(134)	(526)	(500)	(511)	(502)
Other Income / (Expense)	222	12	(7)	17	31	53	13	29	18	2	62	56	57	59
Earnings Before Taxes	**320**	**201**	**44**	**274**	**213**	**732**	**278**	**127**	**229**	**175**	**804**	**920**	**973**	**1,056**
Income Tax Charge	1	(72)	(16)	(100)	(68)	(256)	(98)	(34)	(72)	(54)	(258)	(322)	(340)	(370)
Effective Tax Rate	*-0.3%*	*35.8%*	*36.4%*	*36.5%*	*31.9%*	*35.0%*	*35.3%*	*26.8%*	*31.4%*	*30.9%*	*32.1%*	*35.0%*	*35.0%*	*35.0%*
Preferred Dividends	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Minority & Other	159	(1)	(2)	(1)	(1)	(5)	(1)	(1)	-	(1)	(3)	-	-	-
Net Income - Operating	**480**	**128**	**26**	**173**	**144**	**471**	**179**	**92**	**157**	**120**	**543**	**598**	**632**	**687**
Adjustments, Net	493	84	2	4	(15)	75	(1)	(9)	1	-	(11)	-	-	-
Net Income - GAAP	**973**	**212**	**28**	**177**	**129**	**546**	**178**	**83**	**158**	**120**	**532**	**598**	**632**	**687**
EPS - Operating	**$2.82**	**$0.78**	**$0.16**	**$1.06**	**$0.89**	**$2.89**	**$1.10**	**$0.56**	**$0.95**	**$0.73**	**$3.31**	**$3.55**	**$3.70**	**$3.90**
EPS - GAAP	**$5.72**	**$1.30**	**$0.17**	**$1.09**	**$0.80**	**$3.35**	**$1.09**	**$0.51**	**$0.96**	**$0.73**	**$3.24**	**$3.55**	**$3.70**	**$3.90**
DPS - Period End Rate	$2.12	$0.53	$0.53	$0.53	$0.53	$2.12	$0.53	$0.53	$0.53	$0.53	$2.12	$2.12	$2.16	$2.20
Payout Ratio	75.2%	67.9%	331.3%	50.0%	59.6%	73.4%	48.2%	94.6%	55.8%	72.6%	64.0%	59.7%	58.4%	56.4%
Diluted Avg. Shares (MM)	*170*	*163*	*163*	*163*	*162*	*163*	*163*	*164*	*165*	*165*	*164*	*169*	*171*	*176*
End of Period Shares (MM)	*163*	*163*	*163*	*163*	*163*	*163*	*164*	*164*	*165*	*165*	*165*	*170*	*172*	*181*
Detroit Edison	1,507	331	329	509	374	1,543	402	390	551	404	1,747	1,808	1,887	1,962
MichCon	229	124	21	21	126	292	125	20	10	130	285	322	332	344
Gas Midstream	86	12	14	15	14	55	18	15	16	16	65	69	76	96
Power & Industrial	53	12	(2)	42	19	71	13	2	19	35	69	98	101	105
Uncoventional Gas	(299)	50	9	9	(38)	30	3	3	2	1	9	16	15	17
Energy Trading	89	51	(8)	30	11	84	68	37	14	8	127	98	98	98
Other	(130)	(45)	22	(14)	26	(11)	(3)	2	(3)	(22)	(31)	3	2	2
EBITDA Total	**1,535**	**535**	**385**	**612**	**532**	**2,064**	**626**	**469**	**609**	**572**	**2,271**	**2,414**	**2,512**	**2,624**

Source: Deutsche Bank and DTE Energy

Figure 3: DTE Energy Cash Flow Statement ($ in Millions)

DTE Energy (NYSE: DTE) Cash Flow Statement	2007A	1Q08A	2Q08A	3Q08A	4Q08A	2008A	1Q09A	2Q09A	3Q09E	4Q09E	2009E	2010E	2011E	2012E
Net Income - GAAP	971	212	28	177	129	546	178	85	158	114	535	598	632	687
Depreciation & Amortization	926	225	215	235	224	899	232	240	266	282	1,020	1,050	1,086	1,124
Regulatory Assets & Liabilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Non-Cash Extraordinary Items	(1,153)	(146)	17	(16)	(18)	(163)	(3)	6	1	(14)	(10)	-	-	-
Deferred Taxes	144	190	(10)	100	68	348	66	22	53	64	205	(100)	100	100
Other Operating Cash Flow	41	22	8	(16)	2	16	-	-	-	-	-	-	-	-
Working Capital Changes	196	387	387	(997)	136	(87)	366	109	(105)	(301)	69	-	-	-
Cash Flow From Operations	**1,125**	**890**	**645**	**(517)**	**541**	**1,559**	**839**	**462**	**373**	**145**	**1,819**	**1,548**	**1,818**	**1,911**
CFFO Excluding Working Capital	**929**	**503**	**258**	**480**	**405**	**1,646**	**473**	**353**	**478**	**446**	**1,750**	**1,548**	**1,818**	**1,911**
Capital Expenditures	(1,299)	(329)	(325)	(342)	(377)	(1,373)	(326)	(287)	(206)	(216)	(1,035)	(1,400)	(1,520)	(1,575)
Asset Acquisitions	-	-	(72)	72	-	-	-	-	-	-	-	-	-	-
Asset Divestitures	1,347	260	9	5	4	278	30	2	3	48	83	-	-	-
Other Investing Cash Flow	282	90	(85)	(331)	(102)	(428)	40	(69)	18	(101)	(112)	-	-	-
Cash Flows From Investing	**330**	**21**	**(473)**	**(596)**	**(475)**	**(1,523)**	**(256)**	**(354)**	**(185)**	**(269)**	**(1,064)**	**(1,400)**	**(1,520)**	**(1,575)**
Change in Net Debt	(390)	(851)	273	978	(114)	286	(500)	(67)	(64)	155	(476)	100	24	(245)
Common Stock Issued	-	-	-	-	-	-	9	9	9	8	35	100	50	350
Common Stock Repurchased	(708)	(13)	(3)	-	-	(16)	-	-	-	-	-	-	-	-
Preferred Stock Issued (Net)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Preferred Dividends	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Common Dividends	(364)	(86)	(86)	(86)	(86)	(344)	(86)	(87)	(87)	(88)	(348)	(357)	(369)	(388)
Other Financing	(6)	(4)	(2)	(1)	(3)	(10)	(4)	(9)	(5)	18	-	-	-	-
Cash Flow From Financing	**(1,468)**	**(954)**	**182**	**891**	**(203)**	**(84)**	**(581)**	**(154)**	**(147)**	**93**	**(789)**	**(157)**	**(295)**	**(283)**
Other Cash Flow	**(11)**	**(14)**	**25**	**-**	**-**	**11**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Opening Cash & Equivalents	147	123	66	445	223	123	86	88	42	83	86	52	42	45
Closing Cash & Equivalents	123	66	445	223	86	86	88	42	83	52	52	42	45	98
Net Cash Flow	**(24)**	**(57)**	**379**	**(222)**	**(137)**	**(37)**	**2**	**(46)**	**41**	**(31)**	**(34)**	**(9)**	**3**	**53**
Unlevered Free Cash Flow	328	638	395	(783)	250	501	597	271	257	22	1,141	473	630	662
Free Cash Flow (Ex. Working Cap.)	(370)	174	(67)	138	28	273	147	66	272	230	715	148	298	336
FCF Per Share (Ex. Working Cap.)	($2.18)	$1.07	($0.41)	$0.85	$0.17	$1.67	$0.90	$0.40	$1.65	$1.39	$4.36	$0.88	$1.74	$1.90
FCF to Equity After Dividends	(734)	88	(153)	52	(58)	(71)	61	(21)	185	142	367	(209)	(71)	(52)

Source: Deutsche Bank and DTE Energy

Figure 4: DTE Energy Balance Sheet ($ in Millions)

DTE Energy (NYSE: DTE) Balance Sheet	2007A	1Q08A	2Q08A	3Q08A	4Q08A	2008A	1Q09A	2Q09A	3Q09E	4Q09E	2009E	2010E	2011E	2012E
ASSETS														
Cash & Cash Equivalents	123	66	445	223	86	86	88	42	83	52	52	42	45	98
Fuel Inventory & Other	633	483	583	770	539	539	432	459	585	509	509	509	509	509
Accounts Receivable	2,162	2,012	1,877	1,695	1,832	1,832	1,662	1,281	1,217	1,655	1,655	1,655	1,655	1,655
Regulatory Assets	76	40	47	110	22	22	1	-	-	-	-	-	-	-
Other Current Assets	1,001	839	973	925	849	849	683	753	769	661	661	661	661	661
Total Current Assets	**3,995**	**3,440**	**3,925**	**3,723**	**3,328**	**3,328**	**2,866**	**2,535**	**2,654**	**2,877**	**2,877**	**2,867**	**2,870**	**2,923**
Net Property, Plant & Equipment	11,408	11,497	11,895	12,070	12,231	12,231	12,324	12,393	12,395	12,431	12,431	12,781	13,215	13,666
Long-Term Investments	446	437	559	538	595	595	600	610	630	598	598	598	598	598
Goodwill	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,037	2,024	2,024	2,024	2,024	2,024
Nuclear Decommissioning Funds	824	797	794	756	685	685	657	716	791	817	817	817	817	817
Regulatory Assets	3,910	3,871	2,803	3,865	5,232	5,232	4,218	4,145	4,934	4,980	4,980	4,980	4,980	4,980
Other Long-Term Assets	1,134	1,098	1,956	699	482	482	1,486	1,459	518	468	468	468	468	468
Total Assets	**23,754**	**23,177**	**23,969**	**23,688**	**24,590**	**24,590**	**24,188**	**23,895**	**23,959**	**24,195**	**24,195**	**24,535**	**24,972**	**25,476**
LIABILITIES														
Short Term Debt	1,084	550	100	1,155	744	744	330	201	205	327	327	327	427	427
Currently Maturing LT Debt	454	460	590	362	362	362	518	167	170	671	671	776	265	265
Accounts Payable	1,198	996	1,231	931	899	899	727	611	578	723	723	723	723	723
Regulatory Liabilities	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Current Liabilities	1,495	1,881	1,971	1,145	1,008	1,008	1,258	1,097	1,023	924	924	924	924	924
Total Current Liabilities	**4,231**	**3,887**	**3,892**	**3,593**	**3,013**	**3,013**	**2,833**	**2,076**	**1,976**	**2,645**	**2,645**	**2,750**	**2,339**	**2,339**
Long Term Debt	6,682	6,356	6,997	7,155	7,452	7,452	7,206	7,654	7,585	7,081	7,081	6,946	7,251	6,876
Deferred Taxes	1,932	1,793	1,824	1,951	2,054	2,054	2,087	2,025	2,179	2,181	2,181	2,181	2,181	2,181
Asset Retirement Obligations	1,277	1,282	1,310	1,325	1,340	1,340	1,357	1,378	1,405	1,420	1,420	1,420	1,420	1,420
Pension & Benefit Reserves	1,162	1,123	1,127	1,131	2,305	2,305	2,225	798	2,200	2,168	2,168	2,168	2,168	2,168
Regulatory Liabilities	1,168	1,166	1,156	1,168	1,202	1,202	1,208	1,201	1,251	1,337	1,337	1,337	1,337	1,337
Other Long-Term Liabilities	1,112	1,275	1,412	1,035	897	897	831	2,295	802	758	758	788	1,018	1,248
Total Long-Term Liabilities	**13,333**	**12,995**	**13,826**	**13,765**	**15,250**	**15,250**	**14,914**	**15,351**	**15,422**	**14,945**	**14,945**	**14,840**	**15,375**	**15,230**
Minority Interest	48	41	61	45	43	43	41	38	36	38	38	38	38	38
Preferred Stock	289	289	289	289	289	289	289	289	289	289	289	289	289	289
Common Equity	3,176	3,166	3,169	3,172	3,175	3,175	3,192	3,214	3,235	3,257	3,257	3,357	3,407	3,757
Retained Earnings / (Deficit)	2,790	2,920	2,862	2,952	2,985	2,985	3,076	3,072	3,142	3,168	3,168	3,408	3,672	3,970
Other Comprehensive Income	(113)	(121)	(130)	(128)	(165)	(165)	(157)	(145)	(141)	(147)	(147)	(147)	(147)	(147)
Total Shareholders' Equity	**5,853**	**5,965**	**5,901**	**5,996**	**5,995**	**5,995**	**6,111**	**6,141**	**6,236**	**6,278**	**6,278**	**6,618**	**6,932**	**7,580**
Total Liabilities & Equity	**23,754**	**23,177**	**23,969**	**23,688**	**24,590**	**24,590**	**24,188**	**23,895**	**23,959**	**24,195**	**24,195**	**24,535**	**24,972**	**25,476**

Source: Deutsche Bank and DTE Energy

Figure 5: DTE Energy Credit & Other Metrics ($ in Millions)

DTE Energy (NYSE: DTE) Credit & Other Metrics	2007A	1Q08A	2Q08A	3Q08A	4Q08A	2008A	1Q09A	2Q09A	3Q09E	4Q09E	2009E	2010E	2011E	2012E
Short Term Debt	1,084	550	100	1,155	744	744	330	201	205	327	327	327	427	427
Long Term Debt	7,136	6,816	7,587	7,517	7,814	7,814	7,724	7,821	7,755	7,752	7,752	7,722	7,516	7,141
Less Cash & Equivalents	(123)	(66)	(445)	(223)	(86)	(86)	(88)	(42)	(83)	(52)	(52)	(42)	(45)	(98)
Net Debt (GAAP)	**8,097**	**7,300**	**7,242**	**8,449**	**8,472**	**8,472**	**7,966**	**7,980**	**7,877**	**8,027**	**8,027**	**8,007**	**7,898**	**7,470**
Minority & Preferred	337	330	350	334	332	332	330	327	325	327	327	327	327	327
Shareholders' Equity	5,853	5,965	5,901	5,996	5,995	5,995	6,111	6,141	6,236	6,278	6,278	6,618	6,932	7,580
Total Capitalization	**14,287**	**13,595**	**13,493**	**14,779**	**14,799**	**14,799**	**14,407**	**14,448**	**14,438**	**14,632**	**14,632**	**14,952**	**15,156**	**15,377**
Less Securitization Debt	(1,185)	(996)	(996)	(933)	(1,064)	(1,064)	(861)	(861)	(793)	-	(940)	(810)	(670)	(520)
Plus Leases and Other	-					-					-	-	-	-
Adjusted Net Debt	**6,912**	**6,304**	**6,246**	**7,516**	**7,408**	**7,408**	**7,105**	**7,119**	**7,084**	**8,027**	**7,087**	**7,197**	**7,228**	**6,950**
Adjusted Capitalization	**13,102**	**12,599**	**12,497**	**13,846**	**13,735**	**13,735**	**13,546**	**13,587**	**13,645**	**14,632**	**13,692**	**14,142**	**14,486**	**14,857**
EBITDA - Income Statement	1,535	535	385	612	532	2,064	626	469	609	572	2,271	2,414	2,512	2,624
Securitization Adjustment	(186)	-	-	-	-	(189)	-	-	-	-	(193)	(193)	(194)	(194)
Lease & Other Adjustment	-					-					-	-	-	-
EBITDA - Adjusted	**1,349**	**535**	**385**	**612**	**532**	**1,875**	**626**	**469**	**609**	**572**	**2,078**	**2,221**	**2,318**	**2,429**
Net Debt / Capitalization	56.7%	53.7%	53.7%	57.2%	57.2%	57.2%	55.3%	55.2%	54.6%	54.9%	54.9%	53.5%	52.1%	48.6%
Net Debt / Capitalization (Adjusted)	52.8%	50.0%	50.0%	54.3%	53.9%	53.9%	52.5%	52.4%	51.9%	54.9%	51.8%	50.9%	49.9%	46.8%
Net Debt / EBITDA	5.3x	--	--	--	--	4.1x	--	--	--	--	3.5x	3.3x	3.1x	2.8x
Net Debt / EBITDA (Adjusted)	5.1x	--	--	--	--	4.0x	--	--	--	--	3.4x	3.2x	3.1x	2.9x
EBITDA / Interest	3.1x	4.5x	3.3x	5.1x	4.2x	4.3x	4.9x	3.6x	4.6x	4.3x	4.3x	4.8x	4.9x	5.2x
Retained Cash Flow / Capex	0.6x	2.4x	1.7x	(1.8x)	1.2x	0.9x	2.3x	1.3x	1.4x	0.3x	1.4x	0.9x	1.0x	1.0x
Recurring Net Income	480	--	--	--	--	471	--	--	--	--	543	598	632	687
Total Assets (Avg.)	23,752	--	--	--	--	23,835	--	--	--	--	24,165	24,365	24,753	25,224
Return on Assets	2.0%	--	--	--	--	2.0%	--	--	--	--	2.2%	2.5%	2.6%	2.7%
Recurring NOPAT	601	--	--	--	--	756	--	--	--	--	861	887	927	975
Capital Employed (Avg.)	14,454	--	--	--	--	14,332	--	--	--	--	14,576	14,801	15,060	15,300
Return on Capital Employed	4.2%	--	--	--	--	5.3%	--	--	--	--	5.9%	6.0%	6.2%	6.4%
Recurring Net Income	480	--	--	--	--	471	--	--	--	--	543	598	632	687
Shareholders' Equity (Avg.)	5,821	--	--	--	--	5,942	--	--	--	--	6,152	6,448	6,775	7,256
Return on Equity	8.2%	--	--	--	--	7.9%	--	--	--	--	8.8%	9.3%	9.3%	9.5%
Book Value per Share	$35.84	$36.56	$36.18	$36.78	$36.77	$36.77	$37.29	$37.34	$37.81	$37.96	$37.96	$38.97	$40.30	$41.99

Source: Deutsche Bank and DTE Energy

Figure 6: DTE Energy Valuation & Growth Metrics ($ in Millions)

DTE Energy (NYSE: DTE)

Valuation & Growth Metrics	2007A	1Q08A	2Q08A	3Q08A	4Q08A	2008A	1Q09A	2Q09A	3Q09E	4Q09E	2009E	2010E	2011E	2012E
Diluted EPS - Operating	$2.82	$0.78	$0.16	$1.06	$0.89	$2.89	$1.10	$0.56	$0.95	$0.73	$3.31	$3.55	$3.70	$3.90
Diluted EPS - GAAP	$5.72	$1.30	$0.17	$1.09	$0.80	$3.35	$1.09	$0.51	$0.96	$0.73	$3.24	$3.55	$3.70	$3.90
DPS - Period End Rate	$2.12	$0.53	$0.53	$0.53	$0.53	$2.12	$0.53	$0.53	$0.53	$0.53	$2.12	$2.12	$2.16	$2.20
Payout Ratio	75.2%	--	--	--	--	73.4%	--	--	--	--	64.0%	59.7%	58.4%	56.4%
Op. CFPS - Excl. Working Capital	$5.46	$3.09	$1.58	$2.94	$2.50	$10.10	$2.90	$2.15	$2.90	$2.70	$10.67	$9.18	$10.64	$10.84
Free CFPS - Excl. Working Capital	($2.18)	$1.07	($0.41)	$0.85	$0.17	$1.67	$0.90	$0.40	$1.65	$1.39	$4.36	$0.88	$1.74	$1.90
Pricing Date (Period End/Current)	12/31/07	3/31/08	6/30/08	9/30/08	12/31/08	12/31/08	3/31/09	6/30/09	9/30/09	12/30/09	12/30/09	2/23/10	2/23/10	2/23/10
Stock Price ($/Sh)	$43.96	$38.89	$42.44	$40.12	$35.67	$35.67	$27.70	$32.00	$35.14	$44.35	$44.35	$41.00	$41.00	$41.00
P/E Operating	15.6x	--	--	--	--	12.3x	--	--	--	--	13.4x	11.5x	11.1x	10.5x
P/E GAAP	7.7x	--	--	--	--	10.6x	--	--	--	--	13.7x	11.5x	11.1x	10.5x
P/CF	8.0x	--	--	--	--	3.5x	--	--	--	--	4.2x	4.5x	3.9x	3.8x
P/FCF	(20.2x)	--	--	--	--	21.4x	--	--	--	--	10.2x	46.6x	23.6x	21.6x
P/BV	1.2x	1.1x	1.2x	1.1x	1.0x	1.0x	0.7x	0.9x	0.9x	1.2x	1.2x	1.1x	1.0x	1.0x
Market Capitalization	7,178	6,345	6,922	6,541	5,815	5,815	4,539	5,263	5,796	7,335	7,335	6,964	7,053	7,402
Adjusted Net Debt	6,912	6,304	6,246	7,516	7,408	7,408	7,105	7,119	7,084	8,027	7,087	7,197	7,228	6,950
Adjusted Enterprise Value	14,091	12,649	13,168	14,057	13,223	13,223	11,645	12,383	12,880	15,363	14,423	14,161	14,281	14,352
Adjusted EBITDA	1,349	--	--	--	--	1,875	--	--	--	--	2,078	2,221	2,318	2,429
Adjusted EV/EBITDA	10.4x	--	--	--	--	7.1x	--	--	--	--	6.9x	6.4x	6.2x	5.9x
Earnings Yield	6.4%	--	--	--	--	8.1%	--	--	--	--	7.5%	8.7%	9.0%	9.5%
Dividend Yield	4.8%	--	--	--	--	5.9%	--	--	--	--	4.8%	5.2%	5.3%	5.4%
FCF Yield	-5.0%	--	--	--	--	4.7%	--	--	--	--	9.8%	2.1%	4.2%	4.6%
Growth & Return														
Revenue	1.6%	-4.4%	11.9%	0.8%	-0.7%	1.3%	-12.5%	-24.9%	-16.2%	-2.8%	-14.2%	5.9%	3.9%	2.2%
EBITDA	-24.6%	22.5%	221.2%	49.9%	-6.5%	34.5%	17.0%	21.8%	-0.5%	7.5%	10.0%	6.3%	4.0%	4.5%
Net Income - Operating	-6.9%	13.2%	-60.6%	27.2%	-11.8%	-1.8%	39.9%	253.8%	-9.2%	-16.7%	15.3%	10.1%	5.8%	8.6%
Operating EPS	-2.4%	21.9%	-57.9%	29.3%	-11.0%	2.5%	41.0%	250.0%	-10.4%	-18.0%	14.5%	7.3%	4.2%	5.4%
DPS Growth	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.9%	1.9%
ROCE	4.2%	--	--	--	--	5.3%	--	--	--	--	5.9%	6.0%	6.2%	6.4%
Cost of Debt (A-T)	6.3%	--	--	--	--	4.0%	--	--	--	--	4.4%	4.1%	4.2%	4.2%
Cost of Equity	6.4%	--	--	--	--	8.1%	--	--	--	--	7.5%	8.7%	9.0%	9.5%
WACC	6.3%	--	--	--	--	5.7%	--	--	--	--	5.7%	6.1%	6.4%	6.7%
Calculated EVA	(313)	--	--	--	--	(59)	--	--	--	--	29	(11)	(30)	(57)
Calculated EVA/Share	($1.84)	--	--	--	--	($0.36)	--	--	--	--	$0.18	($0.06)	($0.18)	($0.32)

Source: Deutsche Bank and DTE Energy

Appendix 1

Important Disclosures

Additional information available upon request

Disclosure checklist			
Company	**Ticker**	**Recent price***	**Disclosure**
DTE Energy	DTE.N	43.99 (USD) 23 Feb 10	1,7,8,14,15

*Prices are sourced from local exchanges via Reuters, Bloomberg and other vendors. Data is sourced from Deutsche Bank and subject companies.

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7. Deutsche Bank and/or its affiliate(s) has received compensation from this company for the provision of investment banking or financial advisory services within the past year.

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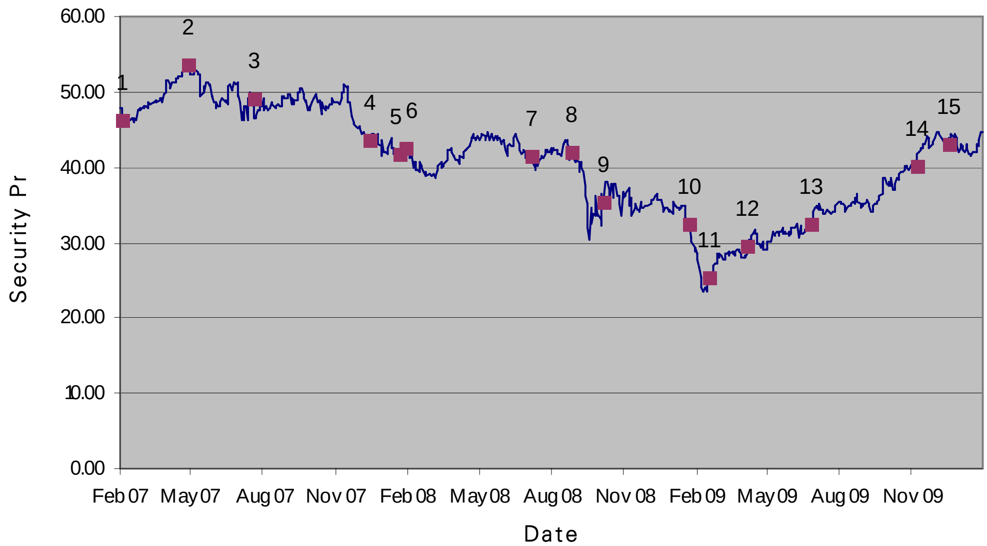
Historical recommendations and target price: DTE Energy (DTE.N)

(as of 2/23/2010)



Previous Recommendations

Strong Buy
Buy
Market Perform
Underperform
Not Rated
Suspended Rating

Current Recommendations

Buy
Hold
Sell
Not Rated
Suspended Rating

*New Recommendation Structure as of September 9, 2002

1.	2/28/2007:	Hold, Target Price Change USD49.00	9.	10/31/2008:	Hold, Target Price Change USD34.00
2.	5/22/2007:	Hold, Target Price Change USD55.00	10.	2/17/2009:	Hold, Target Price Change USD29.00
3.	8/14/2007:	Hold, Target Price Change USD52.00	11.	3/13/2009:	Hold, Target Price Change USD27.00
4.	1/8/2008:	Hold, Target Price Change USD48.00	12.	5/1/2009:	Hold, Target Price Change USD28.00
5.	2/14/2008:	Hold, Target Price Change USD46.00	13.	7/20/2009:	No Recommendation, Target Price Change USD0.00
6.	2/22/2008:	Hold, Target Price Change USD44.00	14.	12/1/2009:	Hold, Target Price Change USD39.00
7.	7/31/2008:	Hold, Target Price Change USD43.00	15.	1/11/2010:	Hold, Target Price Change USD42.00
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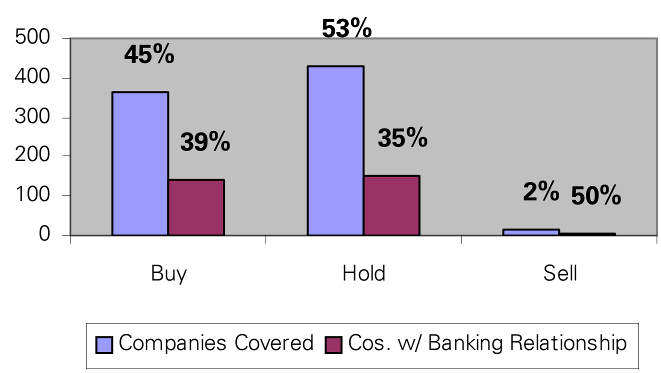
Equity rating dispersion and banking relationships



North American Universe

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Deutsche Bank

Deutsche Bank Securities Inc.

North American locations

Deutsche Bank Securities Inc.
60 Wall Street
New York, NY 10005
Tel: (212) 250 2500

Deutsche Bank Securities Inc.
225 Franklin Street
25th Floor
Boston, MA 02110
Tel: (617) 988 8600

Deutsche Bank Securities Inc.
222 South Riverside Plaza
30th Floor
Chicago, IL 60606
Tel: (312) 537-3758

Deutsche Bank Securities Inc.
3033 East First Avenue
Suite 303, Third Floor
Denver, CO 80206
Tel: (303) 394 6800

Deutsche Bank Securities Inc.
1735 Market Street
24th Floor
Philadelphia, PA 19103
Tel: (215) 854 1546

Deutsche Bank Securities Inc.
101 California Street
46th Floor
San Francisco, CA 94111
Tel: (415) 617 2800

Deutsche Bank Securities Inc.
700 Louisiana Street
Houston, TX 77002
Tel: (832) 239-4600

International locations

Deutsche Bank Securities Inc.
60 Wall Street
New York, NY 10005
United States of America
Tel: (1) 212 250 2500

Deutsche Bank AG London
1 Great Winchester Street
London EC2N 2EQ
United Kingdom
Tel: (44) 20 7545 8000

Deutsche Bank AG
Große Gallusstraße 10-14
60272 Frankfurt am Main
Germany
Tel: (49) 69 910 00

Deutsche Bank AG
Deutsche Bank Place
Level 16
Corner of Hunter & Phillip Streets
Sydney, NSW 2000
Australia
Tel: (61) 2 8258 1234

Deutsche Bank AG
Level 55
Cheung Kong Center
2 Queen's Road Central
Hong Kong
Tel: (852) 2203 8888

Deutsche Securities Inc.
2-11-1 Nagatacho
Sanno Park Tower
Chiyoda-ku, Tokyo 100-6171
Japan
Tel: (81) 3 5156 6701

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