COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF LONNIE E. BELLAR
VICE PRESIDENT OF STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

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

A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to certain of the arguments presented in the testimony of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC"); Stephen J. Baron on behalf of the KIUC; Dennis W. Goins on behalf of the KIUC; Kevin Higgins on behalf of The Kroger Co. ("Kroger"); Jack Burch on behalf of the Community Action Council for Lexington-Fayette, Bourbon, Harrison, and Nicholas Counties ("CAC"); Marlon Cummings on behalf of the Association of Community Ministries ("ACM"); and Glenn Watkins on behalf of the Office of the Attorney General ("AG").

Specifically, my testimony will (1) demonstrate that Mr. Kollen's and Mr. Higgins' off-system sales adjustments are inappropriate; (2) address Mr. Kollen's non-labor generation maintenance outage expense; (3) explain why Mr. Kollen's rate case amortization expense is inappropriate; (4) respond to Mr. Goins' arguments regarding LG&E's curtailable service riders ("CSR"); (5) explain why Mr. Kollen's adjustment, based on the testimony of his colleague Mr. Baron, with regard to a single LG&E customer is a selective post-test year adjustment; and (6) address the positions of CAC and ACM regarding its need for funds, as well as Mr. Cummings' and Mr. Watkins' position regarding LG&E's proposed gas line tracker.

Off-System Sales Adjustment

Q. Does Mr. Kollen offer any evidence to refute the changes in the wholesale power market or the Companies' generation assets as described in the direct testimony of Mr. Thompson or Mr. Blake?

A. No. The Companies have proposed the annualization adjustment described in my direct testimony to reflect the reasonably expected going forward level of off-system sales margins. The changes in the wholesale power market and the Companies' generation assets, which are necessary to support any participation in the wholesale power market, are discussed in detail in the direct testimony of Mr. Thompson and Mr. Blake. Mr. Kollen does not take issue with this evidence.

Q. Does Mr. Kollen misstate the Companies' off-system sales adjustment?

A. Yes. To avoid addressing this evidence, Mr. Kollen creates a straw argument to facilitate his position by incorrectly stating that the Companies have proposed a revised pro forma adjustment for off-system sales to an annualized amount based on the last three months of the test year and the first five months following the test year, and to support Mr. Baron's out-of-period adjustment to LG&E's revenues.[1] In actuality, the Companies, as explained in my direct testimony, have proposed an adjustment to annualize its off-system sales margins utilizing the last three months of the test year.

[1] Direct Testimony and Exhibits of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. in Case Nos. 2012-00221 and 2012-00222, filed October 3, 2012, ("Kollen Direct") p. 7; Direct Testimony and Exhibits of Stephen J. Baron on behalf of the Kentucky Industrial Utility Customers, Inc. in Case No. 2012-00221 and 2012-00222, filed October 3, 2012 ("Baron Direct"), p. 28-29.

Mr. Kollen's claim that the adjustment has been "revised" to include the first five months following the test year is incorrect. Instead, the Companies provided updated off-system sales margin information as required by the Commission in its Second Request for Information to the Companies.[2] Specifically, the Commission requested the Companies to "[p]rovide updates to the proposed off-system sales margin adjustment as monthly results become available. This should be considered an ongoing request."[3] The Companies have responded to this request as required by the Commission, including the revised overall revenue requirement deficiency filing dated October 30, 2012 and therefore deny Mr. Kollen's contention that its responses constitute "revised filings."[4] This is consistent with my direct testimony, which stated that the Companies would provide updated actual off-system sales margins, upon request. This updated information, while affirming the reasonableness of the Companies' adjustment, does not constitute a revised filing or a change to the adjustment presented in my direct testimony.

Q. Does Mr. Kollen characterize the Companies' response to the Commission's data requests as a post-test year adjustment?

A. Yes, Mr. Kollen asserts that by responding to the Commission's data requests, the "Companies changed the nature of the adjustment to a post-test year adjustment."[5] Mr. Kollen then asserts that a "selective" post-test year adjustment "fails to consider all other adjustments that could have been made to revenues, expenses, and capitalization" and "compromises the integrity of the ratemaking process and severely disadvantages the other

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[2] Commission Staff's Second Request for Information to LG&E, Item No. 81; Commission Staff's Second Request for Information to KU, Item No. 71.
[3] *Id.*
[4] Kollen Direct, p. 7.
[5] *Id.*

parties."[6] Mr. Kollen's position is inapposite because the Companies have not proposed a post-test year adjustment in this case, as the adjustment is based on margins for the last three months of the test year. Complying with an ongoing data request by providing updated information does not transform LG&E's or KU's filed position. Mr. Kollen's sharp criticism of post-test year adjustments is ironic because, as will be discussed in detail below, the adjustment his colleague Mr. Baron has proposed, and Mr. Kollen supports, requests that the Commission entirely disregard a customer's billings during the test year and instead annualize its sales based solely on its billings in a month that occurred *five months* after the test year. Mr. Kollen's position on these two issues cannot be reconciled.

Q. Did Mr. Kollen argue that the Companies off-system sales adjustment should be denied?

A. Yes. After setting aside Mr. Kollen's misplaced arguments regarding whether LG&E and KU have revised the adjustment to include post-test year information, Mr. Kollen claims that the Companies have not met their burden of demonstrating that the actual off-system sales margins in the test year were abnormal or nonrecurring.[7] This is incorrect, as the Companies have repeatedly explained, both in testimony and in data responses, that due to decreased natural gas prices and the weak economy, off-system sales margins have decreased significantly - changes which the KIUC and other parties have not attempted to address, much less criticize or refute in their testimony.

Q. Does Mr. Higgins address the Companies' off-system sales adjustment?

A. Yes. Mr. Higgins argues that because he believes off-system sales margins to be volatile, the Commission should not accept the Companies' adjustment, which is based on three

[6] *Id.* at 8-9.
[7] *Id.* at 11.

months of actual data.[8] He instead proposes the Commission establish a tracker with a baseline level of margins, with fluctuations as either a credit or charge to customers based upon a 70/30 sharing mechanism between the Companies and customers.[9]

Q. Is a tracker needed for off-system sales margins as Mr. Higgins has proposed?

A. No, it is not. The Companies have included and the Commission has approved a reasonable level of off-system sales margins in all prior base rate proceedings. In the pending cases, the Companies have demonstrated in testimony and in data responses that off-system sales continue to decline with no reasonable expectation of an increase in the foreseeable future. The Companies' proposed adjustment is reasonable and necessary to reflect the ongoing level of off-system sales margins. The updates requested by the Commission's data requests continue to confirm the need for and reasonable results of the Companies' proposed adjustment.[10] Mr. Higgins has not provided any evidence to refute the decline or the fundamental changes in the wholesale power market, and there is no reasoned basis to not pro form the off-system sales margins in base rates to reflect these known and measurable changes.

A tracker for off-system sales, such as the one Mr. Higgins has proposed, has only been implemented once for electric utilities in Kentucky, and that was the result of the settlement of lengthy litigation between the Commission, the utility and consumer advocate groups involving the allocation of costs from an interstate power pool operated by a multistate utility holding company.[11] The utility in question consented to the off-

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[8] Prefiled Direct Testimony of Kevin C. Higgins on behalf of The Kroger Co. filed October 2, 2012 in Case No. 2012-00221 ("Higgins KU Direct"), p. 8-9; Prefiled Direct Testimony of Kevin C. Higgins on behalf of The Kroger Co. filed October 2, 2012 in Case No. 2012-00222 ("Higgins LG&E Direct"), p. 10-11.
[9] *Id.*
[10] *See* the Companies' October 30, 2012 monthly updates filed with the Commission.
[11] *In the Matter of: General Adjustment in Electric Rates of Kentucky Power Company* (Case No. 9061) Order, October 28, 1988.

system sales tracker in exchange for other consideration of value in a settlement.[12] Because Mr. Higgins fails to provide any compelling, much less a reasonable basis to unilaterally impose a tracker on the Companies with regard to off-system sales margins, his recommendation should be denied.

<u>Non-Labor Generation Maintenance Outage Expense</u>

Q. Please explain Mr. Kollen's proposed adjustment with regard to maintenance outage expense.

A. Mr. Kollen has proposed to normalize the Companies' maintenance expense, which is an extreme position. The Commission has correctly disfavored "normalization" adjustments because they are so susceptible to manipulation, argument and subjectivity. Although LG&E and KU provided evidence that their going-forward level of maintenance expense would be comparable to the expenses incurred during the test year, Mr. Kollen nevertheless has proposed to normalize the expenses using data that is more variable than the Companies' projected costs.[13] When asked by the Commission Staff whether Mr. Kollen would support similar adjustments in the future, regardless of whether the adjustment would increase or decrease expenses, Mr. Kollen stated yes, because maintenance "expense is greater than the storm damage expense and injuries and damage expense."[14] This odd explanation demonstrates that this adjustment is highly selective and seeks only to unfairly reduce the Companies' recovery of prudently incurred costs.

Q. Would a maintenance expense normalization adjustment be comparable to the other kinds of normalization adjustments the Commission has approved?

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[12] *Id.*
[13] Kollen Direct, p. 13-14.
[14] See Kentucky Industrial Utility Customers, Inc.'s Response to Item No. 3 of the Commission Staff's First Request for Information in Case No. 2012-00222.

A. No. There are precisely two normalization adjustments the Commission has approved in electric rate cases: storm damage, and injuries and damages. The fact that this list is quite short is no coincidence, as normalization adjustments are an exception to 807 KAR 5:001, § 10(7), which states that a "utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period."

The few normalization exceptions to the general "known and measurable rule" exist primarily because the revenues or expenses being normalized are essentially random occurrences without any upward or downward trend that is incorporated into the adjustment. For example, neither LG&E nor KU can predict or affect what storms may occur. Furthermore, with storm damage, and injuries and damages there is a central tendency for events to fall within a range that will typically equal a mean value when measured over time. Although the severity of storms varies from year to year, the average values of these random variables are very stable and predictable over time. Although the Companies certainly endeavor to minimize injuries and the effect of storms on their service areas, these events will occur and in no discernible pattern. For these reasons, there is no reason to think that any given test year's storm or injuries and damages expenses are indicative of future cost because what is "normal" can only be understood in reference to a long span of time and data, objectively measured and calculated.

Maintenance expenses, on the other hand, are not random and unpredictable. As the Commission and the parties are aware, LG&E and KU develop planned maintenance schedules for several years in advance and carefully monitor their generation fleet, employing predictive maintenance technologies in order to constantly assess the maintenance needs of the fleet. Although unplanned events may occur, which give rise to maintenance expenses, because LG&E and KU rigorously track the age, condition and needs of their equipment the Companies are able to demonstrate, to a reasonable degree, their going-forward level of maintenance expense. In fact, as the Companies' generating units age the scope of the Companies' inspections has increased, the time required for the inspections, and thus the costs of the inspections themselves have risen; and greater maintenance tasks that need to be performed are consequently revealed. As such, the Companies continue to satisfy the "known and measurable" standard for maintenance expense.

Incredibly, in response to the Commission Staff's data request, Mr. Kollen actually compared the unusual nature of storm damage and injuries and damages with maintenance expense.[15] Mr. Kollen provided no basis for his contention that maintenance expense is essentially a random occurrence other than stating that "generation maintenance expense in the test year was greater than in any of the preceding 5 years."[16] The fact that a certain expense has increased has absolutely nothing to do with whether the expense should be normalized.

Q. Has Mr. Kollen demonstrated that the test year level of maintenance expense is not representative of the going-forward level of expense?

A. No. Although the test year expense was $20.9 million, and LG&E's projected expense levels are $15.2 million in 2013 and $14.9 million in 2014, the expense levels in the five years selected by Mr. Kollen for KIUC's proposed adjustment range from $8.2 to $16.9 million. Similarly, although KU's test year expense was $20.6 million and its projected

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[15] *Id.*
[16] *Id.*

expenses levels are $11.8 million in 2013 and $29.6 million in 2014, the expense levels in the five years Mr. Kollen has selected for his adjustment range from $8.9 to $20.2 million. With a range of this magnitude, Mr. Kollen simply ignores evidence of the future costs of maintenance in an effort to support the KIUC adjustment.

Mr. Kollen offers no evidence to refute that KU and LG&E will have going-forward maintenance expense comparable to the expense in the test year and simply invites the Commission to overlook the evidence that LG&E's projected expense levels are $15.2 million in 2013 and $14.9 million in 2014.

Although there is, of course, some variation from year-to-year, the variability is not so significant that it warrants normalization. Moreover, Mr. Kollen's proposed "normalization" will result in under-recovery of maintenance expense. Mr. Kollen's adjustment is highly selective because while describing maintenance expense as having "variability," the variability in the five years of data Mr. Kollen has used is substantially greater than the variability between the Companies' test year maintenance expense and projected expense in 2012, 2013, 2014. In short, Mr. Kollen is putting more variability into the adjustment simply to reduce maintenance expense. This selective adjustment should be rejected because the Companies must incur these costs in providing service to customers, and Mr. Kollen certainly cannot demonstrate that any of the costs were imprudently or excessively incurred.

Q. Does Mr. Kollen's use of a five-year historical period prejudice the Companies?

A. Yes, because the five-year historical period does not fully include the maintenance costs associated with the significant investments the Companies have made in its generation portfolio in the last several years. From 2007, which is the first year of expense in Mr.

Kollen's adjustment, to June 2012, the Companies have invested over $2.1 billion in generation assets, including the construction of Trimble County Unit 2, a generating unit that has been in service for less than five years. When asked by Commission Staff why he chose a five-year period, Mr. Kollen stated that a five-year period "provides a closer proxy to its [the Companies'] present generation portfolio than would a 10 year average."[17] Neither a five-year nor a ten-year period constitute a "proxy" for the going-forward level of maintenance expense because neither are based on the Companies' actual assets in service. By including historical maintenance costs for years that clearly do not accurately represent LG&E's and KU's present or going-forward generating fleet, Mr. Kollen seeks to prejudice the Companies' ability to recover prudently incurred maintenance expenses that are integral to LG&E's and KU's ability to reliably provide service to customers.

His selection of a five-year period also illustrates why normalization adjustments have been historically disfavored by the Commission because the averaging calculation can be manipulated through the selection of the period to create bias and achieve a desired end-result. Normalizing generation maintenance expense is an example of such manipulation, because it wrongly assumes that the expense is relatively static over time. In contrast, as explained more fully in Mr. Thompson's testimony, the Companies' changing generation portfolio, use of different fuels, and age of the assets has led to increased costs, which are known and measurable. Maintaining the complex and inter-related systems in coal-fired generation assets, which are required by the Environmental Protection Agency's increasingly stringent regulations, has become more complex and challenging, not simpler

[17] *Id.*

and more efficient, over time. For these reasons, maintenance expense should not be normalized and Mr. Kollen's adjustment should be denied.

<u>**Rate Case Expense**</u>

Q. Please explain Mr. Kollen's adjustment to the Companies' recovery of rate case expense.

A. Mr. Kollen takes issue with the manner in which LG&E and KU are recovering its rate case expense from the 2009 proceedings,[18] which is being amortized over a three-year period consistent with Commission orders. Mr. Kollen alleges that the amortization expense for the 2009 proceeding is overstated.[19] Mr. Kollen proposes that the Commission not permit the Companies to recover the remaining deferred 2009 rate case expense when rates are reset in these cases.[20]

Q. Do you agree that the Companies should not be permitted to recover its remaining 2009 rate case expense?

A. No, because these costs were reasonably and prudently incurred. To disallow the Companies complete recovery of the expense is not only unfair, but conflicts with both United States Supreme Court and Commission precedent. The Commission has stated that "[r]ate case expenses have long been considered as appropriate expenses for inclusion in utility rates."[21] This is consistent with the United States Supreme Court, which has held that such expenses "must be included among the costs of operation in the computation of a fair return," and that the "charges of engineers and counsel, incurred in defense of its security and perhaps its very life, were as appropriate and even necessary as expenses

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[18] Kollen Direct, p. 18-19.
[19] *Id.* at 19.
[20] *Id.* at 20.
[21] *In the Matter of: Proposed Adjustment of the Wholesale Water Service Rates of the City of Owenton, Kentucky* (Case No. 98-283) Order, February 22, 1999.

could well be."[22] There is no reasoned basis for Mr. Kollen's adjustment to prohibit the Companies from recovering their remaining 2009 rate case expense and this adjustment should be denied.

Q. Does Mr. Kollen offer an alternative adjustment with regard to the amortization of the 2009 rate case expense?

A. Yes. Mr. Kollen alternatively suggests that the remaining deferred 2009 rate case expense be added to the Companies' estimated rate case expense in this proceeding, with the combined amount to be amortized over a three-year period.[23] Oddly, when asked by Commission Staff to quantify the effect of his alternative adjustment, Mr. Kollen provided inconsistent answers for LG&E and KU, asserting that the effect on LG&E would be "$0," which is not possible as the amortization period will not end until July 2013.[24] KIUC's alternative adjustment erroneously assumes that the Companies' exact cost of service will not vary after the test period and other increases in costs, not reflected in the test period, will not offset the expiration of the rate case amortization expenses in the future. Absent such a demonstration, the adjustment should be denied.

LG&E's Curtailable Service Riders

Q. Have you reviewed the testimony of KIUC witness Goins?

A. Yes. Mr. Goins makes a number of arguments in his testimony challenging the Companies' proposal to reduce the amounts of their CSR credits and to remove restrictions from the Companies' ability to implement physical curtailments. Indeed, rather than

[22] *West Ohio Gas Co. v. Public Utilities Comm'n*, 294 U.S. 63, 74 (1935).
[23] Kollen Direct, p. 21.
[24] See Kentucky Industrial Utility Customers, Inc.'s Response to Item No. 3 of the Commission Staff's First Request for Information in Case No 2012-0022; Kentucky Industrial Utility Customers, Inc.'s Response to Item No. 4 of the Commission Staff's First Request for Information in Case No 2012-00221.

agreeing with the Companies that CSR value reductions are appropriate, Mr. Goins suggests the Companies should increase the value of the CSR credits by 3%.

But all of Mr. Goins's arguments overlook a few basic facts about the Companies' CSRs that make them less valuable than Mr. Goins suggests. In particular, Mr. Goins overlooks the Companies' overarching obligation to serve, the ability of CSR customers to exit their obligations on short notice, the remaining constraints on use, and the fact that the Companies pay the credit year-round though they actually use interruptions in only a few months.

Q. Given the Companies' obligation to serve customers by providing firm service, does Mr. Goins's argument concerning interruptible service reasonably apply to the Companies CSRs?

A. No, it does not. Mr. Goins argues that customers taking interruptible service should pay no demand-related charges: "Since a utility is not required to build or acquire generating capacity to serve interruptible load, only firm service customers should pay for the demand-related costs of this capacity."[25] But the Companies do not offer genuinely interruptible service, i.e., service the Companies can provide wholly at their discretion, because they are duty-bound to provide firm service to their native-load customers. Eliminating a demand charge would be appropriate only for genuinely interruptible service.

But that is not the service KIUC members take. Rather, they take firm service for their entire load and offer to curtail part of their usage for around 1% of the hours of the year (100 hours of physical curtailment is allowed to be requested), and then only under

[25] Direct Testimony and Exhibits of Dennis W. Goins on behalf of the Kentucky Industrial Utility Customers, Inc. in Case No. 2012-00222, filed October 3, 2012 ("Goins LG&E Direct"), p. 17-19.

certain conditions. Even when the Companies issue a physical curtailment order, CSR customers can refuse to comply, albeit at a cost. Moreover, existing CSR customers can terminate their CSR contracts with only six months' notice, and new customers have a minimum contract term of just one year. To suggest that such service is genuinely interruptible, and therefore should incur no demand charges, is to ignore important realities about the Companies' obligation to provide firm service, the costs of serving CSR customers, and the value of the curtailment CSR customers provide.

Q. Mr. Goins suggests the Companies have confused cost of service and value of service.[26] Why is this suggestion incorrect?

A. Mr. Goins differentiates cost of service from value of service, defining the latter to be "pricing typically reflect[ing] … what the market will bear for a product."[27] He states that it is discriminatory to price CSR credits at the value of service rather than the cost of service, the latter of which being the basis for the Companies' other rates.[28]

But again Mr. Goins misses the point: the Companies do not offer interruptible service; rather, they offer, and are required to offer, firm service. Against the backdrop of a firm-service requirement, the Companies offer entirely voluntary demand-response programs, of which the CSRs are one. The question is how to price voluntary demand-response programs from which customers can exit on short notice, not how to formulate the best rate structure for genuinely interruptible service. Moreover, to my knowledge, no KIUC member has requested genuinely interruptible service.

In the case of CSRs, the appropriate pricing for the demand-response program is the value CSR customers provide. In this case, the market has only one buyer—the

[26] *See* Goins LG&E Direct, p. 14-15.
[27] *Id.* at 14.
[28] *Id.* at 15.

Companies—and the value CSR customers provide is the avoided cost of capacity for the limited number of hours and circumstances permitted by the CSRs. Whatever the appropriate avoided cost may be, it cannot be the same as the avoided capacity cost of a peaking unit, which the Companies could dispatch without constraint, excepting outages.

Moreover, Mr. Goins proposes CSR credits that exceed the per-kVA demand charges for both Companies' Rates FLS. If one accepts Mr. Goins's argument that genuinely interruptible load should pay no demand charges, CSR credits should not exceed the demand charges otherwise applicable to a customer's curtailable demand.

Finally, it is important to bear in mind that the Companies' customers pay the cost of the CSR credits; the money the Companies do not recover from CSR customers has to come from somewhere, and that somewhere is the Companies' other customers. Those customers should not have to pay more for the credits than the value they receive, which is the avoided cost of supplying the curtailed load.

Q. Is it reasonable to compare the cost of the Companies' residential load control program to the CSRs, as Mr. Goins does?[29]

A. There are some important differences between the programs that make a comparison difficult thus Mr. Goins's attempt to justify raising the CSR credits by simply citing the residential load control program is unreasonable. For example the values quoted in Mr. Goins testimony are misleading in that they represent not only the cost of maintaining existing participation in the residential load control program but include costs to grow the program by the addition of other customers. Additionally, the residential load control program offers the Companies benefits the CSRs do not. First, the Companies may use physical curtailment during any summer weekday without demonstrating a "system

[29] *Id.* at 21-22.

reliability event," which must be shown to use physical curtailment for CSR customers.[30] Second, the Companies' 140,000 residential load control customers (and 170,000 control devices) are spread throughout the Companies' service territories, offering the Companies operational flexibility in responding to constraints in discrete areas; altogether, such customers give the Companies the ability to curtail up to 130 MW of load. Third, the Companies are not required to give notice to their residential-load-control customers, making such customers valuable resources to address constraints in real time. Fourth, while the residential load control program does not have an individual customer termination notice provision the diversity offered by the 140,000 customers is beneficial.

Q. Why is it appropriate to use recent peaking-unit prices and demand-response-market prices to evaluate appropriate CSR credit levels, Mr. Goins's criticisms notwithstanding?[31]

A. It is appropriate to use such market data because it provides some degree of objectivity in setting the levels of such credits. There is no demand-response market for exactly what the Companies' CSRs provide, but the Bluegrass combustion turbine price and the PJM demand-response-market prices are reasonable market indicators. There must be some objective, reasonable means of setting such credits, and Mr. Goins's proposal simply to add 3% to the existing credits is not among them.

Q. Do the Companies value their relationships with large industrial customers like North American Stainless and Carbide Industries LLC ("Carbide")?

A. Yes, the Companies value very much their relationships with such customers. And the Companies appreciate the jobs and economic vitality such companies bring to the

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[30] The Companies may use residential load control resources in emergencies on weekends or holidays.
[31] *See id.* at 15-18.

Commonwealth. But rates must be fair, just, and reasonable for all customers, including the Companies' more than 800,000 customers who pay to provide CSR credits. Therefore, the Companies have proposed in this proceeding what they believe are fair, just, and reasonable CSRs under current conditions.

<u>Post-Test Year Normalization Adjustment for Carbide</u>

Q. Does Mr. Kollen propose an adjustment with regard to Carbide, which is an LG&E customer?

A. Yes, based on his straw argument for adjusting off-system sales, Mr. Kollen has recommended an out of period adjustment proposed by his colleague Mr. Baron with regard to the revenues associated with Carbide, an LG&E customer.[32] Because Carbide is an LG&E customer, there is no corresponding KU adjustment.[33] Mr. Kollen bases his recommendation on the testimony of Mr. Baron.[34] Mr. Baron's testimony states that Carbide experienced an explosion in 2011 at its plant that reduced its energy usage, but that the plant is now in full operation.[35] Mr. Baron has proposed to remove the actual test year revenues and expenses associated with the Carbide facility and "replace it with a normalized revenue level based on Carbide's actual August 2012 billing amount from LG&E."[36]

Q. Do you agree with this adjustment?

A. No, this adjustment should be rejected for several reasons. First, it is a post-test year adjustment, which is frequently denied by the Commission. Second, normalization adjustments, for the reasons I previously discussed, are disfavored; and one month of

[32] Kollen Direct p. 6.
[33] *Id.*
[34] *Id.*
[35] Baron Direct, p. 28.
[36] *Id.*

information absolutely fails any reasonable period for the measurement of data. Third, the adjustment is highly selective and uses the rate schedule Carbide switched to after the test year. Fourth, the adjustment fails to consider any other changes in revenues and expenses outside the test period. For example, several customers have switched rate schedules since the test period, reducing their respective levels of revenues to LG&E going forward. Finally, the adjustment is simply not material when compared to LG&E's total cost of service margin.

Q. Explain how this is a post-test year adjustment and why it is should be rejected.

A. A post-test year adjustment is when a party proposes an adjustment for events occurring beyond the test year in the rate proceeding. In these cases, LG&E and KU have utilized a historic test year ending March 31, 2012. Mr. Baron's and Mr. Kollen's adjustment attempts to normalize Carbide's revenues based solely upon Carbide's billed amount in August 2012, which is five months after the test year in this proceeding.

The Commission has repeatedly rejected post-test year adjustments because such adjustments violate the matching principle, which is when one item of rates, such as an expense is adjusted, but the other components of rates, such as revenues, rate base, or capitalization is not similarly adjusted. For example, when an intervenor proposed an adjustment to adjust expenses for changes in the cost of gas after the test period, the Commission denied the adjustment because "it is inconsistent to adjust selected items of the rate base for changes occurring after the test year while other components of the rate base remain at year-end levels."[37] The adjustment Mr. Kollen and Mr. Baron has proposed is precisely the type of adjustment the Commission has denied, because it seeks to adjust

[37] *In the Matter of: An Adjustment of Gas Rates of the Union Light, Heat and Power Company* (Case No. 09029) Order, October 24, 1984 at p. 5.

LG&E's revenues and expenses based solely on the normalized revenues of one customer, based upon one month of information received five months after the test year.

Q. Does Mr. Kollen deny that he has proposed a post-test year adjustment?

A. Incredibly, yes. In response to LG&E's data request, Mr. Kollen stated that the Carbide "revenue normalization adjustment proposed by Mr. Baron is similar in nature to the numerous revenue normalization adjustments proposed by LG&E."[38] This is incorrect for two principal reasons. First, neither LG&E nor KU has based any annualization or normalization adjustment on data occurring after the test year. Mr. Baron and Mr. Kollen have based their adjustment on one month of billing that occurred *five* months after the end of the test year. This is certainly a post-test year adjustment that is inconsistent with every adjustment the Companies have proposed in these cases and the Commission's long-standing policy of disfavoring such selective post-test year adjustments. Second, neither LG&E nor KU have proposed "numerous revenue normalization adjustments" as Mr. Kollen claims. As I explained above, the Companies have proposed precisely two normalization adjustments, both of which have been accepted or expressly approved in previous Commission orders for many years.

Q. Did LG&E fail to "remove the effects of a nonrecurring outage at the Carbide facility" as Mr. Kollen has claimed?

A. No. Mr. Kollen's characterization of the explosion at the Carbide facility is inaccurate. Describing the event as an "outage," which suggests there was a known and finite period of inactivity is incorrect. While LG&E maintains contact with its customers, the customer

[38] See Kentucky Industrial Utility Customers, Inc.'s Response to Item No. 10 of Louisville Gas and Electric Company's First Request for Information in Case No 2012-0022.

under the circumstances could provide no assurance that its facility would resume operations and if so, at what revenue level.

Q. Are there other concerns with the adjustment, as well?

A. Yes. The adjustment is highly selective because it isolates billing changes for one customer for one month well after the test year. Mr. Kollen does not purport to have determined whether other LG&E or KU customers have increased or decreased their usage following the test year. Also, the adjustment is based on the rate schedule Carbide switched to after the end of the test year. As with customer usage, Mr. Kollen does not purport to have determined whether other LG&E or KU customers switched rate schedules following the test year. In short, Mr. Kollen has proposed a post-test year combined year-end customer and rate switching adjustment for *one customer*. The selective nature of this adjustment is readily apparent. For these reasons, I recommend the Commission deny this adjustment.

<u>Contributions to CAC and ACM</u>

Q. Does the testimony of Mr. Burch and Mr. Cummings refer to the contributions the Companies have made to CAC and ACM?

A. Yes, both Mr. Burch and Mr. Cummings acknowledge the commitments the Companies have made,[39] which are substantially the result of shareholder contributions. Mr. Burch states that KU's Home Energy Assistance program, which is funded through shareholder contributions, as well as a 16-cent-per-meter charge, has insufficient funds.[40] Similarly,

[39] Direct Testimony of Jack E. Burch on behalf of CAC in Case No. 2012-00221, filed October 2, 2012 ("Burch Direct"), p. 15-16; Direct Testimony of Marlon Cummings on behalf of Association of Community Ministries, Inc. in Case No. 2012-00222 ("Cummings Direct"), p. 10-11.
[40] Burch Direct, p. 15.

Mr. Cummings recommends that the Commission "encourage LG&E to continue and expand its commitments" of financial support to "utility assistance programs."[41]

LG&E and KU appreciate the difficulty that certain customers have in meeting their financial obligations, including their utility bills. As such, the Companies have made shareholder contributions to organizations such as CAC and ACM and undertaken other initiatives to assist those customers. These are described in detail in the direct testimony of Mr. Chris Hermann, Senior Vice President- Energy Delivery in these cases. While the Companies understand and appreciate CAC's and ACM's concerns, the Commission cannot compel shareholders to contribute to the organizations. It is important to note that the Companies have already made certain commitments to CAC and ACM that last to 2015.

Gas Line Tracker

Q. Does Mr. Cummings object to the Gas Line Tracker LG&E has proposed?

A. Yes. Mr. Cummings recommends that the Commission deny the Gas Line Tracker, or alternatively, grant an exemption for renters.[42] Mr. Cummings' only argument as to why the Gas Line Tracker should be denied is because it will be more difficult for low-income customers to pay their utility bill.[43] While LG&E certainly appreciates the impact of any rate increase on its customers, the Gas Line Tracker is part of an important safety program. LG&E has provided thorough proof, through its testimony and data responses, of the need for the program. Because Mr. Cummings provides no reasoned basis for his recommendation, it should be denied.

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[41] Cummings Direct, p. 11.
[42] Cummings Direct, p. 11.
[43] *Id.* at 7-8.

Q. Does Mr. Cummings offer an alternative recommendation regarding an exemption for renters?

A. Yes, Mr. Cummings states that if the Gas Line Tracker is approved, there should be an exemption for renters because renters have no responsibility for maintenance of service lines.[44] Mr. Cummings' proposed exemption is inappropriate for several reasons. First, certain of the costs LG&E has proposed to pass through the Gas Line Tracker affects all customers, regardless of their housing situation. As I explained in my direct testimony, LG&E proposes to recover the costs of its ongoing leak mitigation program, which includes its main replacement program, through the Gas Line Tracker. These programs benefit all customers receiving gas service. Finally, customers who receive and purchase service should pay for the cost of providing that service. The service line and riser are essential to the safe and reliable delivery of gas service. The basic function of these facilities is no different than the meter- all are necessary to the delivery of the service, and thus appropriate for customers to pay as a part of the cost of providing service.

Second, Mr. Cummings' proposed exemption is administratively impractical. LG&E has no means, or reason, to track whether a customer rents or owns the premise at which they take service. Moreover, LG&E is equally unaware whether a tenant's rental agreement requires the tenant or the landlord to pay for gas service. LG&E lacks the business reason or ability to administer the Gas Line Tracker with the exemption Mr. Cummings has proposed.

Q. Did Mr. Watkins, on behalf of the AG, express "concerns" about the Gas Line Tracker?

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[44] *Id.* at 8-9.

A. Mr. Watkins' testimony stated that he had no position on the Gas Line Tracker, but had been "advised by the OAG that he may have concerns."[45] When LG&E, through a data request, requested more information on these "concerns," Mr. Watkins, without any explanation, listed single-issue ratemaking, rate increases without full regulatory review, and that the replacement is "nothing new or extraordinary" as "concerns."[46] None of these three "concerns" are valid, as LG&E's thorough testimony and responses to data requests demonstrate that the Gas Line Tracker, which is important to customer safety, is a proper regulatory mechanism that includes periodic Commission review.

Q. Does this conclude your testimony?

A. Yes, it does.

[45] Prepared Direct Testimony and Schedules of Glenn A. Watkins on behalf of the Kentucky Office of the Attorney General in Case No. 2012-00222, p. 47.

[46] See the Attorney General's Response to Item No. 3 of Louisville Gas and Electric Company's First Request for Information in Case No. 2012-00222.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2ND day of November 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**
APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

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

A. My purpose is to respond to the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), and Mr. Richard A. Baudino, on behalf of the Kentucky Industrial Utility Consumers ("KIUC"), concerning the fair rate of return on equity ("ROE") that Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") should be authorized to earn on their investment in providing electric and gas utility service. In addition, I also respond to the capital structure recommendations of Dr. Woolridge, and Mr. Lane Kollen, on behalf of KIUC.

Q. ARE YOU PROVIDING THE WORK PAPERS YOU RELIED ON IN PREPARING YOUR REBUTTAL TESTIMONY?

A. Yes. My work papers are attached as Appendix A to my rebuttal testimony, with a copy of my electronic spreadsheet files being provided under separate cover.

Q. PLEASE SUMMARIZE THE PRINCIPAL CONCLUSIONS OF YOUR REBUTTAL TESTIMONY.

A. Dr. Woolridge's and Mr. Baudino's recommendations are flawed and should be rejected. Based on my evaluation, I conclude that:

- *Their recommendations are inadequate to compensate investors in the Companies when evaluated against the earnings expected for the proxy utilities that they consider to be comparable;*
- *The Companies must be granted an opportunity to earn a return that is competitive with other utilities. The allowed ROEs for the companies that Dr. Woolridge and Mr. Baudino consider to be comparable in risk also demonstrate that their recommendations are too low to be credible;*
- *Many of the quantitative methods relied on by Dr. Woolridge and Mr. Baudino are applied using data that violate the principles of their own methods, and contain computational errors and omissions that bias their results downward;*
- *In applying quantitative methods to estimate the cost of equity, Dr. Woolridge incorporated data that does not reflect investors' expectations and failed to exclude illogical results, which imparts a downward bias to his conclusions;*
- *Because of flaws in the screening criteria and data used by Dr. Woolridge and Mr. Baudino, their proxy groups of electric utilities should be rejected;*
- *Cost of equity estimates for the Non-Utility Group presented in my direct testimony provide an important benchmark that is consistent with financial theory, how investors operate, and the guidelines underlying a fair ROE. Consistent with expected earnings and allowed ROEs for other utilities, this benchmark demonstrates that the ROE recommendations of Dr. Woolridge and Mr. Baudino are far too low;*
- *If the Companies are unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms, and investors will be denied an opportunity to earn their opportunity cost of capital; and*
- *The failure of Mr. Baudino and Dr. Woolridge to consider the impact of flotation costs contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.*

With respect to Dr. Woolridge's recommended capital structure, my rebuttal testimony demonstrates that there is no basis for the hypothetical equity ratio he selects. Similarly, I demonstrate Mr. Kollen's proposal to consider double-leverage is counter to financial and regulatory principles. Finally, my rebuttal testimony demonstrates that Dr. Woolridge's and Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

II. RECOMMENDATIONS OF OAG AND KIUC NOT SUPPORTED BY CAPITAL MARKET CONDITIONS

Q. DO THE CONCLUSIONS OF DR. WOOLRIDGE AND MR. BAUDINO REFLECT A COMPLETE AND ACCURATE PORTRAYAL OF CAPITAL MARKET CONDITIONS AND INVESTOR SENTIMENT?

A. No. While focusing a great deal of attention on trends in Treasury bond yields and related benchmarks, a review of capital market and economic conditions contradicts their rosy conclusions. As discussed in my direct testimony,[1] investors have recently faced a myriad of challenges and uncertainties, with Value Line recently observing, "The situation is notably worse on the global front, where China is growing more slowly and Europe's outlook is deteriorating, particularly across its southern tier."[2] Meanwhile, there is ongoing speculation that the economy remains exposed to a potential "double-dip" recession, with unemployment remaining stubbornly high, concern over the "fiscal cliff" of mandated tax hikes and spending cuts scheduled for year-end, and continued weakness plaguing the real estate sector.

While stock prices have trended higher, market sentiment remains highly sensitive to disappointment, and Value Line recently noted, "we caution that stocks are now more richly valued, making them vulnerable to possible event risks."[3] S&P noted that, "The effect of a potential financial collapse in the eurozone spreading to

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[1] Avera Direct at 13-15.
[2] The Value Line Investment Survey, *Selection and Opinion* (Oct. 12, 2012).
[3] The Value Line Investment Survey, *Selection & Opinion* (Sep. 21, 2012).

our shores is at the top of the list of events that could push the U.S. into recession."[4] These developments have led to periodic turmoil in capital markets, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk.

Q. DO THESE EXPOSURES AND UNCERTAINTIES SUPPORT THE OAG'S AND KIUC'S CONCLUSION THAT INVESTORS' REQUIRED RETURN ON COMMON STOCKS HAS FALLEN PRECIPITOUSLY?

A. No. In fact, this conclusion is contradicted by OAG's own testimony, which highlights many of the risks faced by common stock investors. For example, Dr. Woolridge observed that, "the U.S. is still saddled with relatively high unemployment, large government budget deficits, continued housing market issues, and uncertainty about future economic growth."[5] He concluded that, "the spillover of the financial crisis to the economy has been ongoing, and noted that, the economy is still on an uncertain path."[6]

Q. ARE TRENDS IN GOVERNMENT BOND YIELDS DIRECTLY REPRESENTATIVE OF CHANGES IN THE COST OF EQUITY CAPITAL FOR REGULATED ELECTRIC UTILITIES, SUCH AS THE COMPANIES?

A. No. The developments noted in my direct testimony, and acknowledged by Dr. Woolridge, have led to periodic turmoil in capital markets, with common stock prices exhibiting the dramatic volatility that is indicative of heightened sensitivity to risk. Nowhere has this turmoil been more evident than in the market for Treasury bonds, with yields being pushed significantly lower due to a global "flight to safety"

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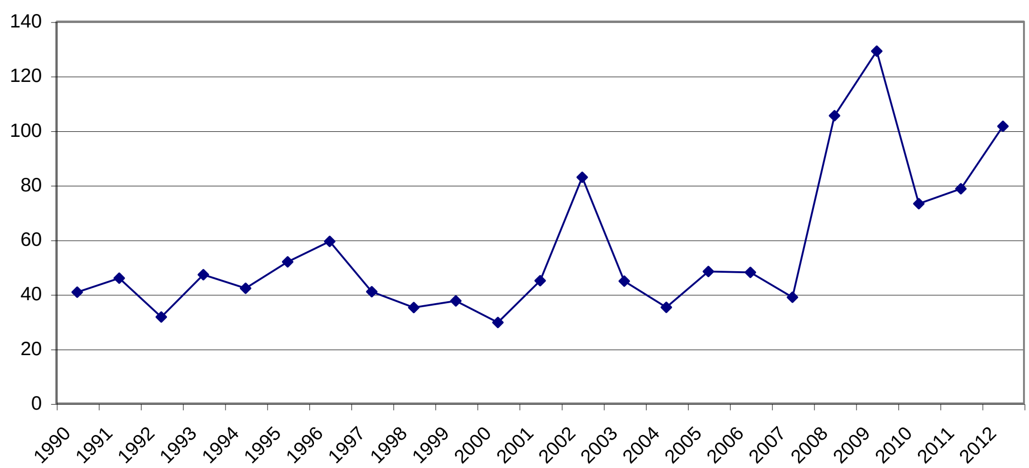
[4] Standard & Poor's Corporation, "Economic Research: U.S. Economic Forecast: Just Like Ol' Times," *RatingsDirect* (Jan 12, 2012).
[5] Woolridge Direct at 9.
[6] *Id.*

in the face of rising political, economic, and capital market risks. In turn, this has led to a dramatic increase in risk premiums, as illustrated by the spreads between triple-B utility bond yields and 30-year Treasuries shown in Figure WEA-1 to my direct testimony.

While the cost of equity cannot be directly observed in capital markets like the yields on bonds, there is every reason to believe that the required return to attract risk capital to utilities has increased relative to the yield on utility bonds. As illustrated below in Figure WEA-1, the spread between bonds of different ratings has clearly expanded in the last few years:

FIGURE WEA-1
YIELD SPREAD – BBB / AA UTILITY BONDS
(BASIS POINTS)



Sourc Source: Moody's Investors Service.

If investors require more additional return to bear the risk of BBB bonds relative to AA bonds, it is likely that they also require addition return to shift from the relative safety of bonds to the higher risk of utility equity. In short, heightened capital market and economic uncertainties, and the increase in risk premiums demanded by investors, further undermine the contention that the Companies' ROE has experienced an unprecedented decline.

Q. IS THERE ANY BASIS FOR THE CONTENTION THAT THE IMPLICATIONS OF FORECASTED TRENDS IN LONG-TERM CAPITAL COSTS SHOULD BE IGNORED WHEN EVALUATING A FAIR ROE FOR THE COMPANIES?

A. No. Dr. Woolridge wrongly concludes that long-term capital costs are expected to remain low, but his position is clearly refuted by reference to widely-referenced projections, such as those presented in Table WEA-1 to my direct testimony. Consideration of interest rate forecasts recognizes that investors' required returns can and do shift over time with changes in capital market conditions. The importance of projections in establishing the expectations and requirements of investors is well accepted, and there is no basis to ignore information regarding the likely state of capital markets during the time when rates established in this proceeding will take effect. The fact that organizations such as GlobalInsight and EIA devote considerable expertise and resources to developing an informed view of the future – and market participants are willing to expend finite resources to purchase such services – confirms the importance of economic forecasts in the minds of capital market participants.

III. FAILED TO CONSIDER END-RESULT TEST

Q. IS IT WIDELY ACCEPTED THAT A UTILITY'S ABILITY TO ATTRACT CAPITAL MUST BE CONSIDERED IN ESTABLISHING A FAIR RATE OF RETURN?

A. Yes. This is a fundamental standard underlying the regulation of public utilities. The Supreme Court's *Bluefield* and *Hope* decisions established that a regulated utility's authorized returns on capital must be sufficient to assure investors' confidence and that, if the utility is efficient and prudent on a prospective basis, it will be able to maintain and support its credit and have the opportunity to raise necessary capital.

Q. DR. WOOLRIDGE AND MR. BAUDINO RECOGNIZED THAT THE ALLOWED ROE MUST MEET CERTAIN STANDARDS TO BE CONSIDERED REASONABLE. DO YOU AGREE?

A. Yes. Dr. Woolridge and Mr. Baudino clearly recognized,[7] but then ignored, this fundamental standard, which underlies the regulation of public utilities and a determination of a fair rate of return, pursuant to the Supreme Court's *Bluefield* and *Hope* decisions. These decisions established that a regulated utility's authorized returns on capital must be commensurate with those expected for other investments involving comparable risk.

While the details underlying a determination of the cost of equity are all significant to a rate of return analyst, there is one fundamental requirement that any ROE recommendation must satisfy before it can be considered reasonable. Competition for capital is intense, and utilities such as the Companies must be granted the opportunity to earn an ROE comparable to contemporaneous returns available from alternative investments if they are to maintain their financial flexibility and ability to attract capital.

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[7] For example, Dr. Woolridge (p. 24) noted that the ROE must "be commensurate with returns on investments in other enterprises having comparable risks." Similarly, Mr. Baudino (p. 12) also recognized these fundamental standards underlying a fair ROE.

Q. DID DR. WOOLRIDGE OR MR. BAUDINO TEST THEIR ROE RECOMMENDATIONS AGAINST THESE FUNDAMENTAL REGULATORY REQUIREMENTS?

A. No. Expected earned rates of return for other utilities provide one useful benchmark to gauge the reasonableness of the ROE recommendation of Dr. Woolridge and Mr. Baudino, but neither witness performed this test. The expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*. From my understanding as a regulatory economist, not as a legal interpretation, these cases required that a utility be allowed an opportunity to earn the same return as companies of comparable risk. That is, the cases recognized that a utility must compete with other companies, including non-utilities, for capital.

Q. DID MR. BAUDINO RECOGNIZE THE ECONOMIC PREMISE UNDERLYING THE EXPECTED EARNINGS APPROACH?

A. Yes. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Baudino recognized (p. 12), economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs." Mr. Baudino went on to explain that, "One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative."

Q. WHAT ARE THE IMPLICATIONS OF SETTING AN ALLOWED ROE BELOW THE RETURNS AVAILABLE FROM OTHER INVESTMENTS OF COMPARABLE RISK?

A. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. This results in taking the value of investors' capital without adequate compensation.

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

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

Q. DESPITE RECOGNIZING THE REGULATORY STANDARDS UNDERLYING YOUR REFERENCE TO EARNINGS ON BOOK VALUE, DR. WOOLRIDGE AND MR. BAUDINO ARE CRITICAL OF THIS METHOD. HAS THE EXPECTED EARNINGS APPROACH BEEN RECOGNIZED AS A VALID ROE BENCHMARK?

A. Yes. While this method predominated before the DCF model became fashionable with academic experts, I continue to encounter it around the country. Indeed, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code § 56-585.1.A.2.a) to consider the earned returns on book value of electric utilities in its region. In orders issued on November 30, 2011 and July 15, 2010 in Dockets PUE-2011-00037 and PUE-2009-00030, the VSCC established the allowed

ROE for Appalachian Power Company based solely on the earned returns on book value for a peer group of other electric utilities. Another example is Ms. Terri Carlock, the long-time financial analyst for the Idaho Public Utilities Commission. She has consistently presented evidence on book earnings for decades, and Idaho regulators continue to confirm the relevance of return on book equity evidence.

A textbook prepared for the Society of Utility and Regulatory Analysts labels the comparable earnings approach the "granddaddy of cost of equity methods" and points out that the amount of subjective judgment required to implement this method is "minimal", particularly when compared to the DCF and CAPM methods.[8] The *Practitioner's Guide* notes that the comparable earnings test method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases,[9] as well as sound regulatory economics. I have used the comparable earnings approach in my consulting, teaching, and testimony for 35 years, and it has been widely referenced in regulatory decision-making.[10]

Q. WHAT IS THE RELEVANCE OF THE DISCUSSION OF MARKET-TO-BOOK RATIOS PRESENTED BY DR. WOOLRIDGE (PP. 20-23, 69) TO THE EARNINGS OF COMPARABLE UTILITIES?

A. Dr. Woolridge implies that utility earnings are too high because the market-to-book ratios generally exceed one. He is suggesting that the KPSC should sacrifice the Companies' financial strength in favor a theoretical ideal of market-to-book ratios equaling unity. The KPSC does not regulate utility stock market prices, and there

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[8] Parcell, David C., *The Cost of Capital—a Practitioner's Guide* (1997).

[9] *Id.* at 7-3.

[10] For example, a NARUC survey reported that 19 regulatory jurisdictions cited the comparable earnings test as a primary method favored in determining the allowed rate of return. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996). In my experience, while a few Commissions have explicitly rejected comparable earnings, most regard it as a useful tool.

are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the KPSC to order a return that would almost certainly lead to a capital loss on the value of the Companies' investment. The implication of this distorted train of logic is that investors are willing to purchase the common stock of a utility in expectation of a *negative* ROE.

Q. IS THERE ANY MERIT TO DR. WOOLRIDGE'S CONCERNS ABOUT A MARKET-TO-BOOK RATIO ABOVE 1.00?

A. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that over 1,400 of the approximately 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[11] Moreover, regulators have previously recognized the fallacy of relying on market-to-book ratios in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[12]

The Presiding Judge found that there was no support in FERC precedent for the use of market-to-book ratios to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration.

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[11] www.valueline.com (retrieved Aug. 23, 2012).

[12] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

Q. DO YOU AGREE WITH MR. BAUDINO (P. 48) THAT MARKET DATA IS THE ONLY USEFUL BENCHMARK IN EVALUATING INVESTORS' OPPORTUNITY COSTS?

A. No. While I agree that market-based models are certainly important tools in estimating investors' required rate of return, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages.

It is a very simple, conceptual principle that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If the Companies are only allowed the opportunity to earn an 8.5% or 9.2% return on the book value of its equity investment, as recommended by Dr. Woolridge and Mr. Baudino, while other electric utilities are expected to earn an average of 10.5%,[13] the implications are clear – the Companies' investors will be denied the ability to earn their opportunity cost.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices,

[13] Value Line reports an average expected return on book equity for 2015-17 of 10.5% for the electric utility industry. The Value Line Investment Survey at 901 (Sep. 21, 2012).

market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT ROE IS IMPLIED BY THE EXPECTED EARNINGS FOR THE PROXY GROUPS OF DR. WOOLRIDGE AND MR. BAUDINO?

A. As shown on page 1 of Schedule WEA-11, reference to expected earnings implied an average cost of equity for the utilities in Dr. Woolridge's proxy group of 10.5%. Similarly, page 2 of Schedule WEA-11 shows that the average expected book return on equity for Mr. Baudino's proxy group is also 10.5%. These book return estimates are an "apples to apples" comparison to the 8.5% and 9.2% recommended ROEs of Dr. Woolridge and Mr. Baudino, respectively.

Q. WHAT WOULD BE THE EFFECT OF AUTHORIZING A BOOK RETURN THAT IS SO FAR BELOW THE AVERAGE EARNINGS OF THE UTILITIES THAT DR. WOOLRIDGE AND MR. BAUDINO CLAIM ARE COMPARABLE?

A Plain and simple, the Companies will find it difficult to compete for investors' capital and investors would not be earning up to the *Bluefield* standard of comparable earnings:

> A public utility is entitled to such rates as will permit it to earn 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.[14]

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[14] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

Q. CAN ALLOWED ROES ALSO BE USED TO EVALUATE WHETHER THE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. BAUDINO ARE SUFFICIENT TO MEET REGULATORY STANDARDS?

A. Yes. Reference to allowed rates of return for other utilities provides one useful guideline that can be used to assess the extent to which the 8.5% and 9.2% ROE recommendations of Dr. Woolridge and Mr. Baudino are comparable and sufficient. As shown on page 1 of Schedule WEA-12, data from the September 2012 *AUS Monthly Utility Report* (a source relied on by Dr. Woolridge and Mr. Baudino) indicates that the average authorized ROE for the firms in Dr. Woolridge's electric proxy group is 10.36%, or 186 basis points higher than his recommendation for the Companies.

With respect to the group of electric utilities that Mr. Baudino concluded were most comparable to the Companies' jurisdictional utility operations, as shown on page 2 of Schedule WEA-12 these firms are presently authorized an average rate of return on equity of 10.62%, or 142 basis points more than Mr. Baudino's ROE recommendation. It is unreasonable to suppose that investors would be attracted by Dr. Woolridge's or Mr. Baudino's recommendations for the Companies, which fall significantly below the allowed returns for other utilities they consider to be comparable.

Q. WHAT DO THESE BENCHMARKS IMPLY WITH RESPECT TO THE ROE RECOMMENDATIONS OF DR. WOOLRIDGE AND MR. BAUDINO?

A. These benchmarks clearly demonstrate that their recommendations are far too low and violate the economic and regulatory standards underlying a fair ROE.

IV. DCF RESULTS ARE UNDERSTATED

Q. WHAT ARE THE FUNDAMENTAL PROBLEMS WITH THE DCF ANALYSES CONDUCTED BY DR. WOOLRIDGE?

A. There are numerous fundamental problems with the DCF analyses presented by Dr. Woolridge that lead to biased end results:

1. Reliance on dividend growth rates and historical growth measures do not reflect a meaningful guide to investors' expectations;
2. Dr. Woolridge discounts reliance on analysts' growth forecasts for earnings per share ("EPS") as somehow biased, and fails to recognize that it is investors' *perceptions and expectations* that must be considered in applying the DCF model;
3. Rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views; and,
4. Because Dr. Woolridge failed to test the reasonableness of model inputs, he incorrectly includes data that results in illogical cost of equity estimates.

As a result of these flaws and omissions, the resulting DCF cost of equity estimates are downward biased and fail to reflect investors' required rate of return.

Q. DO THE GROWTH RATES REFERENCED BY DR. WOOLRIDGE MIRROR INVESTORS' LONG-TERM EXPECTATIONS IN THE CAPITAL MARKETS?

A. No. There is every indication that his growth rates, and resulting DCF cost of equity estimates, are biased downward and fail to reflect investors' required rate of return. If past trends in earnings, dividends, and book value are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. While these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices.

Q. DID DR. WOOLRIDGE AND MR. BAUDINO RECOGNIZE THE PITFALLS ASSOCIATED WITH HISTORICAL GROWTH RATES?

A. Yes. Dr. Woolridge noted that:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[15]

But as he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> [O]ne must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate figure to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[16]

Similarly, Mr. Baudino noted (p. 20) that the analysis of investors' cost of equity "is a forward-looking process," and that "historical growth rates may not accurately represent investors' expectations." Mr. Baudino concluded that analysts' forecasts "provide better proxies for the expected growth components in the DCF model than historical growth rates." Moreover, to the extent historical trends for utilities are meaningful, they are already captured in projected growth rates, including those

[15] Woolridge Direct at 33.
[16] *Id*.

published by Value Line, First Call, Zacks, and Thomson Reuters, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. DR. WOOLRIDGE ARGUES (P. 36) THAT, "THE APPROPRIATE GROWTH RATE IN THE DCF MODEL IS THE DIVIDEND GROWTH RATE." DO YOU AGREE THAT THIS IS WHAT INVESTORS ARE MOST LIKELY TO CONSIDER IN DEVELOPING THEIR LONG-TERM GROWTH EXPECTATIONS?

A. No. Implementation of the DCF model is solely concerned with replicating the forward-looking evaluation of actual investors. In the case of utilities, growth rates in dividends per share (DPS) are not likely to provide a meaningful guide to investors' current growth expectations. This is because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry.[17] As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties. While past conditions for utilities serve to depress DPS growth measures, they are not representative of long-term expectations for the utility industry.

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

A. Future trends in earnings per share ("EPS"), which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. As explained in *New Regulatory Finance*:

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[17] For example, the payout ratio for electric utilities fell from approximately 80% historically to on the order of 60%. *See, e.g.*, The Value Line Investment Survey (Sep. 15, 1995 at 161, Feb. 24, 2012 at 136).

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth].[18]

The reality that analyst EPS growth estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a primary basis for their expectations. The importance of earnings in evaluating investors' expectations and requirements is well accepted in the investment community.

For example, a study published in the *Financial Analysts Journal* reported the results of a survey conducted to determine what analytical techniques investment analysts actually use.[19] Respondents were asked to rank the relative importance of earnings, dividends, cash flow, and book value in analyzing securities. Of the 297 analysts that responded, only 5 ranked book value first while 156 analysts ranked earnings as the most important input in analyzing securities. The article concluded:

> Earnings and cash flow are considered far more important than book value and dividends.[20]

Apart from Value Line, investment advisory services do not generally publish comprehensive DPS growth projections, and this scarcity of dividend growth rates relative to the abundance of earnings forecasts attests to their relative influence. The fact that securities analysts focus on growth EPS, and that DPS growth rates are not routinely published, indicates that projected EPS growth rates

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[18] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006).
[19] Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999).
[20] *Id.* at 88.

are likely to provide a superior indicator of the future long-term growth expected by investors.

Q. DID THE ORIGINATOR OF THE DCF MODEL, DR. MYRON J. GORDON, RECOGNIZE THAT APPLICATION OF THE DCF APPROACH IS NOT LIMITED TO DPS GROWTH RATES?

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

> A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth."[21]

In contrast to Dr. Woolridge's contention that, "the appropriate growth rate in the DCF model is the dividend growth rate, not the earnings growth rate,"[22] the only inputs that matter in implementing the DCF model are those that <u>investors used</u> to value the utility's stock. Any application of the DCF model that does not focus exclusively on investors' actual expectations is a misuse of the DCF model to estimate the cost of equity.

Q. SHOULD THE KPSC GIVE ANY CREDENCE TO DR. WOOLRIDGE'S ALLEGATIONS THAT PROJECTED EPS GROWTH RATES ARE BIASED?

A. No. These arguments were addressed on pages 33-34 of my direct testimony. In applying the DCF model to estimate the cost of equity, the <u>only</u> relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Dr. Woolridge's claim that analysts' estimates are discounted by investors is illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be

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[21] Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974).
[22] Woolridge Direct at 38.

irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a basis for their expectations.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model.

Indeed, despite the findings of his research, Dr. Woolridge has been quoted as saying that he "remains somewhat puzzled that so many continue to put great weight in what [analysts] have to say."[23] As Robert Harris and Felicia Marston noted in their article in *Journal of Applied Finance*:

> …Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia.[24]

Similarly, there is no logical foundation for criticisms such as those raised by Dr. Woolridge that the purported upward bias of analysts' growth rates limits their usefulness in applying the DCF model. As the KPSC has previously concluded:

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

[23] Boselovic, Len, "Study Finds Analysts' Forecasts Have Been Too Sunny," *Pittsburgh Post-Gazette* (Mar. 30, 2008).

[24] Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001) at 8.

> the AG's argument that analysts' projections should be rejected in favor of historical results. The Commission agrees that analysts' projections of growth will be relatively more compelling in forming investors' forward-looking expectations than relying on historical performance…[25]

Q DID DR. WOOLRIDGE PROVIDE ANY MEANINGFUL SUPPORT FOR HIS ALLEGATION THAT VALUE LINE FORECASTS ARE "EXCESSIVE" AND "UNREALISTIC"?

A. No. Dr. Woolridge based this assertion on his personal belief that Value Line does not report a sufficient number of negative growth rates.[26] But as Mr. Baudino recognized (p. 42, Schedule RAB-4), negative growth rates are inconsistent with the assumptions of the DCF model and not likely to be representative of investors' expectations. Dr. Woolridge's personal opinions are irrelevant to a determination of what investors expect and, contrary to his conclusion, Value Line is a well-recognized source in the investment and regulatory communities. For example, *Cost of Capital – A Practitioners' Guide*, published by the Society of Utility and Financial Analysts, noted that:

> [A] number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line."[27]

Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations. Moreover, in contrast to Dr. Woolridge's

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[25] *Case No. 2009-00548*, Final Order at 30-31.

[26] Woolridge Direct at B-14.

[27] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28.

unsupported assertion, the fact that Value Line is not engaged in investment banking or other relationships with the companies that it follows reinforces its impartiality in the minds of investors.

Q. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL AND DPS GROWTH MEASURES SELF EVIDENT?

A. Yes, it is. As shown on page 3 of Exhibit JRW-10, approximately one-quarter of the individual historical growth rates reported by Dr. Woolridge for the companies in his electric proxy group were *zero* or *negative.* These growth rates imply a cost of equity less than the utility's dividend yield, and provide absolutely no meaningful information regarding investors' expectations. As Mr. Baudino correctly recognized (Schedule RAB-4, p. 1), negative growth rates are properly excluded in applying the DCF model.

Similarly, approximately one-third of Dr. Woolridge's historical DPS growth rates are 1.0% or less. Combining a growth rate of 1.0% with Dr. Woolridge's dividend yield of 4.2% (Exhibit JRW-10, p. 1) implies a DCF cost of equity of approximately 5.2%. This implied cost of equity is not materially different than the yield from triple-B public utility bonds, which averaged approximately 4.9% over the six-months ended September 2012.[28] Clearly, the risks associated with an investment in public utility common stocks exceed those of long-term bonds and Dr. Woolridge's historical DPS growth measures provide no meaningful information regarding the expectations and requirements of investors. Meanwhile, projected DPS growth rates included in Dr. Woolridge's analysis ranged from 0.0% to 13.5%. The implied cost of equity range based on these values is 4.2% to 17.7%, which again gives no useful basis to evaluate a fair ROE for the Companies.

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[28] Moody's Analytics, Yields & Spreads Data, http://credittrends.moodys.com/chartroom.asp?c=3.

Q. DO YOU AGREE WITH MR. BAUDINO (P. 40) THAT YOU "ERRED" BY IGNORING VALUE LINE'S DPS GROWTH PROJECTIONS IN YOUR APPLICATION OF THE DCF MODEL?

A. No. As I explained in my direct testimony, specific trends in dividend policies for utilities and evidence from the investment community fully support my conclusion that earnings growth projections are likely to provide a superior guide to investors' expectations. Indeed, Mr. Baudino's own review of DPS growth rates confirms my decision to exclude them. As shown on page 1 of Exhibit RAB-4, the DPS growth rates included in his calculations ranged from 1.0% to 13.5%, which implies an ROE range of 5.2% to 18.0% using Mr. Baudino's average dividend yield.[29] As explained earlier in response to Dr. Woolridge, values of this magnitude are clearly illogical and provide no useful information.

Moreover, I disagree with Mr. Baudino's assertion (p. 41) that because Value Line's projected DPS growth rates "are widely available to investors," they can "reasonably be assumed to influence their expectation with respect to growth." Value Line publishes a wide variety of financial information, including growth rates in revenues and cash flows -- simply because a statistic is included in Value Line's report does not mean that investors would rely on it in determining their growth expectations. Indeed, Value Line makes a number of five and ten-year historical growth rates available to investors, including historical growth in DPS, which Mr. Baudino nevertheless rejected as inconsistent with investors' expectations.[30]

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[29] Mr. Baudino adjusted the dividend yield upward to account for one-half year's growth.
[30] Baudino Direct at 20.

Q. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as demonstrated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application make no economic sense.

Q. DOES REFERENCE TO THE MEDIAN CORRECT FOR ANY UNDERLYING BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH RATES?

A. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a <u>single number</u>, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q. HAS DR. WOOLRIDGE RECOGNIZED THE IMPORTANCE OF EVALUATING MODEL INPUTS IN OTHER FORUMS?

A. Yes. As Dr. Woolridge noted in his testimony (Appendix A, p. 1), he is a founder and managing director of *ValuePro*, which is an online valuation service largely based on application of the DCF model. *ValuePro* confirmed the importance of evaluating the reasonableness of inputs to the DCF model:

> Garbage in, Garbage out! Like any other computer program, if the inputs into our Online Valuation Service are garbage, the resulting valuation also will be garbage.[31]

[31] http://www.valuepro.net/abtonline/abtonline.shtml.

Unlike his approach here, Dr. Woolridge advised investors to use common sense in interpreting the results of valuation models, such as the DCF:

> If a figure comes up for a certain input that is either highly implausible or looks wrong, indeed it may be. If a valuation is way out of line, figure out where the Service may have strayed on a valuation, and correct it.[32]

Given the fact that many of the growth rates relied on by Dr. Woolridge result in illogical cost of equity estimates, it is appropriate to take the same critical viewpoint when evaluating inputs to his DCF model.

Q. WHAT APPROACH SHOULD DR. WOOLRIDGE HAVE USED TO EVALUATE LOW-END DCF ESTIMATES?

A. The ROE that investors require from a utility's common stock, which is the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, Dr. Woolridge should have eliminated growth rates that produce illogical DCF results. Regulators apply similar tests, with FERC consistently recognizing that it is appropriate to eliminate estimates that do not sufficiently exceed observable yields on long-term public utility debt.

Q. HAS DR. WOOLRIDGE ADOPTED THIS EXACT SAME TEST OF LOW-END DCF ESTIMATES IN RECENT TESTIMONY BEFORE FERC?

A. Yes. In testimony filed with FERC on September 30, 2011, and again on October 1, 2012, Dr. Woolridge applied this test to the results of his DCF analysis.[33] As Dr. Woolridge concluded:

> These data suggest that the prospective yield on utility bonds with a rating similar to the proxy group (A-/BBB+) is in the 5.0% range.

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[32] *Id.*
[33] *Direct Testimony of J. Randall Woolridge,* FERC Docket No. EL11-66.

> Given this figure, and FERC's bond yield plus 100 basis point threshold for the low-end outliers, the elimination [of] the low-end results for Entergy (5.6%) and Great Plains Energy (6.2%) is supported.[34]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING LOW-END DCF ESTIMATES?

A. Yields on public utility bonds are expected to increase significantly. As shown in Table WEA-R1 below, forecasts of IHS Global Insight and the EIA imply that the average triple-B bond yield is expected to increase from approximately 5.0% currently to approximately 7.2% over the period 2013-2017:

TABLE WEA-R1
IMPLIED BBB BOND YIELD

	2013-17
Projected AA Utility Yield	
IHS Global Insight (a)	5.92%
EIA (b)	6.33%
Average	6.13%
Current BBB - AA Yield Spread (c)	1.11%
Implied Triple-B Utility Yield	**7.24%**

(a) IHS Global Insight, U.S. Economic Outlook at 19 (May 2012)
(b) Energy Information Administration, Annual Energy Outlook 2012 (Jun. 25, 2012)
(c) Based on monthly average bond yields from Moody's Investors Service for the six-month period Mar. 2012 - Aug. 2012

The rate of return that investors require from a utility's common stock must be considerably higher than this benchmark.

[34] *Id.* at 35-36.

Q. IF DR. WOOLRIDGE HAD ELIMINATED LOW-END VALUES, AS HE DID IN HIS RECENT FERC TESTIMONY, WHAT COST OF EQUITY WOULD HAVE RESULTED FROM HIS DCF ANALYSIS BASED ON HISTORICAL GROWTH RATES?

A. As indicated above, Dr. Woolridge's DPS growth measures provide no meaningful information regarding the expectations and requirements of investors and should be entirely ignored. As shown on Schedule WEA-13, screening Dr. Woolridge's DCF cost of equity estimates based on historical EPS and BVPS growth rates to eliminate illogical low and high-end values resulted in an implied cost of equity range of 9.8% to 10.7%, with the average cost of equity implied by Dr. Woolridge's corrected historical DCF analysis being 10.1%.[35]

Q. DR. WOOLRIDGE (P. 60) IMPLIES THAT THERE SHOULD BE SYMMETRY IN ELIMINATING LOW AND HIGH-END OUTLIERS. IS THIS LOGICAL?

A. No. As discussed in my direct testimony, the evaluation of DCF results to eliminate outliers properly considers each of the cost of equity estimates on a stand-alone basis. This test may eliminate more values at one end of the distribution than the other, but such an outcome does not imply bias or distortion. It is simply a function of the inputs to the DCF formula at a particular point in time. Consider DCF estimates of 4.0%, 4.5%, 9.8%, 10.5%, 11.2%, and 11.5%. Of these six estimates, only two – 4.0% and 4.5% – are outliers, because they fall below the yields on utility bonds. But Dr. Woolridge is implying that removing these two values requires a symmetrical narrowing of the two highest DCF estimates, even though

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[35] I applied the same approach to evaluate low and high-end outliers described in my direct testimony. *See, e.g.*, pages 37-41 of my direct testimony on behalf of LG&E.

there is no basis to believe that these values are extreme outliers. Rather than eliminating bias, such an approach would distort the conclusions because valid estimates would be eliminated without any logical basis.

Q. WHAT ABOUT MR. BAUDINO'S CONTENTION (P. 38) THAT TWO HIGH-END ESTIMATES FROM YOUR DCF ANALYSIS SHOULD HAVE BEEN ELIMINATED?

A. I addressed this issue at page 40 of my direct testimony. Moreover, Mr. Baudino included even higher cost of equity estimates in his own DCF analysis. As shown on page 1 of Exhibit RAB-4, Mr. Baudino included a projected DPS growth rate for Wisconsin Energy Corporation ("WEC") of 13.5%. Combining this growth rate with Mr. Baudino's adjusted dividend yield for WEC of 3.4% results in an implied cost of equity of 16.9%,[36] which was incorporated into the averages presented in his testimony.

Q. WHY DID YOU IGNORE THE INTERNAL, "BR" GROWTH RATES CALCULATED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. The internal growth rates calculated by Dr. Woolridge and Mr. Baudino are downward biased because of computational errors and omissions.[37] These witnesses based their calculations of the internal, "br" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. The need to correct for this downward bias has been

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[36] Computed by adjusting the 3.19% dividend yield for WEC reported on Exhibit RAB-3 for one-half year's growth.

[37] While Mr. Baudino reported "br" growth rates from Value Line for the firms in his proxy group, his DCF analysis ignored these data.

recognized by regulators,[38] and Dr. Woolridge has also recognized and adopted this adjustment to Value Line's projections:[39]

> The average values for r are then adjusted by the 'Adjustment Factor' since Value Line's expected earned rate of return on equity is based on end-of-year figure equity. The Adjustment Factor is calculated as ((2*(1+5-yr Change in Equity)/(2+5-yr Change in Equity)).[40]

Because Dr. Woolridge and Mr. Baudino both ignored this adjustment in this case, their internal, "br" growth rates are distorted and should be ignored.

Q. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN THE INTERNAL, "BR" GROWTH RATES OF DR. WOOLRIDGE AND MR. BAUDINO?

A. Both Dr. Woolridge and Mr. Baudino ignored the impact of additional issuances of common stock in their analyses of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. Professor Gordon recognized the need for the "sv" adjustment in his 1974 study,[41] and Dr. Woolridge also included the additional growth from new share issues by incorporating the "sv" component in his recent testimony before FERC.[42] The fact that Dr. Woolridge and Mr. Baudino failed to consider the incremental impact of new share issues on growth results in another downward bias to their "internal" growth rates, which should be given no weight.

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[38] See, *e.g.*, *Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.

[39] Mr. Baudino's contention (p. 49) that it is not necessary to adjust Value Line projections is refuted by Dr. Woolridge's FERC testimony. Indeed, FERC has recognized that Value Line's projected data is presented on an end of period basis, and must be adjusted to avoid understating book returns.

[40] *Direct Testimony of Randall J. Woolridge,* Federal Energy Regulatory Commission, Docket No. EL-11-66 (Oct. 1, 2012).

[41] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32.

[42] *Testimony of J. Randall Woolridge,* FERC Docket No. EL-66 at Exhibit JRW-8, pp. 3-4 (2011) and Exhibit SC-111 (2012).

Q. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF THE DCF ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. Historical growth rates and trends in DPS are distorted by fundamental changes in industry financial policies and Dr. Woolridge and Mr. Baudino failed to evaluate the underlying reasonableness of individual growth rates. In addition, the calculations used to arrive at the internal growth rates reported by Dr. Woolridge and Mr. Baudino are flawed and incomplete. As a result, their DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return.

V. NO BASIS TO DISREGARD NON-UTILITY GROUP

Q. WHAT IS THE FALLACY UNDERLYING DR. WOOLRIDGE'S AND MR. BAUDINO'S REJECTION OF ANY REFERENCE TO NON-UTILITY COMPANIES IN EVALUATING A FAIR ROE FOR THE COMPANIES?

A. Dr. Woolridge and Mr. Baudino dismiss out of hand my analysis of the cost of equity for non-utility firms based on the claim that utilities are profoundly different and therefore less risky from other companies in the economy. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions.

The idea that investors evaluate utilities against the returns available from other investment alternatives – including the low-risk companies in my Non-Utility Group – is a fundamental cornerstone of modern financial theory. Aside from this theoretical underpinning, any casual observer of stock market commentary and the investment media quickly comes to the realization that investors' choices are almost limitless, and simple common sense supports the notion that utilities must offer a return that can compete with other risk-comparable alternatives, or capital will simply go elsewhere.

In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[43]

Consistent with this view, Mr. Baudino noted (pp. 12-13) that the notion of "opportunity cost" underlies the Supreme Court's economic standards, and that:

> One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. … That alternative could have been another utility stock, a utility bond, <u>a mutual fund</u>, a money market fund, <u>or any other number of investment vehicles</u>. (emphasis added)

As Mr. Baudino correctly observed (p. 13), "The key determinant in deciding whether to invest, however, is based on comparative levels of risk," and he concluded, "[T]he task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms." In other words, Mr. Baudino recognized that investors gauge their required returns from utilities against those available from non-utility firms of comparable risk. My reference to a comparable-risk Non-Utility Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Baudino's own testimony.

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[43] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Q. DOES DR. WOOLRIDGE APPARENTLY CONSIDER NON-UTILITY STOCK RETURNS RELEVANT TO DETERMINING THE COST OF CAPITAL?

A. Yes, he does. Dr. Woolridge cites many studies of past and expected stock market returns in his testimony, including a list of over 30 studies included on Exhibit JRW-11. *Not one* of these studies is limited to utilities, and all include a predominance of non-utility common stocks, *e.g.,* the S&P 500 Index. Moreover, while Dr. Woolridge references a study of industry betas done at New York University that suggests utilities have lower risks than the average firm in the non-regulated sector,[44] this establishes nothing more than the obvious – while some unregulated firms have higher risks than utilities, others have lower risks. As documented in my direct testimony and discussed further in my rebuttal testimony, the firms in my Non-Utility Group are also in the lower range of risk as measured by objective, widely referenced benchmarks.

Q. DID MR. BAUDINO OR DR. WOOLRIDGE PRESENT ANY OBJECTIVE EVIDENCE TO SUPPORT THEIR CONTENTION THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN THE COMPANIES OR YOUR COMBINATION UTILITY GROUP?

A. No. Dr. Woolridge presented no meaningful evidence to rebut the results for my Non-Utility Group; rather, he simply observed that the "lines of business are vastly different " from utilities and they do not operate in a "highly regulated environment."[45] Similarly, apart from sweeping generalizations about the risk differences between regulated and non-regulated companies, Mr. Baudino provided

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[44] Woolridge Direct at 26.
[45] *Id.* at 57.

no support whatsoever for his contention that my Non-Utility Group is riskier than the Companies or my Combination Utility Group. Both Dr. Woolridge and Mr. Baudino ignored any comparison of accepted measures of investment risks, and instead simply noted that there are distinctions in the operating circumstances and degree of regulation between utilities and firms in the competitive sector.

My direct testimony did not contend that the operations of the companies in the Non-Utility Group are comparable to those of utilities. Clearly, operating a worldwide enterprise in the beverage, pharmaceutical, retail, or food industry involves unique circumstances that are as distinct from one another as they are from an electric utility. But as the Supreme Court recognized, investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. So long as the risks associated with my Non-Utility Group are comparable to the Companies and other utilities – and my direct testimony demonstrates conclusively that they are lower – the resulting DCF estimates provide a meaningful benchmark for the cost of equity.

My Non-Utility Group is comprised of 12 of the best-known and most stable corporations in America *and has risk measures that are comparable to, or less than the proxy group of utilities referenced in my analyses*. While these companies are not regulated to the same degree, they also do not bear the burdens of losing control over their prices, undertaking the obligation to serve, and having to invest in infrastructure even in unfavorable market conditions. The Companies cannot relocate their facilities to an area with a more attractive business climate or higher prospects for economic growth, or abandon customers when turmoil roils energy or capital markets. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair ROE.

Consider Mr. Baudino's statement that utilities "have protected markets … enjoy full recovery of prudently incurred costs, and may increase their rates to cover increases in costs."[46] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies have higher overall risk structures." In fact, however, investors are quite aware that utilities are not guaranteed recovery of reasonable and necessary costs incurred to provide service and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an inability to earn the allowed ROE – and potentially, even bankruptcy. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

Q. DOES OBJECTIVE EVIDENCE SUPPORT THE RISK ARGUMENTS OF DR. WOOLRIDGE OR MR. BAUDINO?

A. No. In fact, the objective risk measures specifically cited by Mr. Baudino as being relevant indicia of overall investment risks contradict his assertions and those of Dr. Woolridge. Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding (p. 14), "Bond and credit ratings are tools that investors use to assess the risk comparability of firms." Contradicting Mr. Baudino's unsupported assertion (p. 35) that the companies in my Non-Utility Group "have higher overall risk structures," my direct testimony noted that the average corporate credit rating for the Non-Utility Group of "A" is <u>higher</u> than the "BBB" average for the Combination Utility Group and the Companies.

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[46] Baudino Direct at 35.

Comparisons between credit ratings for utilities and non-utility firms are reinforced by the fact that S&P ceased publishing separate ratings guidelines for regulated utilities in 2007, and now applies the same matrix of business and financial risks used to evaluate non-regulated companies. As S&P concluded, "This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors."[47] In fact, the review of objective indicators of investment risk presented in my direct testimony (Table WEA-2), which consider the impact of competition and market share, demonstrated that, if anything, the Non-Utility Group could be considered <u>less</u> risky in the minds of investors than the common stocks of the proxy group of utilities.

Q. DO THE BETA VALUES FOR THE NON-UTILITY GROUP ADDRESS THE CONCERNS EXPRESSED BY THE KPSC IN THE COMPANIES' LAST RATE PROCEEDING?

A. Yes. The KPSC concluded in Case Nos. 2009-00548 and 2009-00549 that utilities must compete with non-regulated firms for capital and recognized that investors consider the opportunity costs associated with investment alternatives outside the utility industry. However, the Commission found that lower beta values for utility common stocks supported a finding that the non-utility companies were "riskier alternatives."[48] To address the KPSC's concerns, my proxy group criteria restricted the Non-Utility Group to include only firms with beta values of 0.60 or less. As shown in Table WEA-R2, the group's current average beta is 0.58:

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[47] Standard & Poor's Corporation, "U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix," *RatingsDirect* (Nov. 30, 2007).

[48] *Case No. 2009-00548*, Final Order at 31; *Case No. 2009-00549*, Final Order at 33.

TABLE WEA-R2
BETA - NON-UTILITY GROUP

	Company	Beta
1	Abbott Labs.	0.60
2	Bard (C.R.)	0.60
3	Church & Dwight	0.60
4	Coca-Cola	0.60
5	Colgate-Palmolive	0.60
6	Gen'l Mills	0.50
7	Kellogg	0.55
8	Kimberly-Clark	0.55
9	McCormick & Co.	0.60
10	PepsiCo, Inc.	0.60
11	Procter & Gamble	0.60
12	Wal-Mart Stores	0.60
	Average	**0.58**

(b) www.valueline.com (retrieved Oct. 30, 2012).

This average beta of 0.58 is significantly lower than the 0.70 averages for the electric utility proxy groups used by Dr. Woolridge and Mr. Baudino, respectively.[49]

Q. DID DR. WOOLRIDGE ALSO RELY ON BETA TO COMPARE THE INVESTMENT RISKS OF UTILITIES WITH OTHER INDUSTRIES?

A. Yes, he did. Dr. Woolridge noted that beta "is the only relevant measure of investment risk" under modern capital market theory.[50] Based on the average betas for various industry sectors presented on Exhibit JRW-8, Dr. Woolridge concluded that, "the investment risk of utilities is very low."[51] A comparison of the industry average beta values relied on by Dr. Woolridge indicates that my Non-Utility Group

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[49] Similarly, the 0.58 average beta for the Non-Utility Group is also well below the 0.65 average for Dr. Woolridge's gas proxy group.

[50] Woolridge Direct at 26.

[51] *Id.*

is less risky than any of these sectors – including the electric, gas, and water utility industry groups.

Q. DOES THE FACT THAT UTILITIES ARE REGULATED SOMEHOW INVALIDATE THIS COMPARISON OF OBJECTIVE RISK INDICATORS?

A. Absolutely not. Dr. Woolridge and Mr. Baudino argue that regulatory protections make utilities less risky than firms operating in competitive markets. First, it is important to note that my analysis did not focus on the average firm in the competitive sector. Rather, it was restricted to a low-risk group of companies that represent the pinnacle of corporate America. In addition, while I don't disagree that utilities operate under a regulatory regime that differs from firms in the competitive sector, any risk-reducing benefit of regulation is already incorporated in the overall indicators of investment risk presented in Table WEA-2 to my direct testimony.

Q. DO THE HIGHER DCF ESTIMATES FOR THE NON-UTILITY GROUP DEMONSTRATE HIGHER RISK?

A. No. As discussed in my direct testimony,[52] while we are accustomed to associating higher risk with higher returns, DCF estimates of investors' required rate of return do not always produce that result. Performing the DCF calculations for the Non-Utility Group produced ROE estimates that are higher than the DCF estimates for the Combination Utility Group, even though the risks that investors associate with the group of non-utility firms – as measured by S&P's credit ratings and Value Line's Safety Rank, Financial Strength, and Beta – are lower than the risks investors associate with the Combination Utility Group and the Companies. The actual cost of equity is unobservable, and DCF estimates may depart from these values because investors' expectations may not be captured by the inputs to the ROE model,

[52] Avera Direct at 43-44.

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

VI. CAPM RESULTS SHOULD BE DISREGARDED

Q. DID EITHER DR. WOOLRIDGE OR MR. BAUDINO RELY ON THEIR CAPM RESULTS IN ARRIVING AT THEIR RECOMMENDATIONS IN THIS CASE?

A. No. Dr. Woolridge ignored his 7.5% CAPM cost of equity estimate in arriving at his 8.5% recommendation, which is near the top of his 7.3% to 8.6% cost of equity range. Dr. Woolridge noted that he relied primarily on the DCF model, and he concluded that the CAPM provides "a less reliable indication of equity cost rates for public utilities."[53] Similarly, Mr. Baudino noted (p. 30) that his ROE recommendation was based solely on cost of equity estimates implied by his application of the DCF model and ignored his CAPM results entirely.

Q. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF THE CAPM ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. Yes. As discussed in my direct testimony,[54] applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors sought a safe haven in U.S. government bonds and this "flight to safety" pushed Treasury yields

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[53] Woolridge Direct at 25-26.
[54] Avera Direct at 47-50.

significantly lower while yield spreads for corporate debt widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, the backward-looking, historical approaches employed by Dr. Woolridge and Mr. Baudino incorrectly assume that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some past average. This mismatch between investors' current expectations and requirements and historical risk premiums is particularly severe because of the heightened uncertainty and rapidly changing conditions that have recently characterized capital markets. As Mr. Baudino concluded (p. 28), "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."

While I agree with the decision of Dr. Woolridge and Mr. Baudino to give no weight to their CAPM results, for completeness my rebuttal testimony nevertheless addresses the major flaws associated with their applications of this approach.

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE HISTORICAL APPROACHES USED BY DR. WOOLRIDGE AND MR. BAUDINO TO APPLYING THE CAPM?

A. Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Dr. Woolridge recognized that "ex post returns are not the same as ex ante expectations" and noted that "market risk premiums can change over time; increasing when investors become more riskaverse."[55] Nevertheless, his application of the CAPM method was based entirely on *historical* – not projected – rates of return, as was the CAPM method presented on Mr. Baudino's Exhibit (RAB-6). *Morningstar* recognized the primacy of current expectations:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[56]

Because the backward-looking analyses of Dr. Woolridge and Mr. Baudino ignore the returns investors are currently requiring in the capital markets, the resulting CAPM estimates fall woefully short of investors' current required rate of return.

Q. DR. WOOLRIDGE (P. 49) ATTEMPTS TO CHARACTERIZE CAPM STUDY AS INCORPORATING AN "*EX ANTE*" RISK PREMIUM. IS THIS AN ACCURATE ASSESSMENT?

A. No. In order to be considered a forward-looking, *ex ante* estimate of the current market risk premium, the analysis must be predicated on investors' current expectations. Dr. Woolridge did not attempt to develop a market risk premium using current capital market information. Rather, he simply presented the results of various studies and surveys conducted in the past. Certain of these studies may have attempted to infer the equity risk premium using expected data at the time they were developed, but expectations at some point in the past are not equivalent to investors *ex ante* requirements in capital markets today.

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[55] Woolridge Direct at 45.

[56] Morningstar, *Ibbotson SBBI, 2011 Valuation Yearbook* at 21 (2011).

Q. IS THERE EVIDENCE THAT THE STUDIES AND SURVEYS REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A. Yes. The vast majority of the results of the equity risk premium studies reported by Dr. Woolridge do not make economic sense and contradict his own testimony. For example, page 5 of Dr. Woolridge's Exhibit JRW-11 reveals that approximately two-thirds of the historical studies included in Dr. Woolridge's review found market equity risk premiums of approximately 5.0% or below.[57] This was also true for over one-half of the individual risk premium studies that Dr. Woolridge relied on directly to apply the CAPM.[58] But combining a market equity risk premium of 5.0% with Dr. Woolridge's 4.0% risk-free rate results in an indicated cost of equity for the market as a whole of 9.0%, which exceeds Dr. Woolridge's ROE recommendations for the Companies in this case by a meager 50 basis points. Many of his other benchmarks for the market rate of return fall *below* the anemic cost of equity he recommends for the Companies. For example, Dr. Woolridge develops a market rate of return of 7.6% based on his "building blocks" approach,[59] which falls 90 basis points *below* his recommended ROE in this case.

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for electric utilities.[60] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does

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[57] Similarly, Dr. Woolridge reported equity risk premiums of 4.1%, 2.8%, and 5.0% (pp. 51-52) based on selected surveys.
[58] Exhibit JRW-11, p. 6.
[59] Woolridge Direct at C-4.
[60] *Id.* at 24.

not exceed his own downward biased ROE recommendation by a significant margin has no relation to the current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to finance clearly illustrates the frailty of Dr. Woolridge's analyses.

Q. DR. AVERA, ARE YOU IN ANY WAY ALLEGING THAT ALL THESE STUDIES AND SURVEYS ARE INCORRECT?

A. No, not at all. I am challenging the inferences that Dr. Woolridge draws from them, and the particular use being made of the cited studies. The point that I am making is that there is more than one way to define and calculate an equity risk premium. The problem with Dr. Woolridge's approach is that, instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM – he undertakes an unrelated exercise of compiling a list of selected computations culled from the historical record. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they don't answer the question as to what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history – whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

Likewise, surveys of selected corporate executives or economists, or building blocks based on academic research, are not equivalent to investors' required returns in the coming period. Since the benchmark for a fair ROE requires that the utility be able to compete for capital in the current capital market, the relevant inquiry is to determine the return that real world investors in today's markets require from the Companies in order to compete for capital with other comparable risk alternatives. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q. WERE DR. WOOLRIDGE OR MR. BAUDINO JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the

> relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time.[61]

Similarly, Morningstar concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. … The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[62]

I certainly agree that both geometric and arithmetic means are useful, since my Ph.D. dissertation was on the usefulness of the geometric mean.[63] But the issue is not whether both measures can be useful; it is which one best fits the use for a forward-looking CAPM in this case. One does not have to get deeply into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The KPSC is not setting a constant return that the Companies are guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, the Companies' yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year.

The usefulness of the arithmetic mean for making forward-looking estimates was confirmed in *Quantitative Investment Analysis* (2007), one of the textbooks included in the study curriculum for the Chartered Financial Analyst designation, which concluded that the arithmetic mean is the appropriate measure when

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[61] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* AT 275 (1994) (emphasis added).

[62] Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 56 (2011).

[63] William E. Avera, *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice* (1972).

calculating an expected equity risk premium in a forward-looking context.[64] Just as importantly, by relying directly on expectations and estimates of investors' required rate of return, as incorporated in the CAPM analysis presented in my direct testimony, there is no need to debate the merits of geometric versus arithmetic means, because neither is required to apply this forward-looking approach.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S AND MR. BAUDINO'S CAPM RESULTS?

A. For a variable series, such as stock returns, the geometric average will always be less than the arithmetic average. Accordingly, reference to geometric average rates of return provides yet another element of built-in downward bias to the CAPM applications of Dr. Woolridge and Mr. Baudino.

Q. WHAT ABOUT DR. WOOLRIDGE'S VIEW THAT YOUR FORWARD-LOOKING ESTIMATE OF THE MARKET RATE OF RETURN IS TOO HIGH?

A. The use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, in "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts" [*Journal of Applied Finance*, Vol. 11 No. 1, 2001], Robert S. Harris and Felicia C. Marston employed the DCF model and earnings growth projections from IBES – just as I did in my direct testimony. Dr. Woolridge's criticisms of my forward-looking CAPM approach seem to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is considerably higher than his historical benchmarks – the majority of which produce illogical results.

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[64] DeFusco, Richard A., Dennis W. McLeavey, Jerald E. Pinto, and David E. Runkle, *Quantitative Investment Analysis*, John Wiley & Sons, Inc. (2007) at 128.

But estimating investors' required rate of return by reference to current, forward-looking data, as I have done, is entirely consistent with the theory underlying the CAPM methodology. Dr. Woolridge does not suggest that the CAPM model is "wrong" to focus on forward-looking projections instead of backward, historical results, nor does he claim that looking to the future, as I have done, is a misapplication of the CAPM. Instead, he simply believes that the result of applying the CAPM in a manner that is consistent with the underlying assumptions produces a result that he views as being too high. But the application of alternative methods is not a process of deviating from the underlying assumptions of the model until the results are consistent with those produced using an alternative approach.

Q. HAVE OTHER REGULATORS RELIED ON A FORWARD-LOOKING CAPM APPROACH SIMILAR TO THE ONE PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. I based my CAPM approach on the methods used by the Staff at the Illinois Commerce Commission, whose witnesses have routinely relied on a forward-looking market rate of return estimate to apply the CAPM. For example, Illinois Staff witness Rochelle Langfeldt employed an expected market return of 15.31% based on an analysis analogous to the approach described in my direct testimony:

> 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"). … Firms not paying a dividend as of June 28, 2001, or for which neither Zacks nor IBES 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 Salomon Smith Barney, Performance and Weights of the S&P 500: Second Quarter

> 2001. The estimated weighted averaged expected rate of return for the remaining 365 firms composing 78.31% of the market capitalization of the S&P 500 equals 15.31%.[65]

Q. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (P. 43-44) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A. No. As Mr. Baudino recognized (p. 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (p. 28) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of these approximately 1,700 companies, over 650 do not pay common dividends. In other words, over one-third of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my

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[65] Direct Testimony of Rochelle Langfeldt, Illinois Commerce Commission Docket No. 01-0423 at 23-24 (2001).

decision to restrict my analysis to the established, dividend paying firms in the S&P 500.

Q. WHAT OTHER PROBLEMS ARE ASSOCIATED WITH MR. BAUDINO'S MARKET RATE OF RETURN BASED ON VALUE LINE DATA?

A. While expected growth in earnings is far more likely to be representative of investors' forward-looking expectations, Mr. Baudino nevertheless included book value growth rates in the DCF analysis he employed to estimate the expected market rate of return. This had the effect of understating the resulting CAPM cost of equity estimates. As shown on Schedule WEA-14, basing Mr. Baudino's DCF analysis solely on EPS growth rates resulted in an estimated CAPM cost of equity of 11.65%.

Q. DID DR. WOOLRIDGE AND MR. BAUDINO FAIL TO CONSIDER OTHER IMPORTANT FACTORS IN EVALUATING THE CAPM?

A. Yes. As noted in my direct testimony,[66] empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size. To account for this, *Morningstar* – a source relied on by Dr. Woolridge and Mr. Baudino – has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, my revisions to the CAPM analyses of Dr. Woolridge and Mr. Baudino incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization.

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[66] Avera Direct at 45-46.

Q. DO THE ARGUMENTS ADVANCED BY DR. WOOLRIDGE AND MR. BAUDINO UNDERMINE THE NEED FOR THIS ADJUSTMENT?

A. No. Mr. Baudino simply observes that the average beta associated with the lower size deciles examined by *Morningstar* is greater than the average his proxy group.[67] While I don't dispute the observation, this fact has no relevance whatsoever to the implications of *Morningstar's* findings regarding the impact of firm size. The fact that the average beta for smaller size deciles is greater than for 1.00 says nothing about the range of individual beta values underlying this average. While the size premiums reported by *Morningstar* were not estimated on an industry-by-industry basis, this provides no basis to ignore this relationship in estimating the cost of equity for utilities. Utilities are included in the companies used by *Morningstar* to quantify the size premium, and firm size has important practical implications with respect to the risks faced by investors in the utility industry.

Similarly, Dr. Woolridge's arguments concerning the implications of "survivor bias" are equally misplaced.[68] The expected returns of failed companies that are in decline or go out of business are irrelevant to the question of whether or not the CAPM fully accounts for investors' risk perceptions when applied to companies included in broad market indices, such as those reflected in *Morningstar's* analysis. The companies in the proxy groups used by Dr. Woolridge and Mr. Baudino are not start-ups – they are seasoned utilities that have been publicly traded for many years, just like the listed companies in the *Morningstar* data base. The arguments relative to survivor bias may have been relevant to the studies in the 1980's and 1990's, but they do not take away from the solid empirical

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[67] Baudino at 45.
[68] Woolridge Direct at 70.

basis of the size adjustment reported by *Morningstar* that are all based on surviving companies.

Further, it is not necessary to use the historical market risk premium from *Morningstar* to correctly apply the size adjustment. *Morningstar's* size adjustment is based on empirical research using their return data and betas, and there is no reason the size differential could not be properly applied to a CAPM using forward-looking risk premiums, as I have done.

Q. DOES THIS SIZE ADJUSTMENT APPLY TO UTILITIES?

A. Yes. For example, a study reported in *Public Utilities Fortnightly* noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks:

> The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premium (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies. [69]

The study went on to conclude that a publicly traded utility with a market capitalization of $1.0 billion would require a small company premium of approximately 130 basis points above the rate of return for larger firms.

I grant that there are any number of specific factors that distinguish a utility's risks from other firms in the non-regulated sector, just as there are important distinctions between the circumstances faced by airlines and drug manufacturers. But under the assumptions of modern capital market theory on which the CAPM rests, these considerations are reduced to a single risk measure – beta – which

[69] Annin, Michael, "Equity and the Small-Stock Effect", Public Utilities Fortnightly (Oct. 15, 1995), at 43.

captures stock price volatility relative to the market.[70] Within the CAPM paradigm, the degree of regulation, the nature of competition in the industry, the competence of management, and every other firm-specific consideration is boiled down to a single question; namely, how much does the stock's price fluctuate in relation to the market as a whole? Beta is the measure of that variability, and research demonstrates that beta does not fully account for the impact of firm size.

Q. WHAT COST OF EQUITY ESTIMATES WERE INDICATED BY CORRECTING THE CAPM APPLICATIONS OF DR. WOOLRIDGE AND MR. BAUDINO?

A. As shown on page 1 of Schedule WEA-15, application of the forward-looking CAPM approach resulted in an unadjusted ROE of 10.1% for the firms in Dr. Woolridge's proxy group, or 10.9% after adjusting for the impact of firm size. As shown on page 2 of Schedule WEA-15, this CAPM approach implied an unadjusted CAPM result of 9.9% for Mr. Baudino's proxy group, and an adjusted ROE of 10.7%.

Q. IS IT APPROPRIATE TO CONSIDER ANTICIPATED CAPITAL MARKET CHANGES IN APPLYING THE CAPM?

A. Yes. As discussed in earlier and in my direct testimony, there is widespread consensus that interest rates will increase materially as the economy strengthens. Accordingly, in addition to the use of current bond yields, I also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight and Blue Chip.

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[70] Dr. Woolridge also recognized that beta is the only relevant risk measure within the context of the CAPM. Woolridge Direct at 26.

Q. WHAT COST OF EQUITY WAS PRODUCED BY THE FORWARD-LOOKING CAPM FOR DR. WOOLRIDGE'S AND MR. BAUDINO'S PROXY GROUPS AFTER INCORPORATING FORECASTED BOND YIELDS?

A. As shown on page 1 of Schedule WEA-16, incorporating a forecasted Treasury bond yield for 2013-2017 implied an unadjusted cost of equity of approximately 10.6% for the utilities in Dr. Woolridge's proxy group, or 11.4% after accounting for firm size. As shown on page 2 of Schedule WEA-16, based on projected Treasury bond yields, the CAPM approach implied an unadjusted cost of equity of 10.4% for Mr. Baudino's proxy group, and a size-adjusted ROE of 11.2%.

VII. NO INCONSISTENCY IN RISK PREMIUM METHOD

Q. PLEASE RESPOND TO DR. WOOLRIDGE'S COMMENTS REGARDING YOUR RISK PREMIUM ANALYSIS (P. 68)?

A. Dr. Woolridge has two criticisms of my risk premium analysis based on previously allowed ROEs for utilities. The first is that the yield on public utility bonds to which I added the risk premium is somehow overstated. This is not accurate. The yield to maturity is a direct measure of investors' required return to compensate for the risks they associate with utility bonds, including credit risks. Even if his contention were accurate, it wouldn't matter because similar public utility bond yields were used to calculate the risk premium; hence, the risk premium would be understated by a comparable and offsetting amount.

Second, Dr. Woolridge claims that because utility common stocks have been selling in excess of book value for many years, this means regulators have routinely authorized ROEs greater than what investors require. This criticism suggests that Dr. Woolridge has a low regard for regulators' ability to make informed judgments as to the ROE that is necessary to compensate investors fairly for the use of their capital, enable the utility to attract capital on reasonable terms, and maintain the utility's financial integrity. Moreover, as discussed earlier, establishing returns to produce a market-to-book ratio of 1.00 implies a capital loss to investors in utility common stocks, which is inconsistent with regulatory standards and the expectations underlying utility stock prices.

Q. MR. BAUDINO ASSERTS THAT THERE ARE ERRORS AND INCONSISTENCIES IN YOUR APPLICATION OF THE RISK PREMIUM APPROACH. PLEASE RESPOND.

A. Mr. Baudino incorrectly argues that there is a "mismatch" in my application of the risk premium approach because I calculated equity risk premiums for the utility industry using the yield on average public utilities bonds, and then added the adjusted risk premium for the industry to the yield on triple-B rated utility bonds to estimate the cost of equity for the Companies.[71] This is not a "mismatch." Rather, it adjusts for differences between the average risks of the industry as a whole, and those specific to a "BBB" rated utility, such as the Companies.

Mr. Baudino's assertions appear to be based on a faulty premise that "LGE and KU are A rated utilities."[72] S&P has assigned a corporate credit rating of "BBB" to both LG&E and KU, while Moody's long-term rating is "Baa1" for the Companies. My reference to triple-B bond yields in applying the risk premium method is entirely consistent with the facts.

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[71] Baudino Direct at 47.
[72] *Id.* at 48.

VIII. FLOTATION COSTS SHOULD BE CONSIDERED

Q. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT.

A. First, while Dr. Woolridge suggests that flotation costs should be ignored because my adjustment was not predicated on a precise accounting for the Companies, this belies the point of the adjustment. LG&E and KU do not issue common stock, and will never incur flotation costs directly. The approach outlined in my direct testimony is supported by recognized regulatory textbooks and based on research reported in the academic literature, and the fact that the Companies do not incur issuance expenses directly provides no basis to ignore a flotation cost adjustment. Without a flotation adjustment, these legitimate costs of providing utility service will be excluded for ratemaking purposes and will undercut the Companies' ability to earn their authorized ROE.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent dilution of the existing shareholders."[73] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with <u>past</u> issues of common stock.

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[73] Woolridge Direct at 72.

Dr. Woolridge's argument (p. 73) that flotation costs are "not out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs. Just like the issuance costs associated with long-term bonds, which are recorded on the Companies' financial records and reflected in the embedded cost of debt, equity flotation costs are a necessary expense associated with raising long-term capital, and should be considered in establishing a fair ROE.

With respect to Dr. Woolridge's (p. 74) and Mr. Baudino's (p. 50) contention that flotation costs are somehow accounted for in current stock prices, *Regulatory Finance: Utilities' Cost of Capital* has this to say:

> A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.[74]

Similarly, the need to consider past flotation costs has been recognized in the financial literature, including sources that Dr. Woolridge relied on in his testimony. Specifically, Ibbotson Associates concluded that:

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[74] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 174 (1994).

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[75]

IX. PROXY GROUP REVENUE TEST IS UNSUPPORTED

Q. DO YOU AGREE WITH DR. WOOLRIDGE AND MR. BAUDINO THAT THE SOURCE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR THE COMPANIES?

A. No. Dr. Woolridge and Mr. Baudino selected proxy companies with at least 50% of their revenues from electric operations.[76] However, both witnesses failed to demonstrate how their arbitrary criteria translate into differences in the investment risks perceived by investors. Any comparison of objective indicators demonstrates that the investment risks for the firms in my proxy groups are relatively homogeneous and comparable to the Companies. Moreover, there are significant errors and inconsistencies associated with the approach adopted by Mr. Baudino and Dr. Woolridge that justify rejecting their proposed proxy group criteria.

Q. DID DR. WOOLRIDGE OR MR. BAUDINO DEMONSTRATE A NEXUS BETWEEN THEIR REVENUE CRITERIA AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A. No. Under the regulatory standards established by *Bluefield*[77] and *Hope*,[78] the salient criterion in establishing a meaningful proxy group to estimate investors' required return is *relative risk*, not the source of the revenue stream. Dr. Woolridge and Mr. Baudino presented no evidence to demonstrate a relationship between the

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[75] Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 25 (2011).
[76] Woolridge Direct at 14; Baudino Direct at 17.
[77] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).
[78] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

arbitrary criteria that they employed and the views of real-world investors in the capital markets.

Q. ARE THERE INCONSISTENCIES AND ERRORS ASSOCIATED WITH THE PROPOSED REVENUE TEST?

A. Yes. While Dr. Woolridge and Mr. Baudino screened all electric and combination electric and gas utilities followed by Value Line, their revenue test was based solely on <u>electric</u> revenues and ignored the revenue impact of gas utility operations. Considering the similarities in the regulatory and business environments for regulated electric and gas utility operations, the failure to incorporate gas utility revenues in implementing his test is inappropriate.

The arbitrary nature of the 50% revenue criterion proposed by Dr. Woolridge and Mr. Baudino is further illustrated by the lack of any independent, objective findings to support his imposed threshold. In fact, Dr. Woolridge cannot seem to decide for himself what the correct cutoff should be. For example, in his 2010 testimony before the KPSC in Case No. 2009-00548, Dr. Woolridge argued to exclude companies with less than 80% of revenues attributable to electric operations. Dr. Woolridge's revenue statistic has no demonstrable link to risk and his internal inconsistency merely highlights the entirely subjective and baseless nature of his "test."

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE DATA USED BY DR. WOOLRIDGE AND MR. BAUDINO TO SCREEN THEIR PROXY GROUPS?

A. Yes. These witnesses applied their credit rating screen based on bond ratings reported by AUS Utility Reports. However, these reflect senior debt ratings, not the corporate, or issuer, credit rating for the utility as a whole. Because equity investors are focused on the overall investment risks of the firm, and not those attributable to a specific debt issue, the appropriate measure is the corporate credit rating. For example, while Dr. Woolridge included UNS Energy Corporation ("UNS") in his electric proxy group based on a reported S&P bond rating of "BBB+", the corporate credit rating corresponding to UNS is "BB+". This rating falls below the ladder of investment grade ratings and places UniSource in the same category as speculative, or "junk" investments.

X. THE COMPANIES' CAPITAL STRUCTURE SHOULD BE APPROVED

Q. WHAT WAS DR. WOOLRIDGE'S RATIONALE FOR REJECTING THE CAPITALIZATION REQUESTED BY THE COMPANIES?

A. Dr. Woolridge's assertion that the Companies' capital structure should be rejected was based on his conclusion that the equity ratio implied by the Company's capitalization is higher than the average for his electric proxy group, and for the Companies' parent, PPL.[79]

Q. DOES THIS PROVIDE A LOGICAL BASIS TO REJECT THE COMPANIES' ACTUAL CAPITALIZATION?

A. No. As noted in my direct testimony, while industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. While the degree of debt leverage is one consideration impacting investors' risk perceptions, it is not the whole picture. Overall investment risk, such as that reflected in bond ratings and other risk measures referenced by investors, also considers the specific business risks underlying a utility's operations. The Companies' credit ratings, which Dr. Woolridge relied on to establish his proxy

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[79] Woolridge Direct at 18.

group, already reflect the combined impact of these business and financial risk exposures. Moreover, the Companies' equity ratio falls within the range of capitalizations maintained by the firms in the proxy groups that Dr. Woolridge and I relied on to estimate the cost of equity.

As discussed in my direct testimony, investors and bond rating agencies are increasingly focused on the importance of regulatory support. Making unwarranted adjustments to the capital structure or adopting an unreasonably low ROE would undoubtedly have a negative impact on investors' risk perceptions, and doing both would be outright alarming. Dr. Woolridge's proposed hypothetical capital structure amounts to nothing more than an ill-disguised attempt to engineer a lower overall rate of return by substituting debt for equity.

Q. WHAT ABOUT DR. WOOLRIDGE'S COMMENT (P. 17) THAT PPL CARRIES AN "AGGRESSIVE" FINANCIAL PROFILE?

A. While I don't dispute the factual accuracy of Dr. Woolridge's statement, it provides no support for his recommendation to ignore the Companies' capitalization. In fact, S&P assigns an "aggressive" financial risk profile to many of the electric utilities it follows, including over one-half of the companies in Dr. Woolridge's own proxy group.[80]

[80] Standard & Poor's Corporation, "U.S. Regulated Utilities: Strongest to Weakest," *RatingsDirect* (Apr. 20, 2012).

Q. IS THERE ANY SOUND THEORETICAL SUPPORT FOR MR. KOLLEN'S PROPOSAL (PP. 39-40) TO CONSIDER DOUBLE LEVERAGE IN ESTABLISHING THE COMPANIES' CAPITAL STRUCTURE OR ROE?

A. No. The double leverage approach is based on the misguided notion that the capital structure for an operating subsidiary is dependent on how the upstream parent is financed. The cost of equity to the operating subsidiary is then the overall weighted average cost of capital to the parent, since the equity capital is said to have been raised by the parent through a mixture of debt and equity. But taking the premise underlying double leverage to its logical conclusion, the source of the equity capital invested in the parent company should also be traced to its ultimate source; namely, the individual and institutional shareholders. While this would not make sense, it illustrates the serious conceptual and practical flaws underlying the use of double leverage.

In fact, the double leverage approach violates the core notion that an investment's required rate of return depends on its particular risks. Cost of capital has to do with the use of the funds and not with the source of the funds, and the same is true for the appropriate capital structure. The fair rate of return and capital structure corresponding to any investment are dictated by the risk of that investment, and not by the manner in which that investment is financed. Whether the equity capital invested in utilities is provided from a highly leveraged hedge fund, or from the life savings of mom and pop investors, the appropriate return and capital structure must reflect the utility's risks, regardless of the identity of the investor. Many prominent experts have taken positions rejecting the double leverage approach in establishing the capital structure for a regulated utility. As noted in *New Regulatory Finance*:

> The double leverage argument violates the core notion that an investment's required return depends on its particular risks. The Double Leverage approach has no place in regulatory practice and should be discarded.[81]

Similarly, the KPSC should reject any consideration of double leverage in this proceeding.

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

A. Yes.

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[81] Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 528 (2006).

VERIFICATION

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

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

William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 30th day of October 2012.

_______________(SEAL)
Notary Public

My Commission Expires:

1/10/15

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

EXPECTED EARNINGS APPROACH **Schedule WEA-11**

WOOLRIDGE PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	10.5%	1.03824	10.9%
2	Alliant Energy	11.0%	1.02224	11.2%
3	Ameren Corp.	7.5%	1.01001	7.6%
4	American Elec Pwr	9.5%	1.02219	9.7%
5	Avista Corp.	9.0%	1.02270	9.2%
6	Black Hills Corp.	8.0%	1.01447	8.1%
7	Cleco Corp.	11.5%	1.02600	11.8%
8	CMS Energy Corp.	12.5%	1.03155	12.9%
9	Consolidated Edison	9.0%	1.01865	9.2%
10	Dominion Resources	14.5%	1.03301	15.0%
11	DTE Energy Co.	9.5%	1.02566	9.7%
12	Duke Energy	8.0%	1.06669	8.5%
13	Edison International	9.0%	1.02285	9.2%
14	Exelon Corp.	12.5%	1.04971	13.1%
15	FirstEnergy Corp.	10.0%	1.01533	10.2%
16	Great Plains Energy	7.5%	1.02182	7.7%
17	Hawaiian Elec.	10.0%	1.04778	10.5%
18	IDACORP, Inc.	8.5%	1.02807	8.7%
19	MGE Energy	11.0%	1.02716	11.3%
20	NextEra Energy, Inc.	12.5%	1.03443	12.9%
21	Northeast Utilities	9.5%	1.09926	10.4%
22	OGE Energy Corp.	11.0%	1.03391	11.4%
23	Pepco Holdings	8.0%	1.02362	8.2%
24	PG&E Corp.	10.5%	1.02667	10.8%
25	Pinnacle West Capital	9.0%	1.02394	9.2%
26	PNM Resources	9.0%	1.02022	9.2%
27	Portland General Elec.	8.5%	1.01999	8.7%
28	SCANA Corp.	9.5%	1.04571	9.9%
29	Southern Company	12.5%	1.02902	12.9%
30	TECO Energy	13.0%	1.02466	13.3%
31	UIL Holdings	9.5%	1.01632	9.7%
32	UNS Energy	14.0%	1.02192	14.3%
33	Westar Energy	8.5%	1.03177	8.8%
34	Wisconsin Energy	13.5%	1.01739	13.7%
35	Xcel Energy, Inc.	10.0%	1.02787	10.3%
	Average			**10.5%**

(a) The Value Line Investment Survey (Aug. 3, Aug. 24, & Sep. 21, 2012).

(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).

(c) (a) x (b).

BAUDINO PROXY GROUP

	Company	(a) Expected Return on Common Equity	(b) Adjustment Factor	(c) Adjusted Return on Common Equity
1	ALLETE	10.5%	1.03824	10.9%
2	Alliant Energy	11.0%	1.02224	11.2%
3	American Elec Pwr	9.0%	1.02270	9.2%
4	Cleco Corp.	8.0%	1.01447	8.1%
5	Edison International	9.0%	1.01865	9.2%
6	Entergy Corp.	14.5%	1.03301	15.0%
7	IDACORP, Inc.	9.5%	1.02566	9.7%
8	MGE Energy	8.5%	1.02807	8.7%
9	NorthWestern Corp.	8.0%	1.02362	8.2%
10	PG&E Corp.	10.5%	1.02667	10.8%
11	Pinnacle West Capital	8.5%	1.01999	8.7%
12	Portland General Elec.	12.5%	1.02902	12.9%
13	Southern Company	13.0%	1.02466	13.3%
14	Westar Energy	8.5%	1.03177	8.8%
15	Wisconsin Energy	13.5%	1.01739	13.7%
16	Xcel Energy, Inc.	10.0%	1.02787	10.3%
	Average			**10.5%**

(a) The Value Line Investment Survey (Aug. 3, Aug. 24, & Sep. 21, 2012).
(b) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(c) (a) x (b).

ALLOWED ROE **Schedule WEA-12**

Page 1 of 2

WOOLRIDGE PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE	10.38%
2	Alliant Energy	10.34%
3	Ameren Corp.	9.54%
4	American Elec Pwr	10.65%
5	Avista Corp.	10.33%
6	Black Hills Corp.	10.72%
7	Cleco Corp.	10.70%
8	CMS Energy Corp.	10.30%
9	Consolidated Edison	9.93%
10	Dominion Resources	10.52%
11	DTE Energy Co.	10.75%
12	Duke Energy	10.57%
13	Edison International	10.65%
14	Exelon Corp.	10.50%
15	FirstEnergy Corp.	10.52%
16	Great Plains Energy	10.25%
17	Hawaiian Elec.	10.00%
18	IDACORP, Inc.	10.18%
19	MGE Energy	10.30%
20	NextEra Energy, Inc.	10.50%
21	Northeast Utilities	9.38%
22	OGE Energy Corp.	9.98%
23	Pepco Holdings	9.95%
24	PG&E Corp.	11.35%
25	Pinnacle West Capital	11.00%
26	PNM Resources	10.22%
27	Portland General Elec.	10.00%
28	SCANA Corp.	10.72%
29	Southern Company	11.46%
30	TECO Energy	11.00%
31	UIL Holdings	8.75%
32	UNS Energy	9.92%
33	Westar Energy	10.20%
34	Wisconsin Energy	10.38%
35	Xcel Energy, Inc.	10.70%
	Average	**10.36%**

Source: *AUS Monthly Report* (Sep. 2012).

BAUDINO PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE	10.38%
2	Alliant Energy	10.34%
3	American Elec Pwr	10.65%
4	Cleco Corp.	10.70%
5	Edison International	10.65%
6	Entergy Corp.	10.66%
7	IDACORP, Inc.	10.18%
8	MGE Energy	10.30%
9	NorthWestern Corp.	10.90%
10	PG&E Corp.	11.35%
11	Pinnacle West Capital	11.00%
12	Portland General Elec.	10.00%
13	Southern Company	11.46%
14	Westar Energy	10.20%
15	Wisconsin Energy	10.38%
16	Xcel Energy, Inc.	10.70%
	Average	**10.62%**

Source: *AUS Monthly Report* (Sep. 2012).

WOOLRIDGE HISTORICAL GROWTH

		(a)	(b)	(b)	(b)	(b)	(c)	(c)	(c)	(c)
			Historical Growth Rates				**Cost of Equity Estimates**			
			Past 10 Years		**Past 5 Years**		**Past 10 Years**		**Past 5 Years**	
	Company	**Dividend Yield**	**EPS**	**BVPS**	**EPS**	**BVPS**	**EPS**	**BVPS**	**EPS**	**BVPS**
1	ALLETE	4.5%	--	--	0.5%	5.5%	--	--	5.0%	10.1%
2	Alliant Energy	4.0%	2.0%	0.5%	5.0%	3.5%	6.1%	4.5%	9.1%	7.6%
3	Ameren Corp.	4.9%	-1.5%	3.5%	-1.5%	1.0%	3.4%	8.5%	3.4%	5.9%
4	American Elec Pwr	4.8%	2.0%	1.0%	1.5%	5.0%	6.8%	5.8%	6.3%	9.9%
5	Avista Corp.	4.5%	5.0%	3.5%	9.5%	4.0%	9.6%	8.0%	14.2%	8.6%
6	Black Hills Corp.	4.6%	-4.0%	7.5%	-4.0%	4.0%	0.5%	12.3%	0.5%	8.7%
7	Cleco Corp.	3.1%	5.0%	8.0%	10.0%	10.0%	8.2%	11.2%	13.3%	13.3%
8	CMS Energy Corp.	4.2%	-5.5%	-4.5%	8.5%	2.0%	-1.4%	-0.4%	12.9%	6.2%
9	Consolidated Edison	4.0%	1.0%	4.0%	4.5%	4.5%	5.0%	8.1%	8.6%	8.6%
10	Dominion Resources	4.0%	7.0%	3.5%	6.5%	3.5%	11.2%	7.6%	10.6%	7.6%
11	DTE Energy Co.	4.1%	2.0%	3.5%	5.0%	4.0%	6.2%	7.7%	9.2%	8.2%
12	Duke Energy	4.6%	--	--	7.0%	-4.0%	--	--	11.8%	0.5%
13	Edison International	2.9%	--	11.0%	6.0%	8.5%	--	14.1%	9.0%	11.6%
14	Exelon Corp.	5.5%	8.0%	5.5%	4.5%	7.5%	13.8%	11.2%	10.2%	13.2%
15	FirstEnergy Corp.	4.7%	0.5%	3.0%	-2.0%	1.5%	5.2%	7.8%	2.6%	6.2%
16	Great Plains Energy	4.1%	-2.5%	4.5%	-9.5%	5.5%	1.5%	8.7%	-5.6%	9.7%
17	Hawaiian Elec.	4.6%	-2.0%	2.0%	-3.0%	1.5%	2.6%	6.7%	1.5%	6.2%
18	IDACORP, Inc.	3.2%	-0.5%	3.5%	8.5%	5.0%	2.7%	6.8%	11.9%	8.3%
19	MGE Energy	3.3%	4.5%	6.5%	6.5%	6.0%	7.9%	9.9%	9.9%	9.4%
20	NextEra Energy, Inc.	3.7%	7.5%	8.0%	11.0%	9.0%	11.3%	11.8%	14.9%	12.8%
21	Northeast Utilities	3.4%	--	3.0%	18.0%	3.5%	--	6.5%	21.7%	7.0%
22	OGE Energy Corp.	3.0%	6.0%	6.0%	8.5%	8.5%	9.1%	9.1%	11.6%	11.6%
23	Pepco Holdings	5.7%	-4.5%	0.5%	-4.5%	0.5%	1.0%	6.2%	1.0%	6.2%
24	PG&E Corp.	4.1%	--	8.0%	3.5%	6.5%	--	12.3%	7.7%	10.8%
25	Pinnacle West Capital	4.2%	-2.0%	2.0%	1.0%	0.0%	2.2%	6.3%	5.2%	4.2%
26	PNM Resources	3.0%	-7.5%	1.5%	-12.0%	-1.0%	-4.6%	4.5%	-9.2%	2.0%
27	Portland General Elec.	4.2%	--	--	8.5%	2.0%	--	--	12.8%	6.2%
28	SCANA Corp.	4.3%	4.5%	3.5%	2.0%	4.5%	8.8%	7.8%	6.3%	8.8%
29	Southern Company	4.2%	3.0%	3.5%	3.0%	6.0%	7.3%	7.8%	7.3%	10.4%
30	TECO Energy	5.0%	-5.0%	-2.0%	3.5%	6.5%	-0.2%	2.9%	8.5%	11.6%
31	UIL Holdings	5.0%	-2.0%	0.0%	4.5%	-0.5%	2.9%	5.0%	9.6%	4.5%
32	UNS Energy	4.5%	7.0%	7.0%	13.0%	5.0%	11.7%	11.7%	17.8%	9.6%
33	Westar Energy	4.6%	0.0%	-3.0%	1.0%	6.0%	4.6%	1.5%	5.6%	10.7%
34	Wisconsin Energy	3.2%	9.0%	6.5%	10.0%	7.0%	12.4%	9.8%	13.4%	10.3%
35	Xcel Energy, Inc.	3.8%	-1.0%	--	4.5%	4.5%	2.8%	--	8.4%	8.4%
	Average (d)						**10.1%**	**9.8%**	**10.7%**	**9.9%**
	Average - All Growth Rates							**10.1%**		

(a) Exhibit JRW-10, p. 2.
(b) Exhibit JRW-10, p. 4.
(c) Sum of dividend yield (adjusted for one-half year's growth) and respective growth rate.
(d) Excludes highlighted figures.

BAUDINO CAPM ANALYSIS

EPS GROWTH

20-Year Treasury Bond, Value Line Beta

Line No.			Value Line
1	Market Required Return Estimate		
2		Expected Dividend Yield	0.77%
3		Expected Growth	14.84%
4		Required Return	15.61%
5	Risk-free Rate of Return, 20-Year Treasury Bond		
6		Average of Last Six Months	2.54%
8	Risk Premium		
9		@ 6 Month Average RFR (Line 4 minus Line 6)	13.08%
10	Comparison Group Beta		0.70
11	Comparison Group Beta * Risk Premium		
12		@ 6 Month Average RFR (Line 10 * Line 9)	9.11%
13	CAPM Return on Equity		
14		@ 6 Month Average RFR (Line 12 plus Line 6)	11.65%

LOUISVILLE GAS AND ELECTRIC / KENTUCKY UTILITIES

Line No.			Value Line
1	Market Required Return Estimate		
2		Expected Dividend Yield	0.77%
3		Expected Growth	14.84%
4		Required Return	15.61%
5	Risk-free Rate of Return, 5-Year Treasury Bond		
6		Average of Last Six Months	0.79%
8	Risk Premium		
9		@ 6 Month Average RFR (Line 4 minus Line 6)	14.83%
10	Comparison Group Beta		0.70
11	Comparison Group Beta * Risk Premium		
12		@ 6 Month Average RFR (Line 9 * Line 10)	10.33%
13	CAPM Return on Equity		
14		@ 6 Month Average RFR (Line 12 plus Line 6)	11.12%

Source: Exhibit RAB-5.

REVISED CAPM - CURRENT YIELD

WOOLRIDGE PROXY GROUP

		(a)	(b)		(c)		(d)			(e)	(f)	
										Market		
		Dividend		Market	Risk Free	Market		Company	Derived	Cap	Size	
	Company	**Yield**	**Growth**	**Return**	**Return**	**Risk Prem.**	**Beta**	**Risk Prem.**	**CAPM**	**($ mil)**	**Adjustment**	**Ke**
1	ALLETE	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$1,543	1.75%	11.7%
2	Alliant Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$5,077	0.94%	11.3%
3	Ameren Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.80	8.0%	10.9%	$8,062	0.78%	11.7%
4	American Elec Pwr	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$20,009	-0.38%	9.5%
5	Avista Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$1,591	1.75%	11.7%
6	Black Hills Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.85	8.5%	11.4%	$1,383	1.75%	13.2%
7	Cleco Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.65	6.5%	9.4%	$2,613	1.17%	10.6%
8	CMS Energy Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$6,129	0.94%	11.3%
9	Consolidated Edison	2.6%	10.3%	12.9%	2.9%	10.0%	0.60	6.0%	8.9%	$18,413	-0.38%	8.5%
10	Dominion Resources	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$30,689	-0.38%	9.5%
11	DTE Energy Co.	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$10,076	0.78%	11.2%
12	Duke Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.60	6.0%	8.9%	$29,718	-0.38%	8.5%
13	Edison International	2.6%	10.3%	12.9%	2.9%	10.0%	0.80	8.0%	10.9%	$15,075	0.78%	11.7%
14	Exelon Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.80	8.0%	10.9%	$32,008	-0.38%	10.5%
15	FirstEnergy Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.80	8.0%	10.9%	$20,526	-0.38%	10.5%
16	Great Plains Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$2,990	1.17%	11.6%
17	Hawaiian Elec.	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$2,769	1.17%	11.1%
18	IDACORP, Inc.	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$2,150	1.74%	11.6%
19	MGE Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.60	6.0%	8.9%	$1,119	1.75%	10.7%
20	NextEra Energy, Inc.	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$28,536	-0.38%	10.0%
21	Northeast Utilities	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$6,938	0.78%	10.7%
22	OGE Energy Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.80	8.0%	10.9%	$5,060	0.94%	11.8%
23	Pepco Holdings	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$4,403	0.94%	11.3%
24	PG&E Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.55	5.5%	8.4%	$18,775	-0.38%	8.0%
25	Pinnacle West Capital	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$5,716	0.94%	10.8%
26	PNM Resources	2.6%	10.3%	12.9%	2.9%	10.0%	0.95	9.5%	12.4%	$1,574	1.75%	14.2%
27	Portland General Elec.	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$2,034	1.74%	12.1%
28	SCANA Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$6,296	0.94%	10.8%
29	Southern Company	2.6%	10.3%	12.9%	2.9%	10.0%	0.55	5.5%	8.4%	$40,993	-0.38%	8.0%
30	TECO Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.85	8.5%	11.4%	$3,902	0.94%	12.3%
31	UIL Holdings	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$1,864	1.74%	11.6%
32	UNS Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$1,549	1.75%	12.2%
33	Westar Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$3,846	0.94%	11.3%
34	Wisconsin Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.65	6.5%	9.4%	$9,327	0.78%	10.2%
35	Xcel Energy, Inc.	2.6%	10.3%	12.9%	2.9%	10.0%	0.65	6.5%	9.4%	$14,004	0.78%	10.2%
					Average				**10.1%**			**10.9%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Jul. 26, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved Jul. 26, 2012).
(c) Average yield on 30-year Treasury bonds for Sep. 2012 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.
(d) Exhibit JRW-11, p. 3.
(e) www.valueline.com (retrieved Oct. 15, 2012).
(f) Morningstar, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).

REVISED CAPM - CURRENT YIELD

BAUDINO PROXY GROUP

	Company	(a) Dividend Yield	(b) Growth	Market Return	(c) Risk Free Return	Market Risk Prem.	(d) Beta	Company Risk Prem.	Derived CAPM	(e) Market Cap ($ mil)	(f) Size Adjustment	Ke
1	ALLETE	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$1,543	1.75%	11.7%
2	Alliant Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$5,077	0.94%	10.8%
3	American Elec Pwr	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$1,591	1.75%	11.7%
4	Cleco Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.85	8.5%	11.4%	$1,383	1.75%	13.2%
5	Edison International	2.6%	10.3%	12.9%	2.9%	10.0%	0.60	6.0%	8.9%	$18,413	-0.38%	8.5%
6	Entergy Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.65	6.5%	9.4%	$30,689	-0.38%	9.0%
7	IDACORP, Inc.	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$10,076	0.78%	11.2%
8	MGE Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.70	7.0%	9.9%	$2,150	1.74%	11.6%
9	NorthWestern Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$4,403	0.94%	11.3%
10	PG&E Corp.	2.6%	10.3%	12.9%	2.9%	10.0%	0.55	5.5%	8.4%	$18,775	-0.38%	8.0%
11	Pinnacle West Capital	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$2,034	1.74%	12.1%
12	Portland General Elec.	2.6%	10.3%	12.9%	2.9%	10.0%	0.55	5.5%	8.4%	$40,993	-0.38%	8.0%
13	Southern Company	2.6%	10.3%	12.9%	2.9%	10.0%	0.85	8.5%	11.4%	$3,902	0.94%	12.3%
14	Westar Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.75	7.5%	10.4%	$3,846	0.94%	11.3%
15	Wisconsin Energy	2.6%	10.3%	12.9%	2.9%	10.0%	0.65	6.5%	9.4%	$9,327	0.78%	10.2%
16	Xcel Energy, Inc.	2.6%	10.3%	12.9%	2.9%	10.0%	0.65	6.5%	9.4%	$14,004	0.78%	10.2%
					Average				**9.9%**			**10.7%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Apr. 17, 2012).
(b) Weighted average of IBES earnings growth rates for the dividend paying firms in the S&P 500 (retrieved May 8, 2012).
(c) Average yield on 30-year Treasury bonds for Sep. 2012 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data/htm.
(d) Exhibit RAB-5, p. 2.
(e) www.valueline.com (retrieved Oct. 15, 2012).
(f) Morningstar, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).

REVISED CAPM - PROJECTED YIELD

WOOLRIDGE PROXY GROUP

		(a)	(b)		(c)		(d)			(e)	(f)	
	Company	Dividend Yield	Growth	Market Return	Risk Free Return	Market Risk Prem.	Beta	Company Risk Prem.	Derived CAPM	Market Cap ($ mil)	Size Adjustment	Ke
1	ALLETE	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$1,543	1.75%	12.2%
2	Alliant Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$5,077	0.94%	11.8%
3	Ameren Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	6.6%	11.2%	$8,062	0.78%	12.0%
4	American Elec Pwr	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$20,009	-0.38%	10.0%
5	Avista Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$1,591	1.75%	12.2%
6	Black Hills Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.85	7.1%	11.7%	$1,383	1.75%	13.4%
7	Cleco Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	5.4%	10.0%	$2,613	1.17%	11.2%
8	CMS Energy Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$6,129	0.94%	11.8%
9	Consolidated Edison	2.6%	10.3%	12.9%	4.6%	8.3%	0.60	5.0%	9.6%	$18,413	-0.38%	9.2%
10	Dominion Resources	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$30,689	-0.38%	10.0%
11	DTE Energy Co.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$10,076	0.78%	11.6%
12	Duke Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.60	5.0%	9.6%	$29,718	-0.38%	9.2%
13	Edison International	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	6.6%	11.2%	$15,075	0.78%	12.0%
14	Exelon Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	6.6%	11.2%	$32,008	-0.38%	10.9%
15	FirstEnergy Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	6.6%	11.2%	$20,526	-0.38%	10.9%
16	Great Plains Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$2,990	1.17%	12.0%
17	Hawaiian Elec.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$2,769	1.17%	11.6%
18	IDACORP, Inc.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$2,150	1.74%	12.2%
19	MGE Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.60	5.0%	9.6%	$1,119	1.75%	11.3%
20	NextEra Energy, Inc.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$28,536	-0.38%	10.4%
21	Northeast Utilities	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$6,938	0.78%	11.2%
22	OGE Energy Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.80	6.6%	11.2%	$5,060	0.94%	12.2%
23	Pepco Holdings	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$4,403	0.94%	11.8%
24	PG&E Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.55	4.6%	9.2%	$18,775	-0.38%	8.8%
25	Pinnacle West Capital	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$5,716	0.94%	11.4%
26	PNM Resources	2.6%	10.3%	12.9%	4.6%	8.3%	0.95	7.9%	12.5%	$1,574	1.75%	14.2%
27	Portland General Elec.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$2,034	1.74%	12.6%
28	SCANA Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$6,296	0.94%	11.4%
29	Southern Company	2.6%	10.3%	12.9%	4.6%	8.3%	0.55	4.6%	9.2%	$40,993	-0.38%	8.8%
30	TECO Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.85	7.1%	11.7%	$3,902	0.94%	12.6%
31	UIL Holdings	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$1,864	1.74%	12.2%
32	UNS Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$1,549	1.75%	12.6%
33	Westar Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$3,846	0.94%	11.8%
34	Wisconsin Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	5.4%	10.0%	$9,327	0.78%	10.8%
35	Xcel Energy, Inc.	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	5.4%	10.0%	$14,004	0.78%	10.8%
					Average				**10.6%**			**11.4%**

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(c) Average projected 30-year Treasury bond yield for 2013-2017 based on data from the Value Line Investment Survey, *Forecast for the U.S. Economy* (Aug. 24, 2012); HIS GlobalInsight, *U.S. Economic Outlook* at 19 (May 2012); & Blue Chip Financial Forecasts, Vol. 31, No. 6 (Jun. 1, 2012).
(d) Exhibit JRW-11, p. 3.
(e) www.valueline.com (retrieved Oct. 15, 2012).
(f) Morningstar, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).

REVISED CAPM - PROJECTED YIELD

BAUDINO PROXY GROUP

	Company	(a) Dividend Yield	(b) Growth	Market Return	(c) Risk Free Return	Market Risk Prem.	(d) Beta	Company Risk Prem.	Derived CAPM	(e) Market Cap ($ mil)	(f) Size Adjustment	Ke
1	ALLETE	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$1,543	1.75%	12.2%
2	Alliant Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$5,077	0.94%	11.4%
3	American Elec Pwr	2.6%	10.3%	12.9%	4.6%	8.3%	0.70	5.8%	10.4%	$1,591	1.75%	12.2%
4	Cleco Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.85	7.1%	11.7%	$1,383	1.75%	13.4%
5	Edison International	2.6%	10.3%	12.9%	4.6%	8.3%	0.60	5.0%	9.6%	$18,413	-0.38%	9.2%
6	Entergy Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	5.4%	10.0%	$30,689	-0.38%	9.6%
7	IDACORP, Inc.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$10,076	0.78%	11.6%
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9	NorthWestern Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$4,403	0.94%	11.8%
10	PG&E Corp.	2.6%	10.3%	12.9%	4.6%	8.3%	0.55	4.6%	9.2%	$18,775	-0.38%	8.8%
11	Pinnacle West Capital	2.6%	10.3%	12.9%	4.6%	8.3%	0.75	6.2%	10.8%	$2,034	1.74%	12.6%
12	Portland General Elec.	2.6%	10.3%	12.9%	4.6%	8.3%	0.55	4.6%	9.2%	$40,993	-0.38%	8.8%
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15	Wisconsin Energy	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	5.4%	10.0%	$9,327	0.78%	10.8%
16	Xcel Energy, Inc.	2.6%	10.3%	12.9%	4.6%	8.3%	0.65	5.4%	10.0%	$14,004	0.78%	10.8%
					Average				**10.4%**			**11.2%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (retrieved Apr. 17, 2012).
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(d) Exhibit RAB-5, p. 2.
(e) www.valueline.com (retrieved Oct. 15, 2012).
(f) Morningstar, "2012 Ibbotson SBBI Valuation Yearbook," at Appendix C, Table C-1 (2012).

APPENDIX A

WORK PAPERS TO REBUTTAL TESTIMONY OF WILLIAM E. AVERA

DR. WILLIAM E. AVERA REBUTTAL WORK PAPERS

INDEX

NO.	TITLE
WP-1	The Value Line Investment Survey, *Selection and Opinion* (Oct. 12, 2012)
WP-2	The Value Line Investment Survey, *Selection & Opinion* (Sep. 21, 2012)
WP-3	Parcell, David C., *The Cost of Capital—a Practitioner's Guide* at 7-3 (1997)
WP-4	"Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996)
WP-5	The Value Line Investment Survey at 901 (Sep. 21, 2012)
WP-6	Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 298 (2006)
WP-7	Block, Stanley B., "A Study of Financial Analysts: Practice and Theory", *Financial Analysts Journal* (July/August 1999)
WP-8	Gordon, Myron J., "The Cost of Capital to a Public Utility," *MSU Public Utilities Studies* at 89 (1974)
WP-9	Boselovic, Len, "Study Finds Analysts' Forecasts Have Been Too Sunny," *Pittsburgh Post-Gazette* (Mar. 30, 2008)
WP-10	Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001)
WP-11	Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28
WP-12	Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32
WP-13	Standard & Poor's Corporation, "U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix," *RatingsDirect* (Nov. 30, 2007)
WP-14	Morningstar, *Ibbotson SBBI, 2011 Valuation Yearbook* at 21 (2011)
WP-15	Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports*, at 275 (1994)
WP-16	Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 56 (2011)
WP-17	DeFusco, Richard A., Dennis W. McLeavey, Jerald E. Pinto, and David E. Runkle, *Quantitative Investment Analysis*, John Wiley & Sons, Inc. (2007)
WP-18	Annin, Michael, "Equity and the Small-Stock Effect", Public Utilities Fortnightly (Oct. 15, 1995)
WP-19	Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.*at 174 (1994)
WP-20	Morningstar, *Ibbotson SBBI 2011 Valuation Yearbook* at 25 (2011)
WP-21	Standard & Poor's Corporation, "U.S. Regulated Utilities: Strongest to Weakest," *RatingsDirect* (Apr. 20, 2012)
WP-22	Roger A. Morin, "New Regulatory Finance," *Public Utilities Reports, Inc.* at 528 (2006)
WP-23	*AUS Monthly Utility Reports* (Sep. 2012)

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THE VALUE LINE Investment Survey®

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File in page order in the *Selection & Opinion* binder.

PART 2 — *Selection & Opinion* — OCTOBER 12, 2012

Dear Subscribers,

As part of our ongoing efforts to keep *The Value Line Investment Survey* the most valuable investment resource for our subscribers, all updated Ranks are now being released on the Value Line Web Site at 8:00 A.M. Eastern Time on Mondays. You can access all the Ranks each week at www.valueline.com by entering your user name and password. We look forward to continuing to provide you with accurate and timely investment research. Thank you.

The Value Line View

In This Issue

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LXVIII, Number 8.

Published weekly by VALUE LINE PUBLISHING LLC
220 East 42nd Street, New York, NY 10017-5891.

ECONOMIC AND STOCK MARKET COMMENTARY

The downwardly revised growth rate for GDP in the second quarter may well be a harbinger of things to come. Recently, growth in the April-to-June period was revised from 1.7% to 1.3%, a notable adjustment, reflecting, in large part, a lesser gain in consumer spending than estimated previously. The latest growth revision, coupled with the generally mixed tone on the economic front since then, suggests that prospective second-half GDP growth—which we had believed would be in the area of 2%—may now average no more than 1.5%.

The economic releases continue to be uneven. Personal income and personal consumption expenditures, for example, inched forward slightly in August (if we adjust spending for inflation), while durable goods orders tumbled 13% in August. On the other hand, non-manufacturing increased notably last month, while the report on manufacturing showed just slight improvement following three straight monthly declines. One sector that is doing consistently better is housing. However, the gains in this category are from exceptionally low levels, as activity tries to rebound from a long and devastating slump. In all . . .

We think it will be the second half of 2013 before growth picks up appreciably. For now, we believe the crosscurrents are too numerous to envision a formidable advance. In fact, even our modest assumptions assume the "fiscal cliff" of mandated spending cuts and tax hikes—which are set to kick in at the end of 2012 unless the Congress acts—is avoided.

The situation is notably worse on the global front, where China is growing more slowly and Europe's outlook is deteriorating, particularly across its southern tier. The reality of Europe's struggles is prompting some long-term reassessment in the region, which is constructive, if belated.

Thus far, investors are still in a forgiving mood, as they await the full force of third-quarter earnings season and the unfolding of what will probably be a pedestrian finish to an inconclusive 2012 from an earnings perspective. These concerns aside, the bears have yet to throw the bulls off stride following the last bout of profit taking in late spring.

Conclusion: Such bullish resolve notwithstanding, valuations are still somewhat extended, especially in the absence of stronger GDP growth. Please refer to the inside back cover of *Selection & Opinion* for our statistically-based Asset Allocation Model's current reading.

CLOSING STOCK MARKET AVERAGES AS OF PRESS TIME

	9/26/2012	10/3/2012	%Change 1 week	%Change 12 months
Dow Jones Industrial Average	13413.51	13494.61	+0.6%	+26.6%
Standard & Poor's 500	1433.32	1450.99	+1.2%	+32.0%
N.Y. Stock Exchange Composite	8221.32	8297.50	+0.9%	+26.2%
NASDAQ Composite	3093.70	3135.23	+1.3%	+34.2%
NASDAQ 100	2781.63	2818.84	+1.3%	+35.2%
American Stock Exchange Index	2444.50	2463.99	+0.8%	+23.2%
Value Line (Geometric)	357.73	360.65	+0.8%	+27.2%
Value Line (Arithmetic)	3041.52	3068.65	+0.9%	+34.9%
London (FT-SE 100)	5768.09	5825.81	+1.0%	+14.8%
Tokyo (Nikkei)	8906.70	8746.87	-1.8%	+2.4%
Russell 2000	833.93	838.78	+0.6%	+37.6%

The Stock Market Review: Third Quarter, 2012

The old Wall Street maxim of "Sell in May and Go Away," which holds that the stock market's best days are from November to May, has not worked out so far in 2012. In truth, early on in this six-month stretch, it seemed as though the past would be prologue, as equities fell from early May through the first days of June. However, stocks steadied thereafter, and following some backing off during early July, began a steady climb through September. The third-quarter strength from mid-July forward enabled the Dow Jones Industrial Average, the broader Standard & Poor's 500 Index, and the NASDAQ to finish the period with moderate gains. In all, the Dow climbed 4.3% for the quarter; the S&P 500 added 5.8%; and the NASDAQ rose 6.2%. For the nine months, the 30-stock Dow was up by 10.0%; the Standard and Poor's 500 Index was better by 14.6%; and the NASDAQ was in the black by 19.6%. As noted . . .

The third quarter was a positive one for the bulls, but it did not start out that way. And even before the onset of the period, the Dow had been off by more than 8% from April 30th through June 1st. It then spent much of June catching its breath, but shed another 2.4% over the first week and a half of the third quarter. Then, with the index below 12,600 on July 12th, stocks steadied and began a nifty comeback, culminating in the third-quarter advance cited above.

The third-quarter increases were broad, but not wholly inclusive. In all, the 4.3% jump in the Dow Jones Industrials included price gains in 23 of the 30 components. Leading the way in the latest three months were double-digit percentage gains in five of the issues, led by a 13.9% rise in the shares of building supplies retailer *Home Depot*. Other notable winners were *JPMorgan Chase* (up 13.3%), *Procter & Gamble* (up 13.2%), *Cisco Systems* (with a gain of 11.7%), and *Chevron* (ahead by 10.5%). On the other hand, seven of the Dow stocks fell, with the losses most pronounced in *Hewlett-Packard* and *Intel*.

As always, there are exceptions to the rule. Indeed, while the three averages listed above were nicely higher during the recent quarter, the Dow Jones Transports (off 6.1%) and the Dow Utilities (down 1.2%) didn't share in the good times. Weak profits among the rails and higher energy prices (which buffeted the airlines) hurt the Transports, while a greater tolerance for risk and decent yields in other areas restricted the utilities. To date in 2012, the Dow Transports are off 2.5%, while the Utilities are up, but just 2.4%. For the nine months, the biggest winners, respectively, are the NASDAQ and the NASDAQ 100, with the latter up a sizzling 22.9%.

Looking ahead, we have a few concerns, not the least of which are an uncertain economic upturn and a rather overbought market. At the end of the third quarter, the U.S. Commerce Department reported that revised second-quarter GDP showed an increase of an anemic 1.3%. That was down from the opening-period gain of 2.0%. Moreover, recent data generally point to an uninspiring gain in the final six months of this year, which would explain the Federal Reserve's recent move to introduce a third round of quantitative easing. In truth, our situation is a lot better than it is in the euro zone, which is seeing recessions spread across the ailing Continent. However, that is scant comfort for those struggling on our shores under the weight of still-high joblessness and still-depressed real estate values, even after a partial comeback by the latter sector. It is against this uninspired backdrop that a modestly extended stock market begins a new quarter.

Overall, though, we're cautiously optimistic. Our thinking is that the Fed's efforts to lift the economy and the unappealing alternatives to stocks (notably fixed-income investments) in this low-interest-rate environment should lend some further support to the equity market at this juncture.

Harvey S. Katz, CFA
Chief Economist

	THIRD QUARTER			NINE MONTHS		
	6/29/12	9/28/12	% Change	12/30/11	9/28/12	% Change
Dow Jones Industrial Average	12880.09	13437.13	4.3	12217.56	13437.13	10.0
Dow Jones Transportation Average	5209.18	4892.62	-6.1	5019.69	4892.62	-2.5
Dow Jones Utility Average	481.36	475.75	-1.2	464.68	475.75	2.4
Standard & Poor's 500 Index	1362.16	1440.67	5.8	1257.60	1440.67	14.6
NASDAQ Composite	2935.05	3116.23	6.2	2605.15	3116.23	19.6
NASDAQ 100	2615.72	2799.10	7.0	2277.83	2799.10	22.9
New York Stock Exchange Composite	7801.84	8251.00	5.8	7477.03	8251.00	10.4
American Stock Exchange Composite	2327.88	2437.52	4.7	2278.34	2437.52	7.0
Russell 2000	798.49	837.45	4.9	740.92	837.45	13.0
Value Line (Arithmetic) Average	2894.52	3058.03	5.6	2695.60	3058.03	13.4
Value Line (Geometric) Average	345.24	359.58	4.2	329.80	359.58	9.0
Value Line Industrials	276.62	287.86	4.1	263.71	287.86	9.2
Value Line Rails	4652.25	4900.21	5.3	4270.07	4900.21	14.8
Value Line Utilities	249.45	259.67	4.1	254.27	259.67	2.1
London (FT-SE 100)	5571.15	5742.07	3.1	5572.28	5742.07	3.0
Tokyo (Nikkei)	9006.78	8870.16	-1.5	8455.35	8870.16	4.9
Toronto (TSE 300)	11596.56	12317.46	6.2	11955.09	12317.46	3.0

Stocks for Dividend Growth with Low Risk

In this screen, we turned our attention to low-risk stocks that have good records for dividend growth. In addition, our selection criteria focused on those issues that our analysts project to continue providing investors with dividends that are likely to increase at above-average rates.

We began our search with stocks whose dividends have advanced at a compounded annual rate of at least 7% over the last five years. Similarly, we next narrowed the list to equities with projected annual dividend growth rates of at least 7% over the next three to five years. We also set a minimum estimated yield for the year ahead of 3.5%, which is 120 basis points (100 basis points equals one percentage point) higher than the current median for all dividend-paying stocks under our review. For comparative purposes, we also show payout ratios (all dividends as a percentage of net profit) for the most recent fiscal year.

We then restricted our search to stocks with Safety ranks of at least 2 (Above Average), and Financial Strength Ratings of B++ or better (B+ is Average). Companies whose shares earn high marks for these metrics generally will fare better in volatile markets than the typical stock under our review. Lastly, to reduce the risk of underperformance, we limited the selection to issues ranked 3 (Average), or better, for relative price performance over the next six to 12 months.

The set of stocks that made the final cut are not only judged to be safer than most, but also possess proven and prospective dividend growth rates that have and are likely to advance at a rate exceeding the average rate of inflation under the time periods chosen under this review. We note that although this group includes the usual contingent of utility stocks, its composition is much broader, in keeping with most recent screens. As usual, we advise investors to carefully review both full-page and supplementary analyses in our *Ratings & Reports* before making commitments to any of the equities on the list of stocks below.

Ratings & Reports Page	Ticker	Company	Dividend Yield	Timeliness	Safety	Payout Ratio	AVG. ANN'L GROWTH Last 5 Years	AVG. ANN'L GROWTH Next 3-5 Years	Financial Strength Rating	Industry
2238	AVA	Avista Corp.	4.6%	3	2	64%	13%	7%	A	Electric Utility (West)
1990	BTI	Brit. Amer Tobac. ADR	4.0	3	2	64	19	7	B++	Tobacco
2578	CA	CA, Inc.	3.9	3	2	20	13	30	B++	Computer Software
1188	CLX	Clorox Co.	3.6	2	2	58	14	8	B++	Household Products
2308	HAS	Hasbro, Inc.	3.8	3	2	41	23	9	B++	Recreation
1917	HNZ	Heinz (H.J.)	3.7	2	1	59	9	7	A+	Food Processing
221	JNJ	Johnson & Johnson	3.5	3	1	44	11	7	A++	Med Supp Non-Invasive
718	LMT	Lockheed Martin	4.9	3	1	41	21	13	A++	Aerospace/Defense
2312	MAT	Mattel, Inc.	3.5	1	2	41	10	9	A	Recreation
2518	NA.TO	Nat'l Bank of Canada	4.3	2	2	42	9	7	B++	Bank
145	NEE	NextEra Energy	3.5	3	2	46	8	8	A	Electric Utility (East)
146	NU	Northeast Utilities	3.7	3	2	50	9	9	B++	Electric Utility (East)
723	RTN	Raytheon Co.	3.7	3	1	31	11	10	A++	Aerospace/Defense
2250	SRE	Sempra Energy	3.8	3	2	41	9	9	A	Electric Utility (West)
943	VOD	Vodafone Group ADR	5.4	3	2	88	14	7	B++	Telecom. Services
920	WEC	Wisconsin Energy	3.5	3	1	47	14	14	A	Electric Util. (Central)

Model Portfolios: Recent Developments

PORTFOLIO I

We are making two changes to Portfolio I this week. We are selling our positions in Omnicare, Inc. and Oracle Corp. Their removal is occasioned by each stock's Timeliness rank having fallen to 3 (Average), making them ineligible to be held in the portfolio. Although these shares' stay was short, with both being added in July of this year, we should record moderate profits on the sales.

The open positions will be taken by *Flowserve Corporation* and *The Hain Celestial Group*. *Flowserve* makes and markets pumps, valves, and other fluid-handling equipment, targeting applications involving difficult-to-handle or corrosive liquids. The company has recorded good returns on total capital in the last five years, despite the deep recession experienced from late 2007 into early 2009. Indeed, although the stock's price suffered in this span, the company registered only a slight decline in earnings and cash flow, suggesting the company is well-managed. From where we stand, *Flowserve*'s likely financial performance for the year ahead warrants its inclusion in the portfolio. Meanwhile, *Hain Celestial*, the purveyor of natural and organic food and personal care products, is currently experiencing good demand for its offerings. The company's earnings are growing nicely, and the prospects for continued advancement are good, in our view, making *HAIN* shares a worthy choice for our group.

PORTFOLIO II

We have completed the swap of the shares of Mondelez (the surviving entity from the breakup of Kraft), for the spin-off *Kraft Foods Group*. Coverage of *Kraft Foods* will be added to *The Value Line Investment Survey* in two weeks, on October 26th. Encouragingly, *KRFT* shares gained 2.2% on their first day of trading (October 2nd).

We are also pleased with our position in *Lockheed Martin*, which recently reached a 52-week high. The stock has performed very well, in spite of the potential for huge defense-spending cuts at the start of 2013. The showing is likely the result of a high yield (the payout was raised 15% in the third quarter) and the company's ability to rapidly trim costs. Meanwhile, the prospects of the defense cuts left *Lockheed* with the responsibility to send out notices of potential layoffs to its employees by November 1st. However, the U.S. Office of Management and Budget (OMD) said that the notices would not be necessary, as no specific contract actions would be announced until months after January 1st. Furthermore, the OMD and the Department of Defense said the government was prepared to indemnify *Lockheed* for any costs it may incur if contract actions due to budget sequestration were to occur. Accordingly, the notices will not go out, and Portfolio II will continue to hold the issue, for now.

PORTFOLIO III

Portfolio III and the broader equity averages continue to hold firm during the early stages of the fourth quarter, as investors appear hopeful that the housing and labor markets have turned the corner, and that Europe can contain its debt crisis. Indeed, the group, focused on companies with strong long-term prospects, has held onto recent gains, despite notable weakness in *Qualcomm* (the chip sector has barely participated in this latest rally), a further pullback in shares of *Apple* on the heels of the *iPhone 5* release, and underwhelming performances from *U.S. Steel* and fertilizer maker *Mosaic*.

Two issues that have done quite well of late are *Magna International* and *Tenneco*. The entire auto parts space is being buoyed by brisk auto sales. In fact, U.S. auto sales rose 13% in September, the best monthly showing in four and a half years. And the momentum is apt to persist, we think, thanks to rising consumer confidence, easier credit, and a lot of pent-up demand. *Magna* and *Tenneco*, meanwhile, remain well positioned in the auto parts industry, and our holdings in these stocks should continue to prosper.

Adding it all up, we are making no changes this week, as we are satisfied with the balance of Portfolio III at present.

PORTFOLIO IV

The U.S. stock market is holding up well, as we enter the final months of 2012. Traders may well be looking ahead to earnings reports for the third quarter, which are slated to be released over the next few weeks. Notably, over half of the portfolio's holdings are scheduled to post results in October, with the remainder in November.

The issuances will give us a chance to assess the progress of some of our recent winners. We will soon hear from toy maker *Mattel*. The stock has been a solid performer over the past few months. Notably, demand for the company's core products remains strong, and it is making inroads overseas. We will also soon receive a report from *Abbott Labs*, our core drug holding. These shares have logged respectable gains lately, probably based on product developments and efforts to expand internationally. The company is set for a spin off by the end of the year, and we should get additional information on that front with the upcoming release.

The earnings season will also give us better look at the portfolio's weaker performing holdings. On point, *Waste Management* is grappling with sluggish demand for used paper and cardboard. Although acquisitions and a restructuring program should aid the company's prospects, these efforts, assuming they are successful, could take time. We will also be looking carefully at the reports issued by our utility holdings.

For now, though, we are making no changes to Portfolio IV.

PORTFOLIO I: STOCKS WITH ABOVE-AVERAGE YEAR-AHEAD PRICE POTENTIAL

(primarily suitable for more aggressive investors)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
1964	BUD	AB InBev ADR	88.43	1	1	18.0	1.8	0.90	A+	Beverage
1172	BLL	Ball Corp.	42.19	2	2	13.6	0.9	0.95	B++	Packaging & Container
159	CAT	Caterpillar Inc.	85.47	2	3	8.5	2.4	1.30	A+	Heavy Truck & Equip
358	CBRL	Cracker Barrel	67.54	1	3	14.5	3.0	1.00	B+	Restaurant
2435	CYT	Cytec Inds.	64.65	1	3	21.3	0.8	1.45	B++	Chemical (Diversified)
1023	DTV	DIRECTV	52.11	2	3	11.3	Nil	0.90	B+	Cable TV
1013	RDEN	Elizabeth Arden	46.40	1	3	21.2	Nil	1.30	B+	Toiletries/Cosmetics
435	EFX	Equifax, Inc.	47.43	1	2	16.1	1.5	0.90	A	Information Services
1713	FLS	Flowserve Corp.	128.05	1	3	14.4	1.2	1.45	A+	Machinery
2220	FL	Foot Locker	35.04	1	3	14.2	2.1	1.05	B++	Retail (Softlines)
2158	GCO	Genesco Inc.	65.68	2	3	13.5	Nil	1.15	B+	Shoe
1916	HAIN	Hain Celestial Group	65.40	1	3	30.7	Nil	0.95	B+	Food Processing
1336	NCR	NCR Corp.	22.50	2	3	12.2	Nil	1.20	B+	Electronics
963	NSR	NeuStar Inc.	40.79	1	3	17.9	Nil	0.85	B++	Telecom. Equipment
325	ODFL	Old Dominion Freight	29.12	2	3	14.8	Nil	1.10	B+	Trucking
2113	PVH	PVH Corp.	92.92	2	3	14.6	0.2	1.25	B+	Apparel
840	REGN	Regeneron Pharmac.	157.02	1	3	45.6	Nil	1.05	B+	Biotechnology
729	TGI	Triumph Group Inc.	62.89	2	3	10.8	0.3	1.10	B++	Aerospace/Defense
2120	VFC	V.F. Corp.	161.21	1	2	15.4	1.8	0.90	A	Apparel
1630	WPI	Watson Pharmac.	85.43	1	2	13.6	Nil	0.75	B++	Drug

To qualify for purchase in the above portfolio, a stock must have a Timeliness Rank of 1 and a Financial Strength Rating of at least B+. If a stock's Timeliness rank falls below 2, it will be automatically removed. Stocks in the above portfolio are selected and monitored by Charles Clark, Associate Research Director.

PORTFOLIO II: STOCKS FOR INCOME AND POTENTIAL PRICE APPRECIATION

(primarily suitable for more conservative investors)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
1594	ABT	Abbott Labs.	68.54	NR	1	13.2	3.0	0.60	A++	Drug
2600	ADP	Automatic Data Proc.	58.49	1	1	19.9	2.9	0.80	A++	IT Services
503	CVX	Chevron Corp.	117.96	3	1	8.1	3.1	0.95	A++	Petroleum (Integrated)
1969	KO	Coca-Cola	38.34	2	1	18.4	2.7	0.60	A++	Beverage
1189	CL	Colgate-Palmolive	107.92	2	1	19.9	2.4	0.60	A++	Household Products
2395	COP	ConocoPhillips	57.37	NR	1	8.8	4.6	NMF	A++	Petroleum (Producing)
1587	DD	Du Pont	49.50	3	1	11.5	3.5	1.15	A++	Chemical (Basic)
332	GLNG	Golar LNG Ltd.	38.38	2	3	15.3	4.2	1.60	B	Maritime
1752	HON	Honeywell Int'l	61.45	2	1	13.2	2.4	1.15	A++	Diversified Co.
1192	KMB	Kimberly-Clark	86.37	1	1	17.2	3.4	0.55	A++	Household Products
—	KRFT	Kraft Foods Group	44.87	NR	NR	16.1	4.5	—	—	Retail/Wholesale Foods
718	LMT	Lockheed Martin	93.16	3	1	11.7	4.9	0.80	A++	Aerospace/Defense
407	RSG	Republic Services	27.40	3	3	13.7	3.4	0.90	B+	Environmental
1626	SNY	Sanofi ADR	44.02	3	1	21.6	4.1	0.80	A+	Drug
1731	SNA	Snap-on Inc.	71.85	2	2	13.9	1.9	1.10	A+	Machinery
1767	MMM	3M Company	93.54	2	1	14.0	2.5	0.80	A++	Diversified Co.
345	UNP	Union Pacific	119.10	1	2	13.9	2.0	1.15	A	Railroad
316	UPS	United Parcel Serv.	72.02	3	1	15.3	3.2	0.85	A	Air Transport
942	VZ	Verizon Communic.	45.86	1	1	17.9	4.5	0.70	A++	Telecom. Services
2153	WMT	Wal-Mart Stores	73.75	2	1	14.9	2.2	0.60	A++	Retail Store

To qualify for purchase in the above portfolio, a stock must have a yield that is in the top half of the Value Line universe, a Timeliness Rank of at least 3 (unranked stocks may be selected occasionally), and a Safety Rank of 3 or better. If a stock's Timeliness Rank falls below 3, that stock will be automatically removed. (Occasionally a stock will be unranked (NR), usually because of a short trading history or a major corporate reorganization.) Stocks are selected and monitored by Craig Sirois, Editorial Analyst.

PORTFOLIO III: STOCKS WITH LONG-TERM PRICE GROWTH POTENTIAL

(primarily suitable for investors with a 3- to 5-year horizon)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	3- to 5-yr Appreciation Potential	Industry Name
1546	AFL	Aflac Inc.	47.56	3	3	8.1	2.9	1.20	45 - 120%	Insurance (Life)
1399	AAPL	Apple Inc.	661.31	2	2	13.3	1.6	1.00	65 - 120	Computers/Peripherals
974	CVS	CVS Caremark Corp.	48.49	2	1	14.1	1.3	0.80	45 - 85	Pharmacy Services
355	CBOU	Caribou Coffee	13.95	3	4	29.7	Nil	0.95	15 - 80	Restaurant
1602	CELG	Celgene Corp.	78.42	3	2	19.4	Nil	0.75	30 - 80	Drug
2327	DIS	Disney (Walt)	51.64	2	1	16.3	1.2	1.05	15 - 45	Entertainment
927	DY	Dycom Inds.	14.40	3	3	13.7	Nil	1.40	110 - 215	Telecom. Services
2625	GOOG	Google, Inc.	756.99	3	2	20.7	Nil	0.90	20 - 65	Internet
2106	GES	Guess Inc.	25.08	5	3	10.9	3.2	1.25	140 - 260	Apparel
2307	HOG	Harley-Davidson	42.11	3	3	14.0	1.5	1.50	40 - 115	Recreation
1920	HRL	Hormel Foods	29.75	3	1	14.7	2.1	0.65	35 - 70	Food Processing
1001	MGA	Magna Int'l 'A'	44.53	2	3	8.3	2.5	1.20	80 - 170	Auto Parts
1590	MOS	Mosaic Company	55.76	4	3	12.3	1.8	1.55	50 - 125	Chemical (Basic)
2418	NOV	National Oilwell Varco	80.73	2	3	13.3	0.6	1.55	40 - 115	Oilfield Svcs/Equip.
1978	PEP	PepsiCo, Inc.	70.62	3	1	18.2	3.1	0.60	55 - 90	Beverage
966	QCOM	Qualcomm Inc.	61.79	3	2	18.7	1.6	0.85	40 - 85	Telecom. Equipment
1007	TEN	Tenneco Inc.	28.92	3	4	8.2	Nil	2.35	90 - 230	Auto Parts
1579	TIE	Titanium Metals	12.80	3	3	18.6	2.3	1.75	95 - 215	Metals & Mining (Div.)
753	X	U.S. Steel Corp.	18.99	4	3	9.9	1.1	1.75	215 - 350	Steel
814	UNH	UnitedHealth Group	56.80	3	2	11.3	1.5	1.00	65 - 120	Medical Services

To qualify for purchase in the above portfolio, a stock must have worthwhile and longer-term appreciation potential. Among the factors considered for selection are a stock's Timeliness and Safety Rank and its 3- to 5-year appreciation potential. (Occasionally a stock will be unranked (NR), usually because of a short trading history or a major corporate reorganization.) Stocks in the above portfolio are selected and monitored by Justin Hellman, Editorial Analyst.

PORTFOLIO IV: STOCKS WITH ABOVE-AVERAGE DIVIDEND YIELDS

(primarily suitable for investors interested in current income)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
922	T	AT&T Inc.	37.81	1	1	14.9	4.7	0.75	A++	Telecom. Services
1594	ABT	Abbott Labs.	68.54	NR	1	13.2	3.0	0.60	A++	Drug
903	LNT	Alliant Energy	43.49	2	2	14.5	4.3	0.70	A	Electric Util. (Central)
1041	BT	BT Group ADR	37.40	2	3	9.8	3.9	1.00	B+	Telecom. Utility
1990	BTI	Brit. Amer Tobac. ADR	104.74	3	2	15.8	4.0	0.70	B++	Tobacco
140	ED	Consol. Edison	59.65	2	1	15.5	4.1	0.60	A+	Electric Utility (East)
1587	DD	Du Pont	49.50	3	1	11.5	3.5	1.15	A++	Chemical (Basic)
1526	HCN	Health Care REIT	58.61	2	3	60.4	5.4	0.85	B+	R.E.I.T.
1917	HNZ	Heinz (H.J.)	56.36	2	1	15.9	3.7	0.65	A+	Food Processing
1162	IP	Int'l Paper	35.99	3	3	12.9	2.9	1.40	B+	Paper/Forest Products
542	LG	Laclede Group	43.27	3	2	16.3	3.8	0.60	B++	Natural Gas Utility
2312	MAT	Mattel, Inc.	35.42	1	2	14.2	3.5	0.85	A	Recreation
366	MCD	McDonald's Corp.	90.93	3	1	16.4	3.4	0.60	A++	Restaurant
720	NOC	Northrop Grumman	67.86	3	1	9.8	3.2	0.85	A++	Aerospace/Defense
916	OGE	OGE Energy	55.79	3	2	16.1	2.9	0.75	A	Electric Util. (Central)
1993	RAI	Reynolds American	43.37	1	2	14.9	5.4	0.55	B+	Tobacco
513	RDSA	Royal Dutch Shell 'A'	69.92	3	1	9.4	4.9	1.05	A++	Petroleum (Integrated)
151	SO	Southern Co.	45.57	2	1	17.0	4.4	0.55	A	Electric Utility (East)
1037	WPC	W.P. Carey Inc.	48.05	3	3	18.2	5.4	0.90	B+	Property Management
412	WM	Waste Management	31.67	3	2	14.2	4.6	0.80	A	Environmental

To qualify for purchase in the above portfolio, a stock must have a yield that is at least 1% above the median for the Value Line universe, a Timeliness Rank of at least 3, and a Financial Strength Rating of at least B+. If a stock's Timeliness Rank falls below 4, that stock will be automatically removed. Stocks are selected and monitored by Adam Rosner, Editorial Analyst.

Model Portfolios: Company Snapshots

Some of the holdings in the Model Portfolios, though integral to each group of 20 stocks, may have held their positions for some time without receiving attention. To bring interested subscribers up to date, a handful of these less visible contributors are now featured in the Model Portfolios: Company Snapshots page, which appears on an occasional basis in *Selection & Opinion*.

The rationale for making any trades in the portfolios, along with a brief analysis of the salient factors that are currently affecting each group's performance, continues to be found in the Model Portfolios: Recent Developments page included in this and every issue of *Selection & Opinion*.

Regeneron Pharmaceuticals (REGN)

Held In: Portfolio I
Purchase Date: September 24, 2012
Purchase Price: $144.16
Recent Price: $157.02

Regeneron Pharmaceuticals is a Tarrytown, New York-based biopharmaceutical outfit that develops and commercializes medicines for the treatment of serious medical conditions. The company currently has two products: *EYLEA*, which is used to treat wet age-related macular degeneration; and *ARCALYST*, which is used to treat a rare immune disorder called Cryopyrin-Associated Periodic Syndromes (CAPS). It also has many products in clinical development, and has invented a promising antibody technology that should lead to several compounds coming to market.

The shares have been on a meteoric rise over the past several quarters, as regulatory approvals of *Regeneron's* two key drugs have piled up. What's more, near-term prospects appear bright, considering the momentum of *EYLEA* and the likelihood that other medicines in the pipeline will emerge as growth drivers. And the company should have no trouble remaining aggressive on the R&D front, thanks to its sound balance sheet and improving cash flow.

We hold 1,625 *REGN* shares, unchanged from our recent purchase in late September. It is not often that a small biotech firm can make the cut for Portfolio I, but *Regeneron* has gone from posting wide losses to strong earnings in short order, as its drug development efforts have borne fruit. We note the stock has performed well since being added to the group, and our expectations are that it will likely continue to do so.

Aflac Inc. (AFL)

Held In: Portfolio III
Purchase Date: March 30, 2009
Purchase Price: $32.62
Recent Price: $47.56

Aflac, with over $20 billion in annual sales, markets and administers supplemental health and life insurance services. The company is the largest provider of individual guaranteed-renewable insurance products in the U.S., and the number one insurer in terms of individual policies in force in Japan, which accounts for roughly three-quarters of its profits. Its products, which help fill gaps in customers' primary coverage, include care plans, general medical expense plans, living benefit life plans, and cancer expense plans.

The stock has rebounded nicely since we added it to the portfolio in 2009, when investors feared that *Aflac* may have been exposed to hard-hit hybrid securities issued by European financial institutions. Those concerns turned out to be overblown, and investment-related impairment charges proved to be quite manageable. Moreover, the company appears set to deliver record results this year, despite lackluster employment trends in the U.S. and Japan. Growth will be driven, we think, by rate hikes, a favorable repositioning of the Japanese investment portfolio, and a more diverse selling strategy. Stock buybacks should also bolster share net, as *Aflac* plans to step up repurchase activity now that investment losses are narrowing.

We own 4,900 *AFL* shares at a cost of $32.62 a share, which leaves us with an unrealized gain of 46% on the position. And we intend to stand pat for now, given the decent dividend yield (now about 2.8%), as well as the prospects for solid earnings growth both this year and out to 2015-2017.

Health Care REIT (HCN)

Held In: Portfolio IV
Purchase Date: June 25, 2012
Purchase Price: $56.35
Recent Price: $58.61

Health Care REIT is a large-cap REIT that invests in senior housing and healthcare-related real estate, and offers complementary property management and development services. It maintains a portfolio of over 1,000 properties spread across 46 states and Canada.

Health Care REIT has been posting respectable results of late. Significant top-line advances reflect both a better operating environment, as well as contributions from ongoing acquisitions. We look for the REIT to report funds from operations (FFO) of $3.60 per share this year, a decent improvement over last year's showing. Moreover, the company has been actively making investments in properties, and recently announced that it will purchase Sunrise Senior Living. In addition to cash and debt, the REIT often issues equity to help finance investments. Although expansion often creates risk, *Health Care REIT* has historically done a fine job of integrating acquisitions.

We hold 1,550 *HCN* shares, and have a modest unrealized gain on our position. The stock, now favorably ranked for Timeliness, is notably stable, with a beta coefficient of 0.85, somewhat below the market's 1.00 reading. And it offers income-oriented investors a solid, better-than-5% dividend yield at present.

Income Stocks with Worthwhile Total Return Potential

This screen focuses on stocks with good current dividend yields that have at least average prospects for relative price performance over the next three to five years. This combination should result in a group of stocks with worthwhile total return potential.

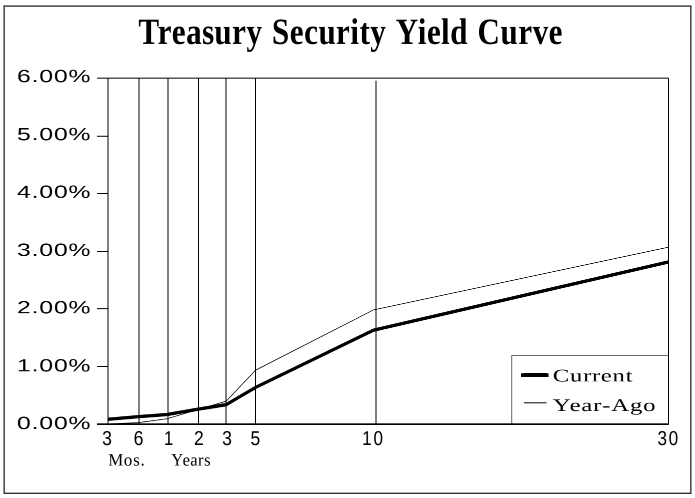
In the first two steps of the selection process, we limited the field to equities with Timeliness ranks of 3 (Average), or better, and Safety ranks of at least 3 (Average). Next, we pared our universe with respect to income generation. We selected issues with current dividend yields of at least 3.5%, 120 basis points (1.2%) above the current median of 2.3% for all dividend-paying stocks under Value Line's review; projected 2015-2017 dividend yields were pegged to be at least 2.5%. We then required that equities with three- to five-year projected price appreciation of less than 75% to be cast aside (the current median is 60%). From this group, we selected issues with a projected average annual total return to 2015-2017 (price gains plus dividends) of at least 19%, which is quite favorable in light of the fact that we may experience a period of lower economic growth with a reduction in available investment returns. Finally, to be included in our list, a company had to have a financial strength rating of no lower than B, and a recent stock price of at least $10 a share.

Investors seeking above-average current income, along with worthwhile three- to five-year total return potential, may find these equities of interest. Nonetheless, we would encourage subscribers to consult each company's most recent review in *Rating & Reports* before making new commitments.

Ratings & Reports Page	Ticker	Company	Recent Price	Timeliness	Safety	Current Yield	3-5 Year Est. Yield	3-5 Year Appreciation Potential	3-5 Year Avg. Total Return
2643	BX	Blackstone Group LP	14.03	3	3	3.7%	3.4%	150%	29%
1045	DTEGY	Deutsche Telekom ADR	12.56	3	2	7.0	5.2	80	21
2549	FII	Federated Investors	20.63	3	3	4.7	3.6	80	20
332	GLNG	Golar LNG Ltd.	38.38	2	3	4.2	3.0	150	28
1991	LO	Lorillard Inc.	116.51	2	2	5.3	3.7	85	21
1549	MFC	Manulife Fin'l	12.11	3	3	4.3	2.6	150	28
1370	MCHP	Microchip Technology	33.37	2	3	4.2	2.9	125	25
1510	PBCT	People's United Fin'l	12.12	3	3	5.3	3.0	105	23
1986	PHG	Philips Electronics NV	23.55	3	3	4.2	2.8	90	20
1954	SWY	Safeway Inc.	16.07	3	3	4.7	2.6	150	28
1027	SJRB.TO	Shaw Commun. 'B'	20.31	3	3	4.8	3.0	85	20
1764	SI	Siemens AG (ADS)	101.54	3	3	3.8	2.5	85	19
517	TOT	Total ADR	50.59	3	1	5.9	4.4	80	20

Selected Yields

	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)		Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
TAXABLE							
Market Rates				**Mortgage-Backed Securities**			
Discount Rate	0.75	0.75	0.75	GNMA 5.5%	0.77	1.39	1.54
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25	FHLMC 5.5% (Gold)	2.00	1.92	2.23
Prime Rate	3.25	3.25	3.25	FNMA 5.5%	1.69	1.84	2.13
30-day CP (A1/P1)	0.28	0.26	0.41	FNMA ARM	2.22	2.27	2.47
3-month LIBOR	0.35	0.46	0.38	**Corporate Bonds**			
Bank CDs				Financial (10-year) A	3.00	3.33	3.88
6-month	0.13	0.20	0.17	Industrial (25/30-year) A	3.78	3.99	4.29
1-year	0.16	0.32	0.21	Utility (25/30-year) A	3.84	3.93	4.21
5-year	0.86	1.09	1.18	Utility (25/30-year) Baa/BBB	4.16	4.37	4.65
U.S. Treasury Securities				**Foreign Bonds (10-Year)**			
3-month	0.09	0.08	0.01	Canada	1.74	1.71	2.14
6-month	0.13	0.15	0.02	Germany	1.47	1.45	1.84
1-year	0.16	0.20	0.09	Japan	0.77	0.82	0.97
5-year	0.62	0.70	0.95	United Kingdom	1.72	1.72	2.36
10-year	1.57	1.63	1.89	**Preferred Stocks**			
10-year (inflation-protected)	-0.90	-0.51	0.08	Utility A	5.14	5.39	5.29
30-year	2.68	2.74	2.85	Financial BBB	6.51	6.53	6.51
30-year Zero	3.08	2.95	3.03	Financial Adjustable A	5.48	5.48	5.48



TAX-EXEMPT	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
Bond Buyer Indexes			
20-Bond Index (GOs)	3.67	3.95	3.93
25-Bond Index (Revs)	4.31	4.69	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.19	0.19	0.20
1-year A	0.82	0.91	0.97
5-year Aaa	0.69	0.86	1.13
5-year A	1.62	1.91	2.18
10-year Aaa	1.90	2.04	2.36
10-year A	3.01	3.13	3.47
25/30-year Aaa	3.30	3.55	3.88
25/30-year A	4.73	4.87	5.53
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.22	4.32	4.56
Electric AA	4.30	4.63	4.92
Housing AA	4.67	4.75	5.55
Hospital AA	4.42	4.57	4.92
Toll Road Aaa	4.23	4.40	4.58

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/19/12	9/5/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1425100	1450818	-25718	1462603	1471716	1498949
Borrowed Reserves	2007	2516	-509	3670	5115	7331
Net Free/Borrowed Reserves	1423093	1448302	-25209	1458934	1466600	1491618

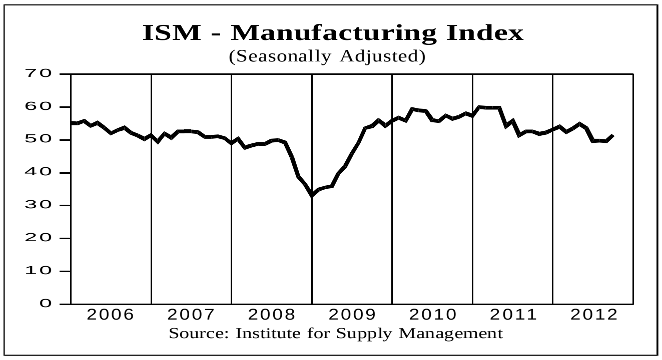
MONEY SUPPLY

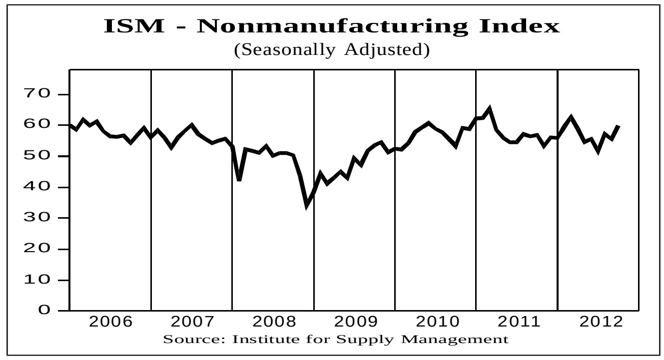
(One-Week Period; in Billions, Seasonally Adjusted)

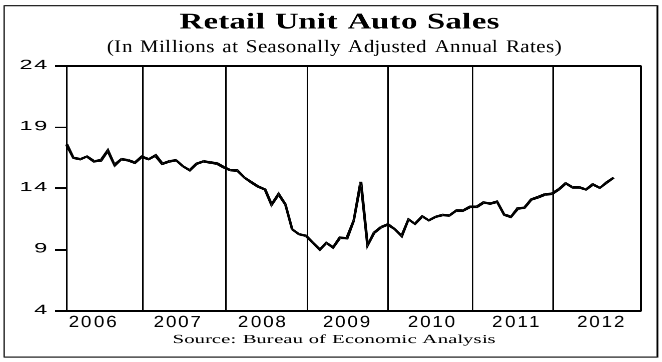
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/17/12	9/10/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2385.8	2373.4	12.4	25.8%	15.7%	12.7%
M2 (M1+savings+small time deposits)	10137.9	10124.1	13.8	8.5%	7.2%	7.1%

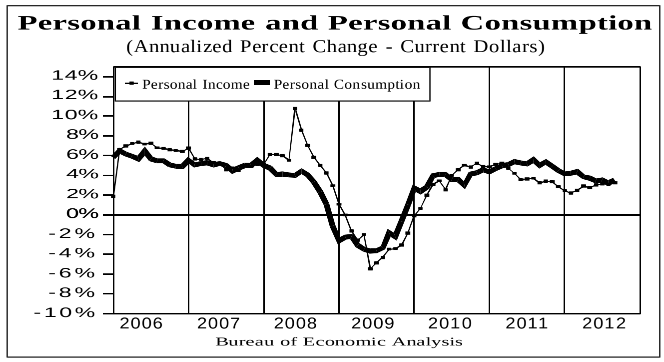
Source: United States Federal Reserve Bank

Tracking the Economy









Major Insider Transactions†

PURCHASES

Latest Full-Page Report	Timeliness Rank	Company	Insider, Title	Date	Shares Traded	Shares Held	Price Range	Recent Price
711	3	Esterline Technologies	J. Morris, Dir.	9/24/12	1,000	10,938	$57.99	58.74
1916	1	Hain Celestial Group	R.C. Berke, Dir.	9/19/12	1,000	18,500	$68.02	65.40
1137	1	Home Depot	R. Sargent, Dir.	9/21/12	1,667	3,467	$59.44	60.33
2375	3	Media General ‘A’	W. Robertson, Dir.	9/24/12	10,000	10,000	$5.16	5.07
2015	5	Rovi Corp.	T. Carson, CEO	9/25/12	15,000	152,160	$15.00	14.29
2235	5	Wet Seal ‘A’	H. Kahn, Dir.	9/21/12	35,000	292,029	$3.22	3.18
2235	5	Wet Seal ‘A’	J. Duskin, Dir.	9/21/12	23,500	133,909	$3.19	3.18

SALES

Latest Full-Page Report	Timeliness Rank	Company	Insider, Title	Date	Shares Traded	Shares Held	Price Range	Recent Price
430	3	Alliance Data Sys.	R.A. Minicucci, Dir.	9/21/12	30,000	121,278	$142.61	141.87
2126	3	AutoZone Inc.	G.R. Mrkonic Jr., Dir.	9/24/12	6,000	3,698	$370.06	369.91
990	1	Drew Industries	E.W. Rose, Dir.	9/21/12-9/24/12	130,657	737,194	$30.15-$30.36	30.80
2383	3	Lamar Advertising	W. Reilly, Dir.	9/24/12	54,850	88,758	$37.02	37.40
1138	3	Lowe’s Cos.	G.M. Keener Jr., Officer	9/20/12	62,453	76,590	$29.52	30.29
1640	2	On Assignment	E.A. Sheridan, Dir.	9/21/12	1,639,832	2,095,433	$16.18	19.95
723	3	Raytheon Co.	W.H. Swanson, Chair.	9/24/12	200,000	665,870	$57.83	54.75

* *Beneficial owner of more than 10% of common stock.*
† *Includes only large transactions in U.S.-traded stocks; excludes shares held in the form of limited partnerships, excludes options & family trusts.*

Major Insider Transactions are obtained from Vickers Stock Research Corporation.

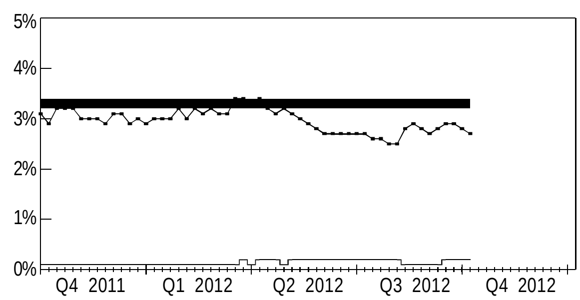
Market Monitor

Valuations and Yields	10/3	9/26	13-week range	50-week range	Last market top (7-13-2007)	Last market bottom (3-9-2009)
Median price-earnings ratio of VL stocks	15.3	15.3	14.2 - 15.3	13.4 - 15.8	19.7	10.3
P/E (using 12-mo. est'd EPS) of DJ Industrials	13.2	13.0	12.2 - 13.3	11.4 - 13.3	16.1	17.3
Median dividend yield of VL stocks	2.3%	2.3%	2.3 - 2.5%	2.1 - 2.5%	1.6%	4.0%
Div'd yld. (12-mo. est.) of DJ Industrials	2.7%	2.7%	2.7 - 2.8%	2.6 - 2.9%	2.2%	4.0%
Prime Rate	3.3%	3.3%	3.3 - 3.3%	3.3 - 3.3%	8.3%	3.3%
Fed Funds	0.2%	0.2%	0.1 - 0.2%	0.1 - 0.2%	5.3%	0.2%
91-day T-bill rate	0.1%	0.1%	0.1 - 0.1%	0.0 - 0.1%	5.0%	0.3%
AAA Corporate bond yield	3.4%	3.4%	3.2 - 3.6%	3.2 - 4.1%	5.8%	5.5%
30-year Treasury bond yield	2.7%	2.8%	2.5 - 2.9%	2.5 - 3.4%	5.1%	3.7%
Bond yield minus average earnings yield	-3.1%	-3.1%	-3.8 - -2.9%	-3.8 - -2.3%	0.7%	-4.3%
Market Sentiment						
Short interest/avg. daily volume (5 weeks)	19.2	20.0	17.8 - 23.0	13.1 - 23.0	8.1	8.6
CBOE put volume/call volume	.87	.85	.74 - 1.00	.67 - 1.31	.91	.93

VALUE LINE ASSET ALLOCATION MODEL

(Based only on economic and financial factors)

	Current (effective market open 4/2/12)	Previous
Common Stocks	60%-70%	65%-75%
Cash and Treasury Issues	40%-30%	35%-25%



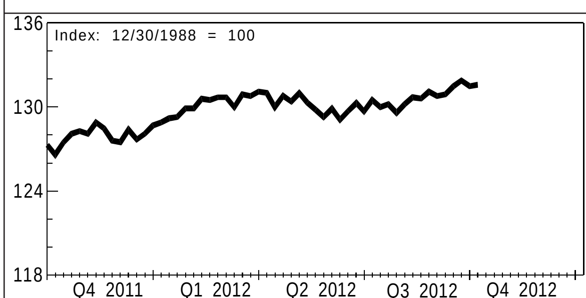
INTEREST RATES

Prime Rate

Federal Funds

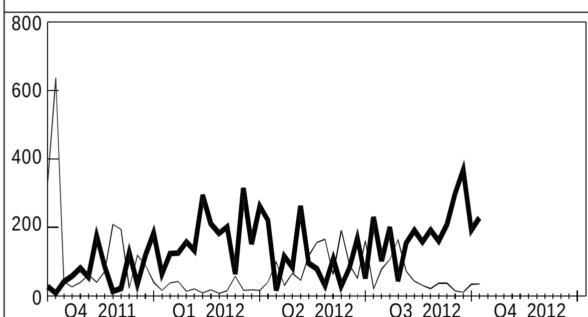
30-Year Treasury Bond

	Recent	Previous Week
Prime Rate	3.3%	3.3%
Fed Funds	0.2%	0.2%
30-Yr. Treasury	2.7%	2.8%



VALUE LINE UNIVERSE

	Recent	Previous Week
Advances	927	488
Declines	753	1198
Issues Covered	1706	1705
Market Value ($ Trillion)	19.728	19.804



VALUE LINE UNIVERSE

New Highs

New Lows

	Recent	Previous Week
New Highs	228	192
New Lows	35	34

INDUSTRY PRICE PERFORMANCE LAST SIX WEEKS ENDING 10/2/2012

7 Best Performing Industries

Homebuilding	+16.1%
Precious Metals	+15.0%
Medical Services	+10.2%
Building Materials	+8.5%
Newspaper	+8.2%
Metals & Mining (Div.)	+7.4%
Furn/Home Furnishings	+6.8%

7 Worst Performing Industries

Trucking	-9.5%
Semiconductor Equip.	-8.2%
Coal	-7.3%
Semiconductor	-6.2%
Electronics	-6.2%
Power	-5.6%
Steel	-5.2%

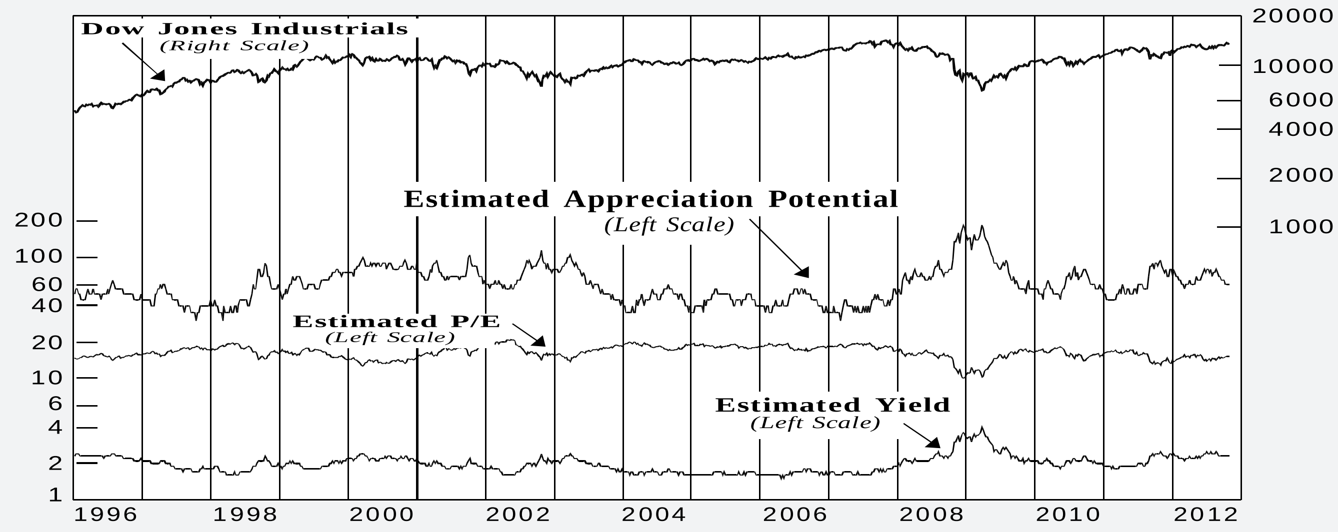
The corresponding change in the Value Line Arithmetic Average* is +2.4%

CHANGES IN FINANCIAL STRENGTH RATINGS

Company	Prior Rating	New Rating	Ratings & Reports Page
Bristol-Myers Squibb	A+	A++	1601
Georgia Gulf	C++	B	1589
PDL BioPharma	C++	C+	1621
Pfizer Inc.	A+	A++	1625

Stock Market Averages

VALUE LINE ESTIMATED P/E, YIELD, APPRECIATION POTENTIAL VERSUS DOW JONES INDUSTRIALS *(JANUARY 2, 1996 - OCTOBER 2, 2012)*



THE VALUE LINE GEOMETRIC AVERAGES

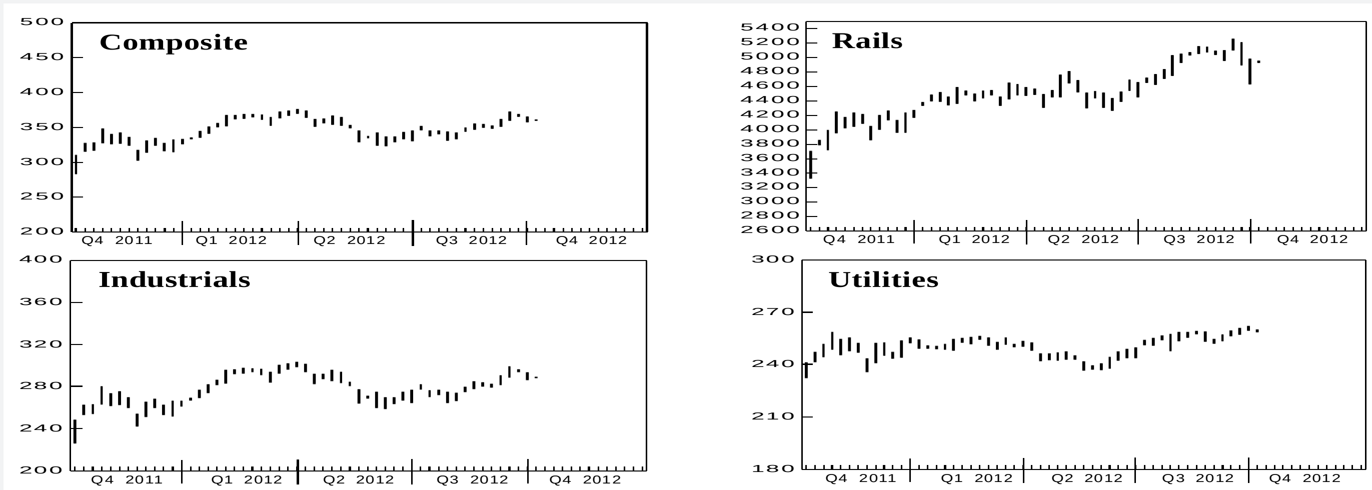
	Composite 1676 stocks	Industrials 1572 stocks	Rails 8 stocks	Utilities 96 stocks
9/27/2012	361.57	289.53	4951.06	260.26
9/28/2012	359.58	287.86	4900.21	259.67
10/1/2012	360.36	288.47	4931.30	258.67
10/2/2012	360.84	288.80	4939.27	259.96
10/3/2012	360.65	288.65	4954.98	259.73
%Change last 4 weeks	+2.5%	+2.5%	-0.1%	+2.4%

Arithmetic* Composite 1676 stocks
3074.63
3058.03
3065.28
3069.80
3068.65
+2.8%

THE DOW JONES AVERAGES

Composite 65 stocks	Industrials 30 stocks	Transportation 20 stocks	Utilities 15 stocks
4458.56	13485.97	4941.20	473.88
4441.70	13437.13	4892.62	475.75
4454.37	13515.11	4899.73	474.11
4453.92	13482.36	4908.44	475.95
4475.05	13494.61	4966.10	478.82
+2.4%	+3.4%	+0.3%	+2.7%

WEEKLY VALUE LINE GEOMETRIC AVERAGES* *(OCTOBER 1, 2011 - OCTOBER 3, 2012)*



THE VALUE LINE
Investment Survey®

PAGES 1361-1372
File in page order in the *Selection & Opinion* binder.

PART 2 *Selection & Opinion* SEPTEMBER 21, 2012

Dear Subscribers,

As part of our ongoing efforts to keep *The Value Line Investment Survey* the most valuable investment resource for our subscribers, all updated Ranks are now being released on the Value Line Web Site at 8:00 A.M. Eastern Time on Mondays. You can access all the Ranks each week at www.valueline.com by entering your user name and password. We look forward to continuing to provide you with accurate and timely investment research. Thank you.

The Value Line View

In This Issue

The *Selection & Opinion* Index appears on page 1560 (August 31, 2012).

In Three Parts: Part 1 is the Summary & Index. This is Part 2, Selection & Opinion. Part 3 is Ratings & Reports. Volume LXVIII, Number 5.

Published weekly by VALUE LINE PUBLISHING LLC
220 East 42nd Street, New York, NY 10017-5891.

ECONOMIC AND STOCK MARKET COMMENTARY

The nation is not creating jobs at the pace needed to materially bring down the unemployment rate. That point was driven home by payroll data issued on September 7th, in which the government reported that 96,000 jobs were added in August, down from the 141,000 positions created in July. True, payrolls are now in a long multi-month uptrend, but the gains remain insufficient to push the jobless rate below 8.1%—a level that was reached in April and again last month. Our sense is that we need 200,000 or so new hires per month to markedly lower the jobless rate. We are clearly nowhere near that level, and may not get there—on a sustained basis—for some months yet.

The dour jobs outlook has major ramifications for housing, where potential buyers—enticed by record low mortgage rates and depressed selling prices—would normally be flooding the market. However, high joblessness, fears about possible employment losses among those still working, and toughened credit standards are making many reluctant to even start a search, thereby putting a cap on housing's nascent recovery.

Elsewhere, things are starting to look up—but at a slow and uneven pace. For example, we are seeing gains in non-manufacturing activity, the auto sector, and personal income. Such improvement, along with better trends in housing, suggests that GDP growth will average 1.5%-2.0% over the next 12 months—assuming the "fiscal cliff" of pending tax hikes and spending cuts can be avoided via timely action by Congress. The recent move by the Federal Reserve Board to launch a major new round of bond buying in an effort to further drive down long-term interest rates reflects the lingering uneasiness about the likely listless pace of GDP growth and, in particular, the jobs market.

The summer rally in the stock market arrived on schedule, and it has been a formidable one, with the averages surging to multi-year highs in September. Low interest rates, a cooperative Fed, and some apparent selective optimism on the domestic economic front cheered on the bulls.

Conclusion: We think there is logic to the market's move higher. But we caution that stocks are now more richly valued, making them vulnerable to possible event risks—especially with regard to the "fiscal cliff" and to uncertain global events, both on the economic front and more recently in the always fractious Middle East. Please refer to the inside back cover of *Selection & Opinion* for our statistically-based Asset Allocation Model's current reading.

CLOSING STOCK MARKET AVERAGES AS OF PRESS TIME

	9/5/2012	9/12/2012	%Change 1 week	%Change 12 months
Dow Jones Industrial Average	13047.48	13333.35	+2.2%	+20.5%
Standard & Poor's 500	1403.44	1436.56	+2.4%	+23.6%
N.Y. Stock Exchange Composite	7992.01	8267.31	+3.4%	+17.3%
NASDAQ Composite	3069.27	3114.31	+1.5%	+24.8%
NASDAQ 100	2766.95	2791.68	+0.9%	+27.4%
American Stock Exchange Index	2404.88	2420.49	+0.6%	+10.5%
Value Line (Geometric)	351.89	363.75	+3.4%	+15.8%
Value Line (Arithmetic)	2983.64	3087.21	+3.5%	+23.2%
London (FT-SE 100)	5657.86	5782.08	+2.2%	+12.7%
Tokyo (Nikkei)	8679.82	8959.96	+3.2%	+5.0%
Russell 2000	821.23	845.12	+2.9%	+24.3%

Model Portfolios: Recent Developments

PORTFOLIO I

Portfolio I has performed well so far in the September period. Nonetheless, we are selling our holdings in Coinstar and Dana Holding shares this week. Both stocks have contributed nicely to the portfolio's performance since being added in the third quarter of 2011. However, their respective Timeliness ranks have dropped to 3 (Average), and they can no longer be held. As it stands now, we should realize respectable gains on these shares' final exit. The open positions will be taken by *Cytec Industries* and *Equifax, Inc.* shares.

Cytec is in the specialty chemicals and materials business. It is now in the process of reconfiguring its operating structure to achieve faster growth. On point, the sale of its Coating Resins group is on track to be completed by yearend. The recent acquisition of Umeco plc and increased investment in its Engineered Materials and Process Separation groups also figure into its strategy for improvement. In the end, the automotive and aerospace markets will have increased importance for *Cytec*.

Meanwhile, consumer and financial information provider *Equifax* has performed well in recent quarters. Although the potential for reduced lending (mortgages) may hamper its growth in the second half, the company has a proven track record of managing through soft spots such as these. The stock should fit in nicely with Portfolio I, while also adding a degree of stability to the group.

PORTFOLIO II

Kraft Foods' roadshow ahead of the planned separation of the international snack business and the North American grocery operations on October 1st was not well received by investors. The grocery group expects organic sales growth to be only in line with the market, and free cash flow will be less than the target range due to an extra tax payment next year. Still, most of the disappointment seems to have stemmed from the snack side. Its 2013 sales were projected to be at the low end of long-term goals, and earnings will likely be hurt by currency valuations. On the day of this presentation, the share price decline erased all of the stock's strong August performance and then some. Portfolio II is not selling its holding at this lower level, however, in light of expectations for consistent earnings growth and a superior dividend payout at Kraft Foods Group, the new name of the grocery business.

More positive news for Portfolio II was the recent approval by the Food and Drug Administration of the new multiple sclerosis pill from *Sanofi*. The oral therapy (the second in the U.S. market) may not be quite as effective as other treatments, but the side effects are milder. Many sufferers in this multi-billion-dollar-a-year market often don't take their drugs because of the nasty side effects.

PORTFOLIO III

Portfolio III continues to push higher as the third quarter draws to a close. Part of this is due to the resiliency of the broader stock market, but a bounce in some of the group's laggards, particularly for-profit school chain *ITT Educational Services*, has also been a plus. Our commodity plays, including *National Oilwell Varco*, *Mosaic*, and *U.S. Steel*, have been bid up by investors, as well.

National Oilwell shares have been a big winner for us since we purchased them back in April of 2007. In fact, we are now up roughly 150% on our initial position in this well-run oilfield services provider. We see no reason to take profits at this time, however, given the tailwinds from what will likely be a multiyear rig replacement cycle. The company is also poised to benefit, we think, from increased drilling activity in the Gulf of Mexico and new regions across East Africa and Southeast Asia. Large infrastructure investments in Brazil, Korea, and Russia should pay off over time, too.

Apple stock, meanwhile, is trading near its all-time high after the tech giant unveiled the long-awaited *iPhone 5*. This latest smartphone offers notable improvements over earlier generations, such as a larger screen, a longer-lasting battery, an updated operating system, and a faster processor. It ought to be a cash cow for the company in the coming quarters. We are making no changes to Portfolio III this week, though we continue to look for quality issues with good long-term appreciation potential.

PORTFOLIO IV

The U.S. stock market continues to head higher as we move through September, with the S&P 500 Index reaching new 52-week high ground. Portfolio IV is holding up relatively well, but has had some laggards this quarter. Our utility stocks have weighed on our performance over the last few months. Also, our real estate issues, *W.P. Carey* and *Health Care REIT* have not done much to help. Elsewhere, tobacco issues, *British American Tobacco* and *Reynolds American* have not participated in the rally either. Some of this may be due to concerns about heightened restrictions on smoking.

Fortunately, we have benefited from strength in a few issues. *International Paper* remains our top performer for the quarter so far, as investors are optimistic about a recent acquisition and restructuring efforts. *BT Group* is doing well despite problems in Europe, as that stock recently gapped up to a hit a new 52 week high. Further, toy maker *Mattel*, which should benefit from new product rollouts, is also near new high ground.

Our cash position has edged upward, to over 3% of our portfolio's value, and we will likely be rebalancing our positions in an effort to bring this figure down. Aside from this, we are not making any significant changes to our holdings this week.

PORTFOLIO I: STOCKS WITH ABOVE-AVERAGE YEAR-AHEAD PRICE POTENTIAL

(primarily suitable for more aggressive investors)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
1172	BLL	Ball Corp.	42.95	2	2	13.5	0.9	0.95	B++	Packaging & Container
159	CAT	Caterpillar Inc.	88.60	1	3	8.8	2.3	1.30	A+	Heavy Truck & Equip
358	CBRL	Cracker Barrel	65.45	1	3	14.0	2.4	1.00	B+	Restaurant
2435	CYT	Cytec Inds.	66.94	1	3	22.0	0.7	1.45	B++	Chemical (Diversified)
1023	DTV	DIRECTV	52.84	1	3	11.4	Nil	0.90	B+	Cable TV
435	EFX	Equifax, Inc.	46.86	1	2	15.9	1.5	0.90	A	Information Services
2220	FL	Foot Locker	36.50	1	3	14.8	2.0	1.05	B++	Retail (Softlines)
2158	GCO	Genesco Inc.	70.62	2	3	14.5	Nil	1.15	B+	Shoe
1014	HELE	Helen of Troy Ltd.	32.69	2	3	8.7	Nil	1.10	B++	Toiletries/Cosmetics
734	KMT	Kennametal Inc.	38.94	2	3	9.4	1.6	1.40	A	Metal Fabricating
1336	NCR	NCR Corp.	23.10	2	3	13.0	Nil	1.20	B+	Electronics
343	NSC	Norfolk Southern	73.52	1	2	12.0	2.7	1.05	A	Railroad
325	ODFL	Old Dominion Freight	31.54	1	3	16.0	Nil	1.10	B+	Trucking
976	OCR	Omnicare, Inc.	33.95	2	3	10.1	0.8	1.00	B++	Pharmacy Services
2587	ORCL	Oracle Corp.	32.32	2	1	12.4	0.9	0.95	A++	Computer Software
2113	PVH	PVH Corp.	92.73	2	3	14.6	0.2	1.25	B+	Apparel
132	TMO	Thermo Fisher Sci.	59.08	2	2	12.1	0.9	0.95	A	Precision Instrument
729	TGI	Triumph Group Inc.	59.23	1	3	10.2	0.3	1.10	B++	Aerospace/Defense
2120	VFC	V.F. Corp.	155.75	1	2	14.9	1.8	0.90	A	Apparel
1630	WPI	Watson Pharmac.	82.81	1	2	13.5	Nil	0.75	B++	Drug

To qualify for purchase in the above portfolio, a stock must have a Timeliness Rank of 1 and a Financial Strength Rating of at least B+. If a stock's Timeliness rank falls below 2, it will be automatically removed. Stocks in the above portfolio are selected and monitored by Charles Clark, Associate Research Director.

PORTFOLIO II: STOCKS FOR INCOME AND POTENTIAL PRICE APPRECIATION

(primarily suitable for more conservative investors)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
1594	ABT	Abbott Labs.	67.33	1	1	13.2	3.0	0.60	A++	Drug
2600	ADP	Automatic Data Proc.	58.84	1	1	20.0	2.9	0.80	A++	IT Services
503	CVX	Chevron Corp.	114.18	3	1	7.9	3.2	0.95	A++	Petroleum (Integrated)
1969	KO	Coca-Cola	37.77	2	1	18.2	2.7	0.60	A++	Beverage
1189	CL	Colgate-Palmolive	102.82	3	1	18.9	2.6	0.60	A++	Household Products
2395	COP	ConocoPhillips	56.37	NR	1	8.6	4.7	NMF	A++	Petroleum (Producing)
1587	DD	Du Pont	51.05	3	1	11.6	3.4	1.15	A++	Chemical (Basic)
332	GLNG	Golar LNG Ltd.	38.44	2	3	15.3	4.2	1.60	B	Maritime
1752	HON	Honeywell Int'l	59.79	2	1	12.9	2.5	1.15	A++	Diversified Co.
1360	INTC	Intel Corp.	23.34	3	1	10.0	3.9	1.00	A++	Semiconductor
1924	KFT	Kraft Foods	39.77	NR	1	15.5	2.9	0.65	A+	Food Processing
718	LMT	Lockheed Martin	92.24	3	1	11.6	4.7	0.80	A++	Aerospace/Defense
407	RSG	Republic Services	28.22	3	3	14.1	3.3	0.90	B+	Environmental
1626	SNY	Sanofi ADR	43.18	3	1	18.4	4.2	0.80	A+	Drug
1731	SNA	Snap-on Inc.	72.21	2	2	14.0	1.9	1.10	A+	Machinery
1767	MMM	3M Company	91.17	3	1	13.7	2.6	0.80	A++	Diversified Co.
345	UNP	Union Pacific	124.19	1	2	14.5	1.9	1.15	A	Railroad
316	UPS	United Parcel Serv.	73.54	3	1	15.6	3.1	0.85	A	Air Transport
942	VZ	Verizon Communic.	44.24	1	1	17.3	4.7	0.70	A++	Telecom. Services
2153	WMT	Wal-Mart Stores	74.06	2	1	14.9	2.1	0.60	A++	Retail Store

To qualify for purchase in the above portfolio, a stock must have a yield that is in the top half of the Value Line universe, a Timeliness Rank of at least 3 (unranked stocks may be selected occasionally), and a Safety Rank of 3 or better. If a stock's Timeliness Rank falls below 3, that stock will be automatically removed. (Occasionally a stock will be unranked (NR), usually because of a short trading history or a major corporate reorganization.) Stocks are selected and monitored by Craig Sirois, Editorial Analyst.

PORTFOLIO III: STOCKS WITH LONG-TERM PRICE GROWTH POTENTIAL

(primarily suitable for investors with a 3- to 5-year horizon)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	3- to 5-yr Appreciation Potential	Industry Name
1546	AFL	Aflac Inc.	48.62	3	3	8.4	2.7	1.20	45 - 115%	Insurance (Life)
1397	AAPL	Apple Inc.	660.59	3	2	14.4	1.6	1.00	65 - 125	Computers/Peripherals
974	CVS	CVS Caremark Corp.	46.05	2	1	13.3	1.4	0.80	50 - 95	Pharmacy Services
355	CBOU	Caribou Coffee	14.09	3	4	30.0	Nil	0.95	15 - 75	Restaurant
1602	CELG	Celgene Corp.	73.62	3	2	14.3	Nil	0.75	35 - 90	Drug
2327	DIS	Disney (Walt)	51.56	2	1	16.3	1.2	1.05	15 - 45	Entertainment
927	DY	Dycom Inds.	14.37	2	3	13.7	Nil	1.40	110 - 215	Telecom. Services
2625	GOOG	Google, Inc.	692.19	3	2	18.9	Nil	0.90	35 - 80	Internet
2106	GES	Guess Inc.	26.93	4	3	11.7	3.0	1.25	125 - 235	Apparel
2307	HOG	Harley-Davidson	45.03	3	3	15.0	1.4	1.50	35 - 100	Recreation
1920	HRL	Hormel Foods	29.07	3	1	14.4	2.2	0.65	40 - 70	Food Processing
2002	ESI	ITT Educational	38.03	4	3	4.5	Nil	0.70	175 - 320	Educational Services
1001	MGA	Magna Int'l 'A'	45.87	1	3	8.5	2.4	1.20	75 - 160	Auto Parts
1590	MOS	Mosaic Company	60.33	3	3	12.7	1.7	1.55	40 - 115	Chemical (Basic)
2418	NOV	National Oilwell Varco	83.13	2	3	13.7	0.6	1.55	40 - 110	Oilfield Svcs/Equip.
1978	PEP	PepsiCo, Inc.	71.58	3	1	18.4	3.1	0.60	55 - 90	Beverage
966	QCOM	Qualcomm Inc.	61.85	3	2	18.7	1.6	0.85	35 - 85	Telecom. Equipment
1007	TEN	Tenneco Inc.	32.00	2	4	9.0	Nil	2.35	70 - 195	Auto Parts
753	X	U.S. Steel Corp.	21.61	4	3	11.3	0.9	1.75	180 - 295	Steel
814	UNH	UnitedHealth Group	52.80	2	2	10.5	1.6	1.00	80 - 135	Medical Services

To qualify for purchase in the above portfolio, a stock must have worthwhile and longer-term appreciation potential. Among the factors considered for selection are a stock's Timeliness and Safety Rank and its 3- to 5-year appreciation potential. (Occasionally a stock will be unranked (NR), usually because of a short trading history or a major corporate reorganization.) Stocks in the above portfolio are selected and monitored by Justin Hellman, Editorial Analyst.

PORTFOLIO IV: STOCKS WITH ABOVE-AVERAGE DIVIDEND YIELDS

(primarily suitable for investors interested in current income)

Ratings & Reports Page	Ticker	Company	Recent Price	Time-liness	Safety	P/E	Yield%	Beta	Financial Strength	Industry Name
922	T	AT&T Inc.	37.62	1	1	14.8	4.8	0.75	A++	Telecom. Services
1594	ABT	Abbott Labs.	67.33	1	1	13.2	3.0	0.60	A++	Drug
903	LNT	Alliant Energy	44.64	2	2	14.9	4.1	0.70	A	Electric Util. (Central)
1041	BT	BT Group ADR	36.26	2	3	9.5	4.0	1.00	B+	Telecom. Utility
1990	BTI	Brit. Amer Tobac. ADR	101.81	3	2	15.3	4.1	0.70	B++	Tobacco
140	ED	Consol. Edison	60.31	2	1	15.6	4.0	0.60	A+	Electric Utility (East)
1587	DD	Du Pont	51.05	3	1	11.6	3.4	1.15	A++	Chemical (Basic)
1526	HCN	Health Care REIT	58.45	3	3	50.0	5.3	0.85	B+	R.E.I.T.
1917	HNZ	Heinz (H.J.)	56.09	2	1	15.8	3.7	0.65	A+	Food Processing
1162	IP	Int'l Paper	34.48	3	3	12.9	3.0	1.40	B+	Paper/Forest Products
542	LG	Laclede Group	42.02	3	2	15.8	4.0	0.60	B++	Natural Gas Utility
2312	MAT	Mattel, Inc.	35.54	1	2	14.3	3.5	0.85	A	Recreation
366	MCD	McDonald's Corp.	91.20	3	1	16.5	3.1	0.60	A++	Restaurant
720	NOC	Northrop Grumman	67.42	3	1	9.7	3.3	0.85	A++	Aerospace/Defense
916	OGE	OGE Energy	54.32	3	2	15.7	3.0	0.75	A	Electric Util. (Central)
1993	RAI	Reynolds American	44.03	1	2	15.1	5.4	0.55	B+	Tobacco
513	RDSA	Royal Dutch Shell 'A'	71.73	3	1	9.6	4.8	1.05	A++	Petroleum (Integrated)
151	SO	Southern Co.	45.42	2	1	16.9	4.4	0.55	A	Electric Utility (East)
1037	WPC	W.P. Carey & Co. LLC	43.53	3	3	16.5	5.2	0.90	B+	Property Management
412	WM	Waste Management	34.15	3	2	15.3	4.2	0.80	A	Environmental

To qualify for purchase in the above portfolio, a stock must have a yield that is at least 1% above the median for the Value Line universe, a Timeliness Rank of at least 3, and a Financial Strength Rating of at least B+. If a stock's Timeliness Rank falls below 4, that stock will be automatically removed. Stocks are selected and monitored by Adam Rosner, Editorial Analyst.

Option Strategies: Verizon Communications

Conservative investors usually limit the risk they are willing to take when considering investments. Although lower-risk stocks tend to be associated with lower total returns, there are relatively straight forward methods of enhancing these issues' prospective performance using options that have attractive reward/risk parameters. Accordingly, we would like to offer readers of *Selection & Opinion* some ideas relating to the sale of options on stocks of companies that have excellent Financial Strength ratings, sound near-term earnings growth prospects, and have appealing, current valuations and/or dividend yields.

Overview

This week, we take a look at *Verizon Communications* (**VZ**; $44.24), one of the world's leading providers of communications, information, and entertainment products with revenues running at $115 billion per annum. Indeed, based on almost 95 million retail customers and associated revenues (65% of the total in the June quarter), its 55%-owned subsidiary, Verizon Wireless, is the largest provider of wireless voice and data services in the United States. Verizon Wireless was formed in 2000 through a combination of the parent company's wireless operations and those of *Vodafone Group Plc* (**VOD**) in this country.

In 2010, this division launched its fourth generation (4G) Long-Term Evolution (LTE) mobile broadband network, which provides higher data throughput performance and improved efficiencies than third-generation (3G) systems. Verizon has deployed 4G LTE in about 200 markets covering more than 200 million people throughout the country, and is on track to cover virtually its entire current 3G network footprint by mid-2013.

Meanwhile, the far less dynamic Wireline segment's services include local and long distance voice, broadband video and data, and Internet Protocol (IP) network. They are offered both in the United States and in over 150 other countries.

Thanks to rising revenues, and more importantly, enhanced operating margins at Verizon Wireless, share earnings of $0.64 in the June quarter were 12%, above the year-earlier period. We look for the final tally in 2012 to be about $2.50 a share, which would be a gain of around 15%, and our current estimate for 2013 is $2.75. Given the progress at the Wireless segment, the latter target may well prove conservative. That is, it should continue to benefit from increased smartphone penetration and Internet device adoption and, in turn, solid sequential monthly gains in retail additions and average fees per customer. In addition, helped by efficiencies associated with the 4G network and excellent churn metrics, Wireless' operating margin in the latest quarter was about two percentage points higher than in the June, 2011 interim.

At the Wireline division, increased revenues derived from domestic retail accounts, due mainly to the uptrend in the adoption of Verizon's comprehensive FiOS service, have been more than offset by declines in global enterprise and wholesale billings, particularly in Europe, in recent quarters. But margins should soon benefit from an ongoing shift in revenue mix that is being bolstered by the discontinuation of numerous lower-margined offerings.

Based on our share-net estimate for 2012, the P/E ratio is 17.7, in line with VZ's historical norm. The stock is currently ranked 1 (Highest) for Timeliness, and is one of the selections included in Model Portfolio II: Stocks for Income and Potential Appreciation appearing in these pages. The current dividend yield of 4.7% is quite attractive relative to those of other high-quality securities. Net of this year's capital budget of $16 billion and expected dividend payments, cash flow should be about $1.4 billion, which augurs well for further enhancement of the balance sheet. Another consideration for the following investment suggestion is that following a strong uptrend between mid-April and mid-June, the stock has generally been trading between $42 and $46 a share.

Option Strategies

The foregoing factors, along with the scheduled payment of the next dividend ($0.515 a share; up 3% sequentially) on November 1st, indicates that the sales of either a November 2012 covered call with a strike price of $45 or the November 2012 cash-covered put with a strike price of $42 are quite attractive.

At press time, the bid price of the call was $0.66 (equivalent to $66 per call). In this case, the call entitles the buyer to purchase the stock at $45 per share. Since the sale of a covered call implies that the seller owns 100 shares per call sold, the potential profit, on an annualized basis, of 13% would increase to around 20% if VZ were at or above $45 a share on the November 17th expiration date.

Meanwhile, the sale of the cash-covered put at the $0.66 bid price ($66 per put) is the more conservative strategy, given the lower breakeven point ($41.34, which is 6.7% below the current price). The potential annualized yield is around 10%. The seller of a cash-covered put would have cash assets (e.g., money market funds) in a brokerage account. In a margin account, the prospective yield, assuming the likely scenario of VZ trading above $42 at the expiration date, would be greatly enhanced. We note that at $42 a share, the stock's dividend yield would be almost 5%, and the aforementioned P/E ratio would be below 17. The put obligates the purchaser to either buy the stock or close out the position if the share price is below the strike price by the expiration date.

David R. Cohen
Senior Analyst

At the time of this article's writing, the author did not have positions in any of the company's mentioned.

Major Institutional Stock Transactions

Investment managers that control accounts of over $100 million are required to file quarterly reports with the Securities and Exchange Commission (SEC) detailing their holdings. The accompanying tables present data on major purchases and sales by such investors during the second quarter of 2012.

Using information compiled by Vickers Stock Research Corp., we have listed the companies in descending order of the net change in the market value. (Only stocks covered in *The Value Line Investment Survey* appear here.) We also show the number of holders; the percentage of shares held; and the quarterly change in the percentage of shares outstanding owned by institutions at the end of June.

When compared with the March quarter, large money managers' interest in financial services stocks in the June period was noticeably reduced. Indeed, the purchase decisions made in the second quarter spanned a broad range of companies. Meanwhile, sales in the June period had a common theme, as money managers lightened their exposure to many of the stocks comprising the Dow Jones Industrials.

Before following in these footsteps, we advise subscribers to consult company and supplementary reports before committing funds.

***(a)** Listed in descending order of net change in market value of institutional holdings from 3/31/12 to 6/30/12. Excludes stocks not covered by* The Value Line Investment Survey. *Under SEC regulations, institutional investors are allowed to delay disclosure of holdings in stocks that they are still accumulating. Accordingly, the figures for institutional holdings reported here, which are based on SEC filings, may differ in some cases from actual data for the period shown.* ***(b)** As a percentage of shares outstanding on 6/30/12.* ***(c)** Change from 3/31/12 to 6/30/12 as a percentage of shares outstanding on 3/31/12.* ***(d)** Unranked due to short trading history.*

Source: Vickers Stock Research Corp.

PURCHASES DURING THE SECOND QUARTER[(a)]

Ratings & Reports Page	Ticker Symbol	Company	Time-liness	Safety	Number of Institutional Holders (6/30/12)	% Shs. Held [(b)]	% Increase In Shs. Held [(c)]
2540	BLK	BlackRock, Inc.	3	3	610	74.6%	12.2%
2536	AIG	Amer. Int'l Group	(d)	5	523	29.3	6.4
2625	GOOG	Google, Inc.	3	2	1374	81.4	1.5
2627	LNKD	LinkedIn	(d)	3	301	67.6	18.1
761	BRKB	Berkshire Hathaway 'B'	3	1	1179	61.3	2.0
439	IHS	IHS Inc.	2	3	242	84.8	22.6
1562	GG	Goldcorp Inc.	4	3	400	63.7	4.8
2196	WTW	Weight Watchers	4	3	148	104.0	47.3
1379	TSM	Taiwan Semic. ADR	3	3	388	21.0	1.7
1596	ALXN	Alexion Pharmac.	3	3	412	96.3	6.2
956	FFIV	F5 Networks	3	3	454	105.2	15.0
609	PPL.TO	Pembina Pipeline Corp.	3	3	175	27.7	14.8
2520	BPOP	Popular Inc.	4	4	146	67.6	60.7
1964	BUD	AB InBev ADR	1	1	310	5.6	0.7
102	DDAIF	Daimler AG	4	3	24	1.9	1.9
142	DUK	Duke Energy	3	2	887	53.8	1.9
1561	ABX	Barrick Gold	4	3	541	65.1	2.2
1581	AGU	Agrium, Inc.	1	3	299	65.3	4.8
527	ECA	Encana Corp.	4	3	388	65.2	4.5
2225	LULU	lululemon athletica	3	3	291	101.3	10.6
600	PVR	PVR Partners, L.P.	3	3	144	68.5	30.8

SALES DURING THE SECOND QUARTER[(a)]

Ratings & Reports Page	Ticker Symbol	Company	Time-liness	Safety	Number of Institutional Holders (6/30/12)	% Shs. Held [(b)]	% Decrease In Shs. Held [(c)]
1397	AAPL	Apple Inc.	3	2	1812	62.3%	3.8%
504	XOM	Exxon Mobil Corp.	3	1	1698	43.8	4.5
1406	IBM	Int'l Business Mach.	2	1	1611	52.6	6.0
503	CVX	Chevron Corp.	3	1	1562	57.2	5.5
922	T	AT&T Inc.	1	1	1425	50.6	4.7
1769	UTX	United Technologies	3	1	1165	69.5	11.7
2515	JPM	JPMorgan Chase	3	3	1465	67.3	5.6
2585	MSFT	Microsoft Corp.	3	1	1799	61.9	3.0
1992	PM	Philip Morris Int'l	3	2	1257	65.1	4.8
1969	KO	Coca-Cola	2	1	1409	58.2	3.9
975	ESRX	Express Scripts	2	2	892	78.9	14.9
2529	WFC	Wells Fargo	2	3	1336	72.2	3.8
1625	PFE	Pfizer, Inc.	3	1	1529	66.1	3.9
2153	WMT	Wal-Mart Stores	2	1	1273	27.7	2.8
159	CAT	Caterpillar Inc.	1	3	1093	52.2	11.3
1196	PG	Procter & Gamble	3	1	1533	51.8	3.7
718	LMT	Lockheed Martin	3	1	668	69.0	20.7
1750	GE	Gen'l Electric	2	3	1558	49.9	2.6
2587	ORCL	Oracle Corp.	2	1	1278	56.5	3.8
221	JNJ	Johnson & Johnson	3	1	1710	59.8	2.9
366	MCD	McDonald's Corp.	3	1	1298	59.5	5.8

Growth Stocks with Moderate Risk

This list is designed for investors seeking stocks with worthwhile long-term appreciation potential and low-to-moderate risk.

We began by screening for companies whose share earnings have compounded at a minimum 10% annual rate over the past five years and which are expected to at least maintain a 10% annual growth rate over the next 3 to 5 years.

Next, we pared the list to stocks with price appreciation potential of 60% or more over the next three to five years, measured from the mid-point of each issue's target price range. By way of comparison, the current projected median appreciation for the entire Value Line universe is also 60%. To control for risk, we required that all stocks selected have a Safety rank of at least 3 (Average). Going one step further, we also set better-than-average hurdles for the two measures that determine the Safety rank. We required that each company have a Financial Strength rating of B+ or better and a score of 85 or more on the Price Stability Index, the range of which runs from 5 to 100. These factors should help select those companies with lower-than-average risk profiles. Finally, to guard against near-term underperformance, we required a Timeliness rank of at least 3 (Average).

Given these relatively stringent criteria, it isn't surprising that there were not too many issues in our universe that made the final cut. In fact, selecting growth stocks with the combination of worthwhile appreciation potential and low-to-moderate risk remains a difficult task, especially given uncertainties regarding in the prospects for global economic growth. Thus, the stocks listed below comprise an elite group. Meanwhile, many growth stocks, including some with better historical and prospective appreciation potential, were eliminated due to their less-than-stellar marks for Financial Strength or their volatile share price movements. We note, however, that the equities included below are likely to provide investors with worthwhile returns over the next 3 to 5 years, reflecting each issue's prospects for price appreciation during that time frame.

This is a short list, with an emphasis towards companies operating in the healthcare and technology-based industries. Those wanting to hold less-risky stocks with good prospects may consider most of the choices listed below. As always, we strongly urge investors to consult the individual analyses in Part 3, *Ratings & Reports*, before committing to any of the issues that appear in this screen.

Ratings & Reports Page	Ticker	Company	Timeliness	Safety	3-5 Year Apprec. Potential	Annual E.P.S. Growth Last 5 Years	Annual E.P.S. Growth Next 5 Years	Price Stability Index	Financial Strength Rating	Industry
206	ABC	AmerisourceBergen	3	2	100%	17.0%	10.0%	100	B++	Med Supp Non-Invasive
974	CVS	CVS Caremark Corp.	2	1	75	15.0	11.0	90	A	Pharmacy Services
1800	CHKP	Check Point Software	3	1	70	13.5	13.0	85	A+	E-Commerce
1746	DHR	Danaher Corp.	3	2	100	10.5	15.5	90	B++	Diversified Co.
1023	DTV	DIRECTV	1	3	150	44.0	23.5	85	B+	Cable TV
2582	INTU	Intuit Inc.	3	1	65	16.0	13.0	90	A+	Computer Software
807	LH	Laboratory Corp.	2	1	70	14.0	10.5	100	A	Medical Services
2585	MSFT	Microsoft Corp.	3	1	80	14.5	11.0	90	A++	Computer Software
374	THI	Tim Hortons	3	2	60	12.0	14.0	95	A	Restaurant
198	VAR	Varian Medical Sys.	2	1	85	16.0	11.0	85	A+	Med Supp Invasive
1383	XLNX	Xilinx Inc.	3	2	65	13.0	10.0	85	A	Semiconductor

Equity Funds Average Performance

TOTAL RETURN*
Percent Change through August, 2012

	Year-to-Date	Three Month	Six Month	One Year	Five Year (Annualized)
Performance Objective					
Aggressive Growth	8.8	4.8	—	8.7	-0.2
Growth	11.2	6.4	0.6	12.1	0.5
Growth/Income	11.1	7.4	2.2	14.1	0.2
Income	9.4	6.9	2.3	12.5	0.8
Balanced	8.4	5.4	1.6	9.1	2.2
International					
European Equity	9.6	11.1	-2.4	2.2	-5.0
Foreign Equity	7.3	8.0	-4.9	-1.9	-3.8
Global Equity	9.2	7.2	-1.7	5.4	-1.2
Pacific Equity	4.7	3.6	-8.0	-7.9	-5.1
Sector					
Energy/Natural Res	-2.1	8.6	-11.8	-9.5	-2.9
Financial Services	15.9	8.0	2.4	12.9	-7.5
Health	16.1	7.4	7.4	19.0	5.3
Precious Metals	-6.7	10.0	-15.1	-24.9	6.5
Real Estate	17.5	8.4	8.2	15.3	0.7
Technology	13.1	6.9	-1.3	11.2	2.2
Utilities	8.6	7.1	5.2	11.2	0.3
Other					
Convertible	6.9	4.8	-1.1	5.4	2.3
Flexible	7.2	4.7	0.9	6.2	1.6
Specialty	6.4	6.2	-1.6	2.8	-1.6
Small Company	9.5	5.9	-0.9	10.8	1.1
S&P 500	**13.5**	**7.9**	**4.1**	**18.0**	**1.3**

Source: The Value Line Fund Advisor
* *Dividends plus capital appreciation. Dividends are reinvested as of the ex-dividend date. The returns are arithmetic averages based on the performances of all funds within each category.*

Fixed-Income Funds Average Performance

TOTAL REINVESTMENT*
Percent Change through August, 2012

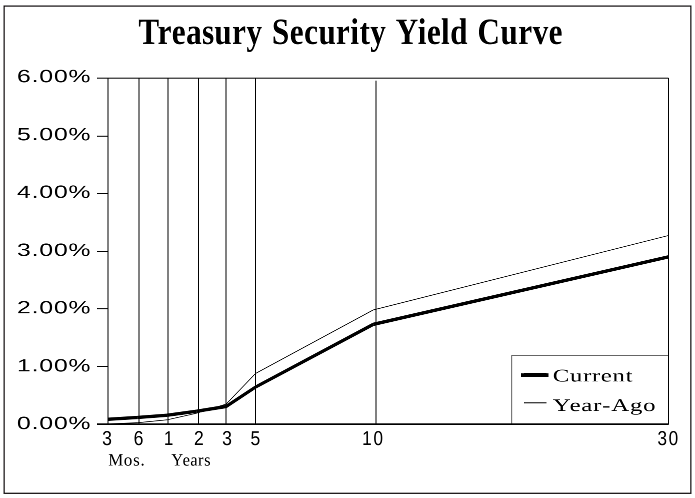
	Year-to-Date	Three Month	Six Month	One Year	Five Year (Annualized)
U.S. Government and Agency Bond					
U.S. Gov't	3.1	1.1	2.2	4.4	4.7
GNMA	3.4	1.5	2.4	4.6	4.8
Corporate Bond					
High Quality	4.9	2.1	3.0	5.7	4.5
High Yield	8.6	4.2	3.7	10.7	4.8
International	6.9	4.7	2.8	3.8	6.4
Municipal Bond					
California Tax Exempt	6.4	1.6	3.2	10.0	4.7
New York State Tax Exempt	5.5	1.6	2.9	8.7	5.0
National Tax Exempt	5.6	1.6	2.9	7.8	4.3

Source: The Value Line Fund Advisor
* *The cumulative rate of investment growth, including the reinvestment of dividend income and capital gains distributions as of the ex-dividend date. The investment objective averages are arithmetic averages calculated on the basis of the total reinvested rates of return produced by all funds within each investment objective category.*

Selected Yields

	Recent (9/12/12)	3 Months Ago (6/13/12)	Year Ago (9/14/11)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.27	0.32	0.38
3-month LIBOR	0.39	0.47	0.35
Bank CDs			
6-month	0.13	0.21	0.17
1-year	0.18	0.32	0.21
5-year	0.94	1.11	1.29
U.S. Treasury Securities			
3-month	0.09	0.09	0.01
6-month	0.12	0.15	0.03
1-year	0.16	0.17	0.08
5-year	0.65	0.70	0.88
10-year	1.73	1.59	1.98
10-year (inflation-protected)	-0.63	-0.54	0.06
30-year	2.90	2.71	3.27
30-year Zero	3.14	2.92	3.58

	Recent (9/12/12)	3 Months Ago (6/13/12)	Year Ago (9/14/11)
Mortgage-Backed Securities			
GNMA 5.5%	0.81	1.28	1.13
FHLMC 5.5% (Gold)	1.94	1.89	1.97
FNMA 5.5%	1.70	1.91	1.88
FNMA ARM	2.25	2.29	2.50
Corporate Bonds			
Financial (10-year) A	3.19	3.34	3.72
Industrial (25/30-year) A	3.83	3.99	4.60
Utility (25/30-year) A	3.97	3.91	4.48
Utility (25/30-year) Baa/BBB	4.33	4.33	5.07
Foreign Bonds (10-Year)			
Canada	1.90	1.77	2.20
Germany	1.62	1.49	1.88
Japan	0.81	0.86	1.00
United Kingdom	1.83	1.75	2.44
Preferred Stocks			
Utility A	5.22	5.37	5.25
Financial BBB	6.10	6.52	6.38
Financial Adjustable A	5.46	5.46	5.46



	Recent (9/12/12)	3 Months Ago (6/13/12)	Year Ago (9/14/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.73	3.92	4.05
25-Bond Index (Revs)	4.43	4.80	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.18	0.19	0.20
1-year A	0.84	0.86	0.98
5-year Aaa	0.78	0.85	0.93
5-year A	1.81	1.84	1.96
10-year Aaa	1.99	2.07	2.17
10-year A	3.14	3.08	3.65
25/30-year Aaa	3.34	3.55	3.88
25/30-year A	4.79	4.86	5.62
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.25	4.37	4.62
Electric AA	4.41	4.68	4.97
Housing AA	4.74	4.74	5.60
Hospital AA	4.46	4.58	4.97
Toll Road Aaa	4.28	4.41	4.69

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	9/5/12	**8/22/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1450818	1480850	-30032	1471978	1480418	1504263
Borrowed Reserves	2516	3527	-1011	4162	5512	7690
Net Free/Borrowed Reserves	1448302	1477323	-29021	1467816	1474906	1496573

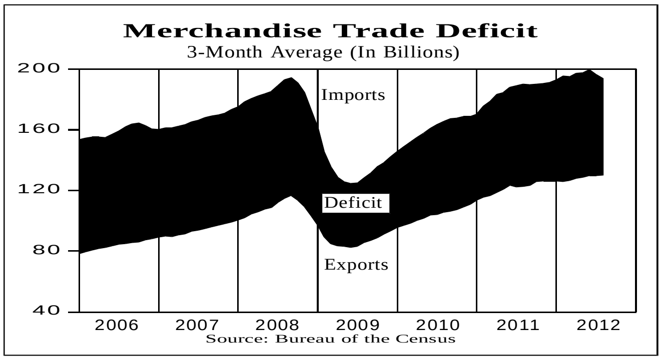
MONEY SUPPLY

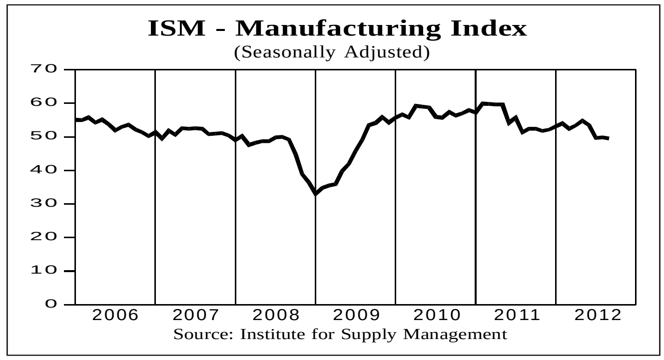
(One-Week Period; in Billions, Seasonally Adjusted)

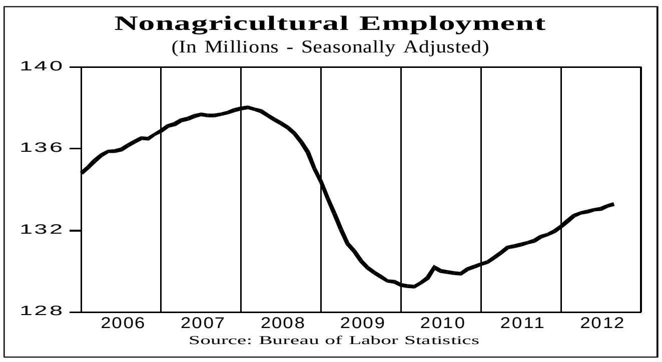
	Recent Levels			Ann'l Growth Rates Over the Last...		
	8/27/12	**8/20/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2320.9	2316.0	4.9	13.9%	9.1%	10.1%
M2 (M1+savings+small time deposits)	10070.4	10044.1	26.3	7.0%	6.0%	6.2%

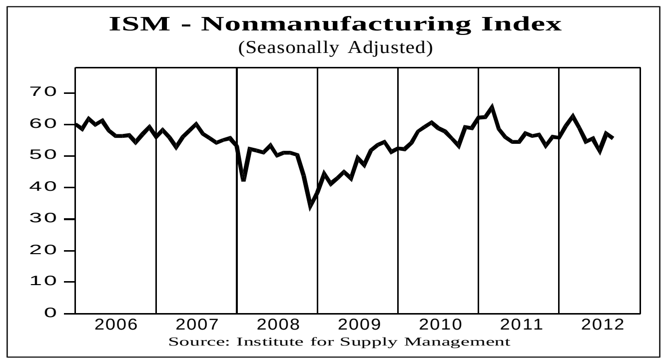
Source: United States Federal Reserve Bank

Tracking the Economy









Major Insider Transactions†

PURCHASES

Latest Full-Page Report	Timeliness Rank	Company	Insider, Title	Date	Shares Traded	Shares Held	Price Range	Recent Price
757	3	Alleghany Corp.	J. Brandon, V.P.	8/31/12	500	20,160	$336.13	347.70
1387	5	Applied Materials	G.H. Parker, Dir.	8/30/12	50,000	170,089	$11.53	11.65
1303	1	Belden Inc.	L.C. Balk, Dir.	8/31/12	3,000	71,972	$34.15	38.40
1967	2	Brown-Forman ‘B’	D. Stubbs, Dir.	8/31/12	3,350	481,952	$65.20	65.52
402	4	Calgon Carbon	W.R. Newlin, Dir.	9/4/12	8,864	211,278	$13.50	14.50
1948	2	Green Mtn. Coffee	J.A. Del Vecchio, Dir.	8/30/12	20,000	260,719	$24.06	32.16
136	3	Woodward, Inc.	P. Donovan, Dir.	9/4/12-9/5/12	5,500	15,000	$34.09-$34.95	36.51

SALES

Latest Full-Page Report	Timeliness Rank	Company	Insider, Title	Date	Shares Traded	Shares Held	Price Range	Recent Price
2617	2	Amazon.com	J.P. Bezos, Chair.	8/30/12	16,783	87,963,414	$250.00	255.67
2205	1	ANN Inc.	J.J. Burke Jr., Dir.	8/30/12	100,000	26,726	$35.69	37.90
1519	2	Camden Property Trust	D.K. Oden, Pres.	8/30/12-8/31/12	69,927	327,518	$69.48-$70.00	68.40
1519	2	Camden Property Trust	R.J. Campo, Chair.	8/30/12-8/31/12	69,927	315,087	$69.48-$70.00	68.40
1111	4	Masco Corp.	R.A. Manoogian, Chair.	9/4/12	500,000	5,898,282	$14.08	14.41
2585	3	Microsoft Corp.	B. Turner, COO	9/4/12	126,913	557,299	$30.52	30.79
2234	3	Urban Outfitters	S.A. Belair, Dir.	9/4/12	200,000	2,500,000	$37.78	38.90

* *Beneficial owner of more than 10% of common stock.*
† *Includes only large transactions in U.S.-traded stocks; excludes shares held in the form of limited partnerships, excludes options & family trusts.*

Major Insider Transactions are obtained from Vickers Stock Research Corporation.

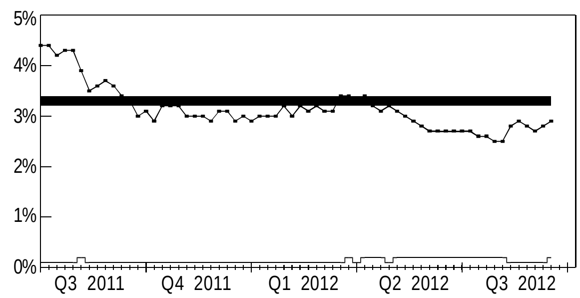
Market Monitor

Valuations and Yields	9/12	9/5	13-week range	50-week range	Last market top (7-13-2007)	Last market bottom (3-9-2009)
Median price-earnings ratio of VL stocks	15.2	14.9	14.1 - 15.2	12.9 - 15.8	19.7	10.3
P/E (using 12-mo. est'd EPS) of DJ Industrials	13.1	12.8	12.2 - 13.1	11.4 - 13.1	16.1	17.3
Median dividend yield of VL stocks	2.3%	2.3%	2.3 - 2.5%	2.1 - 2.5%	1.6%	4.0%
Div'd yld. (12-mo. est.) of DJ Industrials	2.7%	2.8%	2.7 - 2.8%	2.6 - 3.0%	2.2%	4.0%
Prime Rate	3.3%	3.3%	3.3 - 3.3%	3.3 - 3.3%	8.3%	3.3%
Fed Funds	0.2%	0.1%	0.1 - 0.2%	0.1 - 0.2%	5.3%	0.2%
91-day T-bill rate	0.1%	0.1%	0.1 - 0.1%	0.0 - 0.1%	5.0%	0.3%
AAA Corporate bond yield	3.5%	3.4%	3.2 - 3.7%	3.2 - 4.1%	5.8%	5.5%
30-year Treasury bond yield	2.9%	2.8%	2.5 - 2.9%	2.5 - 3.4%	5.1%	3.7%
Bond yield minus average earnings yield	-3.1%	-3.3%	-3.8 - -3.1%	-4.0 - -2.3%	0.7%	-4.3%
Market Sentiment						
Short interest/avg. daily volume (5 weeks)	23.0	22.8	16.8 - 23.0	13.0 - 23.0	8.1	8.6
CBOE put volume/call volume	.78	.95	.78 - 1.04	.67 - 1.31	.91	.93

VALUE LINE ASSET ALLOCATION MODEL

(Based only on economic and financial factors)

	Current (effective market open 4/2/12)	Previous
Common Stocks	60%-70%	65%-75%
Cash and Treasury Issues	40%-30%	35%-25%



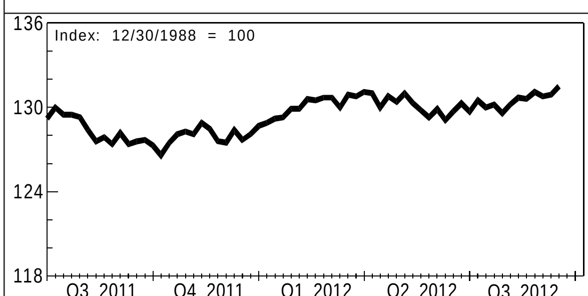
INTEREST RATES

Prime Rate

Federal Funds

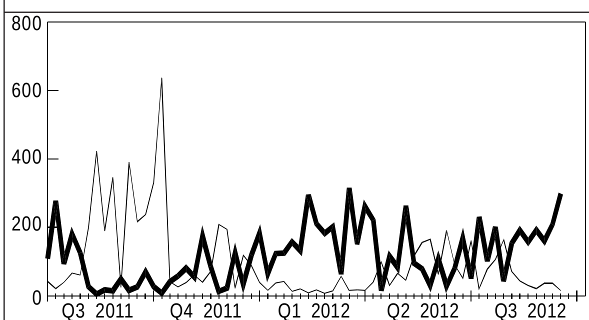
30-Year Treasury Bond

	Recent	Previous Week
Prime Rate	3.3%	3.3%
Fed Funds	0.2%	0.1%
30-Yr. Treasury	2.9%	2.8%



VALUE LINE UNIVERSE

	Recent	Previous Week
Advances	1336	924
Declines	354	747
Issues Covered	1702	1699
Market Value ($ Trillion)	19.729	19.304



VALUE LINE UNIVERSE

New Highs

New Lows

	Recent	Previous Week
New Highs	299	208
New Lows	15	37

INDUSTRY PRICE PERFORMANCE LAST SIX WEEKS ENDING 9/11/2012

7 Best Performing Industries

Homebuilding	+23.0%
Precious Metals	+16.7%
Building Materials	+15.9%
Entertainment Tech	+15.2%
Medical Services	+13.6%
Metals & Mining (Div.)	+12.7%
Retail (Hardlines)	+12.6%

7 Worst Performing Industries

Electric Utility (East)	-4.8%
Trucking	-4.1%
Electric Util. (Central)	-2.6%
Electric Utility (West)	-1.9%
Pipeline MLPs	-1.5%
Natural Gas Utility	-0.5%
Cable TV	-0.3%

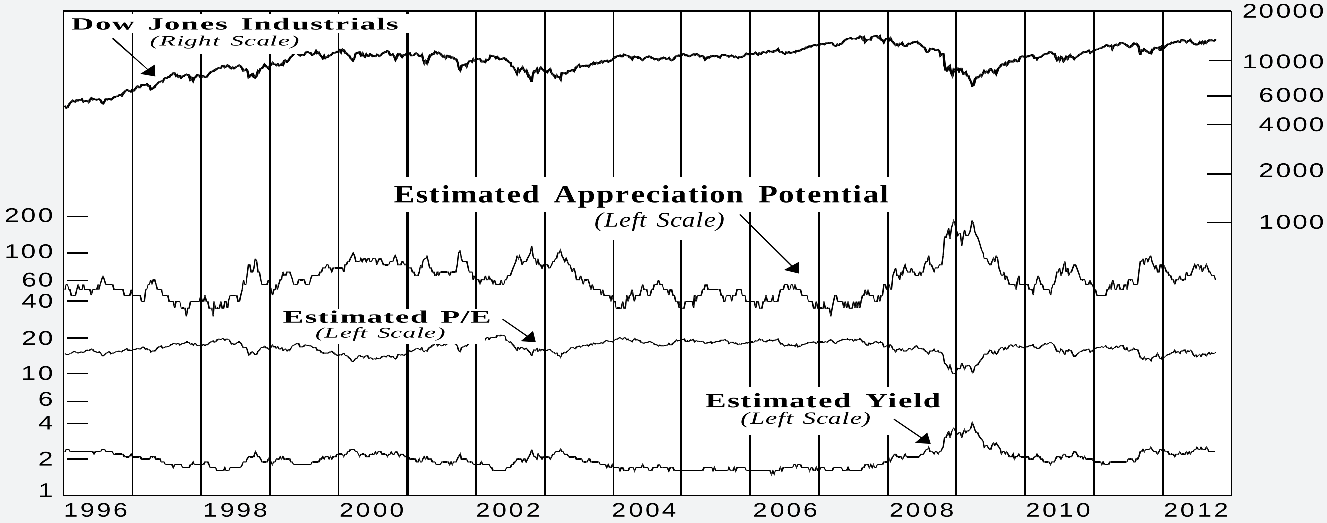
The corresponding change in the Value Line Arithmetic Average* is +7.0%

CHANGES IN FINANCIAL STRENGTH RATINGS

Company	Prior Rating	New Rating	Ratings & Reports Page
Acme Packet	B+	B	946
Alcatel-Lucent (ADR)	C++	C+	948
CenterPoint Energy	B+	B++	907
China Auto. Sys.	B+	C++	985
Inter Parfums, Inc.	B++	B+	1015
Nokia Corp. (ADR)	B+	B	964
Standard Motor Pds.	B	B+	1004
WABCO Hldgs.	B+	B++	1010

Stock Market Averages

VALUE LINE ESTIMATED P/E, YIELD, APPRECIATION POTENTIAL VERSUS DOW JONES INDUSTRIALS *(JANUARY 2, 1996 - SEPTEMBER 11, 2012)*



THE VALUE LINE GEOMETRIC AVERAGES

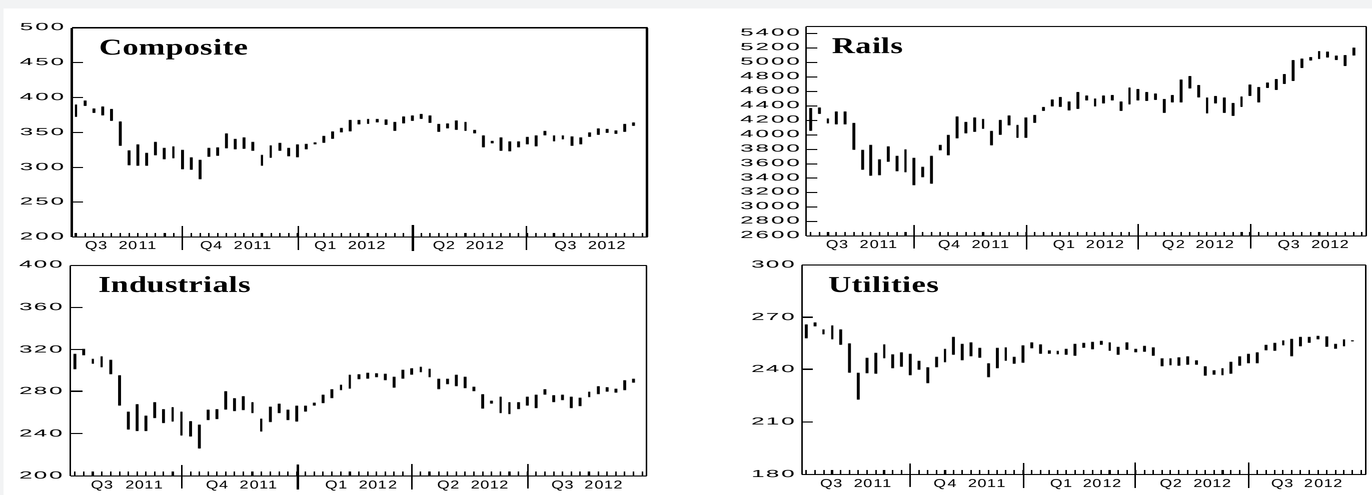
	Composite 1671 stocks	Industrials 1567 stocks	Rails 8 stocks	Utilities 96 stocks
9/6/2012	359.17	287.68	5081.02	256.88
9/7/2012	361.94	290.08	5098.22	256.69
9/10/2012	360.62	288.97	5106.60	256.46
9/11/2012	362.18	290.30	5160.72	256.35
9/12/2012	363.75	291.63	5199.47	256.35
%Change last 4 weeks	+4.0%	+4.3%	+2.0%	-0.9%

Arithmetic* Composite 1671 stocks
3045.95
3070.11
3059.33
3072.90
3087.21
+4.3%

THE DOW JONES AVERAGES

Composite 65 stocks	Industrials 30 stocks	Transportation 20 stocks	Utilities 15 stocks
4446.19	13292.00	5044.63	472.53
4454.17	13306.64	5072.20	471.86
4449.94	13254.29	5098.61	471.23
4468.19	13323.36	5133.50	469.91
4475.96	13333.35	5174.18	467.89
+0.3%	+1.3%	+0.6%	-2.8%

WEEKLY VALUE LINE GEOMETRIC AVERAGES* *(JULY 1, 2011 - SEPTEMBER 12, 2012)*



THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

DAVID C. PARCELL

PREPARED FOR THE SOCIETY OF UTILITY

AND REGULATORY FINANCIAL ANALYSTS

1997 EDITION

CHAPTER 7

COMPARABLE EARNINGS

The comparable earnings method is the "grandaddy" of cost of equity methods, as it is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is based upon the economic concept of "opportunity cost". As noted previously the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk. If, in the opinion of those who save and commit capital, the propective return from a given investment is not equal to that available from other investments of similar risk, the available capital will tend to be shifted to the alternative investments. Through this mechanism, opportunity-cost-driven pricing signals direct capital to its most productive uses; thus, a free enterprise system promotes an efficient allocation of scarce resources.

The established legal standards are consistent with the opportunity cost principle. The two Supreme Court cases most frequently cited (Bluefield and Hope) hold that the return to the equity owners be sufficient to maintain the credit of the enterprise and confidence in its financial integrity; to permit the enterprise to attract required additional capital on reasonable terms; and to provide the enterprise and its investors an earnings opportunity commensurate with the returns available on investments in other enterprises having corresponding risks.

These three interrelated criteria constitute a succinct statement of the opportunity cost principle. An expected return on equity equal to that which can be realized on alternative investments of corresponding risk will, in turn, be sufficient to assure conidence in the financial integrity of the enterprise, to maintain its credit, and to permit it to attract new capital on reasonable terms.

The comparable earnings method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, since it translates into practice the competitive principle upon which regulation rests.

The comparable earnings method normally examines the experienced and/or projected returns on book common equity. The logic for returns on book equity follows from the use of original cost rate base regulation for public utilities which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

It is maintained that the comparable earnings standard is easy to calculate and the amount of subjective judgment required is minimal. The method avoids several of the subjective factors involved in other cost of capital methodologies. For example, the DCF method requires the determination of the growth rate contemplated by investors, which is a subjective factor. The CAPM requires the specification of several expectational variables, such as market return and beta. In contrast, the comparable earnings approach makes use of simple readily available accounting data.

In addition, this method is easily understood and is firmly anchored in regulatory tradition (i.e., Bluefield and Hope). The method is not influenced by the regulatory process to the same extent as market-based methods such as DCF and CAPM. The base to which the comparable earnings standard is applicable is the utility's book common equity, which is much less vulnerable to regulatory influences than stock price which is the base to which the market-based standards are applied. Stock price can be influenced by the actions of regulators.

The rationale for the comparable earnings technique is aptly stated by Morin (1994, 406):

> "Although the Comparable Earnings test does not square well with economic theory, the approach is nevertheless meritorious. If the basic purpose of comparable earnings is to set a fair return rather than determine the true economic return, then the argument is

academic. If regulators consider a fair return as one that equals the book rates or return earned by comparable risk firms rather than one that is equal to the cost of capital of such firms, the Comparable Earnings test is relevant. This notion of fairness, rooted in the traditional legalistic interpretation of the Hope language, validates the Comparable Earnings test."

Use of Book Returns

The ratio return on common equity is computed as follows:

$$(7.1)\ ROE = \frac{NIAC}{CE}$$

where: ROE = return on equity

NIAC = net income available for common equity (after preferred dividends)

CE = common stockholders equity.

The return on equity ratio is often regarded as the primary summary measure in traditional ratio analysis (Penman, 1991, 233). Furthermore, a study by Block (1964, 116) notes:

> "Return on equity appears as a direct influence on the price-earnings ratio, re-emerges as a major cause of growth and is seen as a consistent pattern with earnings stability. Even payout is controlled by expectations of profitability."

AGENCY AUTHORITY OVER RATE OF RETURN

Agency	Agency determines rate of return under its general authority	Capital structure is adjusted to exclude non-utility financing when it is traceable	Method Agency favors in determining rate of return								Duration of call protection provision influences judgement in determining rate of return
			No ONE method ALL are considered	** Discounted cash flow	** Comparable earnings test	** Earnings/price ratio	** Midpoint approach	** Capital asset pricing model	** Risk premium	Other	
FERC	x	x	x	x							
ALABAMA PSC 12/	x	x		x							
ALASKA PUC	x	x			x						Possible
ARIZONA CC	x	x	x 2/	x 7/							
ARKANSAS PSC	x		x	x 11/							
CALIFORNIA PUC	x	x 1/	x 2/	x	x			x	x	x	Possible
COLORADO PUC	x	x		x 9/	x						
CONNECTICUT DPUC	x	x		x							
DELEWARE PSC	x		x 2/	x	x					x	
D.C. PSC	x	x		x							
FLORIDA PSC	x	x 1/	x 2/								
GEORGIA PSC	x	x	x 2/	x					x	x 8/	
HAWAII PUC	x	x	x 2/							x	
IDAHO PUC	x	x		x 9/	x	x					
ILLINOIS CC	x	x	x 2/				x			x	
INDIANA URC	x		x								
IOWA UB	x	x 1/	x	x					x	x 6/	
KANSAS SCC	x	x		x							
KENTUCKY PSC	x	x	x 2/	x	x	x	x			x	
LOUISANA PSC	x			x							
MAINE PUC	x	10/	x 9/	x							
MARYLAND PSC	x	x		x						x 6/	
MASSACHESETTS DPU	x	x		x 5/						x 5/	
MICHIGAN PSC	x	x	2/	x	x		x	x	x	x	
MINNESOTA PUC	x	x		x							
MISSISSIPPI PSC	x	x		x	x						
MISSOURI PSC 13/	x	x		x							
MONTANA PSC	x	x		x	x						
NEBRASKA PSC 4/											
NEVADA PSC	x	x		x	x	x					
NEW HAMPSHIRE PUC	x	x		x							Yes
NEW JERSEY BPU 12/	x	x	x					x	x	x	
NEW MEXICO PUC	x	x	x 2/	x	x					x	
NEW YORK PSC	x	x	x	x 7/						x	
NORTH CAROLINA UC	x	x	x 2/	x	x			x	x	x	
NORTH DAKOTA PSC	x			x							
OHIO PUC	x	x	x	x /7						x 7/	No decision
OKLAHOMA CC	x	x		x	x				x	x	
OREGON PUC	x	x 1/		x				x			
PENNSYLVANIA PUC	x	x	x 2/	x	x	x	x			x	Maybe, If soon
RHODE ISLAND PUC	x	x	x	x	x	x	x			x 3/	
SOUTH CAROLINA PSC	x	x	x	x				x	x		
SOUTH DAKOTA PUC	x	x		x	x						
TEXAS RC	x	x	x 2/						x		
UTAH PSC	x	x		x							
VERMONT PSB	x	x		x	x					x	
VIRGINIA SCC	x	x	x 2/								
WASHINGTON UTC	x	x									
WEST VIRGINIA PSC	x	x	x 2/	x	x			x	x	x	
WISCONSIN PSC	x	x	x 2/	x				x		x	
WYOMING PSC	x		x 2/	x	x			x	x	x	
PUERTO RICO PSC 12/	x	x			x						
VIRGIN ISLAND PSC	x	10/	x 2/	x	x					x	
NATL ENERGY BOARD	x	x	x 14/	x	x			x	x	x	
ALBERTA PUB	x	x	x 2/	x	x					x	
ONTARIO EB	x	x	x 2/		x					x	
QUEBEC NGB	x	x	x 2/							x	

Footnote explanations on following page
ICB = Case-by-Case Basis

AGENCY AUTHORITY OVER RATE OF RETURN
FOOTNOTES

1/ Non-utility investment dollars are always excluded from rate base. Where non-utility investment is comparatively small, capital ratios are not adjusted. When non-utility investment is large, we usually remove non-utility investment from equity.

2/ Commission favors no single method, but rather that which produces the most reasonable results.

3/ It may use any method it desires especially in the case of a small company.

4/ No Commission regulation of electric or gas utilities.

5/ DCF is preferred, but the Department approves other methods which check the DCF result; risk spread analysis preferred by a slight margin. Financial condition of utility also give consideration.

6/ DCF is preferred; other methods are considered.

7/ No single method, however discounted cash flow is frequently used.

8/ Discounted cash flow is used most often, but risk premium method used also. Determined case by case.

9/ DCF has been the preferred method, but its results should be checked with other methods.

10/ Never an issue before this agency.

11/ Agency prefers DCF, but any method presented is considered.

12/ Commission did not respond to request for update information; this data may not be current.

13/ DCF has been the preferred method, but its results are generally checked with other methods such as risk premium and CAPM.

14/ Commission favors no single method, but rather that which produces tolls that are just and reasonable.

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

A court overturned a rule from the Environmental Protection Agency that was supposed to have taken effect in 2012. This doesn't mean that electric utilities are off the hook for environmental upgrades, however.

Regardless of any EPA rules, coal-fired generation has declined this year due to low gas prices.

Investors in dividend-paying stocks, such as utilities, are facing a tax increase next year, unless Congress acts.

Most equities in this Industry are expensively priced, compared to historical standards for utilities.

An Update On EPA Rules

In 2011, the U.S. Environmental Protection Agency issued a rule concerning cross-state air pollution. The new regulation was supposed to have taken effect in early 2012. The rule created much consternation from owners of coal-fired units due to the short time frame for compliance, and litigation ensued. The rule was put on hold by one court order, then struck down by another. This was welcome news for most electric utilities with coal-fired generation, some of which would have had to curtail the usage of coal-fired plants had this rule gone into effect as scheduled originally. EPA will have a chance to revise this rule.

However, utilities with coal-fired facilities are still facing stricter limits on mercury emissions, which will take effect in 2015. This will be costly for many companies, although some (such as FirstEnergy and *American Electric Power*) have found ways to lessen their expected expenditures. In fact, some utilities have closed or plan to close some coal-fired plants. The costs of compliance aren't the only reason for the closings. Low prices for wholesale power have made complying with the new rule uneconomical for some utilities.

A Shift From Coal To Gas

Electric utilities' plants are dispatched based on their variable production costs. Nuclear units are first in the merit order, usually followed by coal, then gas. However, with natural gas prices so low, some electric companies have shifted some of their production from coal to gas. According to the U.S. Energy Information Administration, in 2010 (the latest data available), coal was used to generate 45% of the nation's electricity, and natural gas' share was 24%. Based on information provided by various utilities, these figures will be quite different in 2012, although coal will still exceed gas.

This does not create a windfall for utilities. Most, if not all, of the lower fuel costs are passed on to customers. Even so, this is indirectly beneficial for utilities that are seeking base rate increases. It is easier for a utility to convince the regulators to raise its base electric rates if lower fuel costs will offset part of the rate hike.

The Dividend Tax Rate

In 2003, Congress (with the support of the Bush Administration) lowered the tax rate on dividend income to a maximum of 15%. The law was set to expire at the end of 2010, but was extended for two years. Unless Congress acts, the law will expire at the end of 2012, and dividend income will be taxed as ordinary income beginning in 2013. Many utilities, the Edison Electric Institute (a trade group for investor-owned electric utilities), and the American Gas Association are lobbying Congress to avoid this situation. Investors might well have to wait until after Election Day for this matter to be resolved.

Conclusion

With interest rates so low, electric utility stocks have gotten much attention from investors due to their high dividend yields. The average yield of equities in this industry is above 4%.

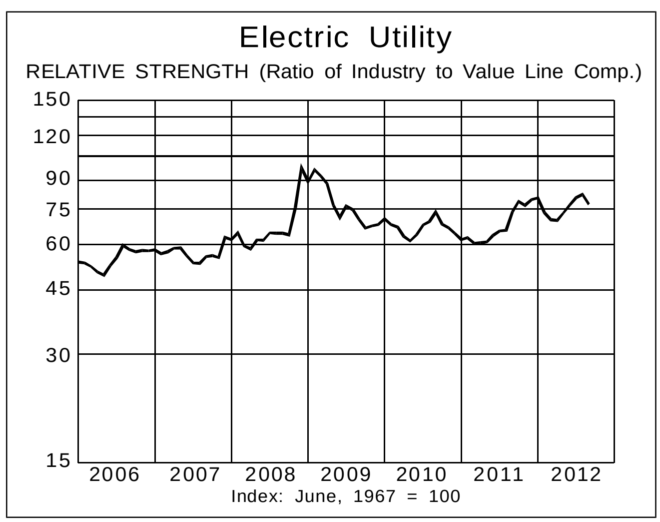
Electric utility issues usually trade at a below-market price-earnings ratio, unless earnings are depressed. (*ITC Holdings* is an exception.) However, several utilities are now trading at a price-earnings ratio that is above the market's. This is an indication of how expensively priced many of these equities have become. Another indication of their high valuation is the fact that many of them are trading within their 2015-2017 Target Price Range.

Paul E. Debbas, CFA

INDUSTRY TIMELINESS: 32 (of 98)

Composite Statistics: Electric Utility Industry

2008	2009	2010	2011	2012	2013		15-17
340.1	301.9	311.2	319.2	***290***	***305***	Revenues ($bill)	***350***
27.2	26.9	29.3	30.3	***27.0***	***29.0***	Net Profit ($bill)	***36.0***
33.3%	32.3%	34.1%	32.4%	***33.5%***	***34.0%***	Income Tax Rate	***34.0%***
7.8%	9.1%	8.8%	7.7%	***7.0%***	***7.0%***	AFUDC % to Net Profit	***6.0%***
53.4%	52.9%	52.6%	52.1%	***51.0%***	***51.0%***	Long-Term Debt Ratio	***50.5%***
45.6%	46.2%	46.6%	47.1%	***48.5%***	***48.5%***	Common Equity Ratio	***49.0%***
500.6	536.2	568.8	601.0	***570***	***595***	Total Capital ($bill)	***680***
538.2	580.6	625.2	688.9	***665***	***700***	Net Plant ($bill)	***800***
7.0%	6.5%	6.6%	6.5%	***6.0%***	***6.0%***	Return on Total Cap'l	***6.5%***
11.7%	10.7%	10.9%	10.5%	***9.5%***	***9.5%***	Return on Shr. Equity	***10.5%***
11.8%	10.8%	10.9%	10.6%	***9.5%***	***10.0%***	Return on Com Equity	***10.5%***
5.1%	4.3%	4.6%	4.1%	***3.5%***	***3.5%***	Retained to Com Eq	***4.0%***
57%	61%	59%	60%	***67%***	***64%***	All Div'ds to Net Prof	***61%***
15.0	12.5	12.8	13.8	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***13.5***
.90	.83	.81	.87			Relative P/E Ratio	***.90***
6.0%	4.8%	4.6%	4.4%			Avg Ann'l Div'd Yield	***4.3%***



NEW REGULATORY FINANCE

Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

The average growth rate estimate from all the analysts that follow the company measures the consensus expectation of the investment community for that company. In most cases, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the widespread availability of earnings forecasts. Given the paucity and variability of dividend forecasts, using the latter would produce unreliable DCF results. In any event, the use of the DCF model prospectively assumes constant growth in both earnings and dividends. Moreover, as discussed below, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts relative to historical estimates when estimating the cost of capital.

The uniformity of growth projections is a test of whether they are typical of the market as a whole. If, for example, 10 out of 15 analysts forecast growth in the 7%–9% range, the probability is high that their analysis reflects a degree of consensus in the market as a whole. As a side note, the lack of uniformity in growth projections is a reasonable indicator of higher risk. Chapter 3 alluded to divergence of opinion amongst analysts as a valid risk indicator.

Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.

Empirical Literature on Earnings Forecasts

Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only.

Academic research confirms the superiority of analysts' earnings forecasts over univariate time-series forecasts that rely on history. This latter category

A Study of Financial Analysts: Practice and Theory

Stanley B. Block

The study reported here focused on determining what analytical techniques financial analysts who are members of AIMR actually use. The study achieved a response rate of 33.75 percent. Questions covered 16 areas, including the use of present value analysis, the importance of quarterly earnings' announcements in decision making, belief in efficient markets, acceptance or rejection of market anomalies, and belief in the importance of international diversification for risk reduction.

The exams, curriculum materials, and seminars designed for the CFA® (Chartered Financial Analyst) Program are based on knowing what is important to practicing financial analysts. Yet, little documentation exists about what financial analysts actually believe in and do. The intent of this research was not necessarily to identify the normative approaches but, rather, to identify the most widely used approaches. Moreover, the results are not intended to suggest that future analysts be directed to the most commonly used approaches. The intention of this article is to share knowledge about what goes on in the day-to-day practice of financial analysts.

For example, use of present value analysis is heavily stressed in the CFA curriculum and is a major focus of textbooks on investments, but how widely is present value analysis actually used and by whom? Also, new techniques for analysis, such as economic value added, have received relatively less attention than traditional measures of analysis, but little is known about how widely accepted EVA is by practitioners. This survey addressed such issues.

The Study

The participants in this study came from the membership of AIMR (the Association for Investment Management and Research). Questionnaires were mailed to a random sample of 900 AIMR members in the United States in October 1998.[1] Because of address changes and other factors, 880 mailings successfully arrived at their intended destinations. Of that number, 297 usable responses were received, for a return ratio of 33.75 percent. A follow-up telephone survey of randomly selected nonrespondents indicated no statistically significant differences between those who initially answered the questionnaire and those who did not.

The final questionnaire, which is reproduced in Appendix A, had been previously tested in three pilot group surveys.

The questionnaire materials made clear to participants that the survey was sponsored by the author and not by any business organization or AIMR itself.[2]

The Respondent Group

The first three tables in this article reveal key characteristics of those who responded to the questionnaire. In **Table 1**, the 297 respondents are delineated by the type of firm for which they worked. The largest number of responding financial analysts were employed by brokerage firms and private money management groups. Investment management counseling firms, mutual funds, and bank trust departments are also represented substantially. Although no attempt was made in this study to stratify the sample by industry classification in advance, the composition of respondents does reasonably represent the membership profile by industry classification as reported by the more than 32,000 AIMR members in the *1998 Membership Directory*.[3]

As indicated in **Table 2**, 67.7 percent of the respondents were CFA charterholders and 53.9 percent held M.B.A. degrees. The charterholder number in this sample is slightly smaller than for the total organization (70 percent), whereas the M.B.A. degree number is slightly larger than for the

Stanley B. Block, CFA, is professor of finance at Texas Christian University.

Table 1. Respondent Breakdown by Industry Classification

Industry	Number	Percent
Brokerage	77	25.9
Private money management group	75	25.2
Investment management counseling	39	13.1
Mutual fund	39	13.1
Bank trust department	32	10.8
Investment banking	18	6.1
Other	12	4.1
Pension fund	5	1.7
Total	297	100.0

total membership (47 percent). Note that the average experience of the respondents is 15.3 years.

Table 3 reports the undergraduate majors of the respondents. A large percentage of the respondents (and perhaps, inferentially, a large percentage of AIMR members, although no industry data are available with which to compare these data) had undergraduate degrees in business and economics. The notion that the typical route to becoming a financial analyst is for an individual to get a liberal arts degree and then use that broad-based background to concentrate later on financial analysis is not supported by these data.

Table 2. Respondent Breakdown by Certification, Education, and Experience

Characteristic	Number	Percent
A. Certification		
Charterholder	201	67.7
Noncharterholder	96	32.3
Total	297	100.0
B. Highest degree		
M.B.A.	160	53.9
Master	4	1.3
Doctor of Jurisprudence (J.D.)	2	0.7
Bachelor	131	44.1
Total	297	100.0
C. Experience (years)		
0–5	30	
6–10	81	
11–15	78	
16–20	36	
21–25	18	
26–30	15	
More than 30	39	
Total	297	
Average	15.3 years	

The Results

This section contains discussion of the survey findings regarding the variables (or inputs to valuation) and tools financial analysts use in equity valuation, their attitudes toward issues important in portfolio management, and their attitudes toward market efficiency versus market anomalies.

Table 3. Respondent Breakdown by Type of Undergraduate Degree

Discipline	Number	Percent
Finance	96	32.3
Economics	76	25.6
General business	38	12.8
Accounting	29	9.8
Liberal arts	28	9.4
Math, science, engineering	17	5.7
Other (psychology, public affairs, etc.)	13	4.4
Total	297	100.0

Valuation Inputs. Respondents were asked about their use of several variables and tools in analyzing securities. Among the most important was present value (PV) analysis; others included corporate earnings and cash flow.

- *Present value.* The use of PV analysis is a central theme in valuation theory. There is probably not a CFA exam preparation course being taught around the world or an investments course being offered at a university that does not include PV analysis techniques. But as Panel A of Table 4 indicates, only 15.2 percent of respondents always use PV analysis and for 45.7 percent, it is not part of their normal procedures. Apparently, practitioners split about 50/50 in their use of PV techniques.

Should this finding be taken as an indictment of the profession? Hardly. When faced with the reality of valuation in the marketplace, the task of projecting earnings, dividends, and a stock price into the future and determining an appropriate discount rate may be too fraught with uncertainty for analysts to rely on discounted cash flow (DCF) analysis in the determination of value. As noted financial economist Stewart Myers (1984) of the Massachusetts Institute of Technology has suggested, "DCF is sensible, and widely used, for valuing relatively safe stocks paying regular dividends, but DCF is not as helpful in valuing companies with significant growth opportunities" (pp. 126–137).

Nevertheless, because PV analysis is part of the foundation of finance, I decided to analyze its use by various categories of participants. Shown in Panels B and C of Table 4 are the use and nonuse of PV analysis by CFA charterholders (hereafter, simply "charterholders") versus noncharterholders and M.B.A.s versus non-M.B.A.s. Although the charterholder group indicated a slightly larger tendency to use PV analysis than the noncharterholder group, the difference is not statistically significant at any

Table 4. Use of PV Techniques

Answer	Numbers	Percent
A. Overall sample		
Always	45	15.2
Sometimes	116	39.1
Never	136	45.7
Total	297	100.0
B. Charterholders versus noncharterholders		
Charterholders		
Always	38	18.9
Sometimes	70	34.8
Never	93	46.3
Total	201	100.0
Noncharterholders		
Always	7	7.3
Sometimes	46	47.9
Never	43	44.8
Total	96	100.0
C. M.B.A.s versus non-M.B.A.s		
M.B.A.s		
Always	17	10.6
Sometimes	71	44.4
Never	72	45.0
Total	160	100.0
Non-M.B.A.s		
Always	28	20.4
Sometimes	44	32.1
Never	65	47.4
Total	137[a]	100.0

[a]Included 131 bachelor, 4 master, and 2 J.D. degrees for a total of 137.

reasonable level of significance on the basis of a chi-square independence of classification test (reported in Appendix B). The same conclusion applies in regard to the use of PV analysis by M.B.A.s versus non-M.B.A.s. If anything, non-M.B.A.s appear to be slightly higher users of PV analysis.

Table 5 shows the breakdown of the use of PV analysis by respondents' industry classifications. In this case, the chi-square test (see Appendix B) indicated a statistically significant difference between the categories. A null hypothesis of no relationship between industry classification and the use of PV analysis could be rejected at the 5 percent level of significance. In this sample, individuals employed by mutual funds and bank trust departments appear to be relatively high users of PV analysis whereas those working for brokerage firms, private money management groups, and investment banking firms do not.[4]

Other inputs. The respondents were also asked to determine the relative importance of other inputs in analyzing securities. **Table 6** shows how the survey participants ranked the importance of earnings, cash flow, book value, and dividends. The average ranking for the input is shown in the far right column. Earnings and cash flow are considered far more important than book value and dividends.

The lack of importance these respondents assigned to dividends is interesting. As reported in Table 6, only 3 of the 297 respondents considered dividends to be the most important variable in valuing a security. One hypothesis is that such conclusions by analysts are linked to the irrelevance of dividends theory initially postulated by Modigliani and Miller (1961)—and debated ever since. But a far more likely cause of the low dividends ranking is that in the momentum-driven environment of 20–30 percent annual returns of the mid-to-late 1990s, dividends do not count for much in the minds of analysts. Furthermore, the sharply lower capital gains rates specified in the Taxpayer Relief Act of 1997 all but wiped out the equalization of taxing investment dividends and capital gains that was an essential element of the Reagan Tax Reform Act of 1986. Finally, the desire by corporations to buy back shares rather than increase cash dividends appears to be a distinctive feature of the 1990s.

Table 5. Industry Classification and Use of PV Techniques

	Always		Sometimes		Never	
Industry[a]	Number	Percent	Number	Percent	Number	Percent
Brokerage (77)	5	6.5	32	41.6	40	51.9
Private money management (75)	11	14.7	25	33.3	39	52.0
Investment management counseling (39)	3	7.7	19	48.7	17	43.6
Mutual fund (39)	12	30.8	16	41.0	11	28.2
Bank trust department (32)	10	31.2	8	25.0	14	43.8
Investment banking (18)	0	0.0	3	16.7	15	83.3
Other (12)	4	33.0	8	66.7	0	0.0
Pension fund (5)	0	0.0	5	100.0	0	0.0
Total	45		116		136	

[a]Total number in category in parentheses.

Table 6. Rank of Inputs in Importance

Variable	First	Second	Third	Fourth	Average Ranking
Earnings	156	118	23	0	1.55
Cash flow	133	140	19	5	1.65
Book value	5	32	133	127	3.29
Dividends	3	7	122	165	3.51

Not all would agree with the lack of importance of dividends. Bernstein (1998) made a strong case that management creates additional reinvestment and earnings risk for shareholders when the company retains a progressively larger percentage of earnings. The unimportance of dividends to this sample of analysts is further reflected, however, in **Table 7**, in which the respondents ranked the most significant inputs in determining a stock's P/E. Only 3 of the 297 respondents ranked dividend policy first among the five inputs listed; 276 ranked it last. Although analysts might change the rankings shown in Table 7 when valuing a real estate investment trust or a company in the later stages of its life cycle, the classification of dividends as unimportant is clear in Tables 6 and 7.

Also in Table 7, the growth potential for the company has a strong #1 ranking as a determinant of a stock's multiplier. The #2 ranking of quality of earnings (above quality of management, risks, and dividend policy) appears to reaffirm the strong concern that practicing analysts have for the legitimacy of reported earnings.

In another question related to valuation, I asked the respondents to rank the importance of the three inputs shown in **Table 8** as part of the determination of whether a stock should be bought, sold, or held. The long-term outlook for the company and the current value of the stock versus its historical trading range received top rankings; next quarter's EPS number was last by a large margin. This response is somewhat surprising; a click on the Internet will bring a deluge of under- and overperformance of quarterly earnings against expected earnings. Perhaps the 15.3 years average experience of the respondents allows them to overcome the hype of the moment.

Valuation Models. In addition to questions about the inputs to stock evaluation, the questionnaire asked respondents about their use of three valuation models. Panels A and B of **Table 9** provide the results for two traditional models—the dividend valuation (dividend discount) model and the capital asset pricing model (CAPM). Neither model fared well in the survey. The dividend model was viewed as very important or moderately important by 42 percent of the respondents, and the same two opinions totaled 31.1 percent for the CAPM.

The model that received the highest number of very or moderately important opinions, as indicated in Panel C of Table 9, is the economic value added (EVA) model developed by Stern Stewart and Company. Strictly speaking, EVA is not a valuation model, but it does have implications for describing stock price behavior. Based on these survey results, EVA may take on increasing importance for analysts. Whether the respondents understood that EVA is primarily a method for splitting earnings between required returns and excess returns is not evident from the questionnaire. Further inquiry about how analysts use EVA would thus be useful.

Portfolio Management

The issues discussed so far have dealt with valuing individual securities. The three items tabulated in **Table 10**—beliefs about market timing, the appeal

Table 7. Rank of Variables in Determining P/E

Variable	First	Second	Third	Fourth	Fifth	Average Ranking
Growth potential	205	62	18	12	0	1.45
Quality of earnings	43	104	115	35	0	2.48
Quality of management	31	74	112	71	9	2.84
Risks	15	56	44	170	12	3.36
Dividend policy	3	2	8	9	276	4.87

Table 8. Rank of Variables in Determining Buy, Hold, and Sell Decisions

Variable	First	Second	Third	Average Ranking
Current versus historical trading range	216	67	14	1.32
Long-term outlook for the company	76	171	50	1.91
Next quarter's EPS	5	59	233	2.77

Table 9. Importance of Models of Stock Price Behavior

Model	Number	Percent
A. Dividend valuation model		
Very important	34	11.8
Moderately important	87	30.2
Not very important	112	38.9
Unimportant	55	19.1
Total	288[a]	100.0
B. Capital asset pricing model		
Very important	5	1.8
Moderately important	83	29.3
Not very important	135	47.7
Unimportant	60	21.2
Total	283[b]	100.0
C. Economic value added		
Very important	41	14.4
Moderately important	151	53.2
Not very important	62	21.9
Unimportant	30	10.5
Total	284[c]	100.0

[a]Nine participants chose not to answer.
[b]Fourteen participants chose not to answer.
[c]Thirteen participants chose not to answer.

of global investing, and near-term reversion to the mean—relate more to portfolio management.

Panel A of Table 10 indicates that only 28.6 percent of the respondents believed that attempts at market timing are likely to enhance portfolio returns (the value is 32.7 percent if only those *with* opinions are included). The consistency of this response with the results shown in Panel C will be discussed shortly.

Table 10. Beliefs about Portfolio Management

Belief	Number	Percent	Among Those with Opinions
A. Does market timing enhance portfolio return?			
Yes	85	28.6	32.7%
No	175	58.9	67.3
No opinion	37	12.5	—
Total	297	100.0	100.0%
B. Has global investing lost appeal in more closely linked markets?			
No	37	12.5	
Some loss	202	68.2	
Substantial loss	57	19.3	
Total	296[a]	100.0	
C. Will there be a reversion to the mean in the next decade for yields and P/Es?			
Yes	171	57.6	71.6%
No	68	22.9	28.4
No opinion	58	19.5	—
Total	297	100.0	100.0%

[a]One participant chose not to answer.

Panel B of Table 10 deals with global investing. A major phenomenon portfolio managers have witnessed in the mid-to-late 1990s is the speed at which international financial markets react to each other. Market performance in the United States on a given day appears to start a chain reaction in London, Tokyo, and other major markets. The sequence may also move in the other direction. The internationalization of the world economy through reduced trading barriers and the increased merger activity between financial institutions in various countries appears to add to this chain reaction. The responses to Question 14 reported in Panel B give strong support to the notion that global investing may have lost some of its appeal in the closely linked markets as a means to achieve better risk–return outcomes through diversification. Slightly more that 87 percent of respondents believed there has been some loss or substantial loss of appeal.

Finally, Panel C of Table 10 addresses a question that all portfolio managers and analysts appear to be asking in the financial press—whether there will be a reversion to the mean for P/Es and dividend yields within the next decade. With the P/E for the S&P 500 Index in the 24–28 range and dividend yields in the 1.6–1.8 percent range in late 1998, this question is timely and of great interest to the profession and investors. Among the respondents, as indicated in Panel C, 57.6 percent expected a reversion to the mean. This statistic suggests that many believe equity values will be lower in the future, but responses to Question 7 (not reported here) indicate that respondents believe high values may be sustainable as long as interest rates and inflation remain low. The reversion is perhaps most likely to come when these mitigating variables are no longer in place.

The totality of information in Table 10 may reveal an inconsistency on the part of respondents. The majority did not believe in market timing but did believe in a coming reversion to the mean. Presumably, a reversion to the mean has implications for the timing of decisions.

Market Efficiency

The respondents were asked to indicate their acceptance or rejection of the efficient market hypothesis (EMH), which in its broadest (semistrong) form suggests that public information is impounded in the current price of the stock and that any additional analysis by an individual analyst is likely to produce little or nothing in the way of added value.[5] The EMH was initially postulated in the 1960s, and it has been under severe attack ever since as researchers claimed to identify anomalies in almost every area of investments. As shown in Table 11, close to 100 percent of practicing analysts in this survey were neutral or strongly disagreed with the EMH.

Table 11. Opinion of the Efficient Market Hypothesis

Opinion	Number	Percent
Strongly agree	8	2.7
Neutral	101	34.2
Strongly Disagree	186	63.1
Total	295[a]	100.0

[a]Two participants chose not to answer this question.

The responses to an allied topic are presented in Table 12. In answering a question about the most important variable in determining portfolio returns, more than 60 percent of the respondents chose the skill and training of the portfolio manager as most important. Despite the emphasis on the risk component often found in the academic literature, risk in the portfolio came in at about half the percentage of skill and training. And the amount of trading in the portfolio came in a poor third. These responses are generally in line with the rejection of the EMH reported in Table 11 but at variance with the responses to the usefulness of the CAPM shown in Table 9.

Table 12. Most Important Variable in Determining Portfolio Return

Variable	Number	Percent
The skill and training of the portfolio manager	179	60.3
The amount of risk in the portfolio	116	39.1
The amount of trading in the portfolio	2	0.6
Total	297	100.0

A number of respondents who indicated that skill and training was the most important variable in determining portfolio return suggested that ego might have played a role in their opinion. Such a suggestion would be consistent with the empirical research in this area in the past decades (Fama 1991; Kandel and Stambaugh 1996). Perhaps hope triumphed over reality for the majority of respondents.

To inquire into analysts' attitudes toward anomalies that tend to disprove the EMH, the respondents were given four market strategies from which to choose (Question 12). These four were by no means inclusive of all the possible strategies, and in spite of research in this area, no one answer can be assumed to be correct. The answers are presented in Table 13.

Table 13 shows that the low-P/E effect and the small-firm effect received the greatest allegiance. This response to the small-firm effect is of particular interest because the small-firm effect has been called too time-period specific and overly dependent on the month of January for high returns. As an example of the time-period specificity, research has found that between 1975 and 1983, small-capitalization stocks averaged a 35.3 percent annual return, more than twice the 15.7 percent return of large-cap stocks. During the same time period, compounded total returns on small-cap stocks exceeded 1,400 percent.[6] However, from 1984 to 1997, small-cap stocks (as defined by Ibbotson and Associates 1998) increased by 526.9 percent while large-cap stocks (S&P 500) were up 902.8 percent. When one strips the 1975–83 period out of the Ibbotson and Associates data, small-cap stocks *fell* one-third below large-cap stocks from 1926 through 1997.

Table 13. Statements about Market Anomalies with Which Respondents Agreed

Statement	Number Agreeing
Low-P/E stocks tend to outperform the market	184
Small-cap stocks tend to outperform the market	165
High-P/E growth stocks tend to outperform the market	39
Large-cap stocks tend to outperform the market	30
	418[a]

[a]Respondents could select more than one answer.

The intent here is not to castigate small-cap stocks; clearly, such stocks as Microsoft, Intel, and Home Depot had to start as small-cap stocks. Furthermore, for the particularly astute analyst, smaller companies may represent especially good areas for study, in that even the strongest advocates of the EMH would admit that small companies provide opportunities. The important point is that the strong support for the small-firm (and low-P/E) anomaly in this study may indicate that many practicing financial analysts maintain a belief in these concepts and a belief that a different market environment may bring the opportunity for strong small-cap performance to reappear. Also, the loyalty that some investors have shown to large-cap high-P/E stocks (such as Coca Cola and General Electric) is not necessarily felt by respondents in this study, who appear to be more value-stock than growth-stock oriented.

Conclusions

The most important conclusion from this survey is that PV techniques are not as widely used in practice as they are in theory. Only 54.3 percent of the respondents said they use PV analysis as part of their normal analytical process. The cause may be that the difficulties of projecting future cash flows and selecting an appropriate discount rate simply make use of PV analysis appear to be too difficult for real-life decisions. Although the length of forecasting periods was not specifically covered in the questionnaire, my observation is that few analysts project earnings or dividends more than two (or at most three) years into the future because of uncertainty. Also, they rarely project future P/Es. The industry practice is to divide the current price by future earnings to create a multiple of future earnings. This approach is, of course, very different from projecting a future P/E that can be used to discount a future stock price back to the present.

Answers to a number of questions indicate that the dividend-paying policy of a company is relatively unimportant in the analytical process. This attitude may be related to the current environment. In addition, although quarterly earnings announcements have received much attention in the financial press, 292 of the 297 analysts said quarterly earnings carry less weight than the long-term outlook for the company or its current versus historical trading range. The respondents gave high marks for importance to the EVA approach to valuation and low marks to the dividend valuation model and CAPM.

The respondents adhere to the notion that the most important variable in determining return on a portfolio is the skill and training of the portfolio manager and that this consideration overweights theories about stock market efficiency. Finally, respondents believe that global investing has lost some appeal as a risk–return optimizer in a world that appears to be increasingly integrated.

Notes

1. The original database from which names were drawn was the *1998 Membership Directory* of AIMR.
2. Although I am a CFA charterholder, I did not communicate that information to participants because of the concern that it could cause bias in answers.
3. The latest profile of AIMR membership can be found on AIMR's World Wide Web site: www.aimr.org.
4. Readers should not conclude anything beyond preliminary observations from these data because some of the industry classifications had relatively low numbers of respondents.
5. The semistrong form of the EMH asserts that only public information is impounded in the price. Some may suggest that the EMH is merely an unbiased estimator of current value, but the major thrust of the semistrong definition and the definition in Question 5 is the same.
6. For more discussion of the small-firm effect, see Chapter 6 in Siegel (1998).

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THE COST OF CAPITAL TO A PUBLIC UTILITY

Myron J. Gordon

1974
MSU Public Utilities Studies

Division of Research
Graduate School of Business Administration
Michigan State University
East Lansing, Michigan

so that the current value can be widely off the mark as a measure of the expected future value.

5.4 Other Measures of Growth

The measure of expected growth in the dividend established in the previous two sections, the intrinsic growth rate, is not the only possible measure of the variable. Another plausible measure is some average of the past rates of growth in the dividend. Under our model of security valuation, dividend, earnings, and price per share all are expected to grow at the same rate. Hence, the rates of growth in the dividend, earnings, and price also are candidates for estimates of the expected rate of growth in the dividend.

Let us consider first the rate of growth in earnings per share. The earnings per share during T adjusted for stock splits and stock dividends to make interperiod comparisons valid is

$$\mathrm{AYPS}(T) = \mathrm{AFC}(T)/.5\,[\mathrm{ANS}(T) + \mathrm{ANS}(T-1)], \tag{5.4.1}$$

where ANS(T) is the number of shares outstanding at the end of T adjusted for stock splits and dividends. The rate of growth in earnings per share during T is

$$\mathrm{YGR}(T) = [\mathrm{AYPS}(T) - \mathrm{AYPS}(T-1)]/\mathrm{AYPS}(T-1). \tag{5.4.2}$$

For reasons to be given shortly, the smoothed rate of growth in earnings is superior to the current rate as a forecast of the expected rate. The smoothed rate of earnings growth is obtained from

$$Ln[1 + \mathrm{YGRS}(T)] = \lambda Ln[1 + \mathrm{YGR}(T)] + (1 - \lambda) Ln[1 + \mathrm{YGRS}(T-1)], \tag{5.4.3}$$

with $\lambda = .15$ and YGRS(1953) = .04.

The primary reason for a difference between YGR and GRTH is a change in the rate of return on the common equity. To illustrate, assume a firm that has been earning a return on common of .10 and retaining one-half of its income to finance its investment. The rate of growth under both measures will be .05. If the firm's rate

of return on common rises from .10 to .11, the retention growth rate will rise from .05 to (.5)(.11) = .055. However, the earnings growth rate will rise from .05 to .155.[5] Furthermore, the earnings growth rate in subsequent periods will be .055 if the return on common remains .11. This example suggests that the intrinsic growth rate is superior to the earnings growth rate as a measure of expected growth. Investors nonetheless may look to past data on earnings growth for information on expected future growth, and it is the growth investors expect that should be used to measure share yield.

A number of considerations suggest that investors may, in fact, use earnings growth as a measure of expected future growth. First, the intrinsic growth rate includes stock financing growth as well as retention growth. The former is difficult for us to measure and may be even more difficult for investors. Consequently, investors may use past earnings growth to forecast the future since it incorporates in one statistic growth from all sources. Second, we saw that inflation will result in a rise in the allowed rate of return on equity for a regulated company. If this response to inflation takes place with a lag, that is, the regulatory agency raises RRC over time, earnings growth will reflect the forecast rate of growth better than intrinsic growth. Finally, it appears that security analysts use past growth in earnings more than any other variable to forecast future growth.

Given that earnings growth is used by investors to forecast future growth, the smoothed value of the variable YGRS is superior to the current value. The previous illustration revealed that YGR overreacts to changes in the allowed rate of return and therefore is subject to large random fluctuations. The data on YGR confirm this conclusion.

The use of dividend growth as a forecast of future growth is subject to the same limitations as earnings if the firm pays a constant fraction of its earnings in dividends. That is, under this assumption the dividend growth rate in any period is the same as the earnings growth rate. Firms tend to change their dividend rate from one

[5] Let the book value per share at the start of T be BVS(T − 1) = \$50.00. With RRC(T) = .10, AYP(T) = \$5.00, and with RETR(T) = .5, BVS(T) = \$52.50. If RRC(T + 1) = .10, AYP(T + 1) = \$5.25, and YGR(T + 1) = RTGR(T − 1) = .05. However, if RRC(T + 1) = .11, RTGR(T + 1) = (.11)(.5) = .055, while AYP(T + 1) = \$5.775, and YGR(T + 1) = (\$5.775 − \$5.00)/\$5.00 = .155.

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Heard off the street: Study finds analysts' forecasts have been too sunny

Sunday, March 30, 2008
By Len Boselovic, Pittsburgh Post-Gazette

Wall Street analysts may have had the last laugh now that their bete noir, former New York Attorney General and Gov. Eliot Spitzer, got his comeuppance over assignations with gilt-edged call girls.

Mr. Spitzer's performance as a crusading reformer was arguably responsible for major Wall Street firms agreeing to pay $1.5 billion in 2003 to settle allegations that they strong-armed their analysts into touting questionable stocks in order to win investment banking business from the companies the analysts were supposed to be analyzing objectively.

The uncaped crusader may have lost his credibility, but Mr. Spitzer's claims about the shortcomings of analysts have not. They are cemented in a new study by J. Randall Woolridge, a finance professor at Penn State's Smeal College of Business.

Mr. Woolridge's previous contribution to a more informed understanding of analyst behavior was research that concluded that investors who followed analyst recommendations would have slightly underperformed the Standard & Poor's 500, even though investing in stocks touted by analysts involved slightly more risk than investing in the broad market index.

This time around, Mr. Woolridge, aided by Penn State Harrisburg assistant finance professor Patrick Cusatis, compared analyst earnings growth forecasts for the companies they covered with what actually happened. After all, expectations of earnings growth are what drives the stock market. The better analysts forecasts are, the more investors can profit by acting on them quickly.

You won't be surprised by what the Penn State profs discovered.

They examined analyst forecasts at more than 1,200 companies from 1984 through 2006. They found that although analysts predicted long-term earnings per share growth of 14.7 percent at the companies they followed, the actual earnings growth that occurred was only 9.1 percent. By comparison, earnings of the S&P 500 over five-year periods grew an average of 7 percent from 1960 through 2006.

As should be expected, analysts fell closer to the mark when they looked only one year out, but their forecasts were unjustifiably cheerful nonetheless. They predicted average earnings per share growth of 13.8 percent vs. the 9.8 percent that actually occurred.

"Analysts' earnings growth rate estimates are consistently overly optimistic," Mr. Woolridge said. "These are very bright people. They have M.B.A.s from the best schools. They get paid very well. But they only see the upside."

And they seldom see the downside. While an average of about 30 percent of the companies studied had negative earnings growth in any given year, analysts predicted shrinking profits for only less than 1 percent of the companies.

"Their models are always forecasting positive growth," Mr. Woolridge said. "They never see the downturns. History tells us things go up, things go down."

The study indicates the positive bias of analysts has persisted even after their $1.5 billion settlement with the Securities and Exchange Commission. The agreement required Wall Street firms to separate their investment banking arms from their research departments in an effort to help analysts produce less biased and more realistic reports on the companies they follow.

Mr. Woolridge and Mr. Cusatis found that the gap between the growth analysts predict and the growth that actually happens has narrowed since the settlement, but remains significant.

There are several explanations for the persistent optimism of analysts. Some of their behavior stems from career concerns or conflicts of interest. Mr. Woolridge believes that one of the reasons why analysts are seldom gloomy is that they are rewarded financially to the extent that their optimistic assessments generate brokerage and underwriting business for their firms.

Anyone who has ever listened to a quarterly earnings conference call can attest to the fact that analysts are more likely to congratulate a CEO despite a miserable performance than they are to ask tough questions.

"People who are doomsayers don't last very long in this business," Mr. Woolridge said. "That's not what people want to hear."

Secondly, analysts only follow stocks they recommend and do not generate forecasts for companies they are not fond of, he says.

"If analysts systematically believe that they follow companies that are superior to others, they will be reluctant to issue negative earnings forecasts," Mr. Woolridge said.

Finally, analysts lose their objectivity because they get too close to the companies they follow, Mr. Woolridge says. They realize that if their forecasts are negative, "companies won't talk to them," he said.

Given what his research reveals about the accuracy of analyst forecasts and the value of their recommendations, Mr. Woolridge remains somewhat puzzled that so many continue to put great weight in what they have to say.

You could say the same about meteorologists, only, unlike analysts, they are more likely to forecast the storm of the century than warm and sunny weather.

Len Boselovic can be reached at lboselovic@post-gazette.com or 412-263-1941.

First published on March 30, 2008 at 12:00 am

The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts

Robert S. Harris and Felicia C. Marston

Using expectational data from financial analysts, we estimate a market risk premium for US stocks. Using the S&P 500 as a proxy for the market portfolio, the average market risk premium is found to be 7.14% above yields on long-term US government bonds over the period 1982-1998. This risk premium varies over time; much of this variation can be explained by either the level of interest rates or readily available forward-looking proxies for risk. The market risk premium appears to move inversely with government interest rates suggesting that required returns on stocks are more stable than interest rates themselves. [JEL: G31, G12]

The notion of a market risk premium (the spread between investor required returns on safe and average risk assets) has long played a central role in finance. It is a key factor in asset allocation decisions to determine the portfolio mix of debt and equity instruments. Moreover, the market risk premium plays a critical role in the Capital Asset Pricing Model (CAPM), the most widely used means of estimating equity hurdle rates by practitioners. In recent years, the practical significance of estimating such a market premium has increased as firms, financial analysts, and investors employ financial frameworks to analyze corporate and investment performance. For instance, the increased use of Economic Value Added (EVA®) to assess corporate performance has provided a new impetus for estimating capital costs.

The most prevalent approach to estimating the market risk premium relies on some average of the historical spread between returns on stocks and bonds.[1] This choice has some appealing characteristics but is subject to many arbitrary assumptions such as the relevant period for taking an average. Compounding the difficulty of using historical returns is the well noted fact that standard models of consumer choice would predict much lower spreads between equity and debt returns than have occurred in US markets—the so called equity risk premium puzzle (see Welch, 2000 and Siegel and Thaler, 1997). In addition, theory calls for a forward-looking risk premium that could well change over time.

This paper takes an alternate approach by using expectational data to estimate the market risk premium. The approach has two major advantages for practitioners. First, it provides an independent estimate that can be compared to historical averages. At a minimum, this can help in understanding likely ranges for risk premia. Second, expectational data allow investigation of changes in risk premia over time. Such time variations in risk premia serve as important signals from investors that should affect a host of financial decisions. This paper provides new tests of whether changes in risk premia over time are linked to forward-looking measures of risk. Specifically, we look at the

Robert S. Harris is the C. Stewart Sheppard Professor of Business Administration and Felicia C. Marston is an Associate Professor at the University of Virginia, Charlottesville, VA 22906.

The authors thank Erik Benrud, an anonymous reviewer, and seminar participants at the University of Virginia, the University of Connecticut and at the SEC for comments. Thanks to Darden Sponsors, TVA, the Walker Family Fund, and McIntire Associates for support of this research and to IBES, Inc. for supplying data.

[1]Bruner, Eades, Harris, and Higgins (1998) provide survey evidence on both textbook advice and practitioner methods for estimating capital costs. As testament to the market for cost of capital estimates, Ibbotson Associates (1998) publishes a "Cost of Capital Quarterly."

relationship between the risk premium and four *ex-ante* measures of risk: the spread between yields on corporate and government bonds, consumer sentiment about future economic conditions, the average level of dispersion across analysts as they forecast corporate earnings, and the implied volatility on the S&P500 Index derived from options data.

Section I provides background on the estimation of equity required returns and a brief discussion of current practice in estimating the market risk premium. In Section II, models and data are discussed. Following a comparison of the results to historical returns in Section III, we examine the time-series characteristics of the estimated market premium in Section IV. Finally, conclusions are offered in Section V.

I. Background

The notion of a "market" required rate of return is a convenient and widely used construct. Such a rate (k) is the minimum level of expected return necessary to compensate investors for bearing the average risk of equity investments and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds). To isolate the effects of risk, it is useful to work in terms of a market risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a market risk premium. Bruner, Eades, Harris, and Higgins (1998) provide recent survey results on best practices by corporations and financial advisors. While almost all respondents used some average of past data in estimating a market risk premium, a wide range of approaches emerged. "While most of our 27 sample companies appear to use a 60+ year historical period to estimate returns, one cited a window of less than ten years, two cited windows of about ten years, one began averaging with 1960, and another with 1952 data" (p. 22). Some used arithmetic averages, and some used geometric. This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that the risk premium is constant over time. Carleton and Lakonishok (1985) demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms. Siegel (1999) cites additional problems of using historical returns and argues that equity premium estimates from past data are likely too high. As Bruner et al. (1998) point out, few respondents cited use of expectational data to supplement or replace historical returns in estimating the market premium.

Survey evidence also shows substantial variation in empirical estimates. When respondents gave a precise estimate of the market premium, they cited figures from 4% to over 7% (Bruner et al., 1998). A quote from a survey respondent highlights the range in practice. "In 1993, we polled various investment banks and academic studies on the issue as to the appropriate rate and got anywhere between 2 and 8%, but most were between 6% and 7.4%." (Bruner et al., 1998). An informal sampling of current practice also reveals large differences in assumptions about an appropriate market premium. For instance, in a 1999 application of EVA analysis, Goldman Sachs Investment Research specifies a market risk premium of "3% from 1994-1997 and 3.5% from 1998-1999E for the S&P Industrials" (Goldman Sachs, 1999). At the same time, an April 1999 phone call to Stern Stewart revealed that their own application of EVA typically employed a market risk premium of 6%. In its application of the CAPM, Ibbotson Associates (1998) uses a market risk premium of 7.8%. Not surprisingly, academics do not agree on the risk premium either. Welch (2000) surveyed leading financial economists at major universities. For a 30-year horizon, he found a mean risk premium of 7.1% but a range from 1.5% to 15% with an interquartile range of 2.4% (based on 226 responses).

To provide additional insight on estimates of the market premium, we use publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow (DCF) model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier work has used FAF in DCF models[2] but generally has covered a span of only a few years due to data availability.

II. Models and Data

The simplest and most commonly used version of the DCF model is employed to estimate shareholders' required rate of return, k, as shown in Equation (2):

[2]See Malkiel (1982), Brigham, Vinson, and Shome (1985), Harris (1986), and Harris and Marston (1992). The DCF approach with analysts' forecasts has been used frequently in regulatory settings. Ibbotson Associates (1998) use a variant of the DCF model with forward-looking growth rates; however, they do this as a separate technique and not as part of the CAPM. For their CAPM estimates, they use historical averages for the market risk premium.

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share.[3] A primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future performance. This paper uses published FAF of long-run growth in earnings as a proxy for g. Equation (2) can be applied for an individual stock or any portfolio of companies. We focus primarily on its application to estimate a market premium as proxied by the S&P500.

FAF comes from IBES Inc. The mean value of individual analysts' forecasts of five-year growth rate in EPS is used as the estimate of g in the DCF model. The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. Growth rates are available on a monthly basis.

Dividend and other firm-specific information come from COMPUSTAT. D_1 is estimated as the current indicated annual dividend times $(1+g)$. Interest rates (both government and corporate) are from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data are used for all stocks in the *Standard and Poor's 500* stock (S&P500) index followed by IBES. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the period from January 1982-December 1998.

The approach used is generally the same approach as used in Harris and Marston (1992). For each month, a market required rate of return is calculated using each dividend-paying stock in the S&P500 index for which data are available. As additional screens for reliability of data, in a given month we eliminate a firm if there are fewer than three analysts' forecasts or if the standard deviation around the mean forecast exceeds 20%. Combined, these two screens eliminate fewer than 20 stocks a month. Later we report on the sensitivity of the results to various screens. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market-required return. The risk premium is constructed by subtracting the interest rate on government bonds.

We weighted 1998 results by year-end 1997 market values since the monthly data on market value did not extend through this period. Since data on firm-specific dividend yields were not available for the last four months of 1998 at the time of this study, the market dividend yield for these months was estimated using the dividend yield reported in the *Wall Street Journal* scaled by the average ratio of this figure to the dividend yield for our sample as calculated in the first eight months of 1998. Adjustments were then made using growth rates from IBES to calculate the market required return. We also estimated results using an average dividend yield for the month that employed the average of the price at the end of the current and prior months. These average dividend yield measures led to similar regression coefficients as those reported later in the paper.

For short-term horizons (quarterly and annual), past research (Brown, 1993) finds that on average analysts' forecasts are overly optimistic compared to realizations. However, recent research on quarterly horizons (Brown, 1997) suggests that analysts' forecasts for S&P500 firms do not have an optimistic bias for the period 1993-1996. There is very little research on the properties of five-year growth forecasts, as opposed to shorter horizon predictions. Boebel (1991) and Boebel, Harris, and Gultekin (1993) examine possible bias in analysts' five-year growth rates. These studies find evidence of optimism in IBES growth forecasts. In the most thorough study to date, Boebel (1991) reports that this bias seems to be getting smaller over time. His forecast data do not extend into the 1990s.

Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia. In light of the possible bias, however, we interpret the estimates as "upper bounds" for the market premium.

This study also uses four very different sources to create *ex ante* measures of equity risk at the market

[3]Our methods follow Harris (1986) and Harris and Marston (1992) who discuss earlier research and the approach employed here, including comparisons of single versus multistage growth models. Since analysts' forecast growth in earnings per share, their projections should incorporate the anticipated effects of share repurchase programs. Dividends per share would grow at the same rate as EPS as long as companies manage a constant ratio of dividends to earnings on a per share basis. Based on S&P500 figures (see the Standard and Poor's website for their procedures), the ratio of DPS to EPS was .51 during the period 1982-89 and .52 for the period 1990-98. Lamdin (2001) discusses some issues if share repurchases destroy the equivalence of EPS and DPS growth rates. Theoretically, i is a risk-free rate, though its empirical proxy is only a "least risk" alternative that is itself subject to risk. For instance, Asness (2000) shows that over the 1946-1998 period, bond volatility (in monthly realized returns) has increased relative to stock volatility, which would be consistent with a drop in the equity market premium.

Exhibit 1. Variable Definitions

k	=	Equity required rate return.
P_0	=	Price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i	=	Yield to maturity on long-term US government obligations (source: Federal Reserve, 30-year constant maturity series).
rp	=	Equity risk premium calculated as $rp = k - i$.
BSPREAD	=	spread between yields on corporate and government bonds, BSPREAD = yield to maturity on long-term corporate bonds (Moody's average across bond rating categories) minus i.
CON	=	Monthly consumer confidence index reported by the Conference Board (divided by 100).
DISP	=	Dispersion of analysts' forecasts at the market level.
VOL	=	Volatility for the S+P500 index as implied by options data.

level. The first proxy comes from the bond market and is calculated as the spread between corporate and government bond yields (BSPREAD). The rationale is that increases in this spread signal investors' perceptions of increased riskiness of corporate activity that would be translated to both debt and equity owners. The second measure, CON, is the consumer confidence index reported by the Conference Board at the end of the month. While the reported index tends to be around 100, we rescale CON as the actual index divided by 100. We also examined use of CON as of the end of the prior month; however, in regression analysis, this lagged measure generally was not statistically significant in explaining the level of the market risk premium.[4] The third measure, DISP, measures the dispersion of analysts' forecasts. Such analyst disagreement should be positively related to perceived risk since higher levels of uncertainty would likely generate a wider distribution of earnings forecasts for a given firm. DISP is calculated as the average of firm-specific standard deviations for each stock in the S&P500 covered by IBES. The firm-specific standard deviation is calculated based on the dispersion of individual analysts' growth forecasts around the mean of individual forecasts for that company in that month. DISP also was estimated using a value-weighted measure of analyst dispersion for the firms in our sample. The results reported use the equally weighted version but similar patterns were obtained with both constructions.[5] Our final measure, VOL, is the implied volatility on the S&P500 index. As of the beginning of the month, a dividend-adjusted Black Scholes Formula is used to estimate the implied volatility in the S&P500 index option contract, which expires on the third Friday of the month. The call premium, exercise price, and the level of the S&P500 index are taken from the *Wall Street Journal*, and treasury yields come from the Federal Reserve. Dividend yield comes from DRI. The option contract that is closest to being at the money is used.

III. Estimates of the Market Premium

Exhibit 2 reports both required returns and risk premia by year (averages of monthly data). The estimated risk premia are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1998) over

[4]We examined two other proxies for Consumer Confidence. The Conference Board's Consumer Expectations Index yielded essentially the same results as those reported. The University of Michigan's Consumer Sentiment Indices tended to be less significantly linked to the market risk premium, though coefficients were still negative.

[5]For the regressions reported in Exhibit 6, the value-weighted dispersion measure actually exhibited more explanatory power. For regressions using the Prais-Winsten method (see footnote 7), the coefficient on DISP was not significant in 2 of the 4 cases.

Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium, 1982-1998

Values are averages of monthly figures in percent. i is the yield to maturity on long-term government bonds, k is the required return on the S&P500 estimated as a value weighted average using a discounted cash flow model with analysts' growth forecasts. The risk premium $rp = k - i$. The average of analysts' growth forecasts is g. *Div yield* is expected dividend per share divided by price per share.

Year	Div. Yield	g	k	i	$rp = k - i$
1982	6.89	12.73	19.62	12.76	6.86
1983	5.24	12.60	17.86	11.18	6.67
1984	5.55	12.02	17.57	12.39	5.18
1985	4.97	11.45	16.42	10.79	5.63
1986	4.08	11.05	15.13	7.80	7.34
1987	3.64	11.01	14.65	8.58	6.07
1988	4.27	11.00	15.27	8.96	6.31
1989	3.95	11.08	15.03	8.45	6.58
1990	4.03	11.69	15.72	8.61	7.11
1991	3.64	11.99	15.63	8.14	7.50
1992	3.35	12.13	15.47	7.67	7.81
1993	3.15	11.63	14.78	6.60	8.18
1994	3.19	11.47	14.66	7.37	7.29
1995	3.04	11.51	14.55	6.88	7.67
1996	2.60	11.89	14.49	6.70	7.79
1997	2.18	12.60	14.78	6.60	8.17
1998	1.80	12.95	14.75	5.58	9.17
Average	3.86	11.81	15.67	8.53	7.14

government bonds is 7.14%, slightly higher than the 6.47% average for 1982 to 1991 reported by Harris and Marston (1992). For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 is approximately equal to the arithmetic (7.5%) long-term differential between returns on stocks and long-term government bonds.[6]

[6]Interestingly, for the 1982-1996 period the arithmetic spread between large company stocks and long-term government bonds was only 3.3% per year. The downward trend in interest rates resulted in average annual returns of 14.1% on long-term government bonds over this horizon. Some (e.g., Ibbotson, 1997) argue that only the income (not total) return on bonds should be subtracted in calculating risk premia.

Exhibit 2 shows the estimated risk premium changes over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Scanning the last column of Exhibit 2, the risk premium is higher in the 1990s than earlier and especially so in late 1997 and 1998. Our DCF results provide no evidence to support the notion of a declining risk premium in the 1990s as a driver of the strong run up in equity prices.

A striking feature in Exhibit 2 is the relative stability of the estimates of k. After dropping (along with interest rates) in the early and mid-1980s, the average annual value of k has remained within a 75 basis point range around 15% for over a decade. Moreover, this stability arises despite some variability in the

Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the US, 1926-1998

Historical Return Realizations	Geometric Mean	Arithmetic Mean
Common Stock (Large Company)	11.2%	13.2%
Long-term Government Bonds	5.3	5.7
Treasury Bills	3.8	3.8
Inflation Rate	3.1	3.2

Source: Ibbotson Associates, Inc., *1999 Stocks, Bonds, Bills and Inflation*, 1999 Yearbook.

underlying dividend yield and growth components of k as Exhibit 2 illustrates. The results suggest that k is more stable than government interest rates. Such relative stability of k translates into parallel changes in the market risk premium. In a subsequent section, we examine whether changes in our market risk premium estimates appear linked to interest rate conditions and a number of proxies for risk.

We explored the sensitivity of the results to our screening procedures in selecting companies. The reported results screen out all non-dividend paying stocks on the premise that use of the DCF model is inappropriate in such cases. The dividend screen eliminates an average of 55 companies per month. In a given month, we also screen out firms with fewer than three analysts' forecasts, or if the standard deviation around the mean forecast exceeds 20%. When the analysis is repeated without any of the three screens, the average risk premium over the sample period increased by only 40 basis points, from 7.14% to 7.54%. The beta of the sample firms also was estimated and the sample average was one, suggesting that the screens do not systematically remove low or high-risk firms. (Specifically, using firms in the screened sample as of December 1997 (the last date for which we had CRSP return data), we used ordinary least squares regressions to estimate beta for each stock using the prior 60 months of data and the CRSP return (SPRTRN) as the market index. The value-weighted average of the individual betas was 1.00.)

The results reported here use firms in the S&P500 as reported by COMPUSTAT in September 1998. This could create a survivorship bias, especially in the earlier months of the sample. We compared our current results to those obtained in Harris and Marston (1992) for which there was data to update the S&P500 composition each month. For the overlapping period, January 1982-May 1991, the two procedures yield the same average market risk premium, 6.47%. This suggests that the firms departing from or entering the S&P500 index do so for a number of reasons with no discernable effect on the overall estimated S&P500 market risk premium.

IV. Changes in the Market Risk Premium Over Time

With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk.

In earlier work covering the 1982-1991 period, Harris and Marston (1992) reported regression results indicating that the market premium decreased with the level of government interest rates and increased with the spread between corporate and government bond yields (BSPREAD). This bond yield spread was interpreted as a time series proxy for equity risk. In this paper, we introduce three additional *ex ante* measures of risk shown in Exhibit 1: CON, DISP, and VOL. The three measures come from three independent sets of data and are supplied by different agents in the economy (consumers, equity analysts, and investors (via option and share price data)). Exhibit 4 provides summary data on all four of these risk measures.

Exhibit 5 replicates and updates earlier analysis by Harris and Marston (1992).[7] The results confirm the earlier patterns. For the entire sample period, Panel A shows that risk premia are negatively related to interest rates. This negative relationship is also true for both

[7]OLS regressions with levels of variables generally showed severe autocorrelation. As a result, we used the Prais-Winsten method (on levels of variables) and also OLS regressions on first differences of variables. Since both methods yielded similar results and the latter had more stable coefficients across specifications, we report only the results using first differences. Tests using Durbin-Watson statistics from regressions in Exhibits 5 and 6 do not accept the hypothesis of autocorrelated errors (tests at .01 significance level, see Johnston, 1984). We also estimated the first difference model without an intercept and obtained estimates almost identical to those reported.

Exhibit 4. Descriptive Statistics on *Ex Ante* Risk Measures

Entries are based on monthly data. BSPREAD is the spread between yields on long-term corporate and government bonds. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the S&P500 index implied by options data. Variables are expressed in decimal form, (e.g., 12% = .12).

Panel A. Variables are Monthly Levels				
	Mean	**Standard Deviation**	**Minimum**	**Maximum**
BSPREAD	.0123	.0040	.0070	.0254
CON	.9504	.2242	.473	1.382
DISP	.0349	.0070	.0285	.0687
VOL	.1599	.0697	.0765	.6085
Panel B. Variables are Monthly Changes				
	Mean	**Standard Deviation**	**Minimum**	**Maximum**
BSPREAD	-.00001	.0011	-.0034	.0036
CON	.0030	.0549	-.2300	.2170
DISP	-.00002	.0024	-.0160	.0154
VOL	-.0008	.0592	-.2156	.4081
Panel C. Correlation Coefficients for Monthly Changes				
	BSPREAD	**CON**	**DISP**	**VOL**
BSPREAD	1.00	-.16**	.054	.22*
CON	-.16**	1.00	.065	-.09
DISP	.054	.065	1.00	.027
VOL	.22*	-.09	.027	1.00

**Significantly different from zero at the .05 level.
*Significantly different from zero at the .01 level.

the 1980s and 1990s as displayed in Panels B and C. For the entire 1982 to 1998 period, the addition of the yield spread risk proxy to the regressions lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations (1) and (2) of Panel A. Furthermore, the coefficient of the yield spread (0.488) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate bonds is translated into a lower equity market risk premium.

In major respects, the results in Exhibit 5 parallel earlier findings. The market risk premium changes over time and appears inversely related to government interest rates but is positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds. One striking feature is the large negative coefficients on government bond yields. The coefficients indicate the equity risk premium declines by over 70 basis points for a 100 basis point increase in government interest rates.[8] This inverse relationship suggests

[8]The Exhibit 5 coefficients on i are significantly different from −1. 0 suggesting that equity required returns do respond to interest rate changes. However, the large negative coefficients imply only minor adjustments of required returns to interest rate changes since the risk premium declines. In earlier work (Harris and Marston, 1992) the coefficient was significantly negative but not as large in absolute value. In that earlier work, we reported results using the Prais-Winsten estimators. When we use that estimation technique and recreate the second regression in Exhibit 5, the coefficient for i is -.584 (t = - 12.23) for the entire sample period 1982-1998.

Exhibit 5. Changes in the Market Equity Risk Premium Over Time

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the S&P500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as i. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Time Period	Intercept	i	BSPREAD	R^2
A. 1982-1998	-.0002 (-1.49)	-.869 (-16.54)		.57
	-.0002 (-1.11)	-.749 (-11.37)	.488 (2.94)	.59
B. 1980s	-.0005 (-1.62)	-.887 (-10.97)		.56
	-.0004 (-1.24)	-.759 (-7.42)	.508 (1.99)	.57
C. 1990s	-.0000 (-0.09)	-.840 (-13.78)		.64
	-.0000 (0.01)	-.757 (-9.85)	.347 (1.76)	.65

Exhibit 6. Changes in the Market Equity Risk Premium Over Time and Selected Measures of Risk

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the S&P500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as i. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the S&P500 index implied by options data. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Time Period		Intercept	i	BSPREAD	CON	DISP	VOL	Adj. R^2
A. 1982-1998								
	(1)	0.0002 (.97)			-0.014 (-3.50)			0.05
	(2)	-0.0001 (-.96)	-0.737 (-11.31)	0.453 (2.76)	-0.007 (-2.48)			0.60
	(3)	0.0002 (.79)				0.224 (2.38)		0.02
	(4)	-0.0001 (-.93)	-0.733 (-11.49)	0.433 (2.69)	-0.007 (-2.77)	0.185 (3.13)		0.62
B. May 1986-1998	(5)	0.0000 (.06)	-0.818 (-11.21)	0.420 (2.52)	-0.005 (-2.23)	0.378 (3.77)		0.68
	(6)	0.0001 (.53)					0.011 (2.89)	0.05
	(7)	0.0000 (.02)	-0.831 (-11.52)	0.326 (1.95)	-0.005 (-2.12)	0.372 (3.77)	0.006 (2.66)	0.69

much greater stability in equity required returns than is often assumed. For instance, standard application of the CAPM suggests a one-to-one change in equity returns and government bond yields.

Exhibit 6 introduces three additional proxies for risk and explores whether these variables, either individually or collectively, are correlated with the market premium. Since the estimates of implied volatility start in May 1986, the exhibit shows results for both the entire sample period and for the period during which we can introduce all variables. Entered individually each of the three variables is significantly linked to the risk premium with the coefficient having the expected sign. For instance, in regression (1) the coefficient on CON is -.014, which is significantly different from zero (t = -3.50). The negative coefficient signals that higher consumer confidence is linked to a lower market premium. The positive coefficients on VOL and DISP indicate the equity risk premium increases with both market volatility and disagreement among analysts. The effects of the three variables appear largely unaffected by adding other variables. For instance, in regression (4) the coefficients on CON and DISP both remain significant and are similar in magnitude to the coefficients in single variable regressions.[9]

Even in the presence of the new risk variables, Exhibit 6 shows that the market risk premium is affected by interest rate conditions. The large negative coefficient on government bond rates implies large reductions in the equity premium as interest rates rise. One feature of our data may contribute to the observed negative relationship between the market risk premium and the level of interest rates. Specifically, if analysts are slow to report updates in their growth forecasts, changes in the estimated k would not adjust fully with changes in the interest rate even if the true risk premium were constant. To address the impact of "stickiness" in the measurement of k, we formed "quarterly" measures of the risk premium that treat k as an average over the quarter. Specifically, we take the value of k at the end of a quarter and subtract from it the average value of i for the months ending when k is measured. For instance, to form the risk premium for March 1998, the average value of i for January, February, and March is subtracted from the March value of k. This approach assumes that, in March, k still reflects values of g that have not been updated from the prior two months. The quarterly measure of risk premium then is paired with the average values of the other variables for the quarter. For instance, the March 1998 "quarterly" risk premium would be paired with averaged values of BSPREAD over the January through March period. To avoid overlapping observations for the independent variables, we use only every third month (March, June, September, December) in the sample.

As reported in Exhibit 7, sensitivity analysis using "quarterly" observations suggests that delays in updating may be responsible for a portion, but not all, of the observed negative relationship between the market premium and interest rates. For example, when quarterly observations are used, the coefficient on i in regression (2) of Exhibit 7 is -.527, well below the earlier estimates but still significantly negative.[10]

As an additional test, movements in the bond risk premium (BSPREAD) are examined. Since BSPREAD is constructed directly from bond yield data, it does not have the potential for reporting lags that may affect analysts' growth forecasts. Regression 3 in Exhibit 7 shows BSPREAD is negatively linked to government rates and significantly so.[11] While the equity premium need not move in the same pattern as the corporate bond premium, the negative coefficient on BSPREAD suggests that our earlier results are not due solely to "stickiness" in measurements of market required returns.

The results in Exhibit 7 suggest that the inverse relationship between interest rates and the market risk premium may not be as pronounced as suggested in earlier exhibits. Still, there appears to be a significant negative link between the equity risk premium and government interest rates. The quarterly results in Exhibit 7 would suggest about a 50 basis point change in risk premium for each 100 basis point movement in interest rates.

Overall, the *ex ante* estimates of the market risk premium are significantly linked to *ex ante* proxies for risk. Such a link suggests that investors modify their required returns in response to perceived changes in the environment. The findings provide some comfort that our risk premium estimates are capturing, at least

[9]Realized equity returns are difficult to predict out of sample (see Goyal and Welch, 1999). Our approach is different in that we look at expectational risk premia which are much more stable. For instance, when we estimate regression coefficients (using the specification shown in regression 7 of Exhibit 6) and apply them out of sample we obtain "predictions" of expectational risk premia that are significantly more accurate (better than the .01 level) than a no change forecast. We use a "rolling regression" approach using data through December 1991 to get coefficients to predict the risk premium in January 1992. We repeat the procedure moving forward a month and dropping the oldest month of data from the regression. Details are available from the authors.

[10]Sensitivity analysis for the 1982-1989 and 1990-1998 subperiods yields results similar to those reported.

[11]We thank Bob Conroy for suggesting use of BSPREAD. Regression 3 in Exhibit 7 appears to have autocorrelated errors: the Durbin-Watson (DW) statistic rejects the hypothesis of no autocorrelation. However, in subperiod analysis, the DW statistic for the 1990-98 period is consistent with no autocorrelation and the coefficient on i is essentially the same (-.24, t = -8.05) as reported in Exhibit 7.

Exhibit 7. Regressions Using Alternate Measures of Risk Premia to Analyze Potential Effects of Reporting Lags in Analysts' Forecasts

The exhibit reports regression coefficients (t-values). Regression estimates use all variables expressed as changes (monthly or quarterly) to correct for autocorrelation. BSPREAD is the spread between yields on long-term corporate and government bonds. rp is the risk premium on the S&P500 index. The yield to maturity on long-term government bonds is denoted as i. For purposes of the regression, variables are expressed in decimal form, (e.g., 12% = .12).

Dependent Variable	Intercept	i	BSPREAD	Adj. R^2
(1) Equity Risk Premium (rp) Monthly Observations (same as Table V)	-.0002 (-1.11)	-.749 (-11.37)	.488 (2.94)	.59
(2) Equity Risk Premium (rp) "Quarterly" nonoverlapping observations to account for lags in analyst reporting	-.0002 (-.49)	-.527 (-6.18)	.550 (2.20)	.60
(3) Corporate Bond Spread (BSPREAD) Monthly Observations	-.0001 (-1.90)	-.247 (-11.29)		.38

in part, underlying changes in the economic environment. Moreover, each of the risk measures appears to contain relevant information for investors. The market risk premium is negatively related to the level of consumer confidence and positively linked to interest rate spreads between corporate and government debt, disagreement among analysts in their forecasts of earnings growth, and the implied volatility of equity returns as revealed in options data.

V. Conclusions

Shareholder required rates of return and risk premia should be based on theories about investors' expectations for the future. In practice, however, risk premia are typically estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. The resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1998) in historical returns between stocks and bonds. As a result, our evidence does not resolve the equity premium puzzle; rather, the results suggest investors still expect to receive large spreads to invest in equity versus debt instruments.

There is strong evidence, however, that the market risk premium changes over time. Moreover, these changes appear linked to the level of interest rates as well as *ex ante* proxies for risk drawn from interest rate spreads in the bond market, consumer confidence in future economic conditions, disagreement among financial analysts in their forecasts and the volatility of equity returns implied by options data. The significant economic links between the market premium and a wide array of risk variables suggests that the notion of a constant risk premium over time is not an adequate explanation of pricing in equity versus debt markets.

These results have implications for practice. First, at least on average, the estimates suggest a market premium roughly comparable to long-term historical spreads in returns between stocks and bonds. Our conjecture is that, if anything, the estimates are on the high side and thus establish an upper bound on the market premium. Second, the results suggest that use of a constant risk premium will not fully capture changes in investor return requirements. As a specific example, our findings indicate that common application of models such as the CAPM will overstate changes in shareholder return requirements when government interest rates change. Rather than a one-for-one change with interest rates implied by use of constant risk premium, the results indicate that equity required returns for average risk stocks likely change by half (or less) of the change in interest rates. However, the picture is considerably more complicated as shown by the linkages between the risk premium and other attributes of risk.

Ultimately, our research does not resolve the answer to the question "What is the right market risk premium?" Perhaps more importantly, our work suggests that the answer is conditional on a number of features in the economy—not an absolute. We hope that future research will harness *ex ante* data to provide additional guidance to best practice in using a market premium to improve financial decisions.■

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THE COST OF CAPITAL –

A PRACTITIONER'S GUIDE

BY

DAVID C. PARCELL

PREPARED FOR THE SOCIETY OF UTILITY
AND REGULATORY FINANCIAL ANALYSTS

1997 EDITION

Author's Note: This manual has been prepared as an educational reference on cost of capital concepts. Its purpose is to describe a broad array of cost of capital models and techniques. No cost of equity model or other concept is recommended or emphasized, nor is any procedure for employing any model recommended. Furthermore, no opinions or preferences are expressed by either the author or the Society of Utility And Regulatory Financial Analysts.

"incorporates all information relating to equity valuation contained in alternative proxies"; however, their studies indicate that forecasts do not contain all relevant information and thus should not be relied upon exclusively. Conroy and Harris (1987) found that analysts' forecasts were better predictors than historic growth over the very short term, but the advantage declined steadily over time. They conclude that combinations of analysts' forecasts and historic growth provide the best forecasting results. Avera and Fairchild (1982) and Newbolt, Zumwalt, and Kannan (1987) reached similar conclusions.

3. Whose Projections Are Best?

Finally, a number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line". Finally, Collins and Hopwood (1980) concluded that Value Line predictions are more accurate than competing models as they produce fewer and smaller extreme errors. In contrast, Avera and Fairchild (1982) contend that Value Line forecasts are not an acceptable surrogate for the growth component in the DCF model.

THE COST OF CAPITAL
TO A
PUBLIC UTILITY

Myron J. Gordon

1974
MSU Public Utilities Studies

Division of Research
Graduate School of Business Administration
Michigan State University
East Lansing, Michigan

its leverage rate. It can be shown that when $x = \rho$ the share price is independent of the firm's leverage rate. Hence, the cost of debt capital remains equal to ρ when retention is present.

2.8 Continuous New Equity Financing

In addition to or as an alternative to expanding through the periodic retention of earnings, a utility can expand through the sale of stock.[7] Consideration of the sale of stock as a source of funds requires the introduction of the following variables not listed previously.

- W_t = total common equity at end of period t;
- W_t^* = total common equity at end of t that accrues to shareholders at $t = 0$;
- s = funds raised from the sale of stock as a fraction of existing common equity;
- Q_t = funds raised from sale of stock during t; and
- v = fraction of Q_t that accrues to shareholders at the start of t.

Let a utility's total common equity at $t = 0$ be $W_0 = NE_0$, and let the expected rate of growth in the common equity due to the sale of stock be s. The common equity one period later will be

$$W_1 = W_0 + bNY_1 + sW_0. \tag{2.8.1}$$

Since $NY_1 = rW_0$,

$$W_1 = W_0 + brW_0 + sW_0 = W_0[1 + br + s], \tag{2.8.2}$$

and

$$W_n = W_0[1 + br + s]^n. \tag{2.8.3}$$

In each period the total equity is raised by the fraction br due to retention and by s due to the sale of additional shares.

At the end of $t = n$ the total common equity will include the equity of the shareholders at $t = 0$ and the equity arising from

[7] This section is based on chapter 9 of M. J. Gordon [15].

the sale of shares from $t = 0$ through $t = n$. What we are interested in, however, is the expected equity and the dividend at $t = n$ on a share outstanding at $t = 0$. Let $Q_n = sW_{n-1}$ be the funds raised from the sale of stock during n, and let v be the fraction of the funds provided during n that accrues to the shareholders at the start of n. The meaning and derivation of v will be developed in the course of what follows.

Let W_n^* be the portion of the total common equity at the end of $t = n$ that belongs to the share outstanding at $t = 0$. Then

$$W_1^* = W_0 + brW_0 + vsW_0, \tag{2.8.4}$$

and

$$W_n^* = W_0[1 + br + vs]^n. \tag{2.8.5}$$

Dividing both sides of Eq. (2.8.5) by N and multiplying by r, we obtain

$$Y_{n+1}^* = Y_1[1 + br + vs]^n. \tag{2.8.6}$$

The earnings on a share at $t = 0$ are expected to grow at the rate br due to retention and at vs due to the sale of additional stock. Making the indicated substitutions, our stock value model becomes

$$P = \sum_{t=1}^{\infty} \frac{(1 - b)Y[1 + br + vs]^{t-1}}{(1 + k)^t}. \tag{2.8.7}$$

If $k > br + vs$, Eq. (2.8.7) becomes

$$P = \frac{(1 - b)Y}{k - br - vs}. \tag{2.8.8}$$

The only change in Eq. (2.7.8) necessary to recognize the expectation of continuous stock financing at the rate s is the change in the expected rate of growth to $br + vs$.

The meaning of v may be explained simply as follows. When a new issue is sold at a price per share $P = E$, the equity of the new shareholders in the firm is equal to the funds they contribute.

and the equity of the existing shareholders is not changed. However, if $P > E$, part of the funds raised accrues to the existing shareholders. Specifically, it can be shown that

$$v = 1 - \frac{E}{P} \tag{2.8.9}$$

is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, v is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.

A more rigorous derivation of v follows. If the market for a firm's new shares is perfectly competitive, the number of shares given to new shareholders during $t = n$ in return for Q_n dollars must satisfy two conditions. The first is that the new issue must be sold at the prevailing price per share at the time of the issue. The other condition is that the dividend expectation a new shareholder obtains should have a present value equal to Q_n, the money he invests, when discounted at the rate k. With r the return the utility earns on common equity investment, b the retention rate, and $(1 - v)$ Q_n the book value of the common equity obtained by the new shareholders, their dividend in $n + 1$ will be

$$D^*_{n+1} = (1 - b)r(1 - v)Q_n. \tag{2.8.10}$$

Once in the corporation the new shares are identical with the old shares. Their dividends also are expected to grow at the rate $br + vs$. Hence, the above two conditions are satisfied if

$$Q_n = \sum_{t=n+1}^{\infty} \frac{(1 - b)r(1 - v)Q_n(1 + br + vs)^{t-n-1}}{(1 + k)^{t-n}}$$

$$= \frac{(1 - b)r(1 - v)Q_n}{k - br - vs}. \tag{2.8.11}$$

Dividing both sides of Eq. (2.8.11) by Q_n and solving for v, we obtain

$$v = \frac{r - k}{r - rb - s}. \tag{2.8.12}$$

It can be shown that Eqs. (2.8.12) and (2.8.9) produce identical values of v. The interesting property of Eq. (2.8.12) is that it makes clear that the cost of new equity capital is ρ for continuous new equity financing as well as one-shot new equity financing. When $r = k$, $v = 0$, and new stock financing at the rate s has no impact on P. Of course, if $r = k$ then $x = \rho$. When $r > k$, v is positive, and share price increases with s.

The assumption that a utility is expected to stock finance at the rate s has implications for the measurement of k. The yield at which a share with continuous growth at the rate g sells is

$$k = \frac{D}{P} + g, \tag{2.8.13}$$

the current dividend yield plus the expected rate of growth in the dividend. However, now $g = br + vs$ and not simply br. It also should be noted that continuous stock financing at the rate s poses problems similar to continuous retention at the rate b. When $k < br + vs$, the model breaks down in explosive growth. The above discussion of the resolution of the dilemma posed by $\rho < bx$ applies here. It also may have been noted from Eq. (2.8.12) that v is negative with $r > k$ when $r < rb + s$ or $r(1 - b) < s$. This is reasonable, although it may appear strange. Notice that $r(1 - b)$ and s are the outflow and inflow of funds due to dividends and stock financing expressed as fractions of the common equity. When $r(1 - b) < s$ the company is expected, in effect, to draw funds from stockholders for all future time. Clearly it is nonoptimal for a company to set $s > r(1 - b)$, and the case may be ignored.

2.9 Finite Horizon Model

We have seen that if $x > \rho$ and b and/or s are large we can have $k \leq g$, and our continuous growth models break down. A resolution of this dilemma consistent with the perfectly competitive capital markets assumptions is provided by withdrawing the assumption that the dividend is expected to grow at the current rate g for all future time. Specifically, a utility with a very large x reasonably will invest at a very high rate. The resultant high values

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November 30, 2007

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

Primary Credit Analysts:
Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com
William Ferara, New York (1 212-438-1776; bill_ferara@standardandpoors.com
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

Secondary Credit Analyst:
Michael Messer, New York (1) 212- 438-1618; michael_messer@standardandpoors.com

U.S. Utilities Ratings Analysis Now Portrayed In The S&P Corporate Ratings Matrix

The electric, gas, and water utility ratings ranking lists published today by Standard & Poor's U.S. Utilities & Infrastructure Ratings practice are categorized under the business risk/financial risk matrix used by the Corporate Ratings group. This is designed to present our rating conclusions in a clear and standardized manner across all corporate sectors. Incorporating utility ratings into a shared framework to communicate the fundamental credit analysis of a company furthers the goals of transparency and comparability in the ratings process. Table 1 shows the matrix.

Table 1

Business Risk/Financial Risk

	Financial Risk Profile				
Business Risk Profile	**Minimal**	**Modest**	**Intermediate**	**Aggressive**	**Highly leveraged**
Excellent	AAA	AA	A	BBB	BB
Strong	AA	A	A-	BBB-	BB-
Satisfactory	A	BBB+	BBB	BB+	B+
Weak	BBB	BBB-	BB+	BB-	B
Vulnerable	BB	B+	B+	B	B-

The utilities rating methodology remains unchanged, and the use of the corporate risk matrix has not resulted in any changes to ratings or outlooks. The same five factors that we analyzed to produce a business risk score in the familiar 10-point scale are used in determining whether a utility possesses an "Excellent," "Strong," "Satisfactory," "Weak," or "Vulnerable" business risk profile:

- Regulation,
- Markets,
- Operations,
- Competitiveness, and
- Management.

Regulated utilities and holding companies that are utility-focused virtually always fall in the upper range ("Excellent" or "Strong") of business risk profiles. The defining characteristics of most utilities--a legally defined service territory generally free of significant competition, the provision of an essential or near-essential service, and the presence of regulators that have an abiding interest in supporting a healthy utility financial profile--underpin the business risk profiles of the electric, gas, and water utilities.

As the matrix concisely illustrates, the business risk profile loosely determines the level of financial risk appropriate for any given rating. Financial risk is analyzed both qualitatively and quantitatively, mainly with financial ratios and other metrics that are calculated after various analytical adjustments are performed on financial statements prepared under GAAP. Financial risk is assessed for utilities using, in part, the indicative ratio ranges in table 2.

Table 2

Financial Risk Indicative Ratios - U.S. Utilities

(Fully adjusted, historically demonstrated, and expected to consistently continue)

	Cash flow		Debt leverage
	(FFO/debt) (%)	**(FFO/interest) (x)**	**(Total debt/capital) (%)**
Modest	40 - 60	4.0 - 6.0	25 - 40
Intermediate	25 - 45	3.0 - 4.5	35 - 50
Aggressive	10 - 30	2.0 - 3.5	45 - 60
Highly leveraged	Below 15	2.5 or less	Over 50

The indicative ranges for utilities differ somewhat from the guidelines used for their unregulated counterparts because of several factors that distinguish the financial policy and profile of regulated entities. Utilities tend to finance with long-maturity capital and fixed rates. Financial performance is typically more uniform over time, avoiding the volatility of unregulated industrial entities. Also, utilities fare comparatively well in many of the less-quantitative aspects of financial risk. Financial flexibility is generally quite robust, given good access to capital, ample short-term liquidity, and the like. Utilities that exhibit such favorable credit characteristics will often see ratings based on the more accommodative end of the indicative ratio ranges, especially when the company's business risk profile is solidly within its category. Conversely, a utility that follows an atypical financial policy or manages its balance sheet less conservatively, or falls along the lower end of its business risk designation, would have to demonstrate an ability to achieve financial metrics along the more stringent end of the ratio ranges to reach a given rating.

Note that even after we assign a company a business risk and financial risk, the committee does not arrive by rote at a rating based on the matrix. The matrix is a guide--it is not intended to convey precision in the ratings process or reduce the decision to plotting intersections on a graph. Many small positives and negatives that affect credit quality can lead a committee to a different conclusion than what is indicated in the matrix. Most outcomes will fall within one notch on either side of the indicated rating. Larger exceptions for utilities would typically involve the influence of related unregulated entities or extraordinary disruptions in the regulatory environment.

We will use the matrix, the ranking list, and individual company reports to communicate the relative position of a company within its business risk peer group and the other factors that produce the ratings.

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Chapter 2

Introduction to the Cost of Capital

Defining the Cost of Capital

Ibbotson® Stocks, Bonds, Bills, and Inflation® (SBBI®) historical data can be used, along with other inputs, to make forecasts of the future, including estimates of the cost of capital. A cost of capital estimate seeks to discern the expected return, or forecast mean return, on an investment in a security, firm, project, or division.

The cost of capital (sometimes called the expected or required rate of return or the discount rate) can be viewed from three different perspectives. On the asset side of a firm's balance sheet, it is the rate that should be used to discount to a present value the future expected cash flows. On the liability side, it is the economic cost to the firm of attracting and retaining capital in a competitive environment, in which investors (capital providers) carefully analyze and compare all return-generating opportunities. On the investor's side, it is the return one expects and requires from an investment in a firm's debt or equity. While each of these perspectives might view the cost of capital differently, they are all dealing with the same number.

The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine the cost of capital. An investor contributes capital to a firm with the expectation that the business's future performance will provide a fair return on the investment. If past performance were the criterion most important to investors, no one would invest in start-up ventures. It should also be noted that the cost of capital is a function of the investment, not the investor.

The cost of capital is an opportunity cost. Some people consider the phrase "opportunity cost of capital" to be

The Ibbotson® SBBI® Data Series

SBBI Data Series	Series Construction	Index Components	Approximate Maturity
1. Large Company Stocks	S&P 500 Composite with dividends reinvested. (S&P 500, 1957–Present; S&P 90, 1926–1956)	Total Return Income Return Capital Appreciation Return	N/A
2. Ibbotson Small Company Stocks	Fifth capitalization quintile of stocks on the NYSE for 1926–1981. Performance of the DFA U.S. 9-10 Small Company Portfolio January 1982–March 2001. Performance of the DFA U.S. Micro Cap Portfolio April 2001–Present.	Total Return	N/A
3. Long-Term Corporate Bonds	Citigroup Long-Term High Grade Corporate Bond Index	Total Return	20 Years
4. Long-Term Government Bonds	A One-Bond Portfolio	Total Return Income Return Capital Appreciation Return Yield	20 Years
5. Intermediate-Term Government Bonds	A One-Bond Portfolio	Total Return Income Return Capital Appreciation Return Yield	5 Years
6. U.S. Treasury Bills	A One-Bill Portfolio	Total Return	30 Days
7. Consumer Price Index	CPI—All Urban Consumers, not seasonally adjusted	Inflation Rate	N/A

The series presented here are total returns and, where applicable or available, capital appreciation returns and income returns. A description of the Center for Research in Security Prices small stock data is found in Chapter 7, Firm Size and Return.

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

Roger A. Morin, PhD

in collaboration with

Lisa Todd Hillman

1994
PUBLIC UTILITIES REPORTS, INC.
Arlington, Virginia

In many cases, it is necessary to use earnings forecasts rather than dividend forecasts due to the extreme scarcity of dividend forecasts compared to the availability of earnings forecasts. Given the paucity and variability of dividend forecasts, using the latter would produce unreliable DCF results. In any event, the use of the DCF model prospectively assumes constant growth in both earnings and dividends. Moreover, there is an abundance of empirical research that shows the validity and superiority of earnings forecasts to estimate the cost of capital.

The uniformity of such growth projections are a test of whether they are typical of the market as a whole. If, for example, 10 out of 15 analysts forecast growth in the 7%–9% range, the probability is high that their analysis reflects a degree of consensus in the market as a whole.

Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns.[9] Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g*. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, not the future as it will turn out to be.

Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only. A study by Brown and Rozeff (1978) showed that analysts, as proxied by Value Line analysts, make better forecasts than could be obtained using only historical data, because analysts have available not only past data but also a knowledge of such crucial factors as rate case decisions, construction programs, new products, cost data, and so on. Brown and Rozeff tested the accuracy of analysts' forecasts versus fore-

[9] The rest of this section is adapted from Brigham (1983).

casts based on past data only, and concluded that their evidence of superior analyses means that analysts' forecasts should be used in studies of cost of capital. Their evidence supports the hypothesis that Value Line analysts consistently make better predictions than time series models.

Cragg and Malkiel (1982) presented detailed empirical evidence that the average analyst's expectation is more similar to expectations being reflected in the marketplace than are historical growth rates, and that they represent the best possible source of DCF growth rates. Cragg and Malkiel showed that historical growth rates do not contain any information that is not already impounded in analysts' growth forecasts. A study by Vander Weide and Carleton (1988) also confirmed the superiority of analysts' forecasts over historical growth extrapolations. A study by Timme and Eiseman (1989) produced similar results. Empirical studies have also been conducted showing that investors who rely primarily on data obtained from several large reputable investment research houses and security dealers obtain better results than those who do not.[10] Thus, both empirical research and common sense indicate that investors rely primarily on analysts' growth rate forecasts rather than on historical growth rates alone.

Ideally, one could decide which analysts make the most reliable forecasts and then confine the analysis to those forecasts. This would be impractical since reliable data on past forecasts are generally not available. Moreover, analysts with poor track records are replaced by more competent analysts, so that a poor forecasting record by a particular firm is not necessarily indicative of poor future forecasts. In any event, analysts working for large brokerage firms typically have a following, and investors who heed a particular analyst's recommendations do exert an influence on the market. So, an average of all the available forecasts from large reputable investment houses is likely to produce the best DCF growth rate.

Growth rate forecasts of several analysts are available from published sources. For example, the IBES (Institutional Brokers Estimate System) publication tabulates analysts' earnings forecasts on a regular basis by conducting a monthly survey of the earnings growth forecasts of a large number of investment advisors, brokerage houses, and other firms that engage in fundamental research on U.S. corporations. IBES forecasts are a product of Lynch, Jones, and Ryan, a major brokerage firm that collects and disseminates such forecasts. Data in IBES represent a compilation of earnings per share estimates of about 2,000 individual analysts from 100

[10] Examples of such studies include Stanley, Lewellen, and Schlarbaum (1981) and Touche Ross Co. (1982).

10.5 Reservations Regarding the Use of M/B Ratios in the Regulatory Process

It is sometimes argued that because current market-to-book (M/B) ratios are in excess of 1.0, this indicates that companies are expected by investors to be able to earn more than their cost of capital, and that the regulating authority should lower the authorized return on equity, so that the stock price will decline to book value. It is therefore plausible, under this argument, that stock prices drop from the current M/B value to the desired M/B ratio range of 1.0 times book.

There are several reasons why this view of the role of M/B ratios in regulation should be avoided.

(1) The inference that M/B ratios are relevant and that regulators should set an ROE so as to produce a M/B of 1.0 is erroneous. The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation.

(2) The condition that the M/B will gravitate toward 1.0 if regulators set the allowed return equal to capital costs will be met only if the actual return expected to be earned by investors is at least equal to the cost of capital on a consistent long-term basis. The cost of capital of a company refers to the expected long-run earnings level of other firms with similar risk. If investors expect a utility to earn an ROE equal to its cost of equity in each period, then its M/B ratio would be approximately 1.0 or higher with the proper allowance for flotation cost.

(3) A company's achieved earnings in any given year are likely to exceed or be less than their long-run average. Depressed or inflated M/B ratios are to a considerable degree a function of forces outside the control of regulators, such as the general state of the economy, or general economic or financial circumstances that may affect the yields on securities of unregulated as well as regulated enterprises. The achievement of a 1.0 M/B ratio is appropriate, but only in a long-run sense. For utilities to exhibit a long-run M/B ratio of 1.0, it is clear that during economic upturns and more favorable capital market conditions, the M/B ratio must exceed its long-run average of 1.0 to compensate for the periods during which the

[1] See Kahn (1970), p. 52.

The *Hope* and *Bluefield* cases established the fundamental premise that investors should receive a return commensurate with returns currently available on comparable risk investments, not that investors be guaranteed a return coinciding with their initial return expectations. Consequently, the determination of a fair and reasonable return on equity should rest preferably on investor expectations, and historical risk premiums should be based on expected returns rather than on realized returns, data permitting.

While forward-looking risk premiums based on expected returns are preferable, historical return studies over long periods still provide a useful guide for the future. This is because over long periods investor expectations and realizations converge. Otherwise, investors would never commit investment capital. Investors expectations are eventually revised to match historical realizations, as market prices adjust to bring anticipated and actual investment results into conformity. In the long-run, the difference between expected and realized risk premiums will decline because short-run periods during which investors earn a lower risk premium than they expect are offset by short-run periods during which investors earn a higher risk premium than they expect.

Computational Issues

The third problem in relying on historical return results is the method of averaging historical returns.

Geometric v. Arithmetic Averages. One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital. When using historical risk premiums as a surrogate for the expected market risk premium, the relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time. This is formally shown in *Principles of Corporate Finance,* a widely used and respected textbook on corporate finance by Brealey and Myers (1991). Appendix 11-A illustrates that only arithmetic averages can be used as estimates of cost of capital, and that the geometric mean is not an appropriate measure of cost of capital. A widely-used Ibbotson Associates publication title contains a rigorous discussion of the impropriety of using geometric averages in estimating the cost of capital (Ibbotson Associates 1993).

The use of the arithmetic mean appears counter-intuitive at first glance, because we commonly use the geometric mean return to measure the average annual achieved return over some time period. In estimating the cost of capital, the goal is to obtain the rate of return that investors expect,

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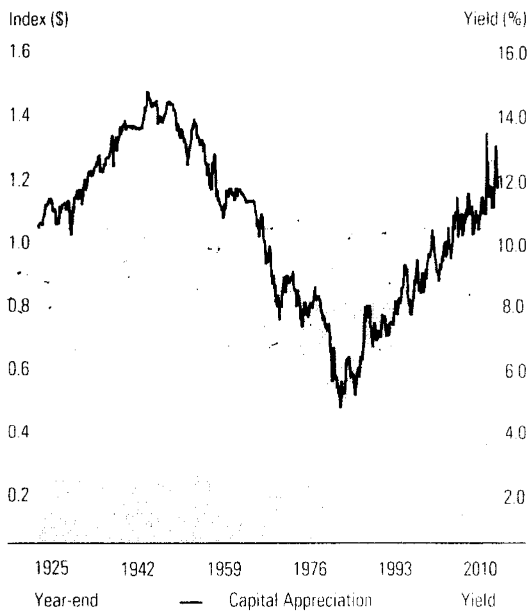
compared to an index of the long-term government bond capital appreciation. In general, as yields rose, the capital appreciation index fell, and vice versa. Had an investor held the long-term bond to maturity, he would have realized the yield on the bond as the total return. However, in a constant maturity portfolio, such as those used to measure bond returns in this publication, bonds are sold before maturity (at a capital loss if the market yield has risen since the time of purchase). This negative return is associated with the risk of unanticipated yield changes.

Graph 5-1: Long-term Government Bond Yields versus Capital Appreciation Index



Data from 1925–2010

For example, if bond yields rise unexpectedly, investors can receive a higher coupon payment from a newly issued bond than from the purchase of an outstanding bond with the former lower-coupon payment. The outstanding lower-coupon bond will thus fail to attract buyers, and its price will decrease, causing its yield to increase correspondingly, as its coupon payment remains the same. The newly priced outstanding bond will subsequently attract purchasers who will benefit from the shift in price and yield; however, those investors who already held the bond will suffer a capital loss due to the fall in price.

Anticipated changes in yields are assessed by the market and figured into the price of a bond. Future changes in yields that are not anticipated will cause the price of the bond to adjust accordingly. Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return.The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss.

Arithmetic versus Geometric Means

The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

The argument for using the arithmetic average is quite straightforward. In looking at projected cash flows, the equity risk premium that should be employed is the equity risk premium that is expected to actually be incurred over the future time periods. Graph 5-2 shows the realized equity risk premium for each year based on the returns of the S&P 500 and the income return on long-term government bonds. (The actual, observed difference between the return on the stock market and the riskless rate is known as the realized equity risk premium.) There is considerable volatility in the year-by-year statistics. At times the realized equity risk premium is even negative.

QUANTITATIVE INVESTMENT ANALYSIS

Second Edition

Richard A. DeFusco, CFA

Dennis W. McLeavey, CFA

Jerald E. Pinto, CFA

David E. Runkle, CFA

John Wiley & Sons, Inc.

Solution to 2: The distribution of PRFDX's annual returns appears to be mesokurtic, based on a sample excess kurtosis close to zero. With skewness and excess kurtosis both close to zero, PRFDX's annual returns appear to have been approximately normally distributed during the period.[48]

10. USING GEOMETRIC AND ARITHMETIC MEANS

With the concepts of descriptive statistics in hand, we will see why the geometric mean is appropriate for making investment statements about past performance. We will also explore why the arithmetic mean is appropriate for making investment statements in a forward-looking context.

For reporting historical returns, the geometric mean has considerable appeal because it is the rate of growth or return we would have had to earn each year to match the actual, cumulative investment performance. In our simplified Example 3-8, for instance, we purchased a stock for €100 and two years later it was worth €100, with an intervening year at €200. The geometric mean of 0 percent is clearly the compound rate of growth during the two years. Specifically, the ending amount is the beginning amount times $(1 + R_G)^2$. The geometric mean is an excellent measure of past performance.

Example 3-8 illustrated how the arithmetic mean can distort our assessment of historical performance. In that example, the total performance for the two-year period was unambiguously 0 percent. With a 100 percent return for the first year and -50 percent for the second, however, the arithmetic mean was 25 percent. As we noted previously, the arithmetic mean is always greater than or equal to the geometric mean. If we want to estimate the average return over a one-period horizon, we should use the arithmetic mean because the arithmetic mean is the average of one-period returns. If we want to estimate the average returns over more than one period, however, we should use the geometric mean of returns because the geometric mean captures how the total returns are linked over time.

As a corollary to using the geometric mean for performance reporting, the use of **semilogarithmic** rather than arithmetic scales is more appropriate when graphing past performance.[49] In the context of reporting performance, a semilogarithmic graph has an arithmetic scale on the horizontal axis for time and a logarithmic scale on the vertical axis for the value of the investment. The vertical axis values are spaced according to the differences between their logarithms. Suppose we want to represent £1, £10, £100, and £1,000 as values of an investment on the vertical axis. Note that each successive value represents a 10-fold increase over the previous value, and each will be equally spaced on the vertical axis because the difference in their logarithms is roughly 2.30; that is, $\ln 10 - \ln 1 = \ln 100 - \ln 10 = \ln 1{,}000 - \ln 100 = 2.30$. On a semilogarithmic scale, equal

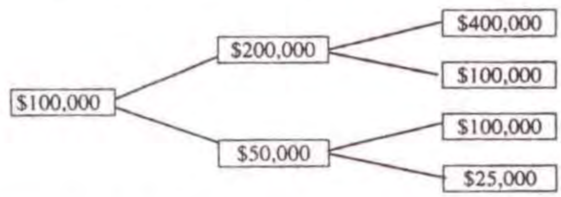
[48]It is useful to know that we can conduct a Jarque-Bera (JB) statistical test of normality based on sample size n, sample skewness, and sample excess kurtosis. We can conclude that a distribution is not normal with no more than a 5 percent chance of being wrong if the quantity $JB = n[(S_K^2/6) + (K_E^2/24)]$ is 6 or greater for a sample with at least 30 observations. In this mutual fund example, we have only 10 observations and the test described is only correct based on large samples (as a guideline, for $n \geq 30$). Gujarati (2003) provides more details on this test.

[49]See Campbell (1974) for more information.

movements on the vertical axis reflect equal percentage changes, and growth at a constant compound rate plots as a straight line. A plot curving upward reflects increasing growth rates over time. The slopes of a plot at different points may be compared in order to judge relative growth rates.

In addition to reporting historical performance, financial analysts need to calculate expected equity risk premiums in a forward-looking context. For this purpose, the arithmetic mean is appropriate.

We can illustrate the use of the arithmetic mean in a forward-looking context with an example based on an investment's future cash flows. In contrasting the geometric and arithmetic means for discounting future cash flows, the essential issue concerns uncertainty. Suppose an investor with $100,000 faces an equal chance of a 100 percent return or a −50 percent return, represented on the tree diagram as a 50/50 chance of a 100 percent return or a −50 percent return per period. With 100 percent return in one period and −50 percent return in the other, the geometric mean return is $\sqrt{2(0.5)} - 1 = 0$.



The geometric mean return of 0 percent gives the mode or median of ending wealth after two periods and thus accurately predicts the modal or median ending wealth of $100,000 in this example. Nevertheless, the arithmetic mean return better predicts the arithmetic mean ending wealth. With equal chances of 100 percent or −50 percent returns, consider the four equally likely outcomes of $400,000, $100,000, $100,000, and $25,000 as if they actually occurred. The arithmetic mean ending wealth would be $156,250 = ($400,000 + $100,000 + $100,000 + $25,000)/4. The actual returns would be 300 percent, 0 percent, 0 percent, and −75 percent for a two-period arithmetic mean return of $(300 + 0 + 0 - 75)/4 = 56.25$ percent. This arithmetic mean return predicts the arithmetic mean ending wealth of $100,000 × 1.5625 = $156,250. Noting that 56.25 percent for two periods is 25 percent per period, we then must discount the expected terminal wealth of $156,250 at the 25 percent arithmetic mean rate to reflect the uncertainty in the cash flows.

Uncertainty in cash flows or returns causes the arithmetic mean to be larger than the geometric mean. The more uncertain the returns, the more divergence exists between the arithmetic and geometric means. The geometric mean return approximately equals the arithmetic return minus half the variance of return.[50] Zero variance or zero uncertainty in returns would leave the geometric and arithmetic returns approximately equal, but real-world uncertainty presents an arithmetic mean return larger than the geometric. For example, Dimson et al. (2002) reported that from 1900 to 2000, U.S. equities had nominal annual returns with an arithmetic mean of 12 percent and standard deviation of 19.9 percent. They reported the geometric mean as 10.1 percent. We can see the geometric mean is approximately the arithmetic mean minus half of the variance of returns: $R_G \approx 0.12 - (1/2)(0.199^2) = 0.10$.

[50]See Bodie, Kane, and Marcus (2001).

By Michael Annin

Equity and the Small-Stock Effect

The capital asset pricing model shows risk inherent in return on equity. But something goes wrong when it's used for small-sized companies.

Does the size of a company affect the rate of return it should earn? If smaller companies should earn a higher return than larger firms, then small utilities, because of their size, should be allowed to adjust the rates they charge to customers.

By far the most notable and well-documented apparent anomaly in the stock market is the effect of company size on equity returns. The first study focusing on the impact that company size exerts on security returns was performed by Rolf W. Banz. Banz sorted New York Stock Exchange (NYSE) stocks into quintiles based on their market capitalization (price per share times number of shares outstanding), and calculated total returns for a value-weighted portfolio of the stocks in each quintile. His results indicate that returns for companies from the smallest quintile surpassed all other quintiles, as well as the Standard & Poor's 500 and other large stock indices. A number of other researchers have replicated Banz's work in other countries; nevertheless, a consensus has not yet been formed on why small stocks behave as they do.

One explanation for the higher returns is the lack of information on small companies. Investors must search more diligently for data. For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.

The Flaw in CAPM

One of the more common cost of equity models used in practice today is the capital asset pricing model (CAPM). The CAPM describes the expected return on any company's stock as proportional to the amount of systematic risk an investor assumes. The traditional CAPM formula can be stated as:

$$R_s = [\beta_s \, x \, RP] + R_f$$

where:

R_s = expected return or cost of equity on the stock of company "s"

β = the *beta* of the stock of company "s"

RP = the expected equity risk premium

R_f = expected return on a riskless asset.

Table 1: The Size Premium in CAPM
(By Decile Portfolio in NYSE, 1926-94)

Decile	*Beta*	Arithmetic Mean Return	Actual Return in Excess of Riskless Rate**	CAPM Return in Excess of Riskless Rate**	Size Premium (Return in Excess CAPM)
1	0.90	11.01%	5.88%	6.33%	–0.44%
2	1.04	13.09	7.97	7.34	0.63
3	1.09	13.83	8.71	7.70	1.01
4	1.13	14.44	9.32	7.98	1.33
5	1.17	15.50	10.38	8.22	2.16
6	1.19	15.45	10.33	8.38	1.95
7	1.24	15.92	10.79	8.75	2.05
8	1.29	16.84	11.72	9.05	2.67
9	1.36	17.83	12.71	9.57	3.14
10	1.47	21.98	16.86	10.33	6.53

**Betas* are estimated from monthly returns in excess of the 20-year government bond income return, January 1926-December 1994.
**Historical riskless rate measured by the 69-year arithmetic mean income return component of 20-year government bonds.
Source: SBBI 1995 Yearbook

Table 2: CAPM vs. CAPM w/ Size Premium

(By Percentile for Electric, Gas, and Sanitary Services Utilities)

	CAPM	CAPM with Size Premium
90th Percentile	16.42%	18.92%
75th Percentile	12.56%	14.72%
Median	10.89%	12.58%
25th Percentile	9.86%	11.39%
10th Percentile	8.63%	10.65%

(Weighted by Market Capitalization)

	CAPM	CAPM with Size Premium
Industry Composite	11.76%	12.33%
Large Company Composite	12.05%	12.07%
Small Company Composite	13.93%	17.95%

Source: Cost of Capital Quarterly '95 Yearbook by Ibbotson Associates
Note: Public utilities include electric, gas, and sanitary services companies.

Table 1 shows *beta* and risk premiums over the past 69 years for each decile of the NYSE. It shows that a hypothetical risk premium calculated under the CAPM fails to match the actual risk premium, shown by actual market returns. The shortfall in the CAPM return rises as company size decreases, suggesting a need to revise the CAPM.

The risk premium component in the actual returns (realized equity risk premium) is the return that compensates investors for taking on risk equal to the risk of the market as a whole (estimated by the 69-year arithmetic mean return on large company stocks, 12.2 percent, less the historical riskless rate). The risk premium in the CAPM returns is *beta* multiplied by the realized equity risk premium.

The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premiums (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10. The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.

Based on this analysis, we modify the CAPM formula to include a small-stock premium. The modified CAPM formula can be stated as follows:

$$R_s = [\beta_s \times RP] + R_f + SP$$

where:

SP = small-stock premium.

Because the small-stock premium can be identified by company size, the appropriate premium to add for any particular company will depend on its equity capitalization. For instance, a utility with a market capitalization of $1 billion would require a small capitalization adjustment of approximately 1.3 percent over the traditional CAPM; at $400 million, approximately 2.1 percent, and at only $100 million, approximately 4 percent.

Again, these additions to the traditional CAPM represent an adjustment over and above any increase already provided to these smaller companies by having higher *betas*.

Implications for Smaller Utilities

These findings carry important ramifications for relatively small public utilities. Boosting the traditional CAPM return by a full 400 basis points for small utilities translates into a substantial premium over larger utilities.

Table 2 shows the results of an analysis of 202 utility companies that calculated cost of equity figures. Composites (arithmetic means) weighted by equity capitalization were also calculated for the largest and smallest 20 companies. The results show the impact size has on cost of equity.

For the traditional CAPM, the large-company composite shows a cost of equity of 12.05 percent; the small company composite, 13.93 percent. However, once the respective small capitalization premium is added in, the spread increases dramatically, to 12.07 and 17.95 percent, respectively. Clearly, the smaller the utility (in terms of equity capitalization), the larger the impact that size exerts on the expected return of that security. ▼

Michael Annin, CFA, is a senior consultant with Ibbotson Associates, specializing in business valuation and cost of capital analysis. He oversees the Cost of Capital Quarterly, *a reference work on using cost of capital for company valuations.*

REGULATORY FINANCE:

UTILITIES' COST OF CAPITAL

Roger A. Morin, PhD

in collaboration with
Lisa Todd Hillman

1994
PUBLIC UTILITIES REPORTS, INC.
Arlington, Virginia

common equity to obtain the final cost of equity financing.[1] This incremental return is referred to as the "flotation cost allowance," and is the sum total of direct flotation expenses, market pressure, and market break.

To demonstrate the need for adjusting the market-determined return on equity for flotation costs, consider the following simple example. Shareholders invest $100 of capital on which they expect to earn a return of 10%, or $10, but the company nets $95 because of issuance costs. It is obvious that the company will have to earn more than 10% on its net book investment (rate base) of $95 to provide investors with a $10 return on the money actually invested. To provide the same earnings of $10 on a reduced capital base of $95 clearly requires a return higher than the shareholder expected return of 10%, namely $10/$95 = 10.53%. This is because only the net proceeds from an equity issue are used to add to the rate base on which the investor earns.

6.2 Magnitude of Flotation Costs

The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue. A more precise figure can be obtained by surveying empirical studies on utility security offerings.

According to empirical studies by Borum and Malley (1986) and Logue and Jarrow (1978), underwriting costs and expenses average 4% - 5.5% of gross proceeds for utility stock offerings in the U.S. Eckbo and Masulis (1987) found an average flotation cost of 4.175% for utility common stock offerings, and found that flotation costs increased progressively for smaller size issues.

As far as the market pressure effect is concerned, empirical studies clearly show that the market pressure effect is real, tangible, and measurable. Appendix 6-A describes one method of measuring the market pressure effect. Logue and Jarrow (1978) found that the absolute magnitude of the relative price decline due to market pressure was less than 1.5%. Bowyer and Yawitz (1980) examined 278 public utility stock issues and found an average market pressure of 0.72%. In a classic and monumental study published in the *Journal of Financial Economics,* which reviewed the aggregate empirical evidence on market pressure from several studies, Smith (1986) found a market pressure effect of 3.14% for industrial stock

[1] An alternate way of stating this requirement is that the utility's stock must be maintained at some minimum market-to-book ratio in such a way that the proceeds from new stock issues will not decline below book value per share.

issues and 0.75% for utility common stock issues. Other studies of market pressure are reported in Logue (1973), Pettway (1984), and Reilly and Hatfield (1969). In Pettway's study, the market pressure effect for a sample of 368 public utility equity sales was in the range of 2% to 3%. Eckbo and Masulis (1987) found that the relative price decline due to market pressure in the days surrounding the announcement amounted to slightly more than 1.5%.

The Eckbo and Masulis study also confirmed that the percentage flotation cost allowance is higher for small issues than for large issues in view of the high fixed cost component of total costs involved in the process of security underwriting. Although total costs of issuing securities vary according to size of the issue and the degree of risk, there are certain expenses that are fixed, regardless of issue size. These include legal fees and prospectus preparation. With respect to the balance, or underwriting costs, there is greater risk assumed with smaller issues.

In summary, based on empirical studies of U.S. utility security offerings, total flotation costs including market pressure conservatively amount to 5% of gross proceeds for U.S. security offerings. This is consistent with the fact that several utilities raise a substantial portion of their external equity every year through an automatic dividend reinvestment plan and offer a 5% discount, suggesting that the savings from abstaining from a public issue of common stock are at least 5%. The flotation cost allowance of 5% is likely to be conservative, since no explicit allowance for market break is incorporated. If negative events should occur during the time period from announcement of a public issue to actual pricing, the price could fall below book value unless a sufficient margin is maintained. Moreover, the 1% allowance for market pressure is probably conservative for large stock issues.

6.3 Application of the Flotation Cost Adjustment

This section formally demonstrates: (1) how and why it is necessary to apply a flotation cost allowance to the dividend yield component of the DCF model in order to obtain the fair return on equity capital; (2) why the flotation adjustment is permanently required to avoid confiscation even if no further stock issues are contemplated; and (3) why flotation costs are only recovered if the rate of return is applied to total equity, including retained earnings, in all future years.

An analogy with bond issues, as discussed in Brigham, Aberwald, and Gapenski (1985), is useful here in order to understand the treatment of issue costs in the case of common stock issues. In the case of bonds, The latter expression is identical to that obtained from the standard DCF model adjusted for underpricing in Equation 6-4.

The more practical version of the extended DCF model cast in terms of G, the growth rate in total book equity, also collapses to an identical expression:

$$r = G + (M/B)\,(K - G) \tag{6-8}$$

To avoid dilution, $v = 0$, which in turn implies $G = g = br$. Equation 6-8 reduces to Equation 6-7 under the condition that $M/B = 1/(1-f)$:

$$\begin{aligned} r &= g + (1/(1-f)\,(K-g) \\ &= g + (1/(1-f))\,D_1/P \\ &= D_1/P\,(1-f) + g \end{aligned}$$

6.4 Flotation Cost Controversies

Several important controversies have surfaced regarding the underpricing allowance. The first is the contention that an underpricing allowance is inappropriate if the utility is a subsidiary whose equity capital is obtained from its parent. This objection is unfounded since the parent-subsidiary relationship does not eliminate the costs of a new issue, but merely transfers them to the parent. It would be unfair and discriminatory to subject parent shareholders to dilution while individual shareholders are absolved from such dilution. Fair treatment must consider that if the utility subsidiary had gone to the capital marketplace directly, flotation costs would have been incurred.

A second controversy is whether a flotation cost allowance should be allowed because a company can always obtain equity from sources other than a public issue of common stock, such as a rights issue for example. There are several sources of equity capital available to a firm, including: public common stock issues, conversions of convertible preferred stock, dividend reinvestment plans, employees' savings plans, warrants, and stock dividend programs. Each carries its own set of administrative costs and flotation cost components, including discounts, commissions, corporate expenses, offering spread, and market pressure.

Equity capital raised through a public issue is typically more expensive than alternate sources of equity. Rights issues, when available, are less expensive, but direct costs would still be incurred. Of course, a rights issue assumes that a willing underwriter and a willing market could be found for such offerings in the first place, an unlikely event in public capital markets for small unproven companies. Internal sources of equity, including dividend reinvestment and/or employee stock option plans, are also typically less expensive, unless a discount on the purchase price is inherent in the plan, in which case they are often equivalent to a public issue. Direct costs are also incurred in an employee stock savings plan and/or a shareholder dividend reinvestment plan.

The flotation cost allowance is still warranted, however, because it is a composite factor that reflects the historical mix of all these sources of equity. The flotation cost allowance factor is a build-up of historical flotation cost adjustments associated and traceable to each component of equity source, and more specifically, is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the company. It is impractical and prohibitive to start from the inception of a company and source all present equity. A practical solution is to rely on the results of the empirical studies discussed earlier that quantify the average flotation cost factor of a large sample of utility stock offerings.

Richter (1982) demonstrated that the flotation cost allowance applicable to all the company's book equity is a weighted average of the current allowances required for each past financing, and suggested some practical means of circumventing the problem of vintaging each equity source. Richter essentially suggested sourcing book equity by broad categories of equity, such as dividend reinvestment plan equity, stock option equity, and public issue equity, and calculating a weighted average underpricing factor.

A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.

It has also been argued that a flotation cost allowance is inequitable since it results in a windfall gain to shareholders. This argument is erroneous. As stated previously, the company's common equity account is credited by an amount less than the market value of the issue, so that the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.

The suggestion that the flotation cost allowance is unwarranted because investors factor this shortcoming in the stock price implies that it is appropriate to use a deficient model because such a deficiency is reflected in stock prices. In other words, it is appropriate to use a deficient model because investors are aware of this. Such circular reasoning could be used to justify any regulatory policy. For example, under this reasoning, it would be appropriate to authorize a return on equity of 1% because investors reflect this fact in the stock price. This is clearly illogical and erroneous. Any regulatory policy, as irrational as it may be, can be justified using this argument.

Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair return on equity, but only at the time when the expenses are incurred. In other words, the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. If the flotation costs of past stock issues have been fully recovered, the argument has merit. If that assumption is not met, the argument is without merit. The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.

A related controversy is whether or not the retained earnings component of equity requires a flotation cost adjustment. There is no flotation cost allowance made to retained earnings because it is implicitly embedded and recognized in the flotation cost adjustment formula. The conventional flotation cost adjustment formula deals with the fact that flotation costs are incurred only when new stock is sold, and not when earnings are retained. This is done by applying the flotation adjustment only to the dividend yield of the DCF formula and not to the growth component. The larger the fraction of earnings retained, the higher the growth rate, the lower the dividend yield component, and the smaller the flotation cost adjustment. In other words, larger retained earnings result in lower flotation costs adjustments as the costs are postponed into the future.

Some have argued that underwriters' discounts are not out-of-pocket expenses and thus should not be included in rates. On the basis of this argument, one might be foolish enough to believe that depreciation of utility plant should not be included in rates on the same grounds that depreciation is not an out-of-pocket expense. Obviously, the argument is without merit.

Lastly, some suggest that the flotation cost allowance should be based on a company's own actual flotation cost experience rather than on empirical studies that pertain to a large sample of stock offerings. To base a flotation cost allowance on a one-company sample, although company specific, would not provide a sufficiently reliable statistical and economic basis to infer a utility's appropriate flotation cost allowance. While it is conceptually correct to rely on the particular company circumstances in quantifying the flotation cost allowance, it is not a practical alternative. As discussed earlier, the flotation cost allowance is a weighted average cost factor designed to capture the average cost of various equity vintages and types of equity capital raised by the company.

As an additional practical matter, the market pressure effect is difficult to measure accurately for a specific issue. This is because one must disentangle the downward effect on stock price resulting from the increased supply of stock from the effect of general movement in the stock market. One must also measure the actual stock price following a common stock issue in relation to a hypothetical benchmark price without the issue over some arbitrary time period. This can be performed more reliably and more rigorously using a sample of utility stock offerings.

Alternative Flotation Cost Adjustment Formulas

Arzac and Marcus (1981) developed an alternative approach to accounting for flotation costs in regulatory hearings. To avoid dilution of the initial shareholders' equity, the allowed rate of return should equal:

$$R = \frac{K}{1 - \dfrac{fh}{1-f}} \tag{6-9}$$

where h = *external equity financing rate*, as a percentage of earnings, and the other symbols are as before.

Patterson (1983A and 1983B) formally compared the properties of the Arzac and Marcus adjustment with those of the conventional adjustment, and showed that the former is equivalent to expensing issue costs in each period when a stock issue occurs. In other words, if Equation 6-9 is consistently applied, the utility is reimbursed for its flotation costs in each year as they are incurred. Patterson also showed that the present value of flotation cost adjustments received by the utility is the same for both the

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Business Valuation

One required element of the income approach to company valuation is the discount rate. Under the income approach, cash flows are projected into the future and discounted back to present value using a discount rate reflective of the risk inherent in those cash flows. The income approach is expressed in the following formula:

$$PV_s = \frac{CF_1}{(1+k_s)^1} + \frac{CF_2}{(1+k_s)^2} + \ldots + \frac{CF_i}{(1+k_s)^i}$$

where:

PV_s = the present value of the expected cash flows for company **s**;
CF_i = the dividend or cash flow expected to be received at the end of period **i**, and
k_s = the cost of capital for company **s**.

The discount rate is synonymous with the cost of capital.

While determining the appropriate future cash flow stream is an essential element of the income approach, determining the appropriate discount rate is equally important. Under the income approach, small changes in the discount rate can have a large impact on the ultimate value that is derived.

Table 2-2 is a simple valuation example that illustrates the impact of small changes in the discount rate. In the example, the entity being valued produces cash flows of $1,000 each year in years one through four, and $10,000 in year five. The lower portion of the table shows the values derived from this cash flow stream using different discount rates.

Table 2-2: Valuing Future Cash Flows with Different Discount Rates

Projected Cash Flows ($)

	Year 1	Year 2	Year 3	Year 4	Year 5
	1,000	1,000	1,000	1,000	10,000

Present Value of Cash Flows ($)

Discount Rate (%)	Year 1	Year 2	Year 3	Year 4	Year 5	Total
10	909	826	751	683	6,209	**9,379**
11	901	812	731	659	5,935	9,037
12	893	797	712	636	5,674	8,712
13	885	783	693	613	5,428	8,402
14	877	769	675	592	5,194	8,107
15	870	756	658	572	4,972	**7,827**

Whether this entity is worth $9,379 using a discount rate of 10 percent or $7,827 using a discount rate of 15 percent may seem trivial. If these values were in thousands or millions of dollars, however, the differences would be significant.

The preceding example focused on values produced from discount rates that are 500 basis points apart. While this may seem extreme, basic assumptions in the determination of the cost of capital can lead to discount rates that are widely divergent. Understanding the assumptions that underlie the discount rate is as important as understanding the assumptions that underlie the cash flows.

Regulatory Proceedings

Even in this era of deregulation, most utilities are regulated to some extent by local government bodies. An appointed commission ensures that the utility, because of its alleged monopolistic power, does not take advantage of its customers and that its investors receive a fair rate of return on their invested capital. One of the most important functions of the commission is to determine an appropriate (often called the "allowed") rate of return. The procedures for setting rates of return for regulated utilities often specify or suggest that the required rate is that which would allow the firm to attract and retain debt and equity capital over the long term.

Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital). In addition, certain regulatory environments may require that shareholders not earn more than the allowed rate of return. If a shareholder does earn more, future rates for the utilities services may be reduced by the regulating body. If the allowed rate of return falls below the cost of capital, regulators may allow a rate increase in order to compensate the investor so that they will on average over time earn the market-required rate of return. Yet other regulatory conditions may require that the allowed rate of return be different from the cost of capital.

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April 20, 2012

Issuer Ranking:
U.S. Regulated Utilities, Strongest To Weakest

Primary Credit Analyst:
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

Secondary Contacts:
Todd A Shipman, CFA, New York (1) 212-438-7676; todd_shipman@standardandpoors.com
Dimitri Nikas, New York (1) 212-438-7807; dimitri_nikas@standardandpoors.com
Barbara A Eiseman, New York (1) 212-438-7666; barbara_eiseman@standardandpoors.com
Gerrit Jepsen, CFA, New York (1) 212-438-2529; gerrit_jepsen@standardandpoors.com
Gabe Grosberg, New York (1) 212-438-6043; gabe_grosberg@standardandpoors.com
Matthew O'Neill, New York (1) 212-438-4295; matthew_oneill@standardandpoors.com
Michael Ferguson, CFA, CPA, New York (1) 212-438-7670; michael_ferguson@standardandpoors.com

Issuer Ranking:

U.S. Regulated Utilities, Strongest To Weakest

The following list ranks all the rated companies in the U.S. regulated electric, gas, and water utility sectors from strongest to weakest based on rating and outlook. We further rank companies with the same rating and outlook by our opinion of credit quality based primarily on business risks for investment-grade companies and primarily on financial risks for speculative-grade companies.

Ratings are displayed as long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates no rating. Issuer credit ratings are identical for local and foreign currency unless noted with the "LC" and "FC" designations.

For the related industry report cards, see "Industry Report Card: U.S. Regulated Electric Utilities Remains Stable," published on March 28, 2012 and "Industry Report Card: U.S. Regulated Gas And Water Utilities' Credit Quality Should Remain Steady in 2012," published on April 12, 2012.

U.S. Regulated Utilities

	Corporate credit rating*	Business profile	Financial profile	Liquidity
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Intermediate	Adequate
Midwest Independent Transmission System Operator Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
Aqua Pennsylvania Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
Washington Gas Light Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
WGL Holdings Inc.	A+/Stable/A-1	Excellent	Intermediate	Adequate
The Baton Rouge Water Works Co.	A+/Stable/--	Excellent	Intermediate	Strong
American States Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Golden State Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Northwest Natural Gas Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
California Water Service Co.	A+/Negative/--	Excellent	Intermediate	Strong
California Independent System Operator Corp.	A/Stable/--	Excellent	Intermediate	Adequate
San Diego Gas & Electric Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Southern California Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Piedmont Natural Gas Co. Inc.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
Alabama Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Georgia Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Mississippi Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Gulf Power Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
San Jose Water Co.	A/Stable/--	Excellent	Intermediate	Adequate
New Jersey Natural Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Laclede Gas Co.	A/Stable/A-1	Excellent	Intermediate	Strong
The Laclede Group Inc.	A/Stable/--	Excellent	Intermediate	Strong
The Brooklyn Union Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
KeySpan Gas East Corp.	A/Stable/--	Excellent	Intermediate	Adequate

U.S. Regulated Utilities (cont.)				
Southern Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Corp.	A/Stable/A-1	Excellent	Intermediate	Adequate
Connecticut Water Service Inc.	A/Negative/--	Excellent	Significant	Adequate
The Connecticut Water Co.	A/Negative/--	Excellent	Significant	Adequate
Central Hudson Gas & Electric Corp.	A/Watch Neg/--	Excellent	Significant	Strong
NSTAR Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Yankee Gas Services Co.	A-/Stable/--	Excellent	Significant	Adequate
NSTAR Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Western Massachusetts Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Connecticut Light & Power Co.	A-/Stable/--	Excellent	Significant	Adequate
Public Service Co. of New Hampshire	A-/Stable/--	Excellent	Significant	Adequate
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Gas LLC	A-/Stable/A-2	Excellent	Significant	Adequate
The York Water Co.	A-/Stable/--	Excellent	Significant	Adequate
Middlesex Water Co.	A-/Stable/--	Excellent	Significant	Adequate
United Water New Jersey Inc.	A-/Stable/--	Excellent	Significant	Adequate
United Waterworks Inc.	A-/Stable/--	Excellent	Significant	Adequate
Indiana Gas Co. Inc.	A-/Stable/--	Excellent	Significant	Adequate
Boston Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Colonial Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Vectren Utility Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Carolinas LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Florida Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate	Adequate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Narragansett Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
New England Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Indiana Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Wisconsin	A-/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of Colorado	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Southwestern Public Service Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Power & Light Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Electric Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
The Peoples Gas Light & Coke Co.	A-/Stable/A-2	Excellent	Significant	Adequate
North Shore Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Peoples Energy Corp.	A-/Stable/--	Excellent	Significant	Adequate
Wisconsin Public Service Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Co.	A-/Stable/A-2	Excellent	Significant	Adequate
PacifiCorp	A-/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Duke Energy Kentucky Inc.	A-/Stable/--	Excellent	Significant	Adequate
Northeast Utilities	A-/Stable/--	Excellent	Significant	Adequate
NSTAR LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid USA	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
KeySpan Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Energy Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Xcel Energy Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Duke Energy Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Integrys Energy Group Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Vectren Corp.	A-/Stable/--	Excellent	Significant	Adequate
Duke Energy Ohio Inc.	A-/Stable/A-2	Strong	Significant	Adequate
NextEra Energy Inc.	A-/Stable/--	Strong	Intermediate	Adequate
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate
Progress Energy Inc.	BBB+/Watch Pos/A-2	Excellent	Significant	Adequate
Atlanta Gas Light Co.	BBB+/Stable/--	Excellent	Significant	Adequate
Nicor Gas Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Atmos Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Tampa Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
International Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Midwest LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Michigan Electric Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Great Plains LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania-American Water Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
New Jersey-American Water Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
American Water Works Co. Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
American Water Capital Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
CenterPoint Energy Houston Electric LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Cascade Natural Gas Corp.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Montana-Dakota Utilities Co.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Southwest Gas Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
Interstate Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of North Carolina Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
South Carolina Electric & Gas Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Oncor Electric Delivery Co. LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Significant	Strong
Potomac Electric Power Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Delmarva Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Atlantic City Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Central Maine Power Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
New York State Electric & Gas Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
ITC Holdings Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
AGL Resources Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Holdings Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
TECO Energy Inc.	BBB+/Stable/--	Excellent	Significant	Adequate
SCANA Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Alliant Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
CenterPoint Energy Resources Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
CenterPoint Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
PEPCO Holdings Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
South Jersey Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Michigan Consolidated Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Detroit Edison Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Sempra Energy	BBB+/Stable/A-2	Strong	Intermediate	Adequate
DTE Energy Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
South Jersey Industries Inc.	BBB+/Stable/--	Strong	Significant	Adequate
OGE Energy Corp.	BBB+/Stable/A-2	Strong	Significant	Adequate
ALLETE Inc.	BBB+/Stable/A-2	Strong	Significant	Adequate
Public Service Electric & Gas Co.	BBB/Positive/A-2	Excellent	Significant	Adequate
Arizona Public Service Co.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
Pinnacle West Capital Corp.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
Rochester Gas & Electric Corp.	BBB/Positive/--	Excellent	Aggressive	Adequate
PECO Energy Co.	BBB/Stable/A-2	Excellent	Significant	Adequate
Commonwealth Edison Co.	BBB/Stable/A-2	Excellent	Significant	Adequate
PPL Electric Utilities Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
AEP Texas Central Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
AEP Texas North Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Westar Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Kansas Gas & Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Connecticut Natural Gas Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Southern Connecticut Gas Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
The United Illuminating Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Utilities Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Louisville Gas & Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
LG&E and KU Energy LLC	BBB/Stable/--	Excellent	Aggressive	Adequate
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
NorthWestern Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive	Adequate

U.S. Regulated Utilities (cont.)				
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kansas City Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
KCP&L Greater Missouri Operations Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Great Plains Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Cleco Power LLC	BBB/Stable/--	Excellent	Aggressive	Strong
Avista Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Portland General Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Puget Sound Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive	Strong
El Paso Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
PPL Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
UIL Holdings Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Cleco Corp.	BBB/Stable/--	Excellent	Aggressive	Strong
IDACORP Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Pacific Gas & Electric Co.	BBB/Stable/A-2	Strong	Significant	Adequate
PG&E Corp.	BBB/Stable/--	Strong	Significant	Adequate
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive	Adequate
Entergy Gulf States Louisiana LLC	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Louisiana LLC	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Mississippi Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Arkansas Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Texas Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy New Orleans Inc.	BBB/Negative/--	Excellent	Significant	Adequate
System Energy Resources Inc.	BBB/Negative/--	Excellent	Significant	Adequate
Entergy Corp.	BBB/Negative/--	Strong	Significant	Adequate
SEMCO Energy Inc.	BBB-/Watch Pos/--	Excellent	Significant	Adequate
Trans-Allegheny Interstate Line Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNG Cos. LLC	BBB-/Stable/--	Excellent	Aggressive	Adequate
Bay State Gas Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ameren Illinois Co.	BBB-/Stable/A-3	Excellent	Significant	Adequate
Ameren Missouri	BBB-/Stable/A-3	Excellent	Significant	Adequate
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Electric Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Metropolitan Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Jersey Central Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ohio Edison Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Cleveland Electric Illuminating Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Toledo Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Duquesne Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate

U.S. Regulated Utilities (cont.)				
Northern Indiana Public Service Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Consumers Energy Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Black Hills Power Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Otter Tail Power Co.	BBB-/Stable/--	Excellent	Significant	Strong
Empire District Electric Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Texas-New Mexico Power Co.	BBB-/Stable/--	Excellent	Aggressive	Strong
Public Service Co. of New Mexico	BBB-/Stable/--	Excellent	Aggressive	Strong
Dayton Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Indianapolis Power & Light Co.	BBB-/Stable/--	Excellent	Highly leveraged	Adequate
CMS Energy Corp.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
NiSource Inc.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Duquesne Light Holdings Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNM Resources Inc.	BBB-/Stable/--	Excellent	Aggressive	Strong
IPALCO Enterprises Inc.	BBB-/Stable/--	Excellent	Highly leveraged	Adequate
DPL Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Hawaiian Electric Co. Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Edison International	BBB-/Stable/--	Strong	Aggressive	Strong
Ameren Corp.	BBB-/Stable/A-3	Strong	Significant	Adequate
FirstEnergy Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Black Hills Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Hawaiian Electric Industries Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Ohio Valley Electric Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Otter Tail Corp.	BBB-/Stable/--	Satisfactory	Significant	Strong
SourceGas LLC	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Nevada Power Co.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Sierra Pacific Power Co.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
NV Energy Inc.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Puget Energy Inc.	BB+/Stable/--	Excellent	Aggressive	Strong
Tucson Electric Power Co.	BB+/Stable/B-2	Strong	Aggressive	Adequate

*Ratings as of April 20, 2012.

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Roger A. Morin, PhD

2006
PUBLIC UTILITIES REPORTS, INC.
Vienna, Virginia

19.2 Critique of Double Leverage

Adherents to the double leverage calculation argue that the true cost of capital to a utility subsidiary is the weighted cost of its own debt and the weighted cost of the parent's debt and equity funding. Moreover, unless the subsidiary's equity is assigned the parent's weighted cost of capital, parent shareholders will reap abnormally high returns. Although persuasive on the surface, these arguments conceal serious conceptual and practical problems. Moreover, the validity of double leverage rests on highly questionable assumptions.

The flaws associated with the double leverage approach have been discussed thoroughly in the academic literature. Pettway and Jordan (1983) and Beranek and Miles (1988) point out the flaws in the double leverage argument, particularly the excess return argument, and also demonstrate that the stand-alone method is a superior procedure. Rozeff (1983) discusses the ratepayer cross-subsidies of one subsidiary by another when employing double leverage. Lerner (1973) concludes that the returns granted an equity investor must be based on the risks to which the investor's capital is exposed and not on the investor's source of funds.

Theoretical Issues

The double leverage approach contradicts the core of the cost of capital concept. Financial theory clearly establishes that the cost of equity is the risk-adjusted opportunity cost to the investors and not the cost of the specific capital sources employed by investors. The true cost of capital depends on the use to which the capital is put and not on its source. The *Hope* and *Bluefield* doctrines have made clear that the relevant considerations in calculating a company's cost of capital are the alternatives available to investors and the returns and risks associated with those alternatives. The specific source of funding and the cost of those funds to the investor are irrelevant considerations.

Carrying the double leverage standard to its logical conclusion leads to even more unreasonable prescriptions. If the common shares of the subsidiary were held by both the parent and by individual investors, the equity contributed by the parent would have one cost under the double leverage computation while the equity contributed by the public would have another. This is clearly illogical. Or, does double leverage require tracing the source of funds used by each individual investor so that its cost can be computed by applying double leverage to each individual investor? Of course not! Equity is equity, irrespective of its source, and the cost of that equity is governed by its use, by the risk to which it is exposed.

To illustrate, let us say that an individual investor borrows money at the bank at an after-tax cost of 8% and invests the funds in a speculative oil exploration venture. Clearly, the required return on the oil venture investment is not the

8% cost but rather the return forgone in speculative projects of similar risk, say 20%. Yet, under the double leverage approach, the individual's fair return on this risky venture would be 8%, which is the cost of the capital source, and not 20%, which is the required return on investments of similar risk. Double leverage implies that for all investors who inherited stock or received stock as a gift, the allowed return on equity would be zero, since the cost of the stock to the investors is zero. It also implies that if, tomorrow morning, a subsidiary were sold to a company with a higher cost of capital than the parent, the subsidiary's cost of equity would suddenly become higher on the next morning as a result of the change in ownership. If we assumed that the double leverage concept were appropriate, we would also have to assume that the day following a divestiture or spinoff, the cost of equity of the newly divested or spunoff company suddenly rises by a substantial amount. This is logically absurd, as it is the use of capital that governs its cost, and not its source.

For example, if a subsidiary with a double leverage cost of equity of 12% were sold to another company with a higher cost of capital of, for example, 15%, would regulation alter the return accordingly just because of the change in ownership? If so, the same utility with the same assets and providing the same service under the new management would have a higher cost of service to ratepayers because of the transfer of ownership. Clearly, if a utility subsidiary were allowed an equity return equal to the parent's weighted cost of capital while the same utility were allowed a fair, presumably higher, return were it not part of a holding company complex, an irresistible incentive to dissolve the holding company structure would exist in favor of the one-company operating utility format. The attendant benefits of scale economies and diversification would then be lost to the ratepayers.

The cost of capital is governed by the risk to which the capital is exposed and not by the cost of those funds or whether they were obtained from bondholders or common shareholders. The identity of the subsidiary's shareholders should have no bearing on its cost of equity because it is the risk to which the subsidiary's equity is exposed that governs its cost of money, not whether it is borrowed from bondholders or sold to common shareholders for issued shares. Had the parent company not been in the picture, and had the subsidiary's stock been widely held by the public, the subsidiary would be entitled to a return that would fully cover the cost of both its debt and equity.

Just as individual investors require different returns from different assets in managing their personal affairs, why should regulation cause parent companies making investment decisions on behalf of their shareholders to act any differently? A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between the subsidiaries. Yet, the double leverage calculation would assign the same return to each activity, based on the parent's cost of capital. Investors recognize that different subsidiaries are exposed to different risks, as evidenced by the different bond ratings and cost rates of operating subsidiaries. The same argument carries over to common equity. If the cost rate for debt is different because the risk is different, the cost rate for common equity is also different, and the double leverage adjustment should not obscure this fact.

The double leverage concept is also at odds with the opportunity cost concept of economics. According to this principle of economics, the cost of any resource is the cost of an alternative forgone. The cost of investing funds in an operating utility subsidiary is the return forgone on investments of similar risk. If the fair risk-adjusted return assigned by the market on utility investments is 15%, and the regulator assigns a return less than 15% because of a double leverage calculation, there is no incentive or defensible reason for a parent holding company to invest in that utility.

Fairness and Capital Attraction

The double leverage approach is highly discriminatory, and violates the doctrine of fairness. If a utility is not part of a holding company structure, the cost of equity is computed using one method, say the CAPM method, while otherwise the cost of equity is computed using the double leverage adjustment. Estimating equity costs by one procedure for publicly held utilities and by another for utilities owned by a holding company is inconsistent with financial theory and discriminates against the holding company form of ownership. Two utilities identical in all respects but their ownership format should have the same set of rates. Yet, this would not be the case under the double leverage adjustment.

The capital attraction standard may also be impaired under the double leverage calculation. This is because a utility subsidiary must compete on its own in the market for debt capital, and therefore must earn an appropriate return on equity to support its credit rating. Imputing the parent's weighted cost to the utility's equity capital may result in inadequate equity returns and less favorable coverage, hence impairing the utility subsidiary's ability to attract debt capital under favorable terms.

Questionable Assumptions

Several assumptions underlying the double leverage standard are highly questionable. One assumption, to which the previous numerical illustrations have already alluded, is the traceability of the subsidiary's equity capital to its parent. None of the subsidiary's retained earnings can be traced to the capital raised by the parent. Some analysts salvage the double leverage approach by assigning one cost rate to retained earnings and another to the common equity capital raised by the parent, with the curious result that equity has two cost rates. The traceability issue goes further. If a parent company issues bonds or preferred stock to acquire an operating subsidiary, the traceability assumption is broken. Corporate reorganizations and mergers further invalidate the traceability assumption.

By virtue of using the parent's weighted cost as the equity cost rate for the subsidiary, another questionable assumption is that the parent capital is invested in subsidiaries that all have the same risks. Lastly, the double leverage procedure makes the unlikely assumption that the parent holding company invests its funds in each subsidiary proportionately to each subsidiary's debt-equity ratio, which is unreasonable.

Double Leverage: A Tautology

The double leverage approach is a tautology. It is not the parent's weighted average cost of capital (WACC) that determines the subsidiary's cost of equity because the parent's WACC is itself a weighted average of equity costs of all subsidiaries. Double leverage adherents confuse the direction of cause and effect. The equity cost of subsidiaries must be found on a stand-alone basis.

The last nail in the double leverage coffin goes like this. If capital market equilibrium is to hold, the cash flows to the parent company's bondholders and stockholders must equal the cash flows from the parent's equity in each subsidiary. Letting K denote the cost of capital, the subscripts p and s denote the parent and subsidiary, D and E the dollar amounts of debt and equity, and the subscripts 'd' and 'e' denote debt and equity, we can therefore say:

$$K_{dp}D_p + K_{ep}E_p = \sum_{s}^{n} K_{es}E_s \qquad (19\text{-}1)$$

The various unknowns, including the parent return on equity, can be found in terms of all the other given variables. What the above equation makes clear is that the parent cost of equity is determined by the subsidiary's cost of equity, and that parent capital costs cannot determine the subsidiary's capital costs. This can be seen even more clearly by dividing the above equation by total parent value V to obtain:

$$K_{dp}D_p/V + K_{ep}E_p/V = \sum_{s}^{n} K_{es}E_s/V \qquad (19\text{-}2)$$

The left side of the equation is the usual expression for the parent's WACC, and the right side is the weighted average of equity costs of all subsidiaries. However,

$$\sum_{s}^{n} E_s = V \qquad (19\text{-}3)$$

so that the parent's WACC is itself a weighted average of equity costs of all subsidiaries. The fundamental logical fault of double leverage is to arbitrarily equate the equity cost of each subsidiary to the left side of the above equation. The inescapable conclusion is that the subsidiary cost of equity must be found on a stand-alone basis, because the parent's WACC is itself a weighted average of subsidiary equity costs.

In summary, the double leverage adjustment has serious conceptual and practical limitations and violates basic notions of finance, economics, and fairness. The assumptions which underlie its use are questionable, if not unrealistic. The approach should not be used in regulatory proceedings.

EXAMPLE 19-1

In the numerical example provided at the beginning of the chapter, the parent's cost of equity capital was arbitrarily and wrongly assumed to be 15%. This example shows that the parent cost of equity consistent with the terms of the example is 23.33%, and not 15%. If the subsidiary was regulated in the correct way, the allowed return is computed as 0.50 × 10% + .50 × 20% = 15%. According to advocates of Double Leverage, this implies excess returns to the parent, that is:

Earnings from the subsidiary to the parent	$100 × 15% = $15.00
Less total interest:	$50 × 10% + $12.50 × 10% = $6.25
Earnings to parent equity:	$8.75

which represents a return of $8.75/$37.50 = 23.33%, far in excess of the *assumed* parent equity cost of 15%.

Double Leverage advocates adjust for this alleged excess by assigning the parent's overall return of 13.78% to the subsidiary's equity. The subsidiary's overall return becomes 11.88%, as shown below:

	$ Amount	% Weight	Cost	Weighted Cost
Debt - Subsidiary	$50.00	50.0%	10.0%	5.00%
Equity provided by parent				
Debt - Parent (25%)	$12.50	12.5%	10.0%	1.25%
Equity - Parent (75%)	$37.50	37.5%	15.0%	5.63%
		Weighted Cost		11.88%

(continued next page)

EXAMPLE 19-1 *(continued)*

The 11.88% becomes the Double Leverage allowed return on the subsidiary's total assets. Only with this allowed rate of return, according to the tenets of Double Leverage, does the parent's equity receive the ***assumed*** rate of return of 15%. That is, the parent receives $100 × 11.88% = $11.88, less the interest cost of $6.25, or $5.63, on an equity investment of $37.50, which is a 15% return. And, so it seems, the parent receives the required rate of return.

The fundamental flaw of this approach is that the assumptions of the example are internally inconsistent and illogical. When an illustration is constructed with an assumed subsidiary cost of equity, the assumed parent cost of equity must be consistent with it. It is not the parent's weighted average cost of capital which determines the subsidiary's cost of equity because the parent's cost of capital is itself a weighted average of equity costs of all subsidiaries.

Equation 19-2 makes it clear that the parent cost of equity is determined by the subsidiary cost of equity, and that parent capital costs cannot determine subsidiary capital costs. Given the cost of debt K_{ds}, the subsidiary's cost of equity K_{es} and the amounts of capital, the above equation implies that the parent equity cost consistent with a 20% subsidiary cost of equity is 23.33%:

$$[\$50 \times 20\% - \$12.50 \times 10\%] / \$37.50 = 23.33\%$$

Conclusions

The double leverage approach has serious conceptual and practical limitations and is not consistent with basic financial theory and the notion of fairness. The assumptions and logic underlying the method are questionable. The double leverage argument violates the core notion that an investment's required return depends on its particular risks. The Double Leverage approach has no place in regulatory practice and should be discarded.

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Dr. Avera workpaper WP-23 is a separate file in Excel format.

Dr. Avera workpaper WP-24 is a separate file in Excel format.

Dr. Avera workpaper WP-25 is a separate file in Excel format.

Value Line Forecast for the U.S. Economy

	ACTUAL					ESTIMATED				
	2007	2008	2009	2010	2011	**2012**	**2013**	**2014**	**2015**	**2016**
GROSS DOMESTIC PRODUCT AND ITS COMPONENTS (2005 CHAIN WEIGHTED $) BILLIONS OF DOLLARS										
Final Sales	13178	13201	12853	13029	13282	*13529*	*13804*	*14191*	*14602*	*15040*
Total Consumption	9263	9212	9038	9221	9421	*9602*	*9814*	*10050*	*10291*	*10548*
Nonresidential Fixed Investment	1550	1538	1263	1319	1436	*1540*	*1631*	*1745*	*1850*	*1943*
Structures	438	466	367	309	323	*344*	*353*	*374*	*399*	*426*
Equipment & Software	1107	1059	890	1019	1126	*1213*	*1306*	*1398*	*1495*	*1600*
Residential Fixed Investment	584	444	346	331	326	*365*	*407*	*480*	*552*	*618*
Exports	1554	1649	1494	1663	1774	*1848*	*1930*	*2027*	*2148*	*2298*
Imports	2203	2144	1853	2085	2188	*2259*	*2338*	*2443*	*2553*	*2656*
Federal Government	906	971	1030	1076	1055	*1029*	*995*	*965*	*946*	*936*
State & Local Governments	1528	1528	1514	1487	1454	*1426*	*1413*	*1417*	*1426*	*1440*
Gross Domestic Product	14029	14292	13939	14527	15088	*15646*	*16249*	*16971*	*17777*	*18676*
Real GDP (2005 Chain Weighted $)	13206	13162	12703	13088	13315	*13579*	*13844*	*14231*	*14658*	*15142*
PRICES AND WAGES-ANNUAL RATES OF CHANGE										
GDP Deflator	2.9	2.2	1.1	1.2	2.1	*1.9*	*1.8*	*1.5*	*1.6*	*1.7*
CPI-All Urban Consumers	2.9	3.8	-0.3	1.6	3.1	*1.7*	*1.9*	*2.0*	*2.1*	*2.3*
PPI-Finished Goods	3.9	6.4	-2.5	4.2	6.0	*1.0*	*2.2*	*1.5*	*1.8*	*2.2*
Employment Cost Index—Total Comp.	3.1	2.9	1.4	1.9	2.2	*2.0*	*2.2*	*2.5*	*2.6*	*2.6*
Productivity	1.5	0.6	2.3	4.1	0.6	*0.7*	*0.6*	*1.0*	*1.3*	*1.5*
PRODUCTION AND OTHER KEY MEASURES										
Industrial Prod. (% Change)	2.7	-3.7	-11.2	5.3	4.1	*3.3*	*2.5*	*3.0*	*3.2*	*3.3*
Factory Operating Rate (%)	79.2	74.9	66.2	71.7	75.0	*77.8*	*78.3*	*79.0*	*79.5*	*80.0*
Nonfarm Inven. Change (2005 Chain Weighted $)	28.7	-37.6	-143.8	60.7	44.3	*44.8*	*42.5*	*45.0*	*50.0*	*40.0*
Housing Starts (Mill. Units)	1.34	0.90	0.55	0.59	0.61	*0.76*	*0.93*	*1.25*	*1.50*	*1.65*
Existing House Sales (Mill. Units)	5.68	4.89	5.15	4.92	4.28	*4.55*	*4.93*	*5.30*	*5.60*	*5.70*
Total Light Vehicle Sales (Mill. Units)	16.1	13.2	10.4	11.6	12.7	*14.2*	*14.9*	*15.5*	*15.8*	*16.0*
National Unemployment Rate (%)	4.6	5.8	9.3	9.6	9.0	*8.3*	*8.0*	*7.7*	*7.0*	*6.5*
Federal Budget Surplus (Unified, FY, $Bill)	-162.0	-455.0	-1416	-1294	-1297	*-1112*	*-850*	*-704*	*-650*	*-600*
Price of Oil ($Bbl., U.S. Refiners' Cost)	67.98	95.29	59.20	76.70	101.80	*100.00*	*105.00*	*110.00*	*115.00*	*120.00*
MONEY AND INTEREST RATES										
3-Month Treasury Bill Rate (%)	4.4	1.4	0.2	0.1	0.1	*0.1*	*0.1*	*0.3*	*1.8*	*3.0*
Federal Funds Rate (%)	5.0	1.9	0.2	0.2	0.1	*0.1*	*0.1*	*0.3*	*1.8*	*3.0*
10-Year Treasury Note Rate (%)	4.6	3.7	3.3	3.2	2.8	*1.8*	*2.2*	*3.0*	*4.0*	*4.5*
Long-Term Treasury Bond Rate (%)	4.8	4.3	4.1	4.3	3.9	*3.2*	*3.7*	*4.0*	*4.6*	*5.0*
AAA Corporate Bond Rate (%)	5.6	5.6	5.3	4.9	4.6	*4.0*	*4.4*	*4.7*	*5.5*	*6.0*
Prime Rate (%)	8.1	5.1	3.3	3.3	3.3	*3.3*	*3.3*	*3.5*	*4.5*	*6.0*
INCOMES										
Personal Income (% Change)	5.7	4.6	-4.3	3.7	5.1	*4.7*	*4.2*	*4.9*	*5.1*	*5.2*
Real Disp. Inc. (% Change)	2.4	2.4	-2.3	1.8	1.3	*2.7*	*2.0*	*3.0*	*3.0*	*3.2*
Personal Savings Rate (%)	2.4	5.4	5.2	5.3	4.7	*3.9*	*3.7*	*4.0*	*4.5*	*5.0*
After-Tax Profits ($Bill)	1293	1051	1183	1408	1480	*1667*	*1793*	*1846*	*1938*	*2093*
Yr-to-Yr % Change	-4.2	-18.7	12.6	19.0	5.1	*12.7*	*7.5*	*3.0*	*5.0*	*8.0*
COMPOSITION OF REAL GDP-ANNUAL RATES OF CHANGE										
Gross Domestic Product	1.9	-0.3	-3.5	3.0	1.7	*2.0*	*2.0*	*2.8*	*3.0*	*3.3*
Final Sales	2.2	0.2	-2.6	1.4	2.0	*1.9*	*2.0*	*2.8*	*2.9*	*3.0*
Total Consumption	2.3	-0.6	-1.9	2.0	2.2	*1.9*	*2.2*	*2.4*	*2.4*	*2.5*
Nonresidential Fixed Investment	6.5	-0.8	-17.9	4.4	8.8	*7.3*	*5.9*	*7.0*	*6.0*	*5.0*
Structures	14.1	6.4	-21.2	-15.8	4.6	*6.6*	*2.6*	*6.0*	*6.5*	*7.0*
Equipment & Software	3.3	-4.3	-16.0	14.6	10.4	*7.8*	*7.6*	*7.0*	*7.0*	*7.0*
Residential Fixed Investment	-18.7	-23.9	-22.2	-4.3	-1.3	*11.9*	*11.5*	*18.0*	*15.0*	*12.0*
Exports	9.3	6.1	-9.4	11.3	6.7	*4.2*	*4.4*	*5.0*	*6.0*	*7.0*
Imports	2.4	-2.7	-13.6	12.5	4.9	*3.3*	*3.5*	*4.5*	*4.5*	*4.0*
Federal Government	1.2	7.2	6.0	4.5	-1.9	*-2.5*	*-3.3*	*-3.0*	*-2.0*	*-1.0*
State & Local Governments	1.4	0.0	-0.9	-1.8	-2.2	*-2.0*	*-0.9*	*0.3*	*0.6*	*1.0*

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BLUE CHIP FINANCIAL FORECASTS

Top Analysts' Forecasts Of U.S. And Foreign Interest Rates, Currency Values And The Factors That Influence Them.

Vol. 31, No. 06
June 1, 2012

Wolters Kluwer
Law & Business

BLUE CHIP FINANCIAL FORECASTS®

EXECUTIVE EDITOR:
RANDELL E. MOORE
3663 Madison Ave.
Kansas City, MO 64111
Phone (816) 931-0131
Fax (816) 931-0430
E-mail: *randy.moore@wolterskluwer.com*

Publisher: Paul Gibson
Marketing Director: Dom Cervi

Blue Chip Financial Forecasts® (ISSN: 0741-8345) is published monthly by Aspen Publishers, 76 Ninth Avenue, New York, NY 10011. Printed in the U.S.A.

Subscriptions: $1045 per year for print or e-mail delivery of 12 monthly issues. $1239 per year for both print and e-mail delivery of 12 monthly issues. For multiple-copy rates and site-license agreements call Terry Watkins in the U.S. toll free at 888-200-2984 or use 212-740-2976 and 786-216-7699. You may also contact her at: *terry.watkins@wolterskluwer.com*

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U.S. Growth Prospects Dim A Bit As Uncertainty About European Risks Increase

Domestic Commentary A majority of our panelists grew a bit more cautious about the pace of U.S. economic growth over the forecast horizon, according to our May 23rd-24th survey. Although the consensus continues to predict real GDP growth of 2.3% (saar) and 2.5%, respectively, in Q2 and Q3 of this year, forecasts of growth in Q4 2012 and in Q1 2013 both slipped 0.2 of a percentage point over the past month. The consensus forecasts of real GDP growth in Q2 and Q3 2013, however, remained at 2.6% and 2.9%, respectively.

Increased caution about the U.S. economic outlook likely stems from the continued mixed nature of high-frequency indicators of U.S. activity, fears of a disorderly exit from the Eurozone by Greece and the contagion to other member states that would likely result, and uncertainty about the "fiscal cliff" that looms for the U.S. at the end of this year when a multitude of tax increases and spending cuts are currently scheduled to occur. The situation in the Eurozone, in particular, has rattled financial markets over the past several weeks, sending stock prices lower, widening some credit spreads, and lifting the value of the U.S. dollar. If the events in the Eurozone spiral into a full-fledged crisis, further reductions in consensus forecasts of U.S. economic growth seem inevitable.

While the consensus outlook for GDP growth has deteriorated a bit the outlook for inflation has improved, primarily on the basis, we suspect, on falling prices for crude oil and related products, especially gasoline. Consensus forecasts of the annualized change in the Consumer Price Index (CPI) during each of the next six quarters fell this month while forecasts of the annualized change in the GDP price index slipped for three of the next six quarters.

Consensus forecasts of average short-term Treasury bill rates over the next six quarters went essentially unchanged this month but forecasts for 10-year Treasury note yields and other longer-term notes slipped once again, the declines reflecting the continued slide in market prices driven by flight-to-safety demand, coupled with a reassessment of the likely trajectory of yields given reduced expectations for both economic growth and inflation. Nonetheless, consensus projections for the federal funds rate suggest a majority of our panelists still believe the Federal Open Market Committee (FOMC) will ultimately opt to begin raising its federal funds rate target either late next year or very early in 2014. Futures markets, on the other hand, suggest an initial tightening closer to the spring or summer of 2014.

U.S. economic data released since our last survey remained mixed, still likely reflecting payback from the unseasonably mild winter that boosted the economy's performance late last year and very early this year. Nonetheless, the most recent data remains consistent with consensus expectations of near-term real GDP growth in the range of 2%-2.5%. That said, it looks as if real GDP growth in Q1 of this year will be revised down from 2.2% to the vicinity of 1.9%-2.0% given the latest readings on business inventory levels during the quarter.

GDP growth in the current quarter is expected to be characterized by an acceleration in final sales to its best pace since Q3 of last year. Personal consumption expenditures will grow a bit slower than in Q1 but growth in nonresidential fixed investment is widely predicted to be somewhat better. Residential investment will continue to grow but at perhaps half the average pace seen in the prior two quarters. Business inventories are expected to be a drag on GDP in Q2 while net exports may prove to be a small contributor. Government spending and investment likely will continue to subtract from GDP but not to the degree seen in recent quarters.

The Institute of Supply Management's manufacturing survey for April increased 1.5 points to 54.8, its highest level since last June. The rise was supported by sizable gains in the new orders and production indices. Moreover, total industrial production surged 1.1% in April, the biggest monthly increase since December 2010. However, a sizable portion of the increase was accounted for by a rebound in mining output following two months of declines, coupled with a surge in utility output as more normal temperatures boosted heating demand. In contrast to the strength in manufacturing, the ISM non-manufacturing index for April slid 2.5 points to 53.5, its lowest level of this year. The ISM manufacturing index for May now is widely expected to slip as suggested by the Richmond Federal Reserve bank's PMI for May that dropped to 4 from 14 in April and the first release of Markit's manufacturing PMI for the U.S. which fell from 56.0 in April to 53.9 in May.

Total nonfarm payrolls grew by just 115,000 in April, the second consecutive month in which the increase fell well short of consensus expectations. Total nonfarm payrolls are currently expected to be up 150,000-160,000 in May with the unemployment rate unchanged at 8.1%, the recent decline halted by stabilization in the labor force participation rate. Total retail sales were also softer than expected in April, rising just 0.1%, the smallest monthly gain of the year. An early Easter and record-high temperatures in March likely pulled demand forward, depressing the sales increase in April. Retail sales likely registered somewhat stronger growth in May, helped by falling gasoline prices that lifted real growth in disposable personal incomes and consumer sentiment to its highest level in a couple of years.

Although new orders for durable goods eked out a 0.2% increase in April, nondefense capital goods orders excluding aircraft dropped for a second consecutive month and shipments of such goods that figure directly into GDP estimates of capital spending fell 1.4%. The figures add credence to the view that the December 2011 expiration of full expensing of capital goods purchases has led to a curtailment of business investment. The housing sector, in contrast, continued to exhibit evidence of recovery as housing starts registered an increase of 2.6% in April while sales of new and existing single-family homes posted respective monthly increases of 3.3% and 3.0%.

At the moment, the FOMC is expected to maintain its current policy stance when it meets on June 19th-20th. Minutes of its April 24th-25th meeting offered no hints that the current version of "Operation Twist" would be extended beyond its scheduled expiration at the end of this June. Nor were there any hints of additional quantitative easing. However, policymakers are expected to instruct managers to maintain the current size of the Fed's balance sheet. The FOMC also is expected to reiterate that meeting its dual mandate will likely require a fed funds rate that is kept "exceptionally low...at least through late 2014."

That said, much will depend on events in Europe, especially the outcome of Greece's June 17th elections, its possible reverberations through financial markets, and the response by European politicians and its central bankers. Should a full fledged crisis erupt in Europe, spreading its tentacles to the U.S., the Fed could employ some of the same liquidity-enhancing tools utilized during the 2008-2009 financial crisis. Odds of additional quantitative easing also would increase if the crisis became prolonged, threatening achievement of the Fed's policy goals. Coordinated Fed action with other major central banks also is a distinct probability if financial markets become unhinged. The most bullish market at present: the one in uncertainty.

Consensus Forecast Real GDP growth of 2%-2.5% is predicted by the consensus over the next four quarters with somewhat better growth thereafter. However, much depends on whether problems in Europe develop into a full-fledged crisis. Inflation expectations have eased as oil and gasoline prices have come down. Fed policy is expected to remain on hold over the bulk of the forecast horizon. However, a crisis that threatens achievement of its dual policy mandate could prompt additional non-conventional easing *(see page 2)*.

Special Questions On page 14 are results of our twice-yearly long-range forecast survey with estimates for the years 2014 through 2018 and averages for the 5-year periods 2014-2018 and 2019-2023.

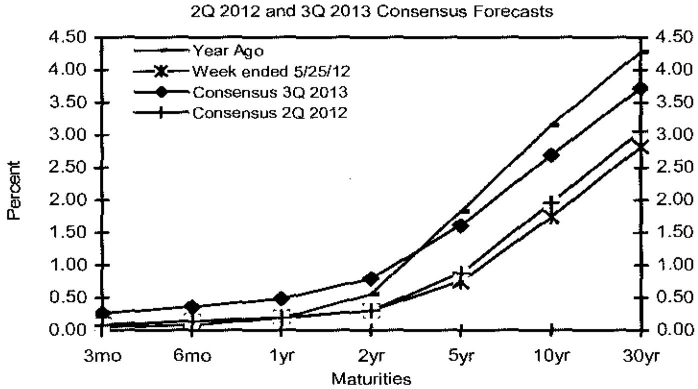
Consensus Forecasts Of U.S. Interest Rates And Key Assumptions[1]

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			Latest Q	2Q	3Q	4Q	1Q	2Q	3Q
Interest Rates	May 25	May 18	May 11	May 4	Apr.	Mar.	Feb.	1Q 2012	2012	2012	2012	2013	2013	2013
Federal Funds Rate	0.16	0.15	0.16	0.14	0.14	0.13	0.10	0.10	**0.1**	**0.1**	**0.1**	**0.2**	**0.2**	**0.3**
Prime Rate	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
LIBOR, 3-mo.	0.47	0.47	0.47	0.47	0.47	0.47	0.50	0.51	**0.5**	**0.4**	**0.5**	**0.5**	**0.5**	**0.6**
Commercial Paper, 1-mo.	0.13	0.13	0.12	0.13	0.13	0.13	0.12	0.11	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Treasury bill, 3-mo.	0.09	0.09	0.10	0.09	0.08	0.08	0.09	0.07	**0.1**	**0.1**	**0.1**	**0.1**	**0.2**	**0.3**
Treasury bill, 6-mo.	0.14	0.15	0.15	0.15	0.14	0.14	0.12	0.11	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.4**
Treasury bill, 1 yr.	0.20	0.20	0.18	0.19	0.18	0.19	0.16	0.16	**0.2**	**0.2**	**0.2**	**0.3**	**0.4**	**0.5**
Treasury note, 2 yr.	0.30	0.30	0.27	0.27	0.29	0.34	0.28	0.29	**0.3**	**0.3**	**0.4**	**0.5**	**0.6**	**0.8**
Treasury note, 5 yr.	0.75	0.74	0.77	0.82	0.89	1.02	0.83	0.90	**0.9**	**1.0**	**1.1**	**1.3**	**1.4**	**1.6**
Treasury note, 10 yr.	1.74	1.74	1.88	1.95	2.05	2.17	1.97	2.04	**2.0**	**2.1**	**2.3**	**2.4**	**2.5**	**2.7**
Treasury note, 30 yr.	2.82	2.87	3.04	3.12	3.18	3.28	3.11	3.14	**3.1**	**3.2**	**3.3**	**3.5**	**3.6**	**3.7**
Corporate Aaa bond	3.72	3.72	3.87	3.95	3.96	3.99	3.85	3.90	**3.8**	**3.9**	**4.0**	**4.1**	**4.2**	**4.4**
Corporate Baa bond	5.02	4.98	5.08	5.15	5.19	5.23	5.14	5.20	**5.1**	**5.1**	**5.2**	**5.3**	**5.4**	**5.5**
State & Local bonds	3.81	3.75	3.71	3.81	3.95	3.91	3.66	3.75	**3.8**	**3.9**	**4.0**	**4.1**	**4.2**	**4.3**
Home mortgage rate	3.78	3.79	3.83	3.84	3.91	3.95	3.89	3.92	**3.9**	**3.9**	**4.1**	**4.2**	**4.3**	**4.5**
	History								Consensus Forecasts-Quarterly					
	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q
Key Assumptions	2010	2010	2010	2011	2011	2011	2011	2012	2012	2012	2012	2013	2013	2013
Major Currency Index	77.6	75.9	73.0	71.9	69.6	69.9	72.4	72.9	**73.8**	**74.2**	**74.4**	**74.5**	**74.5**	**74.8**
Real GDP	3.8	2.5	2.3	0.4	1.3	1.8	3.0	2.2	**2.3**	**2.5**	**2.5**	**2.3**	**2.6**	**2.9**
GDP Price Index	1.5	1.4	1.9	2.5	2.5	2.6	0.9	1.5	**1.7**	**2.0**	**1.9**	**2.0**	**2.0**	**2.1**
Consumer Price Index	-0.3	1.4	3.0	4.5	4.4	3.1	1.3	2.5	**1.9**	**2.1**	**2.1**	**2.2**	**2.2**	**2.4**

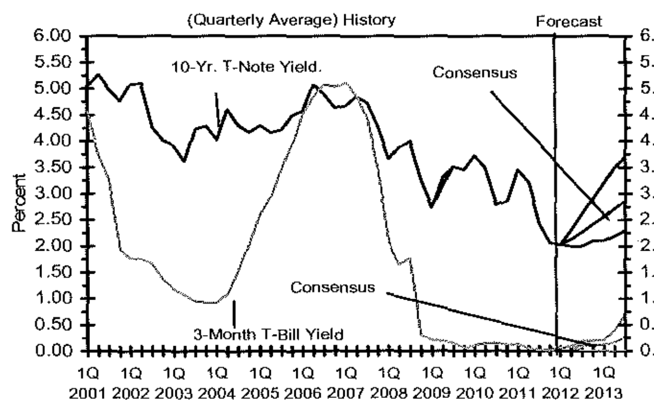
Forecasts for interest rates and the Federal Reserve's Major Currency Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index and Consumer Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data for interest rates except LIBOR is from Federal Reserve Release (FRSR) H.15. LIBOR quotes available from *The Wall Street Journal*. Interest rate definitions are the same as those in FRSR H.15. Treasury yields are reported on a constant maturity basis. Historical data for the Fed's Major Currency Index is from FRSR H.10 and G.5. Historical data for Real GDP and GDP Chained Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index (CPI) history is from the Department of Labor's Bureau of Labor Statistics (BLS).

U.S. Treasury Yield Curve

Week ended May 25, 2012 and Year Ago vs. 2Q 2012 and 3Q 2013 Consensus Forecasts

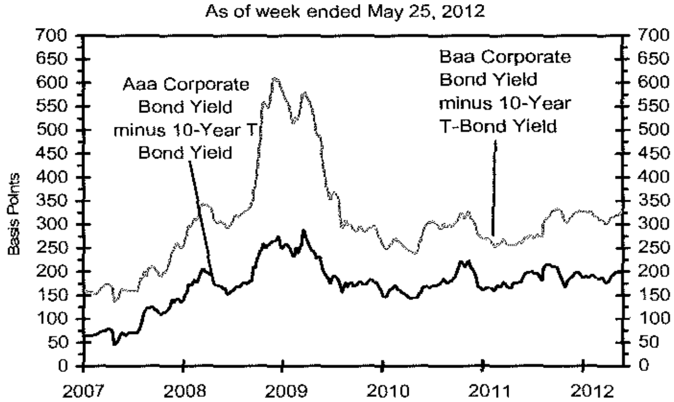


U.S. 3-Mo. T-Bills & 10-Yr. T-Note Yield



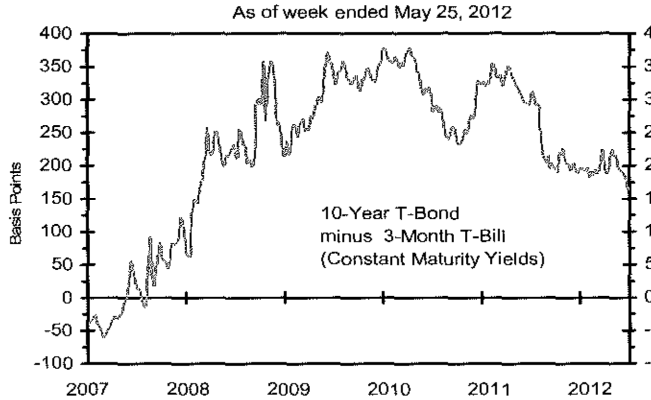
Corporate Bond Spreads

As of week ended May 25, 2012



U.S. Treasury Yield Curve

As of week ended May 25, 2012



3-Month Interest Rates[1]

	History Latest:	Month Ago:	Year Ago:	Consensus Forecasts Months From Now: 3	6	12
U.S.	0.66	0.36	0.38	**0.43**	**0.42**	**0.41**
Japan	0.30	0.30	0.36	**0.23**	**0.23**	**0.23**
U.K.	1.02	1.12	1.05	**0.87**	**0.81**	**0.71**
Switzerland	0.13	0.13	0.30	**0.10**	**0.10**	**0.10**
Canada	1.56	1.56	1.39	**1.30**	**1.35**	**1.87**
Australia	4.13	4.63	4.92	**4.50**	**4.40**	**4.60**
Eurozone	0.68	0.82	1.54	**0.66**	**0.66**	**0.89**

10-Yr. Government Bond Yields[2]

	History Latest:	Month Ago:	Year Ago:	Consensus Forecasts Months From Now: 3	6	12
U.S.	1.75	1.96	3.12	**2.02**	**2.25**	**2.56**
Germany	1.37	1.70	3.05	**1.79**	**1.90**	**2.13**
Japan	0.89	0.92	1.13	**1.01**	**1.05**	**1.15**
U.K.	1.75	2.10	3.35	**2.23**	**2.39**	**2.59**
France	2.53	2.99	3.47	**3.11**	**3.25**	**3.37**
Italy	5.80	5.64	4.79	**5.71**	**5.67**	**5.61**
Switzerland	0.64	0.71	1.87	**1.04**	**1.10**	**1.32**
Canada	1.80	2.07	3.12	**2.14**	**2.32**	**2.64**
Australia	3.16	3.72	5.29	**3.61**	**3.70**	**4.04**
Spain	6.33	5.84	5.47	**6.10**	**6.05**	**5.97**

Foreign Exchange Rates[1]

	History Latest:	Month Ago:	Year Ago:	Consensus Forecasts Months From Now: 3	6	12
U.S.	74.391	72.677	70.403	**74.9**	**75.1**	**75.1**
Japan	79.140	81.600	81.640	**82.5**	**84.5**	**86.4**
U.K.	1.5788	1.6123	1.6222	**1.57**	**1.55**	**1.58**
Switzerland	0.9442	0.9095	0.8776	**0.94**	**0.97**	**0.98**
Canada	1.0211	0.9912	0.9735	**1.00**	**1.00**	**0.99**
Australia	0.9819	1.0375	1.0644	**1.01**	**1.01**	**1.01**
Euro	1.2721	1.3212	1.4172	**1.27**	**1.24**	**1.24**

Consensus 3-Month Rates vs. U.S. Rate

	Now	In 12 Mo.
Japan	-0.36	**-0.17**
U.K.	0.36	**0.31**
Switzerland	-0.53	**-0.31**
Canada	0.90	**1.46**
Australia	3.47	**4.19**
Eurozone	0.02	**0.48**

Consensus 10-Year Gov't Yields vs. U.S. Yield

	Now	In 12
Germany	-0.38	**-0.43**
Japan	-0.86	**-1.41**
U.K.	0.00	**0.04**
France	0.78	**0.82**
Italy	4.05	**3.06**
Switzerland	-1.11	**-1.23**
Canada	0.05	**0.09**
Australia	1.41	**1.48**
Spain	4.58	**3.41**

Forecasts of panel members are on pages 10 and 11. Definitions of variables are as follows: [1]Three month rate on interest-earning money market deposits denominated in selected currencies. [2]Government bonds are yields to maturity. Foreign exchange rate forecasts for U.K., Australia and the Euro are U.S. dollars per currency unit. For the U.S dollar, forecasts are of the U.S. Federal Reserve Board's Major Currency Index.

International Commentary Rising concern that Greece may exit the euro. Deeply troubled banks in Spain. Fresh evidence of deteriorating economic activity in the broader Eurozone and UK. More modest than expected growth in China. The looming "fiscal cliff" in America. All have proved too much for financial markets over the past several weeks. Global stock markets fell, oil prices weakened, the euro dropped to a 22-month low versus the U.S. dollar, and flight-to-quality demand sent sovereign bond yields in the U.S., Germany, and the U.K. to record, or near-record lows. Official comments of support for Greece were of little solace to financial markets as preparations for a Greek exit intensified in European capitals. If Greece fails to get its act together and ultimately exits the Eurozone in a disorderly fashion, no one can speak with confidence of the consequences for financial markets and economies. Although recent polls suggest Greek parties supporting the bailout have regained favor, who is to say how long the populace would support such a government.

Even under the best of plausible circumstances surrounding Greece, the Eurozone still is confronted with a host of unresolved troubles. Among them, a Spanish banking system verging on insolvency and the likelihood that Portugal and perhaps Ireland will require additional bailouts within a year. More broadly speaking, economic activity in the currency zone is clearly worsening. The composite PMI for the Eurozone fell to 45.9 in May, the fourth straight decline and the lowest reading since June 2009 when the currency zone was last in recession. Moreover, business sentiment indices for Germany, France and Belgium each registered sharp declines in May. Due to better-than-expected growth in Germany, Eurozone real GDP was essentially unchanged in Q1 after shrinking 1.2% (saar) in Q4 2011. However, in the wake of the latest PMI readings many analysts now assume GDP in the Eurozone will contract in Q2 and quite possibly Q3 even if Germany still manages to register marginally positive growth. The worries about Greece and broader problems in the Eurozone continue to prompt talk of the need for EU political leaders to initiate the issuance of eurobonds and for the European Central Bank to cut interest rates and announce additional LTROs or some other form of liquidity enhancing provision. However, little is expected out of the ECB's June 6th meeting and any progress toward agreement on adoption of eurobonds will likely await the EU conference on June 28th-29th.

Elsewhere, real GDP in the U.K. contracted a downwardly revised 0.3% in Q1, matching its Q4 2011 decline. Moreover, many analysts anticipate a further contraction in the current quarter. While a rebound in U.K. GDP is expected in the second half of the year, much will depend on the ability of Eurozone officials to contain their sovereign debt crisis and the willingness of the Bank of England to engage in additional quantitative easing. The Reserve Bank of Australia surprised markets by cutting its cash rate by a larger-than-expected 50 basis points to 3.75% on May 1st. Somewhat softer-than-expected economic conditions and moderating inflation were cited as justifications for the rate cut by the RBA. Bank of Canada policy is widely seen as on hold for the time being. Despite its hawkish stance in response to healthy domestic demand, an actual move to remove accommodation remains stymied by uncertainty surrounding the Eurozone's debt crisis, relatively modest growth in the U.S., moderating Chinese demand for Canadian resources and the Federal Reserve's super easy policy. Nonetheless, the BoC still seems destined to become the first of the major central banks to begin tightening, it's just a matter of when. The Bank of Japan left policy unchanged at its May 23rd meeting, matching expectations for no change in its 0.0-0.1% policy rate and no change in its asset purchase target. Real GDP grew a larger-than-expected 4.1% (saar) in Q1 and growth in Q4 2011 was upwardly revised from a -0.7% contraction to a 0.1% increase. Although private consumption improved, the Q1 surge was driven by earthquake reconstruction that will likely diminish over the remainder of this year *(see pages 10-11 for individual panelists' forecasts).*

Second Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	Long-Term: 12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2 H	0.1 H	0.1 L	0.2	0.3 L	1.1	2.3	3.4	4.3 H	5.7 H	4.0	4.2	75.0	3.1	2.6 H	1.8
Swiss Re	0.3 H	3.3	0.4	0.2 H	0.1 H	0.1 L	0.2	0.4 H	0.9	2.0	3.1	3.9	5.2	na	4.0	na	1.6	0.9	1.1
Scotiabank Group	0.3 H	3.3	na	na	0.1 H	na	na	0.3 L	0.9	2.0	3.2	na	na	na	na	na	2.2	2.0	2.7
Wells Fargo	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.8	2.9	3.9	5.1	3.8	3.8	73.8	2.2	1.8	1.5
AIG	0.2	3.3	na	na	0.1 H	0.1 L	0.2	0.3 L	0.9	2.2	3.1	3.6	4.9	na	3.7	74.4	3.8 H	0.6 L	1.3
MacroFin Analytics	0.2	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	1.8	2.9	3.8	5.0	3.9	3.8	73.4	2.1	1.5	1.8
RBS Securities	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	3.8	3.9	73.5	2.2	1.2	1.2
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.8	2.9	3.7	5.0	3.7	3.8	73.5	2.5	1.8	1.5
Nomura Securities, Inc.	0.2	3.3	0.5	0.2 H	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.1	3.8	5.1	na	3.8	73.0	2.5	1.1	1.9
Stone Harbor Investment Partners	0.2	3.3	0.5	0.2 H	0.1 H	0.2 H	0.3 H	0.3 L	0.8	1.9	3.0	3.7	5.1	na	4.0	73.0	1.7	1.8	2.1
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.3	2.5	1.8	2.3
DePrince & Assoc.	0.2	3.3	0.5	0.2 H	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	3.8	3.9	73.4	3.1	1.9	0.8
Barclays Capital	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	1.0	2.0	3.1	4.0	5.2	4.0	4.0	na	2.5	2.6 H	0.9
Naroff Economic Advisors	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	2.0	3.1	3.9	5.1	3.9	3.9	73.5	3.3	2.5	2.3
ClearView Economics	0.2	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.8	5.1	3.8	3.9	73.2	2.2	1.7	2.4
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	2.0	3.1	3.9	na	na	3.9	73.2	2.6	1.5	1.9
Fannie Mae	0.2	3.3	na	na	0.1 H	na	0.2	na	na	1.9	3.1	na	na	na	3.9	na	2.3	1.0	2.1
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.9	1.9	3.1	3.9	5.1	3.9	3.9	74.0	2.7	2.0	1.0
SunTrust Banks	0.1 L	3.3	0.5	0.2 H	0.1 H	0.2 H	0.2	0.4 H	0.9	1.9	2.9	3.9	4.9	4.3	3.4 L	74.4	2.7	1.9	2.2
Action Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.4 H	0.8	1.8	2.9	3.8	5.1	3.8	3.9	74.0	2.5	2.2	1.5
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1 H	0.1 L	0.2	0.3 L	0.8	2.0	3.2	na	na	na	na	na	1.5	na	2.3
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	2.0	3.1	3.9	5.1	3.8	3.8	72.9	2.2	0.9	1.5
GLC Financial Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	3.8	5.1	3.8	3.9	72.9	1.9	1.7	1.8
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	3.8	5.2	3.8	3.8	73.8	1.5	2.1	1.9
Economist Intelligence Unit	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	na	na	na	3.9	na	2.1	na	2.0
J.W. Coons Advisors LLC	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	na	3.8	72.5	1.5	2.3	2.5
Oxford Economics	0.1 L	3.3	0.5	na	0.0 L	0.1 L	0.2	0.3 L	0.9	2.1	3.2	na	na	na	4.0	73.3	2.3	2.0	2.9
BMO Capital Markets	0.1 L	3.3	0.5	0.2 H	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.0	3.9	5.1	3.9	3.8	73.5	2.3	1.4	2.3
J.P. Morgan Chase	0.1 L	na	0.5	na	0.1 H	na	na	0.3 L	0.9	2.0	3.1	na	na	na	na	na	2.5	1.2	1.3
UBS	0.1 L	na	0.5	na	0.1 H	na	na	0.4 H	0.9	2.1	3.2	na	na	na	na	na	2.0	1.5	1.3
Wells Capital Management	0.1 L	na	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.8	1.9	3.0	3.8	5.0	3.9	3.9	74.3	2.3	1.9	2.4
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1 H	na	na	0.3 L	0.9	2.1	3.2	na	na	na	na	na	2.0	1.8	1.3
Societe Generale	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.1 L	0.3 L	1.0	1.9	3.0	3.8	5.1	na	na	na	1.3 L	1.8	0.8
Standard & Poor's Corp.	0.1 L	3.3	0.5	0.2 H	0.1 H	0.1 L	0.2	0.3 L	0.9	2.0	na	4.0	5.2	4.0	3.9	na	2.0	1.2	1.5
Goldman Sachs & Co.	0.1 L	3.3	0.4	na	0.0 L	na	na	0.4 H	1.0	2.3	3.3	3.5	na	na	4.0	na	2.2	1.3	2.3
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1 H	0.2 H	0.2	0.3 L	0.8	1.9	3.1	na	na	na	4.0	na	1.7	1.8	-0.2 L
Mesirow Financial	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.4 H	1.1	2.1	3.2	3.9	5.1	3.9	3.9	72.0 L	2.3	1.0	1.4
RDQ Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	1.2 H	2.0	3.1	3.8	5.1	3.7	3.8	73.6	2.8	2.1	1.7
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.8	1.8	2.9	3.9	5.2	3.7	3.8	74.0	2.0	1.6	1.9
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2 H	0.1 H	0.1 L	0.1 L	0.3 L	0.7 L	1.7 L	2.7 L	3.6	4.8 L	3.5	3.6	72.8	2.3	1.8	2.3
Russell Investments	0.1 L	3.3	0.5	0.1 L	0.1 H	0.2 H	0.2	0.3 L	0.9	1.9	2.9	3.8	5.0	3.9	3.9	73.4	2.5	1.8	2.4
Thredgold Economics	0.1 L	3.3	0.5	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.7 L	1.8	2.8	3.5 L	4.8 L	3.7	3.8	74.0	2.4	1.9	2.4
RidgeWorth Investments	0.1 L	3.3	0.4	0.2 H	0.1 H	0.1 L	0.2	0.3 L	1.0	2.1	3.1	3.9	5.0	3.4 L	4.0	77.0	2.0	1.8	1.8
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	2.0	3.1	3.9	5.1	3.9	3.9	73.0	2.3	2.0	2.4
Nat'l Assn. of Realtors	0.1 L	3.3	0.4	0.1 L	0.1 H	0.1 L	0.2	0.3 L	0.9	1.9	2.9	3.8	5.1	3.9	3.9	na	2.3	2.4	3.0
Kellner Economic Advisers	0.1 L	3.3	0.2 L	0.2 H	0.1 H	0.1 L	0.2	0.4 H	1.0	2.1	3.1	3.9	5.0	4.5 H	3.8	78.0 H	2.2	2.0	2.2
The Northern Trust Company	0.1 L	3.3	0.2 L	na	0.1 H	na	na	0.3 L	0.9	2.0	3.1	na	na	na	na	na	2.5	2.3	2.5
Georgia State University	0.1 L	3.3	na	na	0.1 H	0.1 L	0.2	0.3 L	1.2	2.2	3.2	4.2	5.3	na	4.0	na	1.5	0.7	3.1 H
Moody's Analytics	0.1 L	3.3 L	0.5	0.2 H	0.1 H	0.2 H	0.2	0.3 L	1.0	2.4 H	3.5 H	4.2	5.4	na	4.3 H	na	2.9	2.0	1.6
June Consensus	**0.1**	**3.3**	**0.5**	**0.1**	**0.1**	**0.1**	**0.2**	**0.3**	**0.9**	**2.0**	**3.1**	**3.8**	**5.1**	**3.8**	**3.9**	**73.8**	**2.3**	**1.7**	**1.9**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.2	0.2	0.4	1.1	2.2	3.3	4.0	5.3	4.0	4.0	74.9	3.0	2.3	2.6
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	0.8	1.8	2.9	3.7	4.9	3.7	3.7	72.9	1.6	1.0	1.0
May Consensus	0.1	3.3	0.5	0.1	0.1	0.1	0.2	0.3	1.0	2.1	3.2	4.0	5.2	3.9	4.0	73.2	2.3	1.9	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	0	0	10	7	7	6	8	19	34	38	37	29	23	18	30	5	17	25	29
Same	34	44	29	22	33	27	23	23	11	9	10	7	8	5	8	8	17	14	12
Up	15	0	6	8	9	8	11	6	3	2	1	3	2	2	4	18	15	8	8
Diffusion Index	65 %	50 %	46 %	51 %	52 %	52 %	54 %	36 %	18 %	13 %	13 %	17 %	18 %	18 %	19 %	71 %	48 %	32 %	29 %

Third Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.5	0.2	0.1	0.1 L	0.2	0.4	1.4	2.6	3.5	4.4 H	5.9 H	4.2	4.5 H	74.0	3.3	2.8	2.8
Swiss Re	0.3 H	3.3	0.3	0.2	0.1	0.2	0.3	0.4	1.0	2.1	3.1	3.9	5.1	na	4.2	na	2.5	1.5	1.7
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.3	1.0	2.1	3.3	na	na	na	na	na	2.6	1.5	2.5
Wells Fargo	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	0.9	1.9	3.0	3.8	5.1	3.7	3.8	74.4	1.8	1.9	2.0
Russell Investments	0.2	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.1	2.0	3.1	3.9	5.2	4.1	3.9	75.0	2.8	2.0	2.3
AIG	0.2	3.3	na	na	0.1	0.1	0.2	0.3	0.9	2.4	3.3	3.7	5.0	na	3.7	75.1	3.3	0.6 L	1.2 L
Stone Harbor Investment Partners	0.2	3.3	0.5	0.2	0.2 H	0.3 H	0.4 H	0.4	0.9	2.2	3.2	4.0	5.2	na	4.0	75.0	2.4	1.6	2.3
DePrince & Associates	0.2	3.3	0.5	0.3 H	0.2 H	0.2	0.2	0.4	0.8	1.9	3.0	3.8	4.9	3.4	3.8	74.1	2.3	1.9	2.0
MacroFin Analytics	0.2	3.3	0.4	0.2	0.1	0.2	0.2	0.3	1.0	1.9	3.0	3.9	5.1	4.0	3.9	73.0	2.4	1.4	1.7
Fannie Mae	0.2	3.3	na	na	0.1	na	0.2	na	na	2.0	3.2	na	na	na	4.0	na	2.4	1.6	2.5
ClearView Economics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	0.8	1.8 L	2.8	3.8	5.0	3.8	3.8	73.7	2.5	2.0	2.4
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.0	2.1	3.2	3.9	5.2	3.9	3.9	74.5	2.5	1.6	1.5
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.4	1.0	2.2	3.3	4.1	5.3	4.0	4.0	73.5	3.7 H	2.5	2.2
RBS Securities	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	0.9	2.0	3.0	3.8	4.9	3.8	3.8	72.5	2.4	2.8	3.1 H
Nomura Securities, Inc.	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	3.8	5.1	na	3.8	73.5	2.6	2.3	1.4
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.4	2.7	1.8	2.2
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.2	4.0	na	na	3.9	72.9	2.4	1.9	2.3
SunTrust Banks	0.2	3.3	0.4	0.2	0.1	0.2	0.3	0.4	1.0	1.9	2.6 L	3.9	4.6 L	4.6 H	3.6 L	75.8	2.9	2.3	1.5
Barclays Capital	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	1.1	2.1	3.4	4.0	5.2	4.0	4.0	na	3.0	2.7	2.5
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.0	2.3	3.5	4.2	5.4	4.2	4.2	75.0	2.6	2.2	2.3
J.W. Coons Advisors LLC	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.4	0.9	1.9	2.9	3.9	5.1	na	3.8	72.0 L	1.9	2.2	2.5
Action Economics	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.2	2.0	3.0	3.7	5.0	3.7	3.7	74.1	2.6	1.6	1.9
Economist Intelligence Unit	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	na	na	na	3.9	na	1.8	na	2.1
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	1.1	2.1	3.3	4.0	5.2	3.8	3.8	73.8	2.2	1.6	2.3
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.4	0.9	2.1	3.2	4.0	5.4	4.0	4.0	74.5	2.6	1.8	1.4
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1	0.1 L	0.2	0.3	0.9	2.1	3.4	na	na	na	na	na	1.7	na	2.0
BMO Capital Markets	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.3	0.8	2.0	3.0	3.9	5.1	3.8	3.8	73.6	2.8	1.9	2.2
Mesirow Financial	0.1 L	3.3	0.5	0.2	0.2 H	0.2	0.3	0.5	1.2	2.3	3.5	4.2	5.3	4.2	4.1	73.0	2.4	1.6	2.4
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.1 L	0.2 L	1.1	2.2	3.4	na	na	na	4.0	74.6	2.6	3.3 H	2.1
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3	0.9	2.0	3.1	na	na	na	na	na	3.0	1.3	1.8
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.3	0.8	1.9	3.0	na	na	na	na	na	1.3 L	1.6	1.8
UBS	0.1 L	na	0.4	na	0.1	na	na	0.4	0.9	2.1	3.1	na	na	na	na	na	2.3	2.5	2.3
GLC Financial Economics	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	0.9	1.9	3.0	3.8	5.1	3.7	3.8	73.0	2.7	2.1	2.0
Societe Generale	0.1 L	3.3	0.5	0.1 L	0.1	0.1 L	0.1 L	0.3	1.0	2.0	3.1	3.8	4.8	na	na	na	1.8	2.1	2.2
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1	0.2	0.2	0.3	0.8	2.0	3.2	na	na	na	4.0	na	2.3	2.1	1.9
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	0.7 L	1.8 L	2.8	3.7	4.9	3.6	3.7	73.1	2.5	1.9	2.2
Thredgold Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.4	0.8	1.9	2.9	3.6	4.9	3.7	3.8	74.0	2.4	1.9	2.4
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	0.9	1.9	3.0	3.9	5.2	3.7	3.9	75.0	2.3	1.7	1.8
Standard & Poor's Corp.	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.1	na	4.0	5.3	4.1	4.0	na	2.1	2.0	2.8
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	0.9	2.0	3.1	3.9	5.1	3.9	3.9	73.0	2.3	2.0	2.3
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.4 H	0.6 H	1.6 H	2.5	3.6	4.2	5.5	4.1	4.2	73.8	3.3	2.4	2.3
Nat'l Assn. of Realtors	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.4	1.1	2.0	3.1	3.9	5.2	4.0	4.0	na	3.0	2.3	2.8
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.2	3.2	3.9	5.0	3.2 L	4.0	76.0	2.5	1.8	1.8
Goldman Sachs	0.1 L	3.3	0.4	na	0.0 L	na	na	0.4	1.1	2.5	3.4	3.5 L	na	na	4.1	na	2.0	1.6	1.9
The Northern Trust Company	0.1 L	3.3	0.3	na	0.1	na	na	0.3	1.2	2.1	3.1	na	na	na	na	na	2.7	1.5	1.7
Kellner Economic Advisers	0.1 L	3.3	0.2 L	0.2	0.2 H	0.2	0.3	0.5	1.0	2.2	3.2	4.0	5.1	4.6 H	3.9	80.0 H	1.8	2.0	2.3
Georgia State University	0.1 L	3.3	na	na	0.0 L	0.1 L	0.1 L	0.3	1.3	2.3	3.3	4.2	5.3	na	4.1	na	1.6	1.7	1.2 L
Wells Capital Management	0.1 L	na	0.5	0.1 L	0.1	0.1 L	0.2	0.3	0.8	2.0	2.9	3.6	4.7	3.8	3.9	74.5	2.5	2.2	2.4
Moody's Analytics	0.1 L	3.3 L	0.4	0.3 H	0.1	0.2	0.3	0.5	1.3	2.8 H	3.8 H	4.4	5.7 H	na	4.5 H	na	3.3	2.3	1.8
June Consensus	**0.1**	**3.3**	**0.4**	**0.2**	**0.1**	**0.2**	**0.2**	**0.3**	**1.0**	**2.1**	**3.2**	**3.9**	**5.1**	**3.9**	**3.9**	**74.2**	**2.5**	**2.0**	**2.1**
Top 10 Avg.	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.2	2.4	3.5	4.2	5.4	4.2	4.2	75.6	3.2	2.6	2.6
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.1	0.3	0.8	1.9	2.9	3.7	4.9	3.6	3.7	73.0	1.8	1.4	1.5
May Consensus	0.1	3.3	0.4	0.2	0.1	0.1	0.2	0.4	1.1	2.3	3.4	4.1	5.3	4.0	4.1	73.2	2.5	2.0	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	0	9	5	6	3	6	17	31	35	36	31	26	19	29	3	12	16	24
Same	35	44	30	23	36	27	27	23	14	12	11	7	9	9	9	10	26	22	16
Up	11	0	6	9	7	11	9	8	3	2	1	1	2	1	4	18	11	9	9
Diffusion Index	58 %	50 %	47 %	55 %	51 %	60 %	54 %	41 %	21 %	16 %	14 %	12 %	18 %	19 %	20 %	74 %	49 %	43 %	35 %

Fourth Quarter 2012

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
	Percent Per Annum – Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3 H	0.6	0.2	0.1	0.1 L	0.2	0.7	1.7	2.9	3.7	4.6	6.0 H	4.4	4.8	72.0	3.5	3.0 H	2.6
Swiss Re	0.3 H	3.3	0.3 L	0.2	0.1	0.2	0.3	0.5	1.1	2.2	3.2	4.0	5.0	na	4.3	na	2.7	1.6	1.8
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.5	1.4	2.6	3.8	na	na	na	na	na	2.6	1.5	2.4
DePrince & Assoc.	0.2	3.3	0.6	0.4 H	0.2	0.3 H	0.3	0.6	0.9	2.0	3.1	3.8	4.8	3.3	3.9	74.1	2.6	1.9	2.1
Stone Harbor Investment Partners	0.2	3.3	0.6	0.3	0.2	0.3 H	0.5 H	0.5	1.1	2.4	3.4	4.1	5.1	na	4.0	76.0	1.8	2.2	2.8
Wells Fargo	0.2	3.3	0.5	0.2	0.2	0.3 H	0.3	0.4	0.9	2.0	3.1	4.0	5.2	3.8	3.9	74.9	2.1	2.1	1.7
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.2	0.3 H	0.3	0.5	1.3	2.4	3.6	4.4	5.5	4.2	4.2	72.5	4.3 H	2.6	2.6
Russell Investments	0.2	3.3	0.4	0.2	0.1	0.3 H	0.2	0.4	1.3	2.2	3.3	4.0	5.3	4.2	4.0	75.3	2.2	2.2	2.2
Kellner Economic Advisers	0.2	3.3	0.3 L	0.3	0.3 H	0.3 H	0.4	0.6	1.2	2.3	3.3	4.1	5.2	4.7 H	3.9	82.0 H	1.5	1.8	2.4
Fannie Mae	0.2	3.3	na	na	0.2	na	0.2	na	na	2.1	3.2	na	na	na	4.0	na	2.4	1.6	2.2
AIG	0.2	3.3	na	na	0.1	0.1 L	0.2	0.3	0.9	2.6	3.6	3.8	5.1	na	3.9	75.2	3.3	0.8 L	1.5
ClearView Economics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	74.1	2.8	2.3	2.6
SunTrust Banks	0.2	3.3	0.4	0.2	0.1	0.2	0.3	0.4	0.9	1.7 L	2.5 L	3.8	4.5	4.5	3.4 L	77.3	3.1	2.0	2.5
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.1	2.2	3.3	4.0	5.3	4.0	4.0	75.0	1.0 L	1.6	1.6
RBS Securities	0.2	3.3	0.5	0.2	0.1	0.2	0.2	0.3	0.9	2.0	3.0	3.5 L	4.5 L	3.8	3.7	71.5 L	2.8	1.9	2.5
Nomura Securities, Inc.	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.3	1.1	2.1	3.3	4.0	5.3	na	3.9	74.5	2.1	2.6	1.6
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.2	1.9	1.8	2.0
MacroFin Analytics	0.2	3.3	0.5	0.2	0.1	0.2	0.3	0.4	1.1	2.0	3.1	4.0	5.2	4.1	4.0	73.5	2.8	1.3	1.7
Mesirow Financial	0.2	3.3	0.4	0.2	0.2	0.3 H	0.3	0.6	1.4	2.6	3.7	4.4	5.5	4.4	4.4	74.0	2.5	1.4	1.5
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	1.0	2.2	3.3	4.1	na	na	4.0	72.5	2.1	1.4	2.2
Barclays Capital	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3	1.0	2.0	3.4	4.0	5.2	4.0	4.0	na	3.0	2.7	2.5
Pierpont Securities	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.4	2.9	4.3 H	4.7 H	5.9	4.7 H	4.8	76.0	3.1	2.4	3.1 H
J.W. Coons Advisors LLC	0.1 L	3.3	0.7 H	0.2	0.2	0.3 H	0.3	0.5	1.0	2.0	3.0	4.0	5.2	na	3.8	71.5 L	2.0	2.2	2.5
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1	0.1 L	0.2	0.3	1.0	2.3	3.7	na	na	na	na	na	1.1	na	2.0
Economist Intelligence Unit	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.0	2.1	3.2	na	na	na	4.0	na	2.2	na	2.3
Action Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.7	1.4	2.2	3.2	3.7	5.1	3.6	3.6	73.9	2.7	2.2	2.8
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3	1.3	2.3	3.3	4.1	5.3	3.9	3.9	74.7	2.3	1.3	2.0
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.5	1.0	2.2	3.2	4.0	5.4	4.1	4.0	75.0	2.6	1.9	2.1
BMO Capital Markets	0.1 L	3.3	0.4	0.2	0.1	0.2	0.2	0.4	1.0	2.3	3.4	4.1	5.2	3.9	4.2	74.2	2.9	1.4	1.7
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.1 L	0.2 L	1.2	2.2	3.6	na	na	na	4.1	75.0	2.9	2.8	1.9
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3	1.2	2.4	3.5	na	na	na	na	na	2.0	1.3	1.6
Bank of America Merrill Lynch	0.1 L	na	0.5	na	0.1	na	na	0.3	0.9	2.3	3.6	na	na	na	na	na	1.0	1.5	2.0
UBS	0.1 L	na	0.4	na	0.2	na	na	0.5	1.2	2.3	3.4	na	na	na	na	na	2.8	2.0	0.5 L
GLC Financial Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.4	0.9	2.0	3.1	3.9	5.1	3.8	4.0	73.2	2.6	2.0	2.2
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1	0.2	0.2	0.3	1.0	2.2	3.5	na	na	na	4.0	na	2.7	2.2	2.0
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	0.8 L	1.9	3.0	3.9	5.1	3.8	3.9	73.4	2.5	2.0	2.1
Thredgold Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.4	0.9	2.0	3.0	3.6	4.9	3.8	3.9	74.0	2.6	2.0	2.4
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.6	1.3	2.4	3.4	4.1	5.3	4.1	4.2	na	2.9	2.2	2.7
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.5	1.0	2.0	3.1	4.0	5.3	3.8	3.9	76.0	2.5	1.8	2.0
Standard & Poor's Corp.	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.4	1.0	2.2	na	4.1	5.2	4.1	4.0	na	2.3	1.4	1.4
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.2	0.3	1.0	2.1	3.2	4.0	5.3	3.9	3.9	73.0	2.3	2.2	2.3
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.5 H	0.8 H	1.9 H	3.0	4.1	4.6	5.9	4.6	4.7	73.9	3.3	2.7	2.8
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3	1.0	2.2	3.3	3.8	4.8	3.1 L	4.0	74.0	2.5	1.9	1.8
Goldman Sachs & Co.	0.1 L	3.3	0.3 L	na	0.0 L	na	na	0.5	1.2	2.5	3.4	3.5 L	na	na	4.1	na	2.5	1.5	1.4
The Northern Trust Company	0.1 L	3.3	0.3 L	na	0.1	na	na	0.3	1.2	2.5	3.6	na	na	na	na	na	na	na	na
Georgia State University	0.1 L	3.3	na	na	0.0	0.1 L	0.1 L	0.4	1.3	2.4	3.3	4.2	5.3	na	4.1	na	1.7	1.5	1.6
Societe Generale	0.1 L	3.3	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.0	2.2	3.3	3.9	4.8	na	na	na	2.6	2.1	2.2
Wells Capital Management	0.1 L	na	0.5	0.2	0.1	0.2	0.3	0.3	1.0	2.1	3.1	3.7	4.8	3.9	4.1	74.5	2.6	2.1	2.1
Moody's Analytics	0.1 L	3.3 L	0.5	0.3	0.1	0.2	0.3	0.6	1.7	3.2 H	4.2	4.6	5.9	na	4.9 H	na	1.8	2.3	2.1
June Consensus	**0.1**	**3.3**	**0.5**	**0.2**	**0.1**	**0.2**	**0.2**	**0.4**	**1.1**	**2.3**	**3.3**	**4.0**	**5.2**	**4.0**	**4.1**	**74.4**	**2.5**	**1.9**	**2.1**
Top 10 Avg.	0.2	3.3	0.6	0.2	0.2	0.3	0.4	0.6	1.5	2.7	3.8	4.4	5.6	4.4	4.5	76.3	3.2	2.6	2.7
Bottom 10 Avg.	0.1	3.3	0.3	0.1	0.0	0.1	0.2	0.3	0.9	1.9	3.0	3.7	4.8	3.7	3.8	72.7	1.6	1.3	1.4
May Consensus	0.1	3.3	0.4	0.2	0.1	0.2	0.2	0.4	1.2	2.4	3.5	4.2	5.4	4.1	4.2	73.3	2.7	2.0	2.2
Number of Forecasts Changed From A Month Ago:																			
Down	1	0	7	4	4	1	8	12	30	32	33	29	25	18	28	4	20	13	17
Same	38	44	32	28	37	31	27	28	17	13	12	9	10	10	10	10	25	24	22
Up	10	0	6	5	8	9	7	8	1	4	3	1	2	1	4	17	3	9	9
Diffusion Index	59 %	50 %	49 %	51 %	54 %	60 %	49 %	46 %	20 %	21 %	19 %	14 %	19 %	21 %	21 %	71 %	32 %	46 %	42 %

First Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For Qtr.: A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Russell Investments	0.3 H	3.3 H	0.4	0.2	0.2	0.3	0.4	0.6	1.5	2.4	3.4	4.1	5.4	4.3	4.2	74.7	1.5	2.2	2.5
Kellner Economic Advisers	0.3 H	3.3	0.4	0.4 H	0.4 H	0.4 H	0.5	0.7	1.4	2.4	3.4	4.2	5.3	4.8	4.1	83.0 H	2.5	2.5	2.6
J.W. Coons Advisors LLC	0.3 H	3.3	0.7 H	0.3	0.3	0.4	0.5	0.6	1.2	2.1	3.1	4.1	5.3	na	3.9	71.6	1.6	2.2	2.5
Bank of Toyko-Mitsubishi UFJ	0.3 H	3.3	0.6	0.2	0.1	0.1 L	0.2	1.3 H	1.9	3.1	3.8	4.7	6.1	4.5	5.0	71.0	2.8	2.9 H	2.5
Swiss Re	0.3 H	3.3	0.3 L	0.2	0.1	0.2	0.3	0.5	1.1	2.2	3.2	4.0	5.0	na	4.3	na	2.7	1.6	1.8
Scotiabank Group	0.3 H	3.3	na	na	0.1	na	na	0.6	1.5	2.8	3.9	na	na	na	na	na	2.2	1.8	2.3
DePrince & Assoc.	0.2	3.3	0.6	0.3	0.2	0.3	0.4	0.6	1.1	2.1	3.2	4.0	4.9	3.3	4.1	73.9	2.6	1.9	2.2
Naroff Economic Advisors	0.2	3.3	0.5	0.2	0.3	0.3	0.4	0.7	1.5	2.6	3.7	4.6	5.7	4.4	4.4	71.0 L	2.8	2.8	2.5
Stone Harbor Investment Partners	0.2	3.3	0.5	0.3	0.2	0.3	0.5	0.7	1.4	2.7	3.7	4.4	5.2	na	4.2	75.0	2.3	1.9	2.7
Wells Fargo	0.2	3.3	0.4	0.2	0.2	0.3	0.4	0.5	1.0	2.1	3.2	4.0	5.2	3.9	3.9	75.4	1.7	2.1	1.7
Fannie Mae	0.2	3.3	na	na	0.2	na	0.2	na	na	2.2	3.2	na	na	na	4.1	na	2.3	1.7	2.1
SunTrust Banks	0.2	3.3	0.4	0.2	0.1	0.2	0.3	0.4	0.8 L	1.5 L	2.3 L	3.7	4.6	4.4	3.2 L	78.9	3.3	1.5	2.0
AIG	0.2	3.3	na	na	0.1	0.1 L	0.2	0.3	0.9	2.6	3.6	3.9	5.1	na	4.0	75.1	3.0	1.1 L	1.2 L
ClearView Economics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3 L	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	74.8	3.1	2.5	2.7
Mesirow Financial	0.2	3.3	0.4	0.2	0.3	0.3	0.4	0.8	1.6	2.9	4.0	4.7	5.7	4.4	4.7	74.9	2.2	2.0	2.2
Pierpont Securities	0.2	3.3	0.6	0.2	0.1	0.2	0.3	0.8	1.8	3.6 H	5.0 H	5.3 H	6.5 H	5.4 H	5.6 H	77.0	3.5 H	2.8	3.3
Nomura Securities, Inc.	0.2	3.3	0.5	0.2	0.1	0.1 L	0.2	0.4	1.2	2.2	3.3	4.0	5.3	na	3.9	74.5	1.9	2.8	1.4
Woodworth Holdings	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.4	1.2	2.4	3.5	4.2	5.4	4.1	4.2	75.0	1.0 L	1.5	1.6
RBS Securities	0.2	3.3	0.5	0.2	0.1	0.2	0.2	0.3 L	0.9	2.0	3.0	3.3 L	4.3 L	3.8	3.6	73.0	2.4	2.4	2.5
JPMorgan Private Banking	0.2	3.3	0.5	0.1 L	0.1	0.2	0.2	0.3 L	0.9	2.0	3.1	3.9	5.2	3.9	3.9	74.0	1.5	2.0	2.2
Chmura Economics & Analytics	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.4	1.1	2.3	3.4	4.2	na	na	4.1	72.4	2.9	1.7	2.2
Barclays Capital	0.2	3.3	0.4	0.1 L	0.1	0.2	0.2	0.3 L	1.0	2.0	3.4	4.0	5.2	4.0	4.0	na	2.0	2.7	2.3
Economist Intelligence Unit	0.1 L	3.3	0.6	0.2	0.1	0.2	0.2	0.4	1.2	2.2	3.5	na	na	na	4.3	na	1.6	na	2.6
MacroFin Analytics	0.1 L	3.3	0.5	0.2	0.2	0.2	0.3	0.4	1.2	2.1	3.2	4.2	5.3	4.2	4.2	74.0	2.5	1.2	1.6
Action Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.6 H	0.9	1.7	2.4	3.5	3.8	5.1	3.6	3.7	73.7	2.3	2.0	3.3 H
Loomis, Sayles & Company	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.3 L	1.3	2.3	3.3	4.1	5.3	3.3	3.9	74.9	1.7	1.9	2.2
Moody's Capital Markets Group	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.3	0.5	1.1	2.3	3.3	4.1	5.4	4.1	4.0	75.3	2.3	1.8	2.0
RBC Capital Markets	0.1 L	3.3	0.5	na	0.1	0.1 L	0.2	0.4	1.1	2.4	3.8	na	na	na	na	na	na	na	na
BMO Capital Markets	0.1 L	3.3	0.4	0.2	0.1	0.2	0.3	0.5	1.2	2.6	3.6	4.3	5.4	4.0	4.6	74.3	1.8	1.9	2.2
Oxford Economics	0.1 L	3.3	0.4	na	0.0 L	0.1 L	0.2	0.4	1.4	2.4	3.8	na	na	na	4.2	75.3	2.5	2.5	2.0
J.P. Morgan Chase	0.1 L	na	0.5	na	0.0 L	na	na	0.3 L	1.3	2.5	3.6	na	na	na	na	na	1.5	1.4	1.7
UBS	0.1 L	na	0.5	na	0.2	na	na	0.6	1.4	2.5	3.6	na	na	na	na	na	2.8	2.0	1.3
GLC Financial Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.2	0.4	1.0	2.1	3.2	4.0	5.2	3.9	4.1	73.1	2.0	2.4	2.4
Comerica Bank	0.1 L	3.3	0.7 H	na	0.1	0.2	0.2	0.3 L	1.2	2.5	3.7	na	na	na	4.4	na	1.8	1.8	2.3
Wintrust Wealth Management	0.1 L	3.3	0.5	0.2	0.1	0.1 L	0.1 L	0.4	0.9	2.1	3.1	4.0	5.1	3.9	4.0	74.0	2.3	2.1	2.2
Thredgold Economics	0.1 L	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.1	2.0	3.0	3.6	4.9	3.8	3.9	74.0	2.8	2.0	2.4
Nat'l Assn. of Realtors	0.1 L	3.3	0.5	0.2	0.2	0.3	0.5	0.8	1.8	2.8	3.7	4.4	5.6	4.4	4.3	na	2.8	2.2	2.7
Daiwa Capital Markets America	0.1 L	3.3	0.5	0.1 L	0.1	0.2	0.2	0.6	1.1	2.1	3.2	4.0	5.3	3.9	4.0	76.0	3.0	1.9	2.0
Moody's Analytics	0.1 L	3.3	0.5	0.3	0.1	0.2	0.4	0.7	2.1	3.5	4.4	4.8	6.1	na	5.1	na	2.9	2.1	2.1
Cycledata Corp.	0.1 L	3.3	0.4	0.1 L	0.1	0.1 L	0.3	0.4	1.1	2.4	3.5	4.2	5.5	4.0	4.0	73.0	1.5	2.3	2.5
RDQ Economics	0.1 L	3.3	0.4	0.2	0.1	0.2	0.6 H	0.9	2.1 H	3.3	4.5	4.9	6.1	5.0	5.0	74.0	3.2	2.9 H	3.3 H
RidgeWorth Investments	0.1 L	3.3	0.4	0.2	0.1	0.1 L	0.2	0.3 L	1.1	2.2	3.3	3.7	4.7	2.6 L	4.0	73.0	3.0	2.0	2.4
Goldman Sachs & Co.	0.1 L	3.3	0.3 L	na	0.0 L	na	na	0.5	1.3	2.6	3.5	3.5	na	na	4.1	na	2.0	1.3	1.7
Georgia State University	0.1 L	3.3	na	na	0.0 L	0.1 L	0.1 L	0.4	1.4	2.6	3.5	4.3	5.3	na	4.2	na	2.3	1.6	1.7
Societe Generale	0.1 L	3.3	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.1	2.3	3.3	4.0	4.9	na	na	na	1.2	1.9	1.3
Standard & Poor's Corp.	0.1 L	3.3 L	0.4	0.2	0.1	0.1 L	0.2	0.4	1.1	2.3	na	4.1	5.1	4.0	4.1	na	2.2	1.4	1.7
Wells Capital Management	0.1 L	na	0.6	0.2	0.1	0.2	0.3	0.4	1.1	2.4	3.4	3.9	4.9	4.1	4.4	74.5	2.8	2.1	2.4
June Consensus	**0.2**	**3.3**	**0.5**	**0.2**	**0.1**	**0.2**	**0.3**	**0.5**	**1.3**	**2.4**	**3.5**	**4.1**	**5.3**	**4.1**	**4.2**	**74.5**	**2.3**	**2.0**	**2.2**
Top 10 Avg.	0.2	3.3	0.6	0.3	0.2	0.3	0.5	0.8	1.7	3.0	4.0	4.6	5.8	4.6	4.7	76.6	3.1	2.7	2.8
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	0.9	2.0	3.0	3.7	4.8	3.6	3.8	72.6	1.5	1.4	1.5
May Consensus	0.1	3.3	0.5	0.2	0.1	0.2	0.3	0.5	1.4	2.6	3.7	4.3	5.5	4.2	4.3	73.3	2.5	2.1	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	3	0	7	6	4	2	11	14	26	30	29	28	22	14	27	2	21	12	15
Same	34	43	30	24	34	30	27	25	18	15	14	10	11	13	10	13	20	22	24
Up	10	0	6	7	9	9	4	7	2	2	3	1	4	2	5	16	5	11	7
Diffusion Index	57 %	50 %	49 %	51 %	55 %	59 %	42 %	42 %	24 %	20 %	22 %	15 %	26 %	29 %	24 %	73 %	33 %	49 %	41 %

Second Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum -- Average For Quarter: Short-Term: 1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	Intermediate-Term: 8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	Long-Term: 11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	Avg. For ---Qtr.--- A. Fed's Major Currency $ Index	(Q-Q % Change) (SAAR): B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	0.8 H	3.8 H	1.2 H	0.9 H	0.9 H	1.0 H	1.2 H	2.0 H	2.4	3.2	3.9	5.0	6.3	4.5	5.0	72.0	3.4	2.8	2.7
J.W. Coons Advisors LLC	0.6	3.6	1.0	0.6	0.5	0.7	0.8	0.9	1.5	2.2	3.2	4.3	5.5	na	4.1	71.3	2.1	2.1	2.5
Kellner Economic Advisers	0.4	3.4	0.5	0.5	0.5	0.5	0.7	0.8	1.6	2.5	3.5	4.3	5.4	4.9	4.3	84.0 H	3.0	2.7	2.8
Thredgold Economics	0.3	3.5	0.6	0.4	0.3	0.4	0.5	0.7	1.2	2.1	3.0	3.6	4.9	3.9	4.0	74.0	3.0	2.1	2.4
Russell Investments	0.3	3.3 L	0.5	0.2	0.3	0.4	0.5	0.8	1.7	2.7	3.5	4.3	5.4	4.4	4.2	74.9	2.1	2.3	2.2
Stone Harbor Investment Partners	0.3	3.3 L	0.5	0.5	0.2	0.4	0.6	0.8	1.7	3.0	4.0	4.7	5.5	na	4.4	73.0	2.5	2.0	2.5
Naroff Economic Advisors	0.3	3.3 L	0.5	0.3	0.3	0.4	0.5	0.7	1.7	2.7	3.9	4.8	5.9	4.5	4.5	68.0 L	2.6	2.6	2.8
Moody's Capital Markets Group	0.3	3.3 L	0.5	0.3	0.2	0.3	0.4	0.6	1.2	2.3	3.3	4.1	5.3	4.1	4.1	75.5	2.8	1.9	2.1
Swiss Re	0.3	3.3 L	0.3 L	0.2	0.1	0.2	0.3	0.8	1.5	2.4	3.3	4.2	4.9	na	4.3	na	2.9	2.1	2.3
Scotiabank Group	0.3	3.3 L	na	na	0.2	na	na	0.7	1.7	3.0	4.0	na	na	na	na	na	2.4	1.8	2.2
SunTrust Banks	0.2	3.3 L	0.4	0.2	0.1	0.3	0.4	0.5	0.9	1.6 L	2.3 L	3.8	4.6	4.4	3.3 L	80.4	2.8	1.8	2.3
DePrince & Associates	0.2	3.3 L	0.6	0.4	0.2	0.3	0.5	0.7	1.3	2.4	3.4	4.2	5.1	3.5	4.3	74.2	2.9	1.9	2.2
Wells Fargo	0.2	3.3 L	0.4	0.2	0.2	0.3	0.4	0.6	1.1	2.2	3.3	4.1	5.3	3.9	4.0	72.3	2.0	2.1	1.9
Cycledata Corp.	0.2	3.3 L	0.4	0.2	0.2	0.2	0.5	0.7	1.5	2.6	3.7	4.5	5.8	4.2	4.2	73.0	1.7 L	2.4	2.6
Fannie Mae	0.2	3.3 L	na	na	0.3	na	0.2	na	na	2.2	3.3	na	na	na	4.2	na	2.2	1.6	1.9
Pierpont Securities	0.2	3.3 L	0.8	0.2	0.2	0.4	0.6	1.5	2.8 H	4.2 H	5.6 H	5.8 H	7.0 H	5.9 H	6.2 H	80.0	3.8 H	2.6	3.5 H
AIG	0.2	3.3 L	na	na	0.1	0.1 L	0.2	0.3 L	0.9	2.8	3.8	4.1	5.3	na	4.2	75.1	2.9	0.7 L	1.2
Mesirow Financial	0.2	3.3 L	0.4	0.2	0.3	0.4	0.5	0.9	1.8	3.1	4.1	4.9	5.8	4.5	4.9	73.9	2.5	1.1	1.5
ClearView Economics	0.2	3.3 L	0.4	0.1 L	0.1	0.2	0.2	0.3 L	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	75.2	3.4	2.5	2.8
Nomura Securities, Inc.	0.2	3.3 L	0.6	0.2	0.1	0.1 L	0.2	0.4	1.2	2.2	3.4	4.0	5.4	na	4.0	74.5	2.1	2.3	1.7
MacroFin Analytics	0.2	3.3 L	0.5	0.2	0.2	0.2	0.5	0.5	1.3	2.2	3.3	4.2	5.4	4.3	4.2	74.5	2.7	1.3	1.6
Woodworth Holdings	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.3	0.5	1.3	2.4	3.5	4.2	5.5	4.2	4.2	76.0	2.0	1.5	1.5
JPMorgan Private Banking	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.2	0.3 L	0.9	2.0	3.1	3.9	5.2	3.9	3.9	73.5	1.9	1.9	2.1
RBS Securities	0.2	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	0.9	2.0	3.0	3.2 L	4.1 L	3.8	3.6	73.5	2.5	2.0	2.2
Chmura Economics & Analytics	0.2	3.3 L	0.4	0.2	0.1	0.2	0.2	0.4	1.2	2.4	3.5	4.3	na	na	4.1	72.2	3.3	2.1	1.8
Economist Intelligence Unit	0.1 L	3.3 L	0.6	0.2	0.1	0.2	0.2	0.6	1.4	2.4	3.7	na	na	na	4.4	na	2.0	na	1.8
Action Economics	0.1 L	3.3 L	0.5	0.2	0.2	0.4	0.8	1.2	1.9	2.7	3.7	3.8	5.2	3.7	3.7	73.6	2.5	2.3	3.3
RBC Capital Markets	0.1 L	3.3 L	0.5	na	0.1	0.1 L	0.2	0.5	1.3	2.6	3.9	na	na	na	na	na	na	na	na
Loomis, Sayles & Company	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.2	0.3 L	1.3	2.4	3.4	4.1	5.2	3.8	4.0	74.9	2.3	1.6	2.0
Oxford Economics	0.1 L	3.3 L	0.4	na	0.0 L	0.1 L	0.3	0.6	1.4	2.4	3.9	na	na	na	4.3	75.7	2.7	2.2	1.9
BMO Capital Markets	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.4	0.6	1.4	2.8	3.8	4.4	5.5	4.0	4.9	73.9	2.6	2.2	2.6
UBS	0.1 L	na	0.6	na	0.4	na	na	0.7	1.6	2.6	3.7	na	na	na	na	na	2.7	2.0	1.4
GLC Financial Economics	0.1 L	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	1.0	2.1	3.3	4.1	5.4	3.9	4.2	73.1	2.9	2.7	2.4
Moody's Analytics	0.1 L	3.3 L	0.6	0.4	0.2	0.3	0.4	0.8	2.6	3.6	4.5	5.0	6.2	na	5.5	na	3.7	2.1	2.1
Comerica Bank	0.1 L	3.3 L	0.7	na	0.1	0.2	0.2	0.4	1.3	2.6	3.8	na	na	na	4.7	na	2.0	2.3	2.1
Wintrust Wealth Management	0.1 L	3.3 L	0.6	0.2	0.1	0.2	0.2	0.5	1.0	2.2	3.2	4.1	5.2	3.9	4.1	74.3	2.4	1.9	2.4
Nat'l Assn. of Realtors	0.1 L	3.3 L	0.6	0.3	0.3	0.4	0.7	1.1	2.3	3.0	3.9	4.6	5.7	4.5	4.4	na	2.6	2.3	2.8
Daiwa Capital Markets America	0.1 L	3.3 L	0.5	0.1 L	0.1	0.2	0.2	0.8	1.3	2.3	3.4	4.1	5.4	4.1	4.1	76.0	3.1	2.0	2.2
RDQ Economics	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.6	1.0	2.3	3.5	4.7	5.0	6.2	5.1	5.2	74.1	3.3	3.0 H	3.4
RidgeWorth Investments	0.1 L	3.3 L	0.4	0.2	0.1	0.1 L	0.2	0.3 L	1.1	2.2	3.3	3.7	4.7	2.6 L	4.0	72.0	3.0	2.2	2.2
Goldman Sachs & Co.	0.1 L	3.3 L	0.3 L	na	0.0 L	na	na	0.6	1.4	2.8	3.6	3.7	na	na	4.3	na	2.0	1.3	1.7
Georgia State University	0.1 L	3.3 L	na	na	0.0	0.1 L	0.1 L	0.4	1.5	2.7	3.6	4.4	5.4	na	4.2	na	2.4	0.9	1.6
Wells Capital Management	0.1 L	na	0.6	0.3	0.2	0.3	0.4	0.5	1.2	2.7	3.5	4.1	4.9	4.3	4.7	74.8	3.0	2.2	2.6
Societe Generale	0.1 L	3.3 L	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.1	2.3	3.3	4.0	4.9	na	na	na	1.7 L	2.0	1.8
Standard & Poor's Corp.	0.1 L	3.3 L	0.4	0.2	0.1	0.1 L	0.2	0.4	1.4	2.6	na	4.3	5.4	4.2	4.4	na	2.4	0.9	1.1 L
June Consensus	**0.2**	**3.3**	**0.5**	**0.3**	**0.2**	**0.3**	**0.4**	**0.6**	**1.4**	**2.5**	**3.6**	**4.2**	**5.4**	**4.2**	**4.3**	**74.5**	**2.6**	**2.0**	**2.2**
Top 10 Avg.	0.4	3.4	0.7	0.4	0.4	0.5	0.7	1.1	2.1	3.2	4.2	4.9	6.0	4.7	5.0	77.3	3.3	2.6	2.9
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.0	0.1	0.2	0.3	1.0	2.0	3.1	3.7	4.8	3.7	3.8	72.0	2.0	1.3	1.5
May Consensus	0.2	3.3	0.5	0.2	0.2	0.3	0.4	0.7	1.5	2.7	3.8	4.4	5.6	4.3	4.4	73.3	2.6	2.0	2.3
Number of Forecasts Changed From A Month Ago:																			
Down	4	0	8	7	4	3	10	12	25	30	28	24	19	14	23	3	15	11	12
Same	33	40	26	23	33	28	25	24	18	14	16	11	15	10	13	13	17	22	24
Up	8	2	6	5	8	9	6	8	1	1	0	3	1	3	5	13	12	10	8
Diffusion Index	54 %	52 %	48 %	47 %	54 %	58 %	45 %	45 %	23 %	18 %	18 %	22 %	24 %	30 %	28 %	67 %	47 %	49 %	45 %

Third Quarter 2013

Interest Rate Forecasts

Key Assumptions

Blue Chip Financial Forecasts Panel Members	Percent Per Annum – Average For Quarter: Short-Term							Intermediate-Term			Long-Term					Avg. For Qtr.	(Q-Q % Change) (SAAR)		
	1 Federal Funds Rate	2 Prime Bank Rate	3 LIBOR Rate 3-Mo.	4 Com. Paper 1-Mo.	5 Treas. Bills 3-Mo.	6 Treas. Bills 6-Mo.	7 Treas. Bills 1-Yr.	8 Treas. Notes 2-Yr.	9 Treas. Notes 5-Yr.	10 Treas. Notes 10-Yr.	11 Treas. Bond 30-Yr.	12 Aaa Corp. Bond	13 Baa Corp. Bond	14 State & Local Bonds	15 Home Mtg. Rate	A. Fed's Major Currency $ Index	B. Real GDP	C. GDP Price Index	D. Cons. Price Index
Bank of Toyko-Mitsubishi UFJ	1.3 H	4.3 H	1.6 H	1.4 H	1.4 H	1.5 H	1.7 H	2.5 H	3.0	3.4	4.3	5.3	6.5	4.6	5.1	72.0	3.2	3.0	2.9
J.W. Coons Advisors LLC	0.9	3.9	1.4	0.9	0.8	0.9	1.0	1.2	1.7	2.4	3.3	4.7	5.6	na	4.2	70.8	2.7	2.2	2.5
Pierpont Securities	0.9	3.9	1.6 H	1.0	1.0	1.2	1.5	2.5 H	3.9 H	4.6 H	5.9 H	6.1 H	7.2 H	6.2 H	6.6 H	83.0	4.0 H	2.8	3.8 H
Nat'l Assn. of Realtors	0.5	3.5	0.7	0.5	0.6	0.7	0.9	1.4	2.5	3.2	4.1	4.9	6.0	4.8	4.7	na	3.2	2.4	3.0
Kellner Economic Advisers	0.5	3.5	0.6	0.6	0.6	0.6	0.8	0.9	1.8	2.6	3.6	4.4	5.5	5.0	4.5	85.0 H	3.0	2.9	3.0
Cycledata Corp.	0.5	3.3 L	0.7	0.5	0.4	0.5	0.7	1.0	1.8	2.9	4.0	4.8	6.1	4.5	4.4	73.0	2.2	2.4	2.7
Thredgold Economics	0.4	3.5	0.7	0.5	0.4	0.5	0.6	0.9	1.2	2.2	3.1	3.7	4.9	3.9	4.1	74.0	3.2	2.1	2.4
UBS	0.3	na	0.8	na	0.6	na	na	1.0	1.8	2.8	3.9	na	na	na	na	na	2.6	2.0	3.7
Russell Investments	0.3	3.3 L	0.5	0.3	0.3	0.4	0.6	1.0	1.9	2.8	3.7	4.4	5.4	4.5	4.4	75.0	2.4	2.4	2.2
RidgeWorth Investments	0.3	3.5	0.5	0.5	0.3	0.4	0.5	0.6	1.4	2.6	3.7	4.0	4.9	2.9 L	4.3	74.0	3.5	2.2	2.2
SunTrust Banks	0.3	3.3 L	0.8	0.6	0.1	0.3	0.5	0.6	1.0	1.7 L	2.1 L	3.8	4.7	4.4	3.4 L	80.3	3.5	1.9	2.4
Action Economics	0.3	3.3 L	0.8	0.3	0.5	0.9	1.2	1.5	2.3	3.0	4.0	3.9	5.3	3.7	3.9	73.5	3.0	2.2	3.3
Moody's Capital Markets Group	0.3	3.3 L	0.5	0.3	0.2	0.3	0.5	0.7	1.3	2.4	3.4	4.1	5.2	4.1	4.1	75.8	3.1	2.0	1.9
Naroff Economic Advisors	0.3	3.3 L	0.5	0.3	0.4	0.4	0.5	0.8	1.8	2.9	4.0	5.0	6.1	4.7	4.7	68.5 L	3.1	2.5	2.6
Stone Harbor Investment Partners	0.3	3.3 L	0.5	0.5	0.3	0.5	0.7	1.0	1.9	3.1	4.1	4.8	5.6	na	4.5	71.0	3.1	2.3	2.2
Swiss Re	0.3	3.3 L	0.3	0.2	0.1	0.2	0.3	0.8	1.7	2.5	3.4	4.3	5.0	na	4.4	na	2.9	1.6	1.8
Scotiabank Group	0.3	3.3 L	na	na	0.2	na	na	0.9	2.0	3.3	4.2	na	na	na	na	na	2.5	1.8	2.1
DePrince & Associates	0.2	3.3 L	0.6	0.4	0.2	0.4	0.6	0.9	1.5	2.7	3.7	4.5	5.4	3.7	4.6	74.6	3.1	1.9	2.2
Wells Fargo	0.2	3.3 L	0.4	0.2	0.3	0.4	0.5	0.7	1.2	2.3	3.4	4.2	5.4	4.0	4.1	76.7	2.1 L	2.2	2.1
Fannie Mae	0.2	3.3 L	na	na	0.3	na	0.2	na	na	2.3	3.4	na	na	na	4.2	na	2.4	1.9	2.1
Moody's Analytics	0.2	3.3 L	0.7	0.5	0.3	0.4	0.5	0.9	2.9	3.9	4.7	5.1	6.4	na	5.8	na	4.0 H	2.1	2.5
AIG	0.2	3.3 L	na	na	0.1	0.1	0.2	0.3 L	0.9	2.9	3.9	4.2	5.4	na	4.5	74.8	3.2	0.9 L	1.7
MacroFin Analytics	0.2	3.3 L	0.6	0.2	0.2	0.2	0.6	0.6	1.4	2.3	3.4	4.3	5.5	4.4	4.3	74.8	2.8	1.3	1.5 L
Mesirow Financial	0.2	3.3 L	0.4	0.2	0.4	0.4	0.6	1.0	1.9	3.3	4.3	5.1	6.0	4.7	5.0	72.8	2.9	1.4	2.0
ClearView Economics	0.2	3.3 L	0.4	0.1 L	0.1	0.2	0.2	0.3 L	0.8 L	1.8	2.8	3.8	5.0	3.8	3.8	75.7	3.5	2.5	2.9
Nomura Securities, Inc.	0.2	3.3 L	0.6	0.2	0.1	0.1	0.2	0.5	1.3	2.3	3.4	4.0	5.4	na	4.0	75.0	2.5	1.9	2.5
JPMorgan Private Banking	0.2	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	0.9	2.1	3.1	4.0	5.2	4.0	3.9	73.0	2.3	1.9	2.3
Woodworth Holdings	0.2	3.3 L	0.5	0.1 L	0.1	0.2	0.3	0.5	1.3	2.4	3.5	4.2	5.5	4.2	4.2	77.0	3.0	1.5	1.5 L
RBS Securities	0.2	3.3 L	0.4	0.2	0.1	0.2	0.3	0.4	1.0	2.0	3.0	3.1 L	4.0 L	3.8	3.6	74.0	2.6	2.2	2.0
Chmura Economics & Analytics	0.2	3.3 L	0.4	0.2	0.1	0.2	0.2	0.5	1.3	2.5	3.5	4.3	na	na	4.2	71.9	3.7	2.4	2.4
Economist Intelligence Unit	0.1 L	3.3 L	0.6	0.2	0.2	0.2	0.2	0.8	1.5	2.6	4.0	na	na	na	4.7	na	2.8	na	2.3
RBC Capital Markets	0.1 L	3.3 L	0.5	na	0.1	0.1 L	0.3	0.6	1.4	2.8	4.1	na	na	na	na	na	na	na	na
Loomis, Sayles & Company	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.2	0.3 L	1.4	2.5	3.5	4.2	5.2	3.8	4.1	74.9	3.0	1.6	2.1
Oxford Economics	0.1 L	3.3 L	0.4	na	0.0 L	0.1 L	0.3	0.7	1.5	2.6	4.0	na	na	na	4.4	76.1	2.8	2.0	2.0
BMO Capital Markets	0.1 L	3.3 L	0.4	0.2	0.1	0.2	0.5	0.8	1.7	3.1	4.0	4.6	5.6	4.1	5.3	73.4	3.1	1.9	2.2
GLC Financial Economics	0.1 L	3.3 L	0.5	0.2	0.1	0.2	0.2	0.3 L	1.0	2.1	3.3	4.1	5.3	3.9	4.3	73.0	2.1 L	2.4	2.5
Wells Capital Management	0.1 L	na	0.6	0.3	0.2	0.3	0.5	0.6	1.1	2.9	3.7	4.2	4.9	4.5	4.8	75.1	3.2	2.3	2.7
Comerica Bank	0.1 L	3.3 L	0.7	na	0.1	0.2	0.2	0.4	1.4	2.7	3.9	na	na	na	4.9	na	2.7	2.1	1.9
Wintrust Wealth Management	0.1 L	3.3 L	0.7	0.2	0.1	0.2	0.3	0.5	1.1	2.3	3.3	4.2	5.3	4.1	4.2	74.6	2.4	2.0	2.2
Daiwa Capital Markets America	0.1 L	3.3 L	0.5	0.2	0.2	0.2	0.3	0.9	1.4	2.4	3.5	4.2	5.4	4.2	4.2	77.0	3.5	2.0	2.2
RDQ Economics	0.1 L	3.3 L	0.4	0.2	0.1	0.3	0.7	1.1	2.4	3.7	4.9	5.2	6.4	5.2	5.4	74.2	3.3	3.1 H	3.5
Goldman Sachs & Co.	0.1 L	3.3 L	0.3 L	na	0.0 L	na	na	0.7	1.6	2.9	3.7	3.8	na	na	4.4	na	2.5	1.5	1.9
Georgia State University	0.1 L	3.3 L	na	na	0.0 L	0.1 L	0.1 L	0.4	1.5	2.8	3.7	4.4	5.5	na	4.3	na	2.5	1.7	1.6
Societe Generale	0.1 L	3.3 L	0.6	0.1 L	0.1	0.1 L	0.1 L	0.4	1.1	2.3	3.3	4.0	4.9	na	na	na	2.2	2.0	1.8
Standard & Poor's Corp.	0.1 L	3.3 L	0.4	0.3	0.1	0.1 L	0.2	0.4	1.5	2.8	na	4.5	5.6	4.3	4.6	na	2.7	1.7	2.3
June Consensus	**0.3**	**3.3**	**0.6**	**0.3**	**0.3**	**0.4**	**0.5**	**0.8**	**1.6**	**2.7**	**3.7**	**4.4**	**5.5**	**4.3**	**4.5**	**74.8**	**2.9**	**2.1**	**2.4**
Top 10 Avg.	0.6	3.6	1.0	0.7	0.7	0.8	1.0	1.4	2.5	3.4	4.4	5.1	6.2	4.9	5.2	78.2	3.5	2.6	3.2
Bottom 10 Avg.	0.1	3.3	0.4	0.1	0.1	0.1	0.2	0.4	1.0	2.1	3.1	3.8	4.9	3.7	3.9	71.9	2.3	1.5	1.8
May Consensus	0.3	3.3	0.6	0.4	0.3	0.4	0.5	0.8	1.7	2.9	3.9	4.5	5.7	4.4	4.5	73.4	2.9	2.1	2.4
Number of Forecasts Changed From A Month Ago:																			
Down	4	3	9	7	8	5	9	11	23	27	29	21	18	14	23	5	12	8	11
Same	34	38	25	22	30	27	25	25	19	14	14	11	13	10	12	11	21	25	26
Up	7	1	7	7	7	8	7	8	2	4	1	6	5	4	6	15	11	10	7
Diffusion Index	53 %	48 %	48 %	50 %	49 %	54 %	48 %	47 %	26 %	24 %	18 %	30 %	32 %	32 %	29 %	66 %	49 %	52 %	45 %

International Interest Rate And Foreign Exchange Rate Forecasts

United States

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Fed's Major Currency $ Index		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	2.05	2.60	3.00	na	na	na
Moody's Analytics	0.48	0.46	0.48	2.40	2.82	3.45	na	na	na
Nomura Securities	na	na	na	na	na	na	na	na	na
Barclays	0.35	0.35	na	2.00	2.00	na	na	na	na
BMO Capital Markets	0.45	0.40	0.35	1.90	2.30	2.80	73.50	74.30	73.90
Mizuho Research Institute	0.46	0.43	0.40	1.90	2.00	1.90	77.3	78.7	79.9
UBS	na	na	na	2.20	2.40	2.85	na	na	na
Wells Fargo	0.45	0.45	0.40	1.90	2.00	2.20	na	na	na
ING Financial Markets	0.40	0.40	0.40	1.80	1.90	1.90	75.7	74.3	72.7
Moody's Capital Markets	na	na	na	2.05	2.20	2.35	73.2	73.3	73.8
June Consensus	**0.43**	**0.42**	**0.41**	**2.02**	**2.25**	**2.56**	**74.9**	**75.1**	**75.1**
High	0.48	0.46	0.48	2.40	2.82	3.45	77.3	78.7	79.9
Low	0.35	0.35	0.35	1.80	1.90	1.90	73.2	73.3	72.7
Last Months Avg.	0.42	0.41	0.42	2.10	2.18	2.49	75.6	75.3	74.5

Japan

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			Yen/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	na	na	na
Moody's Analytics	na	na	na	1.14	1.15	1.19	82.8	83.6	85.4
Nomura Securities	na	na	na	1.30	1.25	1.40	na	na	na
BMO Capital Markets	0.20	0.20	0.20	0.95	1.00	1.10	82.0	84.0	89.0
Mizuho Research Institute	0.33	0.33	0.33	0.95	1.00	0.95	77.0	80.0	79.0
Barclays	0.20	0.20	na	1.12	1.03	na	88.0	90.0	90.0
UBS	na	na	na	0.90	1.10	1.30	na	85.0	na
Wells Fargo	0.20	0.20	0.20	0.96	1.00	1.02	na	na	na
ING Financial Markets	0.20	0.20	0.20	0.85	0.90	1.20	82.0	85.0	90.0
Moody's Capital Markets	na	na	na	0.95	1.00	1.05	83.0	84.0	85.0
June Consensus	**0.23**	**0.23**	**0.23**	**1.01**	**1.05**	**1.15**	**82.5**	**84.5**	**86.4**
High	0.33	0.33	0.33	1.30	1.25	1.40	88.0	90.0	90.0
Low	0.20	0.20	0.20	0.85	0.90	0.95	77.0	80.0	79.0
Last Months Avg.	0.23	0.23	0.23	1.08	1.12	1.22	82.0	83.3	84.8

United Kingdom

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gilt Yields %			USD/Pound Sterling		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	1.61	1.62	1.65
Moody's Analytics	na	na	na	2.45	2.57	2.88	1.58	1.58	1.59
Nomura Securities	na	na	na	2.30	2.35	2.55	na	na	na
BMO Capital Markets	1.00	0.90	0.75	2.00	2.40	2.95	1.59	1.57	1.60
Mizuho Research Institute	1.00	0.90	0.80	1.95	2.10	2.10	na	na	na
Barclays	0.95	0.95	na	2.83	3.03	na	1.55	1.52	1.50
UBS	na	0.80	na	2.60	2.65	3.00	na	1.44	na
Wells Fargo	0.75	0.65	0.65	2.00	2.20	2.50	na	na	na
ING Financial Markets	0.65	0.65	0.65	1.90	2.10	2.40	1.53	1.53	1.56
Moody's Capital Markets	na	na	na	2.05	2.10	2.35	1.58	1.57	1.55
June Consensus	**0.87**	**0.81**	**0.71**	**2.23**	**2.39**	**2.59**	**1.57**	**1.55**	**1.58**
High	1.00	0.95	0.80	2.83	3.03	3.00	1.61	1.62	1.65
Low	0.65	0.65	0.65	1.90	2.10	2.10	1.53	1.44	1.50
Last Months Avg.	0.87	0.77	0.70	2.31	2.39	2.56	1.56	1.58	1.60

Switzerland

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			CHF/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	0.97	0.98	1.00
Moody's Analytics	na	na	na	1.30	1.40	1.59	0.82	0.86	0.90
Nomura Securities	na	na	na	na	na	na	na	na	na
BMO Capital Markets	na	na	na	na	na	na	0.93	0.96	0.99
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Barclays	na	na	na	na	na	na	0.96	1.04	1.08
UBS	na	0.12	na	1.25	1.25	1.70	na	1.04	na
Wells Fargo	na	na	na	na	na	na	na	na	na
ING Financial Markets	0.10	0.08	0.10	0.80	0.90	1.00	1.04	1.04	1.00
Moody's Capital Markets	na	na	na	0.80	0.85	1.00	0.90	0.90	0.92
June Consensus	**0.10**	**0.10**	**0.10**	**1.04**	**1.10**	**1.32**	**0.94**	**0.97**	**0.98**
High	0.10	0.12	0.10	1.30	1.40	1.70	1.04	1.04	1.08
Low	0.10	0.08	0.10	0.80	0.85	1.00	0.82	0.86	0.90
Last Months Avg.	0.10	0.80	0.10	1.00	1.08	1.30	0.94	0.95	0.96

Canada

Blue Chip Forecasters	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			CAD/USD		
	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	2.00	2.40	2.85	1.00	0.99	0.97
Moody's Analytics	na	na	na	2.04	1.81	1.73	1.00	1.00	1.02
Nomura Securities	na	na	na	2.30	2.40	2.75	na	na	na
BMO Capital Markets	1.25	1.25	1.75	2.10	2.45	3.00	1.01	1.01	0.99
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Barclays	na	na	na	na	na	na	0.98	0.96	0.95
UBS	na	na	na	2.45	2.50	2.85	na	1.05	na
Wells Fargo	1.15	1.20	1.75	2.30	2.70	3.20	na	na	na
ING Financial Markets	1.50	1.60	2.10	1.90	2.10	2.40	1.02	1.01	1.00
Moody's Capital Markets	na	na	na	2.05	2.20	2.35	1.00	1.00	1.02
June Consensus	**1.30**	**1.35**	**1.87**	**2.14**	**2.32**	**2.64**	**1.00**	**1.00**	**0.99**
High	1.50	1.60	2.10	2.45	2.70	3.20	1.02	1.05	1.02
Low	1.15	1.20	1.75	1.90	1.81	1.73	0.98	0.96	0.95
Last Months Avg.	1.25	1.35	1.78	2.21	2.38	2.80	1.00	1.00	1.00

International Interest Rate And Foreign Exchange Rate Forecasts

Australia

	3 Mo. Interest Rate %			10 Yr. Gov't Bond Yield %			USD/AUD		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	na	na	na	1.06	1.08	1.09
Moody's Analytics	na	na	na	3.99	4.01	4.30	1.02	1.00	0.97
Nomura Securities	na	na	na	3.85	3.85	4.25	na	na	na
BMO Capital Markets	na	na	na	na	na	na	1.00	1.00	1.05
Mizuho Research Institute	na	na	na	na	na	na	na	na	na
Barclays	na	na	na	na	na	na	1.05	1.06	1.07
UBS	na	na	na	3.90	4.10	4.60	na	1.00	na
Wells Fargo	na	na	na	na	na	na	na	na	na
ING Financial Markets	4.50	4.40	4.60	3.00	3.20	3.60	0.93	0.91	0.90
Moody's Capital Markets	na	na	na	3.30	3.35	3.45	1.00	0.99	0.95
June Consensus	**4.50**	**4.40**	**4.60**	**3.61**	**3.70**	**4.04**	**1.01**	**1.01**	**1.01**
High	4.50	4.40	4.60	3.99	4.10	4.60	1.06	1.08	1.09
Low	4.50	4.40	4.60	3.00	3.20	3.45	0.93	0.91	0.90
Last Months Avg.	4.60	4.50	4.50	3.95	4.04	4.32	1.03	1.03	1.02

Eurozone

	3 Mo. Interest Rate %			USD/EUR		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
Scotiabank Group	na	na	na	1.28	1.26	1.25
Moody's Analytics	na	na	na	1.30	1.29	1.27
Nomura Securities	na	na	na	na	na	na
BMO Capital Markets	0.65	0.65	0.90	1.30	1.30	1.32
Mizuho Research Institute	0.60	0.50	0.60	1.26	1.24	1.21
Barclays	0.65	0.75	na	1.30	1.25	1.20
UBS	na	na	na	na	1.15	na
Wells Fargo	0.60	0.60	0.90	na	na	na
ING Financial Markets	0.80	0.80	1.15	1.15	1.15	1.20
Moody's Capital Markets	na	na	na	1.28	1.26	1.24
June Consensus	**0.66**	**0.66**	**0.89**	**1.27**	**1.24**	**1.24**
High	0.80	0.80	1.15	1.30	1.30	1.32
Low	0.60	0.50	0.60	1.15	1.15	1.20
Last Months Avg.	0.64	0.65	0.83	1.26	1.26	1.27

10 Yr. Gov't Bond Yields %

	Germany			France			Italy			Spain		
Blue Chip Forecasters	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.	In 3 Mo.	In 6 Mo.	In 12 Mo.
ING Financial Markets	1.50	1.60	1.80	3.10	3.30	3.30	6.20	6.40	6.40	6.70	6.70	6.60
UBS	2.30	2.40	2.70	3.09	3.19	3.49	5.52	5.62	5.92	na	na	na
Mizuho Research Institute	1.65	1.70	1.75	na	na	na	na	nas	na	na	na	na
BMO Capital Markets	1.65	2.00	2.55	na	na	na	na	na	na	na	na	na
Moody's Capital Markets	1.65	1.70	1.95	2.90	2.95	2.95	5.50	5.25	5.00	5.70	5.35	5.20
Moody's Analytics	2.00	2.00	2.00	3.33	3.55	3.75	5.61	5.41	5.13	5.90	6.10	6.10
June Consensus	**1.79**	**1.90**	**2.13**	**3.11**	**3.25**	**3.37**	**5.71**	**5.67**	**5.61**	**6.10**	**6.05**	**5.97**
High	2.30	2.40	2.70	3.33	3.55	3.75	6.20	6.40	6.40	6.70	6.70	6.60
Low	1.50	1.60	1.75	2.90	2.95	2.95	5.50	5.25	5.00	5.70	5.35	5.20
Last Months Avg.	1.89	1.93	2.08	3.05	3.14	3.30	5.68	5.67	5.48	5.53	5.44	5.39

Consensus Forecasts 10-year Bond Yields vs U.S. Yield

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.86	-1.01	-1.20	-1.41
United Kingdom	0.00	0.21	0.14	0.04
Switzerland	-1.11	-0.98	-1.15	-1.23
Canada	0.05	0.12	0.07	0.09
Australia	1.41	1.59	1.46	1.48
Germany	-0.38	-0.23	-0.35	-0.43
France	0.78	1.08	1.00	0.82
Italy	4.05	3.69	3.42	3.06
Spain	4.58	4.08	3.80	3.41

Consensus Forecasts 3 Mo. Deposit Rates vs U.S. Rate

	Current	In 3 Mo.	In 6 Mo.	In 12 Mo.
Japan	-0.36	-0.21	-0.64	-0.17
United Kingdom	0.36	0.44	0.39	0.31
Switzerland	-0.53	-0.33	-0.32	-0.31
Canada	0.90	0.87	0.94	1.46
Australia	3.47	4.07	3.99	4.19
Eurozone	0.02	0.23	0.25	0.48

Viewpoints:

A Sampling of Views on the Economy, Financial Markets and Government Policy Excerpted from Recent Reports Issued by our Blue Chip Panel Members and Others

The Europe Link

With the situation in Europe becoming more uncertain and the euro at a 22-month low against the dollar, there is rising concern about the spillover to the US. Most of the contagion would come from the banking system and financial markets, particularly if the situation deteriorates into a full-blown crisis. There are also linkages through trade flows, which take longer to be realized. In our baseline case where the Eurozone avoids a crisis but falls into a mild recession, US exports to the region will slow. This is mostly due to a decline in demand rather than an adjustment in the exchange rate, as we argue below.

Intuitively, exchange rate changes should cause fluctuations in trade flows. The logic is simple: depreciation of a country's currency will support exports but hurt imports as it becomes more expensive to buy foreign goods. This assumes that changes in exchange rates "pass through" to import prices and in turn business and consumer prices.

This is where the link breaks in practice. Most literature finds incomplete exchange rate pass-through in the US. Recent work by the IMF, BIS and Federal Reserve has found that the pass-through from exchange rates to core import prices has declined from about 50% in the 1970-80s to about 20% during the past decade. The impact will differ depending on how long the change in the exchange is sustained, the magnitude of the decline and the reason for the change. Moreover, the relationship between import prices and trade flows is loose.

Our international economist, Gustavo Reis, has developed a model to determine the impact of changes in the real exchange rate on trade flows (real exchange rate is the price of foreign goods in units of domestic goods). He finds that a 10% depreciation in the real exchange rate would only boost net exports by 3.2pp over the following two quarters. Focusing on the past few quarters, he finds that the real exchange rate only explains 0.2pp of the change in exports. The bulk of export growth is explained by the change in global demand.

The OECD takes it a step further and investigates the impact of exchange rate changes on overall GDP and inflation. Focusing on the euro, a 10% nominal depreciation against the dollar, holding all else equal, would only slice 0.1pp from US GDP over a one year period, provided the exchange rate holds at that level for the year. Assuming it holds for four years, it would cut 0.3pp from baseline growth.

The above simulation controls for magnitude and duration of the change in exchange rates, but it does not account for the reason behind the move. This is a crucial part of the story. If the real exchange rate is altered because of an external shock to the global economy, any impact the exchange rate would have on trade flows will be marginalized. A negative shock will cut income and therefore reduce aggregate demand, shrinking all trade flows. The income effect overwhelms the price/exchange rate effect.

The Lehman bankruptcy and financial crisis in the fall of 2008 is the perfect example of such a shock. It caused large swings in exchange rates, but more importantly, it stifled economic growth. The sharp decline in global demand dwarfed all else, causing trade activity to collapse across the world. From mid- 2008 through mid-2009, world trade fell by 20%. As a percent of GDP, global trade declined nearly 30% during the recession. This caused a rebalancing in the global economy – deficits were reduced and surpluses shrank.

In addition to the dramatic loss of income and demand, the crisis created a freezing of the credit markets. Many firms rely on credit lines, particularly dollar dominated, for international trade. Lenders pulled back dramatically, which disproportionately hurt small firms and the emerging markets. A Federal Reserve Board paper found that domestic-oriented firms that were able to receive domestic trade credit experienced smaller decline in sales than firms that were reliant on external finance.

Laurence Boone, our Chief European Economist, believes that if Greece were to exit the Eurozone with a disorderly default, it would create a crisis akin to the Lehman bankruptcy, which would be sufficient to push the global economy back into recession. The credit markets would likely freeze and demand would collapse, leading to a dramatic decline in trade volumes. Once again, exchange rate differentials would have negligible effects.

The baseline forecast for the Eurozone is that a crisis is avoided and the region falls into a mild recession this year. Under this forecast, the US continues along with its rehab recovery. Without big swings in demand or change in credit availability for external trade financing, exchange rate adjustments could matter more. However, as we argue above, there would need to be a sustained large movement in the Euro/USD for it to matter to the outlook.

Since the problems with Greece surfaced two years ago, the Euro/USD swung around 1.30, with a low of 1.19 reached on June 7, 2010 and a high of 1.49 reached on May 2, 2011. Our FX strategists believe that 1.30 is close to fair value. If the exchange rate falls below this level and holds, it would hurt US export growth. This would lead to modest widening in the trade deficit, partly reversing the sharp narrowing that occurred during the recession.

It is also important, however, to remember that Europe only makes up 18% of US exports, so there could be offsetting factors from other economies. The two other main countries the US exports to are Canada and Mexico

While potential dollar appreciation will only have a modest effect on overall growth, it would disproportionately hurt the manufacturing sector, which is reliant on international trade. Providing some offset would be lower manufacturing costs since US firms rely on foreign equipment and components in producing their goods. A NY Fed paper, which focused on the dollar appreciation in the late 1990s, found that the loss of revenue from dollar appreciation exceeds the cost saving from lower import prices. While output and profits will be affected, there is little evidence that firms will reduce employment in response to exchange rate changes. It does, however, keep downward pressure on wages.

Dollar strength would not, in itself, be a sufficient condition for stopping the "manufacturing renaissance" in the US. We believe this is a secular trend. It would simply create a hiccup in this trend.

For equity investors, it means those corporations that have exposure to the European market and rely on external financing are likely to see the biggest drag. The manufacturing industry is particularly vulnerable. The macro implications, however, are only modest. The US trade deficit, and therefore the current account deficit, will widen, reversing some of the narrowing during the crisis. We expect net exports to slice 0.1pp from growth this year and 0.2pp next year year. In the worst-case scenario where a Greece exit creates a Lehman-sized shock, all bets are off. Trade flows would likely collapse amid weak global demand and tight credit. It would spur further global rebalancing, but it will leave painful scars on the global economy.

Michelle Meyer, Bank of America-Merrill Lynch, New York, NY

The Fiscal Cliff -- Serious, But Not Likely

The Congressional Budget Office recently published its estimates of the approaching fiscal cliff, or the tightening in fiscal policy that will occur in January if Congress does not extend a long list of expiring tax and spending provisions. The estimates are valuable because the CBO has the resources to monitor and assess all the *(continued on next page)*

Viewpoints

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changes that are scheduled to occur. The major items are well known, such as the Bush tax cuts and the automatic spending reductions that fell out of the resolution of the debt-ceiling debate, but a host of other changes also are on tap and a proper reckoning of the fiscal shift should include the long list of lesser known items. (A listing of expiring tax provisions in 2012 published by the Joint Committee on Taxation covers nine pages.)

The headline estimate published by the CBO was striking, as total fiscal tightening would amount to $607 billion, enough to cut the deficit in the current fiscal year by approximately half. This amount, while notable, understates the significance of the approaching changes. The Congressional Budget Office typically calculates its budget figures on a fiscal-year basis (October to September). Because most of the tax increases and spending cuts begin in January, they affect only three-quarters of the next fiscal year. Thus, the estimated budget effect would be even larger if the changes were in place for an entire fiscal year (more than $800 billion or two-thirds of the likely deficit in the current fiscal year).

These effects represent the first round influences on the budget deficit. The fiscal tightening would undoubtedly slow economic activity, and the slowing in the rate of economic growth would trigger various automatic stabilizers. That is, with lower incomes, many individuals would see their tax burdens reduced, and some individuals would begin receiving income-support payments. These shifts would reverse some of the effect of the scheduled adjustments and leave net fiscal tightening of $560 billion ($743 billion when quoted at an annual rate).

Back-of-the-envelope calculations suggest that the economic impact of the fiscal tightening would be profound. The annualized net effect of fiscal tightening represents almost five percent of our estimate of nominal GDP at the end of this year. With a multiplier of 1.0 to 1.5 and a likely inflation rate of two percent, the fiscal shift would shave approximately four percentage points from GDP growth. Our current forecast for GDP next year, which assumes no fiscal tightening, totals 3.25 percent. Thus, if the fiscal tightening occurs, the economy will most likely contract next year.

The CBO also provided an estimate of GDP growth, and its view was less dire than ours, showing Q4-over-Q4 growth of 0.5 percent (a drop of 1.3 percent in the first half and growth of 2.3 percent in the second half). However, the CBO has an optimistic view on growth in the absence of fiscal tightening (4.4 percent). That view seems ambitious in light of recent developments suggesting moderate growth.

The effects of the fiscal cliff on the economy would be pronounced, but we do not expect Congress to allow the tightening to occur. Legislators seem to understand that the changes would tip the economy into recession, and they are not likely to risk such an outcome at this time. In addition, the experience in Europe and the shift in sentiment away from austerity in this region will probably lead most representatives and senators to believe that fiscal tightening should be delayed.

The timing of the election cycle is also likely to lead Congress to extend most or all of the expiring tax and spending provisions. Legislators will probably not address these issues before the election, and they will not have sufficient time after the balloting to debate the issues fully. The easiest course will be to extend the provisions and allow the new Congress to consider matters carefully. In addition, many will probably believe that a lame-duck Congress should not be making such weighty decisions on tax and spending policy. We look for little or no fiscal tightening in early 2013, but we hope the new Congress will begin meaningful debate on long-term deficit reduction.

Michael Moran, Daiwa Capital Markets America, New York, NY

Grexit?

It's been three weeks since the Greek elections produced a stalemate between pro- and anti-bailout parties, unleashing a wave of doubts about Greece's future in the euro, and about the common currency itself. In that short span, the euro has dropped by more than 4% to US$1.251, 10-year Treasury yields have hit century-lows of 1.7%, and global equity markets have dropped almost 5%. The market cap of the MSCI World index has shed more than US$2 trillion in value in those three weeks, taking the index almost all the way back to where it started 2012. Global stocks are also now almost back to where they stood in November 2009, when Greece's deep debt woes first came fully to the light of day. Putting the market cap loss of more than $2 trillion into some perspective, the value of Greece's nominal GDP was US$265 billion (and falling) over the past four quarters, or roughly three Facebooks. True, this comparison mixes stocks (equity values) and flows (GDP), but it gives a sense of just how much havoc a grand total of 0.16% of the world's population can cause for financial markets.

Global equities actually had a small reprieve this week, in no small part due to a steady drumbeat of decent U.S. economic data, particularly on the housing front. New and existing home sales both provided more compelling evidence that the U.S. market has finally turned the corner, while a trio of measures suggested that home prices are following. But that news played a secondary role against the much greater drama unfolding in Europe. Markets were somewhat calmed by official comments of support for Greece, but also keenly aware of the fact that preparations for a Greek exit are intensifying across the continent. As Ben points out, it certainly is not just Greece that is roiling European markets, with deepening concerns about Spain, its banks, and its regional finances, as well as underlying softness in the broader European economy. While last week's Q1 GDP report suggested that the Eurozone had just managed to skirt a technical recession, a deep drop in May PMIs leave little doubt that the region is in fact in a very real recession. While that's bad enough, the really bad news for markets is that the next Greek elections are still another three weeks away.

Douglas Porter, BMO Capital Markets, Toronto, Canada

U.S. Manufacturing Shows More Signs Of A Slowdown

While the U.S. manufacturing expansion does not look to be in any near-term danger of reversing, there was more data this week to support the view that U.S. manufacturing momentum is decelerating. An economic recession in much of Europe and slower growth in many emerging market economies such as China, India and Brazil is starting to take a toll on the U.S. manufacturing expansion as well. The week started on a sour note with the release of the Richmond Fed manufacturing PMI for May, which came in weaker than expected at 4, down from a 14 reading in April.

This view of a slower manufacturing expansion was corroborated by the first release of the Markit manufacturing PMI for the United States, which also fell to 53.9 from 56.0 in April. This index is the first national read on U.S. manufacturing for May, and according to Markit, is based on about 85 percent of the usual monthly replies to the ISM PMI released later in the month. While we do not yet have a lot of history to go on with this manufacturing index, it may become a closely watched first take on manufacturing activity in the months ahead. The PMI was pulled down by deterioration in output, new orders, employment, and slower inventory growth. The April durable goods orders also showed broad-based weakness in machinery, fabricated metals, and computer orders that suggests less durable goods manufacturing and business equipment spending in the months ahead.

Wells Fargo Securities, Charlotte, NC

Long-Range Forecasts:

The table below contains results of our semi-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are estimates for the years 2014 through 2018 and averages for the five-year periods 2014-2018 and 2019-2023. Apply these projections cautiously. Few economic, demographic and political forces can be evaluated accurately over such long time spans.

		-----------Average For The Year-----------					Five-Year Averages	
Interest Rates		**2014**	**2015**	**2016**	**2017**	**2018**	**2014-2018**	**2019-2023**
1. Federal Funds Rate	**CONSENSUS**	**0.7**	**1.9**	**2.9**	**3.3**	**3.5**	**2.5**	**3.6**
	Top 10 Average	1.3	2.9	3.8	4.3	4.4	3.3	4.4
	Bottom 10 Average	0.2	1.0	1.7	2.1	2.4	1.5	2.6
2. Prime Rate	**CONSENSUS**	**3.8**	**4.8**	**6.0**	**6.4**	**6.6**	**5.5**	**6.6**
	Top 10 Average	4.4	5.9	6.9	7.3	7.4	6.3	7.4
	Bottom 10 Average	3.3	4.0	4.9	5.3	5.5	4.6	5.6
3. LIBOR, 3-Mo.	**CONSENSUS**	**1.1**	**2.4**	**3.3**	**3.7**	**3.8**	**2.9**	**3.9**
	Top 10 Average	1.7	3.4	4.2	4.6	4.6	3.7	4.6
	Bottom 10 Average	0.6	1.6	2.2	2.7	2.8	2.0	3.0
4. Commercial Paper, 1-Mo.	**CONSENSUS**	**0.9**	**2.1**	**3.0**	**3.4**	**3.5**	**2.6**	**3.6**
	Top 10 Average	1.4	2.9	3.8	4.3	4.4	3.3	4.3
	Bottom 10 Average	0.4	1.4	2.0	2.3	2.6	1.7	2.7
5. Treasury Bill Yield, 3-Mo.	**CONSENSUS**	**0.7**	**1.8**	**2.8**	**3.3**	**3.4**	**2.4**	**3.5**
	Top 10 Average	1.3	2.7	3.7	4.2	4.3	3.2	4.2
	Bottom 10 Average	0.2	1.1	1.8	2.2	2.4	1.5	2.6
6. Treasury Bill Yield, 6-Mo.	**CONSENSUS**	**0.8**	**2.0**	**3.0**	**3.4**	**3.6**	**2.6**	**3.6**
	Top 10 Average	1.5	2.9	3.9	4.3	4.4	3.4	4.4
	Bottom 10 Average	0.3	1.3	1.9	2.3	2.5	1.7	2.7
7. Treasury Bill Yield, 1-Yr.	**CONSENSUS**	**1.1**	**2.2**	**3.2**	**3.6**	**3.7**	**2.8**	**3.8**
	Top 10 Average	1.7	3.2	4.1	4.5	4.7	3.6	4.6
	Bottom 10 Average	0.5	1.5	2.1	2.5	2.6	1.8	2.7
8. Treasury Note Yield, 2-Yr.	**CONSENSUS**	**1.4**	**2.6**	**3.4**	**3.8**	**4.0**	**3.0**	**4.0**
	Top 10 Average	2.1	3.4	4.4	4.7	5.0	3.9	5.0
	Bottom 10 Average	0.8	1.8	2.4	2.7	2.8	2.1	3.0
10. Treasury Note Yield, 5-Yr.	**CONSENSUS**	**2.3**	**3.2**	**3.9**	**4.2**	**4.4**	**3.6**	**4.4**
	Top 10 Average	3.1	4.3	4.9	5.1	5.3	4.5	5.4
	Bottom 10 Average	1.6	2.3	2.9	3.1	3.2	2.6	3.3
11. Treasury Note Yield, 10-Yr.	**CONSENSUS**	**3.3**	**4.1**	**4.5**	**4.7**	**4.8**	**4.3**	**4.9**
	Top 10 Average	4.1	4.9	5.3	5.6	5.7	5.1	5.8
	Bottom 10 Average	2.7	3.3	3.6	3.7	3.9	3.4	3.9
12. Treasury Bond Yield, 30-Yr.	**CONSENSUS**	**4.2**	**4.9**	**5.3**	**5.5**	**5.5**	**5.1**	**5.5**
	Top 10 Average	5.0	5.7	6.2	6.4	6.5	6.0	6.6
	Bottom 10 Average	3.5	4.1	4.5	4.4	4.5	4.2	4.4
13. Corporate Aaa Bond Yield	**CONSENSUS**	**4.9**	**5.6**	**6.0**	**6.2**	**6.2**	**5.8**	**6.2**
	Top 10 Average	5.7	6.2	6.6	7.1	7.1	6.5	7.2
	Bottom 10 Average	4.2	5.0	5.3	5.3	5.3	5.0	5.2
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.6**	**7.0**	**7.2**	**7.3**	**6.8**	**7.2**
	Top 10 Average	6.7	7.2	7.6	8.1	8.1	7.5	8.2
	Bottom 10 Average	5.4	6.1	6.4	6.4	6.5	6.1	6.3
14. State & Local Bonds Yield	**CONSENSUS**	**4.5**	**5.1**	**5.4**	**5.6**	**5.6**	**5.2**	**5.5**
	Top 10 Average	5.1	5.7	6.0	6.2	6.4	5.9	6.3
	Bottom 10 Average	3.9	4.5	4.8	4.9	4.9	4.6	4.8
15. Home Mortgage Rate	**CONSENSUS**	**5.1**	**5.8**	**6.2**	**6.4**	**6.5**	**6.0**	**6.5**
	Top 10 Average	5.9	6.6	7.0	7.3	7.3	6.8	7.3
	Bottom 10 Average	4.4	5.1	5.5	5.6	5.7	5.3	5.7
A. FRB - Major Currency Index	**CONSENSUS**	**75.5**	**76.2**	**77.2**	**77.3**	**77.5**	**76.8**	**77.1**
	Top 10 Average	78.1	79.4	81.8	82.4	82.8	80.9	82.8
	Bottom 10 Average	72.9	73.1	73.1	72.7	72.6	72.9	72.0
		----------Year-Over-Year, % Change----------					**Five-Year Averages**	
		2014	**2015**	**2016**	**2017**	**2018**	**2014-2018**	**2019-2023**
B. Real GDP	**CONSENSUS**	**2.9**	**3.0**	**2.9**	**2.8**	**2.7**	**2.8**	**2.5**
	Top 10 Average	3.4	3.4	3.3	3.1	3.1	3.3	2.8
	Bottom 10 Average	2.3	2.5	2.5	2.4	2.3	2.4	2.3
C. GDP Chained Price Index	**CONSENSUS**	**2.1**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.5	2.7	2.6	2.5	2.6	2.6	2.5
	Bottom 10 Average	1.7	1.9	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**	**2.4**
	Top 10 Average	2.9	3.0	2.9	2.9	2.9	2.9	2.8
	Bottom 10 Average	2.0	2.0	2.0	1.9	2.0	2.0	2.0

Databank:

2012 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.6	1.0	0.7	0.1								
Auto & Light Truck Sales (b)	14.13	15.04	14.32	14.37								
Personal Income (a, current $)	0.3	0.3	0.4									
Personal Consumption (a, current $)	0.5	0.9	0.3									
Consumer Credit (e)	8.4	4.4	10.2									
Consumer Sentiment (U. of Mich.)	75.0	75.3	76.2	76.4	79.3							
Household Employment (c)	847	428	-31	-169								
Non-farm Payroll Employment (c)	275	259	154	115								
Unemployment Rate (%)	8.3	8.3	8.2	8.1								
Average Hourly Earnings (All, cur. $)	23.28	23.33	23.37	23.38								
Average Workweek (All, hrs.)	34.5	34.6	34.5	34.5								
Industrial Production (d)	4.3	5.0	3.5	5.2								
Capacity Utilization (%)	78.7	78.9	78.4	79.2								
ISM Manufacturing Index (g)	54.1	52.4	53.4	54.8								
ISM Non-Manufacturing Index (g)	56.8	57.3	56.0	53.5								
Housing Starts (b)	0.720	0.718	0.699	0.717								
Housing Permits (b)	0.684	0.707	0.769	0.715								
New Home Sales (1-family, c)	339	358	332	343								
Construction Expenditures (a)	-0.7	-1.4	0.1									
Consumer Price Index (nsa., d)	2.9	2.9	2.7	2.3								
CPI ex. Food and Energy (nsa., d)	2.3	2.2	2.3	2.3								
Producer Price Index (n.s.a., d)	4.1	3.3	2.8	1.9								
Durable Goods Orders (a)	-4.9	2.0	-3.9	0.2								
Leading Economic Indicators (g)	0.1	0.7	0.3	-0.1								
Balance of Trade & Services (f)	-52.5	-45.4	-51.8									
Federal Funds Rate (%)	0.08	0.10	0.13	0.14								
3-Mo. Treasury Bill Rate (%)	0.03	0.09	0.08	0.08								
10-Year Treasury Note Yield (%)	1.97	1.97	2.17	2.05								

2011 Historical Data

Monthly Indicator	Jan	Feb	Mar	Apr	May	Jun	Jly	Aug	Sep	Oct	Nov	Dec
Retail and Food Service Sales (a)	0.8	0.9	0.8	0.4	0.0	0.5	0.4	0.2	1.2	0.9	0.5	0.0
Auto & Light Truck Sales (b)	12.64	13.24	13.02	13.13	11.68	11.51	12.20	12.09	13.05	13.22	13.60	13.50
Personal Income (a, current $)	1.1	0.5	0.5	0.4	0.3	0.1	0.1	0.1	0.3	0.4	0.1	0.4
Personal Consumption (a, current $)	0.4	0.8	0.6	0.3	0.2	-0.2	0.8	0.1	0.7	0.2	0.0	0.2
Consumer Credit (e)	2.2	3.2	2.2	2.8	3.0	5.6	5.8	-4.7	3.7	3.3	9.8	7.9
Consumer Sentiment (U. of Mich.)	74.2	77.5	67.5	69.8	74.3	71.5	63.7	55.7	59.4	60.9	64.1	69.9
Household Employment (c)	110	221	213	-136	180	-423	65	304	353	190	317	176
Non-Farm Payroll Employment (c)	110	220	246	251	54	84	96	85	202	112	157	223
Unemployment Rate (%)	9.1	9.0	8.9	9.0	9.0	9.1	9.1	9.1	9.0	8.9	8.7	8.5
Average Hourly Earnings (All, cur. $)	22.86	22.88	22.92	22.97	23.02	23.05	23.13	23.12	23.16	23.12	23.23	23.25
Average Workweek (All, hrs.)	34.3	34.3	34.3	34.4	34.4	34.4	34.4	34.3	34.4	34.4	34.4	34.5
Industrial Production (d)	5.8	5.1	5.4	4.4	3.1	3.2	3.3	3.4	3.3	4.2	4.1	3.8
Capacity Utilization (%)	76.1	75.9	76.5	76.1	76.3	76.3	77.0	77.1	77.2	77.6	77.7	78.3
ISM Manufacturing Index (g)	59.9	59.8	59.7	59.7	54.2	55.8	51.4	52.5	52.5	51.8	52.6	53.1
ISM Non-Manufacturing Index (g)	58.3	59.0	56.3	54.4	54.5	53.3	53.4	53.8	52.6	52.6	52.6	53.0
Housing Starts (b)	0.632	0.518	0.600	0.552	0.551	0.615	0.614	0.581	0.647	0.630	0.708	0.697
Housing Permits (b)	0.566	0.536	0.590	0.578	0.624	0.633	0.627	0.645	0.616	0.667	0.709	0.701
New Home Sales (1-family, c)	308	273	301	312	308	304	297	292	306	314	327	339
Construction Expenditures (a)	-1.4	-1.0	-0.2	0.7	2.5	1.6	-3.3	2.2	1.1	0.3	1.9	1.1
Consumer Price Index (s.a., d)	1.6	2.1	2.7	3.2	3.6	3.6	3.6	3.8	3.9	3.5	3.4	3.0
CPI ex. Food and Energy (s.a., d)	1.0	1.1	1.2	1.3	1.5	1.6	1.7	2.0	2.0	2.1	2.2	2.2
Producer Price Index (n.s.a., d)	3.6	5.4	5.6	6.6	7.1	6.9	7.1	6.6	7.0	5.8	5.6	4.7
Durable Goods Orders (a)	4.0	-1.1	4.6	-2.5	2.0	-1.2	4.2	0.1	-1.4	0.1	4.2	3.3
Leading Economic Indicators (g)	0.2	0.9	1.1	0.0	0.5	0.0	0.2	-0.7	-0.5	0.6	0.3	0.4
Balance of Trade & Services (f)	-47.5	-45.4	-46.1	-43.2	-50.2	-51.8	-45.6	-45.1	-44.0	-43.1	-47.5	-50.4
Federal Funds Rate (%)	0.17	0.16	0.14	0.10	0.09	0.09	0.07	0.10	0.08	0.07	0.08	0.07
3-Mo. Treasury Bill Rate (%)	0.15	0.13	0.10	0.06	0.04	0.04	0.04	0.02	0.01	0.02	0.01	0.01
10-Year Treasury Note Yield (%)	3.39	3.58	3.41	3.46	3.17	3.00	3.00	2.30	1.98	2.15	2.01	1.98

(a) month-over-month % change; (b) millions, saar; (c) thousands, saar; (d) year-over-year % change; (e) annualized % change; (f) $ billions; (g) level. Most series are subject to frequent government revisions. Use with care.

Calendar Of Upcoming Economic Data Releases

Monday	Tuesday	Wednesday	Thursday	Friday
May 28 **Memorial Day** **U.S. Markets Closed**	**29** Chicago FRB Midwest Mfg. Index (Apr) S&P Case-Shiller Home Price Index ((Mar) Consumer Confidence (May, Conference Board) ABC Consumer Comfort Index Weekly Store Sales	**30** ADP National Employment Report (May) Pending Home Sales (Apr) EIA Crude Oil Stocks Mortgage Applications	**31** Gross Domestic Product (Q1, Second Estimate) Corporate Profits (Q1, Preliminary) ISM Chicago (May) ISM New York (May) Chain Store Sales (May) Job-Cut Announcements (May) Weekly Jobless Claims Weekly Money Supply	**June 1** Employment Report (May) Personal Income & Consumption (Apr) ISM Manufacturing (May) Motor Vehicle Sales (May) Construction Spending (Apr)
4 Factory Orders (Apr)	**5** ISM Non-Manufacturing (May) ABC Consumer Comfort Index Weekly Store Sales	**6** Productivity (Q1, Revised) Beige Book Mortgage Applications EIA Crude Oil Stocks	**7** Consumer Credit (Apr) Flow of Funds Accounts (Q1) Weekly Jobless Claims Weekly Money Supply	**8** International Trade (Apr) Wholesale Trade (Apr)
11	**12** Federal Budget (May) Import/Export Prices (May) Manpower Employment survey (Q3) Weekly Store Sales ABC Consumer Comfort Index	**13** Retail Sales (May) Business Inventories (Apr) Producer Price Index (May) EIA Crude Oil Stocks Mortgage Applications	**14** Consumer Price Index (May) Current Account (Q1) Weekly Jobless Claims Weekly Money Supply	**15** Industrial Production (May) NY FRB Manufacturing Survey (Jun) Consumer Sentiment (Jun, preliminary, University of Michigan) Treasury International Capital Data (Apr)
18 Housing Market Index (Jun)	**19** **FOMC Meeting** Housing Starts (May) Weekly Store Sales ABC Consumer Comfort Index	**20** **FOMC Meeting** EIA Crude Oil Stocks Mortgage Applications	**21** Existing Home Sales (May) Leading Economic Indicators (May) Philadelphia Fed Survey (Jun) Weekly Jobless Claims Weekly Money Supply	**22**
25 New Home Sales (May) Chicago Fed National Activity Index (May)	**26** Consumer Confidence (Jun, Conference Board) S&P Case-Shiller Home Price Index (Apr) ABC Consumer Comfort Index Weekly Store Sales	**27** Durable Goods Orders (May) Pending Home Sales (May) Chicago Fed Midwest Manufacturing Index (May) EIA Crude Oil Stocks Mortgage Applications	**28** Gross Domestic Product (Q1, final estimate) Corporate Profits (Q1, revised) Agricultural Prices (Mid-Jun) Weekly Jobless Claims Weekly Money Supply	**29** Personal Income and Consumption (May) ISM-Chicago (Jun) ISM-New York (Jun) Consumer Sentiment (Jun, Final, University of Michigan)
July 2 ISM Manufacturing (Jun) Construction Spending (Jun)	**3** Motor Vehicle Sales (Jun) ADP National Employment Report (Jun) Factory Orders (May) ABC Consumer Comfort Index Weekly Store Sales	**4** **Independence Day** **U.S. Markets Closed**	**5** ISM Non-Manufacturing (Jun) Chain Store Sales (Jun) Job-Cut Announcements (Jun) Mortgage Applications EIA Crude Oil Stocks Weekly Jobless Claims Weekly Money Supply	**6** Employment Report (Jun)

BLUE CHIP FORECASTERS

CONTRIBUTORS TO DOMESTIC SURVEY

Action Economics, LLC, Boulder, CO
Michael Englund

AIG, New York, NY
Ardavan Mobasheri

Bank of America Merrill Lynch, New York, NY
Ethan Harris

Bank of Tokyo-Mitsubishi UFJ, Ltd., New York, NY
Christopher S. Rupkey

Barclays Capital, New York, NY
Dean Maki

BMO Capital Markets Economics, Toronto, Canada
Sherry Cooper and Douglas Porter

Chmura Economics & Analytics, Richmond, VA
Christine Chmura and Dr. Xiaobing Shuai

ClearView Economics, LLC, Cleveland, OH
Kenneth T. Mayland

Comerica, Dallas, TX
Robert A. Dye

Cycledata Corp., San Diego, CA
Robert S. Powers

Daiwa Capital Markets America, New York, NY
Michael Moran

Economist Intelligence Unit, New York, NY
Leo Abruzzese and Jan Friederich

DePrince & Associates, Murfreesburo, TN
Albert E. DePrince Jr.

Fannie Mae, Washington, DC
Douglas Duncan

Georgia State University, Atlanta, GA
Rajeev Dhawan and Emin Hajiyev

GLC Financial Economics, Providence, RI
Gary L. Ciminero

Goldman, Sachs & Co., New York, NY
Jan Hatzius

J.P. Morgan Chase, New York, NY
Bruce Kasman and Robert Mellman

JPMorgan Private Wealth Management, New York, NY
Anthony Chan

J.W. Coons Advisors, LLC, Columbus, OH
James W. Coons

Kellner Economic Advisers, Port Washington, NY
Irwin L. Kellner

Loomis, Sayles & Company, L.P., Bloomfield, MI
Brian Horrigan and David Sowerby

MacroFin Analytics, Wayne, NJ
Parul Jain

Mesirow Financial, Chicago, IL
Diane Swonk

Moody's Capital Markets Group, New York, NY
John Lonski

Moody's Analytics, West Chester, PA
Mark M. Zandi

Naroff Economic Advisors, Philadelphia, PA
Joel L. Naroff

National Association of Realtors, Washington, DC
S. Lawrence Yun

Nomura Securities International, Inc., New York, NY
David H. Resler

Oxford Economics, Wayne, PA
Lea Tyler

Pierpont Securities, Stamford, CT
Stephen Stanley

PNC Financial Services Group, Pittsburgh, PA
Stuart G. Hoffman

RBC Capital Markets, New York, NY
Thomas Porcelli

RBS, Greenwich, CT
Michelle Girard

RDQ Economics, New York, NY
John Ryding and Conrad DeQuadros

RidgeWorth Capital Management, Richmond, VA
Alan Gayle

Russell Investments, Seattle, WA
Michael Dueker

Scotiabank Group, Toronto, Canada
Aron Gampel and Dr. Warren Jestin

Societe Generale, NY, New York
Stephen W. Gallagher

Standard & Poor's Corp., New York, NY
Beth Ann Bovino

Stone Harbor Investment Partners, LP, New York, NY
Brian Keyser

SunTrust Banks, Inc., Atlanta, GA
Gregory L. Miller

Swiss Re, New York, NY
Kurt Karl

The Northern Trust Company, Chicago, IL
Paul L. Kasriel and Asha G. Bangalore

Thredgold Economic Associates, Salt Lake City, UT
Jeff K. Thredgold

UBS, New York, NY
Maury Harris, Samuel Coffin and Kevin Cummins

Wintrust Wealth Management., Chicago, IL
William B. Hummer

Wells Capital Management, San Francisco, CA
Gary Schlossberg

Wells Fargo, Charlotte, NC
John Silvia and Mark Vitner

Woodworth Holdings, Ltd., Summit, NJ
Jay N. Woodworth

CONTRIBUTORS TO INTERNATIONAL SURVEY

Barclays Capital, New York, NY

ING Financial Markets, London, England

Mizuho Research Institute, Tokyo, Japan

Moody's Analytics, West Chester, PA

Moody's Capital Markets Group, New York, NY

Nomura Securities International, New York, NY

Scotiabank Group, Toronto, Canada

Societe Generale, New York, NY

UBS, New York, NY

Wells Fargo, Charlotte, NC

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Research

Economic Research:

U.S. Economic Forecast: Keeping The Ball In Play

17-Aug-2012

With the Olympics having just ended, I can't help but think that the U.S. economy is starting to look like a ping-pong ball. Last month, we were disappointed with weak jobs data. But this month, employment is looking a little bit better: The economy created 163,000 jobs in July, according to the Bureau of Labor Statistics. In addition, retail sales surged 0.8%, and the gains were broad-based. That came after three straight months of declines, even when we exclude gasoline sales.

Team Recovery has been showing some muscle in other areas as well. The drop in oil prices has helped people save a little more, and households are finally starting to spend. News from property markets also remained relatively upbeat in July. Housing sales and starts treaded higher and prices may bottom out soon. Commercial construction, a lagging indicator to residential construction, has also started to improve, with private nonresidential construction up by 14% over June 2011.

Overview

- Recent jobs data were mixed, showing soft potential for U.S. economic growth.
- We expect U.S. GDP growth of just 2.1% this year and only 1.8% in 2013.
- Our expectation for the chances of another U.S. recession is still about 25%.

Still, the recovery faces some strong opponents: July's job gain was still lower than the 226,000 average monthly gains in the first quarter, and it wasn't enough to ease the unemployment rate. In fact, the rate ticked up to 8.3%. And there's more: Manufacturing slowed and manufacturers' sentiment worsened, while consumer confidence readings remain near historical recessionary levels.

And while our "ball" keeps bouncing, there's still a risk it could fall off the table. We still believe the risk of another recession is 25%, if the eurozone crisis worsens, China's economy experiences a hard landing, and U.S. government spending falls off the fiscal cliff at year-end. The more likely alternative, in our view, is subpar growth through the end of this year. For 2012, we expect U.S. GDP growth of 2.1%, a bit stronger than our 2.0% forecast in July. Growth for 2013, at 1.8%, is softer than our previous 2.0% forecast. Both are not enough to make a dent in the unemployment rate.

Working For A Living

The gain of 163,000 new employees was more than twice the monthly gains of 73,000 in the second quarter and the highest level in five months. If we stopped there, we could walk away feeling pretty good about the report. However, the report also said that the unemployment rate increased by 0.1 percentage point to 8.3% in July, which was a surprise.

Here it gets tricky. An increase in the unemployment rate, on its own, doesn't necessarily mean bad news. When the unemployment rate rises while more people are getting jobs and others are entering the labor force, it's good news. Stronger participation and more jobs is a healthy combination, even if it pushes the unemployment rate up.

But that's not what happened in the July report. Instead, we saw more job losses, more people leaving the labor force altogether, and the long-term unemployed staying that way. People who have been unemployed for 27 weeks or longer still represent 41% of the total unemployed. The labor participation rate decreased by 0.1 percentage point to 63.7%—near a three-decade low. When they come back to the work force, they will be counted as unemployed, keeping that rate high for some time.

Since a growing labor force provides a substantial boost to an economy's potential rate of expansion, the longer people sit on the sidelines, the worse it is for overall U.S. growth. According to Say's Law, our ability to demand items—from food to a fancy car—comes from the income we produce with our labor and assets. The higher our productivity, the higher our power to demand even more goods and services from others. This creates more employment opportunities. Unfortunately, it's working in reverse now after decades of being in forward gear.

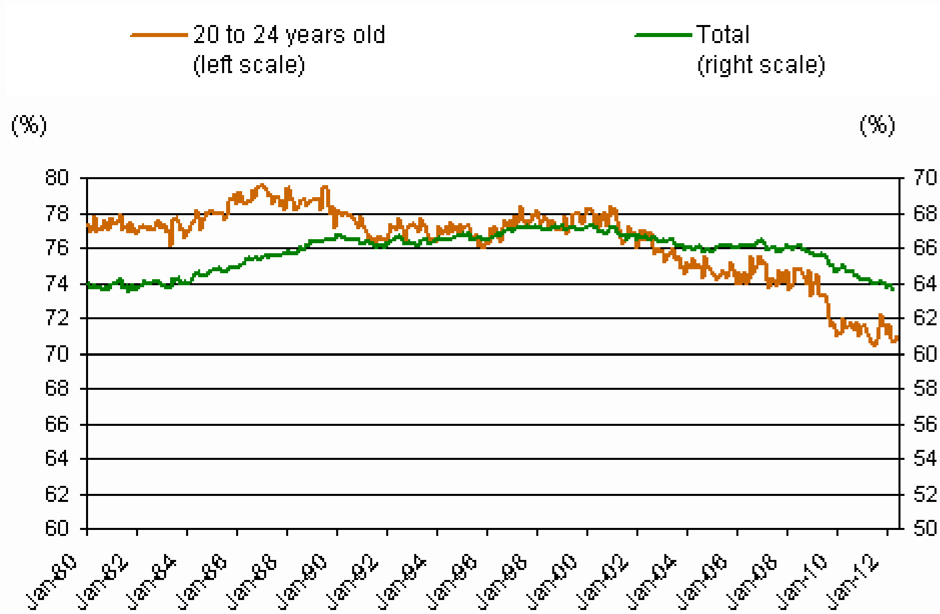
The growing labor force in the U.S. over the past 50 years provided a sizable boost to the economy's potential growth rate. According to a 2007 Congressional Budget Office (CBO) report, the labor participation rate grew to a peak of over 67% in 2000, swelled by the baby boom generation and the entry of women. This explains about 1.6 percentage points of the average annual growth in potential real GDP of 3.4% from 1950 to 2006. Absent faster gains in productivity—the other key determinant of potential growth—the CBO estimated that as the baby boomers retire, labor force growth will add only 0.5% to potential real GDP growth. This translates into projected potential growth in real GDP of 2.6% per year from 2013 to 2017. That's a lot lower than what we saw from 1950 to 2006. Since the labor force participation rate eroded even more than we expected, to 63.7% in July, the U.S. is facing an even lower projected potential growth than 2.6%. We'll need an amazing boost in productivity to make up for it.

Back To School

Why did so many people leave the work force? It wasn't because of retirement, according to the Chicago Fed, which said that only about one-fourth of those who left the work force since 2008 were retirees. The surge in disability claims explains some of the attrition. In the three years since June 2009, when the recovery started, more than 3 million people signed up for disability insurance, about the same number of people who got hired.

The answer may lie in the behavior of younger workers. The labor force participation rate among 20 to 24 year-olds fell to 70.8% in July. That's a 40-year low! It's also below the recent high of 75.6% in 2006 and the all-time high of 79.6% in the beginning of 1987. Either they went back to school or are spending their time watching TV at home with their parents, waiting out the recession. However, non-revolving credit has climbed higher for 24 of the last 25 months, with the gains largely due to student loans. So it looks like many went back to school.

Where Did The Younger Workers Go?
(Labor participation rate by age, percent)



Source: BLS, S&P Economics.

For both the individual and the economy, most studies and data support the notion that more education is a good thing (see "**In Tough Economic Times, Is Higher Education Still Worth The Price?**" published Aug. 16, 2012, on RatingsDirect). The St. Louis Fed found that the return to each additional year of schooling after high school increases hourly wages on average by 8% to 13%. A weaker economy, no doubt, will hurt a new college grad's prospects and income potential. But higher education opens the door to more job opportunities. The unemployment rate for people with a bachelor's degree and higher, at 4.1% in July, is less than half the 8.7% rate for people with only a high school degree and one-third of the 12.7% rate for people with less than that.

Society also stands to gain from an individual's investment in education. Economic theory predicts that education not only increases an individual's own productivity, it boosts the productivity of others through the spillover of knowledge. It also has a positive effect on the wages of others. According to Enrico Moretti, a professor of economics at the University of California, Berkeley, "a percentage point increase in the supply of college graduates raised high school graduates' wages by 1.6%." The educated are also more likely to accept innovation and adopt new technology, a win-win for everyone.

The Consumer Is King

It seems that retail therapy was just what the doctor ordered for American households in July. The 0.8% bounce in retail sales was over twice what the markets had expected, with strength across most sectors. It was about time. Retail sales had contracted for three straight months when consumers kept their wallets closed this spring, not even spending the extra savings they got from lower prices at the gas pump. And even if we assume a modest pullback in core retail sales over the next two months, the July bounce in retail sales will likely provide some nice support to third-quarter growth.

And it wasn't just Team USA that was eager to buy our homemade goods. The June trade data indicated that the world also had an appetite for American products. The U.S. trade deficit narrowed to its lowest level since December 2010. Sluggish U.S. demand and lower oil prices have restrained imports, as we expected. But we also saw a nice uptick in exports to another record high in June. The strong report defied market worries that the global slowdown would cut into sales, but we don't expect the strength in exports to last through the year.

Property Markets Strengthen

The construction sector may be showing signs of life, mostly because of the burgeoning rental market. People have to live somewhere, and if they can't afford to buy, they'll rent. Those who lost their homes in foreclosure are, in a sense, a captive market for multifamily units or apartments. Total construction spending showed a 0.4% month-over-month gain in June. Private residential construction jumped by 1.3% over May and is up 12.1% over last June. While private nonresidential construction activity was up by just 0.1% over May, it's still up 14% over last June.

The housing sector, in particular, appears ready for action after three years on life support. While the recent home sales readings were mixed in June, both existing and new home sales are up over last year and from their troughs. We also expect a 24.5% increase in housing starts in 2012 and a 22.4% increase in 2013, though that's from a low base. Even with those gains, starts are well below the 50-year average rate of 1.5 million units. In addition, the National Association of Realtors' Pending Home Sales index, which is a forward-looking indicator of sales based on contract signings, is near its highest level in two years, suggesting that more sales are coming down the road, which should help give a boost to U.S. GDP in 2012. Furthermore, we think housing prices are nearing the bottom, though we expect them to drop a bit further later this year. This would bring the S&P/Case-Shiller Home Price Index to a new record low.

We lost 9 million jobs during the recession and have gained back only 3 million since the trough in December 2009. That adds up to a lot of empty office space. We have seen some improvement in terms of vacancy rates in the commercial sector, but I don't expect a strong rebound in that area. Office construction picked up modestly, but the publicly financed parts of the industry, including institutional building and the public works sectors, are still suffering the effects of tight state and local budgets. Unfortunately, with governments continuing to mend their balance sheets by firing employees, they don't need buildings to house them. Public construction spending was flat in June and down 3.7% for the year. We expect public spending to continue to contract, although not by enough to completely erase the gains in the private sector. After two straight years of double-digit declines, nonresidential construction activity rose by just 2.7% in 2011, though we expect it to rise another 10.3% this year.

The economic data in July gave our team more hope that the recovery is still in play. People finally spent some of the money they saved at the gas pump, exports were surprisingly strong, and housing continues to heal. The recent news further reduces the chance of another round of quantitative easing in September. It doesn't rule it out, but it certainly gives the Fed a little bit more breathing room to decide while it keeps its powder dry.

It could be that the economic ball ends up in another court. That is, if the eurozone flares up again, China contracts too much, or if our own government can't prevent us from falling off the fiscal cliff—and back into recession.

S&P Economic Outlook

August 2012	**2011**	**2012**										
	Q4	**Q1**	**Q2e**	**Q3e**	**Q4e**	**2009**	**2010**	**2011**	**2012e**	**2013e**	**2014e**	**2015e**
% change												
Real GDP	4.1	2.0	1.5	1.5	1.6	(3.1)	2.4	1.8	2.1	1.8	2.8	3.4
Real final sales	1.5	2.4	1.2	1.7	2.5	(2.3)	0.9	2.0	1.9	2.0	2.8	3.4
Consumer spending	2.0	2.4	1.5	1.8	2.2	(1.9)	1.8	2.5	1.9	2.2	2.5	2.5
Equipment investment	8.8	5.4	7.2	6.8	7.5	(16.4)	8.9	11.0	8.3	7.0	7.2	7.1
Nonresidential	11.5	12.9	0.9	5.3	(1.9)	(21.1)	(15.6)	2.7	10.3	0.6	5.7	6.7

construction												
Residential construction	12.3	21.2	10.1	12.6	9.1	(22.7)	(3.9)	(1.6)	11.9	11.0	20.2	18.7
Federal government	(4.4)	(4.2)	(0.4)	(1.9)	(3.5)	6.1	4.5	(2.8)	(2.8)	(3.1)	(3.0)	(2.1)
S&L government	(0.7)	(2.2)	(2.1)	(0.9)	(1.4)	2.2	(1.8)	(3.4)	(1.7)	(0.8)	0.1	0.5
Exports	1.4	4.4	5.3	2.7	4.7	(9.1)	11.1	6.7	4.0	4.4	5.4	7.5
Imports	4.9	3.1	6.0	3.3	(0.3)	(13.5)	12.5	4.8	3.8	3.8	4.7	4.1
CPI	1.3	2.5	0.8	2.1	0.5	(0.3)	1.6	3.1	2.0	1.6	1.9	1.7
Core CPI	1.9	2.1	2.6	2.4	1.8	1.7	1.0	1.7	2.2	1.9	2.1	2.1
Nonfarm unit labor costs	(3.3)	5.6	1.7	1.5	2.1	(1.4)	(1.1)	1.9	1.2	2.4	2.1	1.8
Nonfarm productivity	2.8	(0.5)	1.6	0.7	0.3	3.0	3.1	0.7	0.9	0.4	1.0	1.4
Levels												
Unemployment rate	8.7	8.3	8.2	8.3	8.2	9.3	9.6	8.9	8.2	8.0	7.7	7.0
Payroll employment (mn)	132.0	132.7	133.0	133.4	133.8	130.8	129.9	131.4	133.2	135.0	137.3	140.0
Federal funds rate	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.3	1.8
10-yr. T-note yield	2.0	2.0	1.8	1.6	1.6	3.3	3.2	2.8	1.8	2.1	3.0	3.9
Aaa corporate bond yield	3.9	3.9	3.8	3.4	3.4	5.3	4.9	4.6	3.6	4.0	4.7	5.5
Mortgage rate (30-year conventional)	4.0	3.9	3.8	3.5	3.4	5.0	4.7	4.5	3.7	3.5	4.5	5.7
3-month T-bill rate	0.0	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.2	1.8
S&P 500 Index	1,226	1,347	1,350	1,371	1,418	947	1,139	1,269	1,372	1,475	1,481	1,554
S&P operating earnings ($/share)	23.73	24.24	25.56	25.81	26.26	56.86	83.77	96.44	101.86	107.41	119.67	127.44
Current account (bil. $)	(475)	(549)	(541)	(525)	(448)	(382)	(442)	(466)	(516)	(443)	(509)	(539)
Exchange rate (major trading partners)	86.3	86.9	88.1	89.0	88.6	92.6	89.8	84.6	88.2	92.5	90.0	87.7
Crude iil ($/bbl, WTI)	94	103	93	87	85	62	79	95	92	90	86	81
Saving rate	3.4	3.6	4.0	4.1	4.0	4.7	5.1	4.3	3.9	3.5	4.0	4.6
Housing starts (mil.)	0.68	0.71	0.74	0.77	0.82	0.55	0.59	0.61	0.76	0.93	1.24	1.54
Unit sales of light vehicles (mil.)	13.5	14.1	14.1	14.1	14.2	10.4	11.6	12.7	14.1	14.8	15.6	16.2
Federal surplus (FY unified, bil. $)	(322)	(457)	(125)	(229)	(292)	(1,416)	(1,294)	(1,297)	(1,133)	(846)	(691)	(626)

e--Estimate. WTI--West Texas Intermediate.

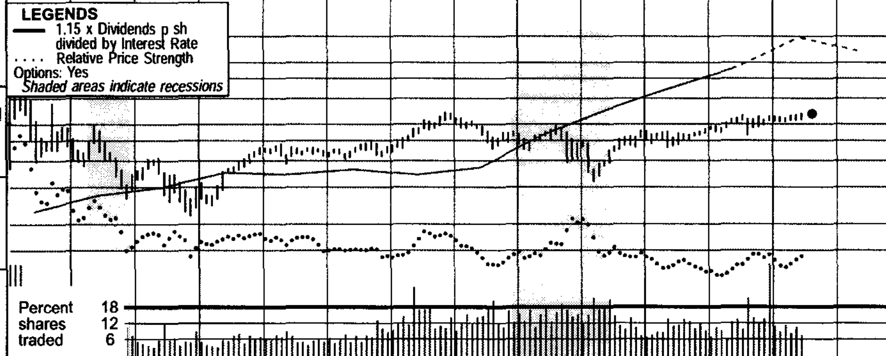
Credit Market Services: Beth Ann Bovino, Deputy Chief Economist, New York (1) 212-438-1652; **bethann_bovino@standardandpoors.com**

AVISTA CORP. NYSE-AVA

RECENT PRICE	26.90	P/E RATIO	14.9 (Trailing: 16.4 / Median: 16.0)	RELATIVE P/E RATIO	1.05	DIV'D YLD	4.4%	VALUE LINE

TIMELINESS 3 Lowered 8/12/11
SAFETY 2 Raised 5/7/10
TECHNICAL 3 Raised 7/13/12
BETA .70 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	24.0	16.6	18.7	19.4	20.2	27.5	25.8	23.6	22.4	22.8	26.5	27.8				
Low:	10.6	8.8	9.8	15.4	16.3	17.6	18.2	15.5	12.7	18.5	21.1	24.5				



Target Price Range

2015	2016	2017
64	48	40
32	24	20
16	12	8
6		

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+30%)	10%
Low	25	(-5%)	3%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	1	0	5	1	0	0
to Sell	2	0	3	1	0	7	3	0	1

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	88	82	77
to Sell	85	93	85
Hld's(000)	40696	40895	41881

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.8	-4.1
3 yr.	72.1	68.8
5 yr.	53.3	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.89	23.27	91.07	221.75	167.59	126.17	20.41	23.24	23.76	27.98	28.68	26.80	30.77	27.58	27.29	27.73	*26.65*	*28.10*	Revenues per sh	*32.25*
2.64	3.20	3.47	2.28	3.31	2.71	2.19	2.63	2.35	2.72	4.27	2.93	3.98	4.45	3.62	3.78	*3.90*	*4.15*	"Cash Flow" per sh	*5.00*
1.35	1.96	1.28	.12	1.76	1.20	.67	1.02	.73	.92	1.47	.72	1.36	1.58	1.65	1.72	*1.80*	*1.90*	Earnings per sh A	*2.25*
1.24	1.24	1.05	.48	.48	.48	.48	.49	.52	.55	.57	.60	.69	.81	1.00	1.10	*1.16*	*1.22*	Div'd Decl'd per sh B ■ †	*1.40*
1.67	1.82	2.70	3.30	4.24	5.92	1.74	2.21	2.47	3.23	3.14	4.04	4.09	3.86	3.64	4.20	*4.40*	*4.25*	Cap'l Spending per sh	*4.50*
12.70	13.38	11.76	10.69	15.34	15.12	14.84	15.54	15.54	15.87	17.46	17.27	18.30	19.17	19.71	20.30	*21.10*	*21.80*	Book Value per sh C	*24.00*
55.96	55.96	40.45	35.65	47.21	47.63	48.04	48.34	48.47	48.59	52.51	52.91	54.49	54.84	57.12	58.42	*60.00*	*60.50*	Common Shs Outst'g D	*62.00*
13.8	10.0	16.5	NMF	13.6	13.7	19.3	13.8	24.4	19.4	15.4	30.9	15.0	11.4	12.7	14.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*13.0*
.86	.58	.86	NMF	.88	.70	1.05	.79	1.29	1.03	.83	1.64	.90	.76	.81	.89	*estimates*		Relative P/E Ratio	*.85*
6.7%	6.4%	5.0%	2.8%	2.0%	2.9%	3.7%	3.5%	2.9%	3.0%	2.5%	2.7%	3.4%	4.5%	4.8%	4.5%			Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1369.3 mill. **Due in 5 Yrs** $201.0 mill.
LT Debt $1300.9 mill. **LT Interest** $68.2 mill.
Incl. $51.5 mill. debt to affiliated trusts; $29.2 mill. nonrecourse debt.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/11 $328.2 mill. **Oblig.** $494.2 mill.
Pfd Stock None
Common Stock 58,674,851 shs. as of 4/23/12
MARKET CAP: $1.6 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
980.4	1123.4	1151.6	1359.6	1506.3	1417.8	1676.8	1512.6	1558.7	1619.8	*1600*	*1700*	Revenues ($mill)	*2000*
34.3	51.8	37.8	47.2	75.1	38.5	73.6	87.1	92.4	100.2	*110*	*120*	Net Profit ($mill)	*140*
46.6%	40.5%	36.4%	35.4%	35.9%	38.7%	38.3%	34.3%	35.0%	35.4%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
21.8%	2.1%	3.7%	3.6%	3.9%	22.4%	14.0%	4.2%	4.0%	5.2%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
57.3%	57.1%	56.5%	58.0%	53.7%	41.0%	48.1%	50.9%	51.6%	51.4%	*50.5%*	*50.5%*	Long-Term Debt Ratio	*52.0%*
40.8%	41.3%	41.9%	40.6%	46.3%	59.0%	51.9%	49.1%	48.4%	48.6%	*49.5%*	*49.5%*	Common Equity Ratio	*48.0%*
1748.7	1819.4	1796.2	1900.8	1980.1	1548.9	1919.5	2139.0	2325.3	2439.9	*2550*	*2665*	Total Capital ($mill)	*3100*
1563.7	1944.6	1956.1	2126.4	2215.0	2351.3	2492.2	2607.0	2714.2	2860.8	*3000*	*3120*	Net Plant ($mill)	*3475*
4.8%	5.2%	4.3%	4.8%	6.1%	5.2%	5.8%	5.5%	5.4%	5.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*6.0%*
4.6%	6.6%	4.8%	5.9%	8.2%	4.2%	7.4%	8.3%	8.2%	8.5%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
4.5%	6.6%	4.7%	5.9%	8.0%	4.2%	7.4%	8.3%	8.2%	8.5%	*8.5%*	*9.0%*	Return on Com Equity E	*9.0%*
1.2%	3.4%	1.4%	2.4%	4.9%	.8%	3.7%	4.1%	3.3%	3.1%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
74%	50%	72%	60%	40%	82%	50%	51%	60%	64%	*63%*	*62%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-.8	-1.1	+2.0
Avg. Indust. Use (MWH)	1397	1525	1556
Avg. Indust. Revs. per KWH (¢)	5.53	5.47	5.71
Capacity at Peak (Mw)	2514	2905	2923
Peak Load, Winter (Mw)	2371	2507	2381
Annual Load Factor (%)	61.0	60.0	61.0
% Change Customers (yr-end)	+.5	+.7	+.4
Fixed Charge Cov. (%)	299	301	318

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-16.5%	.5%	*2.5%*
"Cash Flow"	3.5%	5.0%	*4.0%*
Earnings	5.0%	9.5%	*5.5%*
Dividends	7.5%	12.5%	*6.5%*
Book Value	3.5%	4.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	487.5	307.1	314.7	403.3	1512.6
2010	456.4	360.7	367.2	374.4	1558.7
2011	476.6	360.6	343.7	438.9	1619.8
2012	452.3	*350*	*350*	*447.7*	*1600*
2013	*475*	*375*	*375*	*475*	*1700*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.57	.47	.15	.40	1.58
2010	.52	.46	.22	.45	1.65
2011	.73	.39	.18	.42	1.72
2012	.65	*.45*	*.20*	*.50*	*1.80*
2013	*.70*	*.48*	*.22*	*.50*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.165	.165	.18	.18	.69
2009	.18	.21	.21	.21	.81
2010	.25	.25	.25	.25	1.00
2011	.275	.275	.275	.275	1.10
2012	.29	.29			

BUSINESS: Avista Corporation (formerly The Washington Water Power Company) supplies electricity & gas in eastern Washington & northern Idaho. Supplies gas to part of Oregon. Customers: 360,000 electric, 321,000 gas. Has nonutility subsidiary (Ecova) involved in energy-management services. Electric revenue breakdown: residential, 33%; commercial, 28%; industrial, 12%; wholesale, 8%; other, 19%. Generating sources: hydro, 37%; coal, 11%; gas, 6%; wood waste, 2%; purchased, 44%. Fuel costs: 49% of revenues. '11 reported deprec. rate (utility): 2.9%. Has 2,800 employees. Chairman, President & CEO: Scott L. Morris. Inc.: Washington. Address: 1411 E. Mission Ave., Spokane, Washington 99202-2600. Tel.: 509-489-0500. Internet: www.avistacorp.com.

Avista has a general rate case pending in Washington. The utility requested an electric tariff hike of $41.0 million (8.8%) and a gas rate increase of $10.1 million (6.8%). Avista based its application on a 10.9% return on a 48.4% common-equity ratio. Unless the utility is able to reach a settlement, new rates will go into effect in early March.

Avista plans to file a rate case in Idaho, as well. Tariffs there are frozen until April 1, 2013. We expect the utility to put forth its petition in September, so that any rate hike can go into effect as soon as possible.

There is a good reason for all of this regulatory activity. Due to the effects of regulatory lag, Avista has not earned an adequate return on equity for many years. In fact, the utility's petition in Washington occurred just three months after electric and gas rate increases took effect in the state. At least, earned ROEs are showing signs of improvement. These have exceeded 8% in each of the past three years, and we figure that they will continue to get better.

Earnings should increase this year and next. The aforementioned rate hike in Washington ($20 million electric, $3.75 million gas) is a key reason. Our 2012 profit estimate is within Avista's targeted range of $1.65-$1.85 a share. Rate relief should help boost the bottom line in 2013, as well. On the nonregulated side of the business, the Ecova energy-services subsidiary should continue to benefit from acquisitions that are enabling it to provide a new array of services to its customers. Avista's guidance includes $0.16-$0.19 a share of income from Ecova, at least as much as the $0.16 a share it contributed in 2011.

Financing needs are modest. Avista entered into a purchase agreement to issue $80 million of bonds in November. This will probably be the company's only long-term debt financing this year. The company also expects to issue up to $45 million of common equity in 2012 through its "dribble" program.

We regard this stock as an average utility selection. The dividend yield and 3- to 5-year total return potential are comparable with the industry averages.

Paul E. Debbas, CFA *August 3, 2012*

(A) Dil. EPS. Excl. nonrec. losses: '00, 27¢; '02, 9¢; '03, 3¢; gain (losses) on disc. ops.: '01, ($1.00); '02, 2¢; '03, (10¢). '09 EPS don't add due to rounding. Next egs. report due early Aug. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. def'd chgs. In '11: $9.69/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in WA in '12: none specified; in ID in '10: none specified; earned on avg. com. eq., '11: 8.7%. Regulatory Climate: WA, Avg.; ID, Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	65

BLACK HILLS CORP. NYSE-BKH

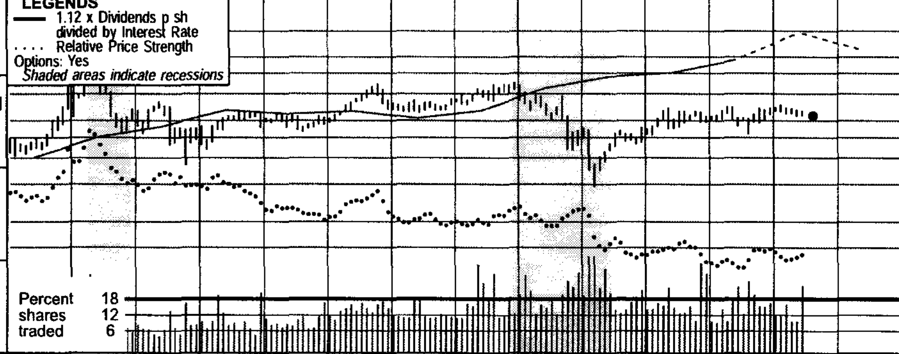
RECENT PRICE 31.60 | P/E RATIO 14.4 (Trailing: 41.0; Median: 17.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 2/12/10
SAFETY 3 Lowered 8/15/03
TECHNICAL 4 Lowered 6/29/12
BETA .85 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	58.5	36.9	33.5	32.5	44.6	37.9	45.4	44.0	28.0	34.5	34.8	35.8
Low:	26.0	18.3	21.8	26.5	29.2	32.5	35.4	21.7	14.5	25.7	25.8	30.3

Target Price Range 2015 | 2016 | 2017

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



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	10%
Low	25	(-20%)	Nil

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	73	67	82
to Sell	76	70	65
Hld's(000)	29150	28653	29480

Percent shares traded 18 12 6

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.9	-4.1
3 yr.	62.0	68.8
5 yr.	3.0	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
7.50	14.45	31.48	37.05	69.69	57.96	15.74	35.17	34.54	41.97	19.69	18.41	26.03	32.58	33.29	28.96	*29.05*	*31.30*	Revenues per sh	*35.25*
2.45	2.52	2.72	2.88	3.68	5.27	4.93	4.26	4.46	4.81	5.04	5.29	2.95	5.41	4.88	4.01	*5.45*	*5.70*	"Cash Flow" per sh	*6.75*
1.40	1.49	1.60	1.70	2.37	3.42	2.33	1.84	1.74	2.11	2.21	2.68	.18	2.32	1.66	1.01	*2.20*	*2.20*	Earnings per sh A	*2.50*
.92	.95	1.00	1.04	1.08	1.12	1.16	1.20	1.24	1.28	1.32	1.37	1.40	1.42	1.44	1.46	*1.48*	*1.50*	Div'd Decl'd per sh B ■	*1.60*
1.13	.98	1.18	4.89	5.79	14.07	8.65	2.80	2.80	4.18	9.24	6.92	8.51	8.90	12.04	10.03	*8.95*	*10.60*	Cap'l Spending per sh	*9.00*
8.91	9.46	9.58	10.14	11.95	18.95	19.66	21.72	22.43	22.29	23.68	25.66	27.19	27.84	28.02	27.53	*28.00*	*28.65*	Book Value per sh C	*31.00*
21.68	21.70	21.58	21.37	23.30	26.89	26.93	32.30	32.48	33.16	33.37	37.80	38.64	38.97	39.27	43.92	*44.20*	*44.40*	Common Shs Outst'g D	*45.00*
11.9	13.0	14.9	13.6	10.9	11.4	12.5	15.9	17.1	17.3	15.8	15.0	NMF	9.9	18.1	31.1	Bold figures are		Avg Ann'l P/E Ratio	*13.5*
.75	.75	.77	.78	.71	.58	.68	.91	.90	.92	.85	.80	NMF	.66	1.15	1.96	Value Line		Relative P/E Ratio	*.90*
5.5%	4.9%	4.2%	4.5%	4.2%	2.9%	4.0%	4.1%	4.2%	3.5%	3.8%	3.4%	4.2%	6.2%	4.8%	4.6%	estimates		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1506.0 mill. Due in 5 Yrs $911.0 mill.
LT Debt $1272.0 mill. LT Interest $78.9 mill.
(LT interest earned: 1.5x)
Leases, Uncapitalized Annual rentals $2.8 mill.

Pension Assets-12/11 $221.7 mill.
Oblig. $325.9 mill.

Pfd Stock None

Common Stock 44.1 mill. shs.

MARKET CAP: $1.4 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
423.9	1136.1	1121.7	1391.6	656.9	695.9	1005.8	1269.6	1307.3	1272.2	*1285*	*1390*	Revenues ($mill)	*1590*
63.2	57.1	57.2	70.3	74.0	100.1	6.8	89.7	64.6	40.4	*95.0*	*100*	Net Profit ($mill)	*115*
31.9%	34.4%	31.8%	33.8%	31.3%	31.3%	33.1%	30.7%	26.4%	31.1%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
18.2%	.7%	.3%	1.0%	9.7%	14.8%	173.2%	20.1%	28.0%	65.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*9.0%*
53.6%	55.0%	49.9%	47.6%	44.3%	36.8%	32.3%	48.4%	51.9%	51.4%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*50.5%*
45.9%	44.5%	49.6%	52.4%	55.7%	63.2%	67.7%	51.6%	48.1%	48.6%	*53.0%*	*53.0%*	Common Equity Ratio	*49.5%*
1154.0	1578.2	1469.3	1409.1	1418.4	1534.2	1551.8	2100.7	2286.3	2489.7	*2340*	*2410*	Total Capital ($mill)	*2825*
1476.3	1442.4	1445.7	1435.4	1646.4	1823.5	2022.2	2160.7	2495.4	2789.6	*3040*	*3355*	Net Plant ($mill)	*4000*
6.6%	4.8%	5.3%	6.6%	6.8%	7.9%	1.6%	5.9%	4.4%	3.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
11.8%	8.0%	7.8%	9.5%	9.4%	10.3%	.7%	8.3%	5.9%	3.3%	*8.0%*	*7.5%*	Return on Shr. Equity	*8.0%*
11.9%	8.1%	7.8%	9.5%	9.4%	10.3%	.7%	8.3%	5.9%	3.3%	*8.0%*	*7.5%*	Return on Com Equity E	*8.0%*
6.0%	2.8%	2.3%	3.8%	3.8%	5.1%	NMF	3.2%	.7%	NMF	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
50%	65%	71%	60%	59%	50%	NMF	62%	87%	NMF	*67%*	*68%*	All Div'ds to Net Prof	*63%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	+24.7	+2.9	+1.3
Avg. Indust. Use (MWH)	7542	8489	8113
Avg. Indust. Revs. per KWH (¢)	6.34	6.95	7.58
Capacity at Yearend (Mw)	1060	1127	1315
Peak Load, Summer (Mw)	921	956	1025
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.5	-.1	+.3
Fixed Charge Cov. (%)	149	174	160

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-5.5%	-.5%	2.0%
"Cash Flow"	2.0%	--	6.0%
Earnings	-4.0%	-4.0%	7.0%
Dividends	3.0%	2.5%	2.0%
Book Value	7.5%	4.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.9	257.4	225.8	348.5	1269.6
2010	442.3	271.3	264.4	329.3	1307.3
2011	400.8	260.7	249.5	361.2	1272.2
2012	365.9	*280*	*275*	*364.1*	*1285*
2013	*420*	*295*	*290*	*385*	*1390*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.94	.64	d.10	.84	2.32
2010	.81	d.22	.22	.85	1.66
2011	.73	.09	d.29	.44	1.01
2012	.80	*.35*	*.40*	*.65*	*2.20*
2013	*.70*	*.40*	*.45*	*.65*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.35	.35	.35	.35	1.40
2009	.355	.355	.355	.355	1.42
2010	.36	.36	.36	.36	1.44
2011	.365	.365	.365	.365	1.46
2012	.37	.37			

BUSINESS: Black Hills Corporation is a holding company for utilities that serve 201,000 electric customers in CO, SD, WY and MT, and 564,000 gas customers in NE, IA, KS, CO and WY. Electric revenue breakdown: res'l, 31%; comm'l, 35%; ind'l, 12%; wholesale, 13%; other, 9%. Generating sources: coal, 38%; purchased, 62%. Mines coal & has a gas & oil E&P business. Acq'd Wickford Energy Mktg. 7/97 (discontinued in '11); Mallon Resources 3/03; Cheyenne Light 1/05; utility ops. from Aquila 7/08. Discont. telecom in '05; oil mktg. in '06. Fuel costs: 45% of revs. '11 depr. rate: 3.6%. Has 2,000 empls. Chairman, President & CEO: David R. Emery. Inc.: SD. Address: P.O. Box 1400, 625 Ninth St., Rapid City, SD 57701. Tel.: 605-721-1700. Internet: www.blackhillscorp.com.

One of Black Hills' utility subsidiaries received a rate order in Wyoming. The state commission granted Cheyenne Light, Fuel & Power tariff hikes of $2.7 million (2.7%) for electricity and $1.6 million (4.9%) for gas, based on a return of 9.6% on a common-equity ratio of 54%. New rates took effect at the start of July.

Another regulatory matter is pending in the state. The company is asking the commission for permission to build 132 megawatts of gas-fired generating capacity at an estimated cost of $237 million. The targeted in-service date is in 2014. A ruling is expected by yearend.

Another utility subsidiary filed a general rate case. Black Hills Energy asked the Colorado regulators for a $1.0 million (4.9%) gas base rate increase, based on a 10.25% return on equity. When a decision will be announced is not known.

As always, mark-to-market gains or losses will affect the company's earnings. These items arise from interest-rate swaps. Because they are ongoing each quarter, we *include* them in our earnings presentation, but because they are impossible to predict, we don't assume any in our estimates. (Management excludes them from its earnings guidance.) Mark-to-market items hurt 2011 profits by $0.68 a share (primarily in the third quarter), but added $0.18 a share to March-quarter 2012 results. That's why our $2.20-a-share earnings estimate for the full year is above Black Hills' targeted range of $1.90-$2.10. We estimate the same level of profits next year. Rate relief is a positive factor, but low natural gas prices are hurting the company's gas exploration and production subsidiary.

Black Hills raised $166.3 million from the sale of its energy marketing business in the first quarter. These funds will enable the company to avoid an equity issuance this year. Black Hills recorded a $0.12-a-share loss from discontinued operations in the period.

This stock's dividend yield is fractionally above the utility average. However, we project only modest dividend growth over the 3- to 5-year period, and with the share price already near the midpoint of our 2015-2017 Target Price Range, total return potential is unspectacular.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted EPS. Excl. nonrec. gain (losses): '05, (99¢); '08, ($1.55); '09, (28¢); '10, 10¢; gains (losses) on disc. ops.: '03, 30¢; '04, 2¢; '05, (7¢); '06, 21¢; '07, (4¢); '08, $4.12; '09, 7¢; '11, 23¢; '12, (12¢). '11 EPS don't add due to chg. in shs. Next egs. due early Nov. (B) Div'ds paid in early Mar., Jun., Sept. and Dec. ■ Div'd reinv. plan avail. (C) Incl. def'd chgs. In '11: $12.28/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate all'd on com. eq. in SD in '10: none spec.; in CO in '12: 9.8%-10.2%; earn. on avg. com. eq., '11: 3.5%. Reg. Climate: Above Avg.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	35

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE 45.33 | P/E RATIO 16.5 (Trailing: 15.7; Median: 12.0) | RELATIVE P/E RATIO 1.16 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Lowered 3/11/11

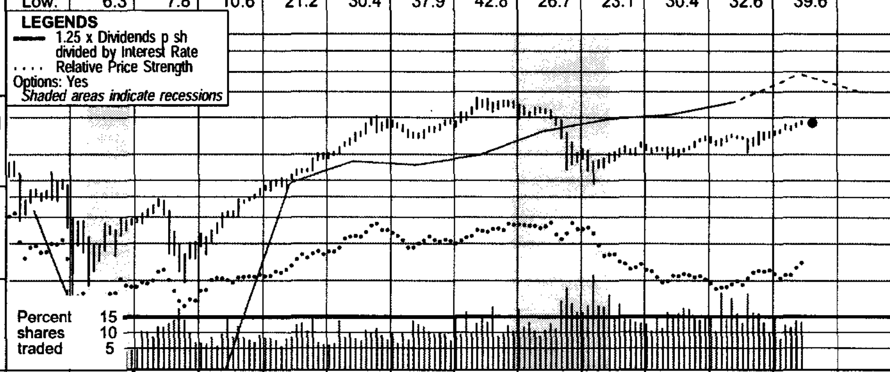
SAFETY 3 Raised 11/11/05

TECHNICAL 4 Lowered 7/6/12

BETA .80 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	16.1	19.6	22.1	32.5	49.2	47.2	60.3	55.7	36.7	39.4	41.6	46.8
Low:	6.3	7.8	10.6	21.2	30.4	37.9	42.8	26.7	23.1	30.4	32.6	39.6

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



Target Price Range 2015 | 2016 | 2017

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

Percent shares traded 15 · 10 · 5

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+20%)	8%
Low	35	(-25%)	-2%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	168	193	168
to Sell	183	186	210
Hld's(000)	251875	250890	253559

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.0	-4.1
3 yr.	62.6	68.8
5 yr.	-3.1	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
20.13	24.58	29.12	27.85	35.96	35.10	35.26	37.25	31.30	36.38	38.74	40.25	43.31	37.98	38.09	39.16	*40.20*	*41.75*	Revenues per sh	*51.50*
4.45	5.49	6.65	7.20	d.52	4.35	4.79	5.88	3.79	6.99	7.25	7.60	8.08	7.96	8.41	9.03	*8.90*	*9.40*	"Cash Flow" per sh	*11.50*
1.64	1.75	1.86	2.03	d5.84	1.30	1.82	2.38	.69	3.34	3.28	3.32	3.68	3.24	3.35	3.23	*2.75*	*2.80*	Earnings per sh A	*3.50*
1.00	1.00	1.04	1.08	.83	--	--	--	.80	1.02	1.10	1.18	1.23	1.25	1.27	1.29	*1.31*	*1.33*	Div'd Decl'd per sh B ■	*1.55*
1.75	2.08	2.75	3.55	4.57	2.86	4.88	3.95	5.32	5.73	7.78	8.67	8.67	10.07	13.94	14.76	*16.65*	*14.15*	Cap'l Spending per sh	*13.75*
15.07	14.71	14.55	15.01	7.43	10.04	13.62	16.52	18.57	20.30	23.66	25.92	29.21	30.20	32.44	30.86	*32.25*	*33.65*	Book Value per sh C	*38.75*
424.52	375.76	350.55	347.21	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	*325.81*	*325.81*	Common Shs Outst'g D	*325.81*
10.8	13.7	15.1	12.9	--	10.0	7.8	7.0	37.6	11.7	13.0	16.0	12.4	9.7	10.3	11.8	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*12.5*
.68	.79	.79	.74	--	.51	.43	.40	1.99	.62	.70	.85	.75	.65	.66	.75	*estimates*		Relative P/E Ratio	*.85*
5.7%	4.2%	3.7%	4.1%	3.9%	--	--	--	3.1%	2.6%	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%			Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $14535 mill. **Due in 5 Yrs** $3993.0 mill.
LT Debt $14131 mill. **LT Interest** $826.0 mill.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $1.25 bill.
Pension Assets-12/11 $3.15 bill. **Oblig.** $4.49 bill.
Pfd Stock $1374 mill. **Pfd Div'd** $81.0 mill.
4,800,198 shs. 4.08%-4.78%, $25 par, call. $25.50-$28.75/sh. 8,000,000 shs. 5.349%-6.125%, $100 par; 1,250,000 shs. 6.5%, $100 liquidation value; 350,000 shs. 6.25%, $1000 liquidation value.
Common Stock 325,811,206 shs.
as of 4/30/12
MARKET CAP: $15 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
11488	12135	10199	11852	12622	13113	14112	12374	12409	12760	*13100*	*13600*	Revenues ($mill)	*16750*
644.0	738.0	220.0	1132.0	1134.0	1151.0	1266.0	1115.0	1153.0	1112.0	*980*	*1000*	Net Profit ($mill)	*1240*
37.8%	22.4%	--	26.0%	31.4%	27.3%	30.7%	33.0%	32.1%	25.7%	*26.0%*	*26.0%*	Income Tax Rate	*26.0%*
3.3%	3.7%	11.4%	4.9%	5.1%	8.2%	8.9%	10.5%	16.9%	14.8%	*15.0%*	*15.0%*	AFUDC % to Net Profit	*12.0%*
66.6%	68.1%	60.5%	54.6%	51.3%	49.1%	51.2%	49.3%	51.8%	55.3%	*54.5%*	*55.5%*	Long-Term Debt Ratio	*56.0%*
25.6%	31.1%	37.8%	40.9%	43.5%	46.0%	44.5%	46.5%	44.3%	40.6%	*40.5%*	*39.5%*	Common Equity Ratio	*40.0%*
17352	17299	15995	16167	17725	18375	21374	21185	23861	24773	*25925*	*27625*	Total Capital ($mill)	*31600*
8247.0	12587	13475	14469	15913	17403	18969	21966	24778	32116	*35525*	*38000*	Net Plant ($mill)	*43500*
6.7%	7.2%	4.2%	9.4%	8.6%	8.3%	7.4%	6.9%	6.3%	6.0%	*5.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
11.1%	13.4%	3.5%	15.4%	13.1%	12.3%	12.1%	10.4%	10.0%	10.0%	*8.5%*	*8.0%*	Return on Shr. Equity	*9.0%*
11.9%	13.6%	3.5%	16.7%	14.0%	13.0%	12.8%	10.8%	10.4%	10.5%	*8.5%*	*8.5%*	Return on Com Equity E	*9.0%*
11.9%	13.6%	NMF	12.2%	10.1%	9.2%	8.6%	6.7%	6.5%	6.3%	*4.5%*	*4.5%*	Retained to Com Eq	*5.0%*
18%	1%	121%	29%	31%	33%	35%	41%	40%	43%	*51%*	*51%*	All Div'ds to Net Prof	*47%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.4	-2.7	+.9
Avg. Indust. Use (MWH)	669	710	736
Avg. Indust. Revs. per KWH (¢)	6.95	7.38	7.09
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22112	22771	22374
Annual Load Factor (%)	53.4	50.7	50.7
% Change Customers (yr-end)	+.4	+.5	+.4
Fixed Charge Cov. (%)	268	240	209

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	1.5%	*5.0%*
"Cash Flow"	8.5%	7.0%	*5.0%*
Earnings	--	6.0%	*1.0%*
Dividends	7.0%	5.5%	*3.5%*
Book Value	11.0%	8.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2812	2834	3678	3050	12374
2010	2810	2742	3788	3069	12409
2011	2782	2983	3981	3014	12760
2012	2856	*3094*	*4050*	*3100*	*13100*
2013	*3025*	*3200*	*4175*	*3200*	*13600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.78	.78	1.08	.59	3.24
2010	.70	.62	1.46	.58	3.35
2011	.62	.54	1.31	.76	3.23
2012	.28	*.47*	*1.40*	*.60*	*2.75*
2013	*.60*	*.50*	*1.15*	*.55*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.305	.305	.305	.305	1.22
2009	.31	.31	.31	.31	1.24
2010	.315	.315	.315	.315	1.26
2011	.32	.32	.32	.32	1.28
2012	.325	.325	.325		

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison (SCE), which supplies electricity to 4.9 million customers in a 50,000 sq. mi. area in central, coastal, and southern California (excl. Los Angeles and San Diego). Edison Mission Group (EMG) is an independent power producer. Electric revenue breakdown: residential, 40%; commercial, 42%; industrial, 6%; other, 12%. Generating sources: nuclear, 24%; coal, 7%; gas, 6%; hydro, 6%; purchased, 57%. Fuel costs: 33% of revs. '11 reported deprec. rate (utility): 4.2%. Has 19,900 employees. Chairman, President & CEO: Theodore F. Craver, Jr. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Internet: www.edison.com.

Edison International's nonregulated generating assets are being hurt by low power prices and more-stringent environmental rules. Edison Mission Group (EMG), the company's nonutility subsidiary, lost $0.07 a share in 2011 (excluding sizable one-time charges) and $0.26 a share in the first quarter of 2012. EMG was unable to obtain financing for environmental upgrades to the Homer City coal-fired plant in Pennsylvania, and intends to transfer Homer City to its owner-lessors. The company also plans to close two coal-fired facilities in Chicago in September. At this juncture, management is evaluating the future of EMG.

Southern California Edison (SCE) is still waiting for an order in its general rate case. The utility is seeking rate hikes of $809 million, $117 million, and $513 million in 2012, 2013, and 2014, respectively. No matter when the order comes out, new tariffs will be retroactive to the start of 2012. Management won't provide earnings guidance until the California Public Utilities Commission (CPUC) issues its decision.

A cost-of-capital application is pending. SCE proposed an allowed return on equity of 11.1% and a 48% common-equity ratio. The allowed ROE would be adjusted if there is a significant change in interest rates. If the utility's request is granted, this would reduce annual rates by $128 million due in part to a lower allowed ROE than the current 11.5%. The CPUC's order is expected in late 2012, and will take effect at the start of 2013.

The San Onofre nuclear station is out of service. SCE might be able to recover the replacement power costs stemming from the unplanned outage (subject to a CPUC review), but the repair costs will hurt pretax income by an estimated $55 million-$65 million in 2012. It is unknown when the plant will return to service.

More-attractive utility selections are available elsewhere. The stock's yield is more than a percentage point below the industry average, and the dividend growth we project over the 3- to 5-year period probably won't be enough to provide a good total return. Moreover, the quotation is near the midpoint of our 2015-2017 Target Price Range.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '01, $1.88; '02, $1.48; '03, (12¢); '04, $2.12; '09, (64¢); '10, 54¢; '11, ($3.33); gain (losses) from disc. ops.: '07, (1¢); '09, (2¢); '10, 1¢; '11, (1¢). Incl. nonrec. losses: '00, $7.58; '01, $1.88. '09 & '10 EPS don't add due to rounding. Next egs. due early Nov. (B) Div'ds paid late Jan., Apr., July & Oct. ■ Div'd reinv. plan avail. (C) Incl. def'd charges. In '11: $16.78/sh. (D) In mill. (E) Rate base: net orig. cost. Rate all'd on com. eq. in '08: 11.5%; earned on avg. com. eq., '11: 9.7%. Reg. Climate: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	75
Earnings Predictability	80

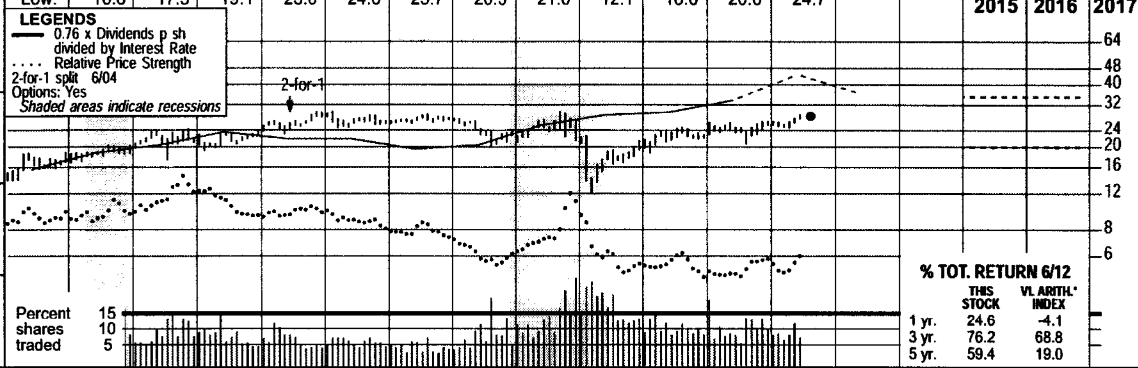
HAWAIIAN ELECTRIC NYSE-HE

RECENT PRICE 28.20 | P/E RATIO 17.6 (Trailing: 18.3 / Median: 19.0) | RELATIVE P/E RATIO 1.24 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 2 Raised 11/18/11
SAFETY 3 Lowered 5/8/09
TECHNICAL 3 Raised 8/3/12
BETA .70 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	20.6	24.5	24.0	29.5	29.8	28.9	27.5	29.8	22.7	25.0	26.8	29.2
Low:	16.8	17.3	19.1	23.0	24.6	25.7	20.3	21.0	12.1	18.6	20.6	24.7

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+25%)	10%
Low	20	(-30%)	-2%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	72	102	93
to Sell	86	73	77
Hld's(000)	36149	34567	35033

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.6	-4.1
3 yr.	76.2	68.8
5 yr.	59.4	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.86	22.95	23.12	23.64	26.05	24.26	22.46	23.49	23.85	27.36	30.21	30.40	35.56	24.96	28.14	33.76	34.70	33.15	Revenues per sh	32.00
2.81	3.01	3.23	3.35	3.08	3.33	3.52	3.54	3.09	3.22	3.19	3.01	2.72	2.59	2.88	3.18	3.40	3.40	"Cash Flow" per sh	3.75
1.30	1.38	1.48	1.45	1.27	1.60	1.62	1.58	1.36	1.46	1.33	1.11	1.07	.91	1.21	1.44	1.60	1.70	Earnings per sh A	2.00
1.21	1.22	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	Div'd Decl'd per sh B ■ †	1.40
3.33	2.31	2.60	2.09	2.04	1.77	1.74	2.15	2.66	2.76	2.58	2.62	3.12	3.29	1.92	2.45	3.55	4.15	Cap'l Spending per sh	7.50
12.52	12.77	12.87	13.16	12.72	13.06	14.21	14.36	15.01	15.02	13.44	15.29	15.35	15.58	15.67	15.95	16.45	17.45	Book Value per sh C	20.25
61.71	63.79	64.23	64.43	65.98	71.20	73.62	75.84	80.69	80.98	81.46	83.43	90.52	92.52	94.69	96.04	98.00	104.00	Common Shs Outst'g D	122.00
13.7	13.2	13.4	12.1	12.9	11.8	13.5	13.8	19.2	18.3	20.3	21.6	23.2	19.8	18.6	17.1	Bold figures are		Avg Ann'l P/E Ratio	13.5
.86	.76	.70	.69	.84	.60	.74	.79	1.01	.97	1.10	1.15	1.40	1.32	1.18	1.08	Value Line		Relative P/E Ratio	.90
6.8%	6.7%	6.2%	7.1%	7.5%	6.6%	5.7%	5.7%	4.8%	4.6%	4.6%	5.2%	5.0%	6.9%	5.5%	5.0%	estimates		Avg Ann'l Div'd Yield	5.1%
						1653.7	1781.3	1924.1	2215.6	2460.9	2536.4	3218.9	2309.6	2665.0	3242.3	3400	3450	Revenues ($mill)	3900
						120.2	120.1	109.6	120.3	109.9	93.6	92.2	84.9	115.4	140.1	160	175	Net Profit ($mill)	250
						34.6%	34.9%	45.8%	36.4%	36.5%	35.4%	34.7%	34.1%	37.0%	35.1%	35.0%	34.0%	Income Tax Rate	29.0%
						4.8%	5.1%	7.6%	5.9%	8.4%	8.3%	14.2%	20.6%	7.4%	6.0%	5.0%	7.0%	AFUDC % to Net Profit	43.0%
						52.0%	48.6%	47.6%	45.2%	49.9%	47.6%	46.0%	48.0%	44.5%	44.9%	45.5%	40.5%	Long-Term Debt Ratio	45.0%
						46.5%	49.8%	51.0%	53.3%	48.6%	51.0%	52.7%	50.7%	54.3%	53.9%	53.5%	58.5%	Common Equity Ratio	54.0%
						2251.0	2186.9	2375.1	2283.9	2252.7	2501.8	2635.2	2840.8	2732.9	2841.3	3020	3105	Total Capital ($mill)	4575
						2079.3	2311.9	2422.3	2542.8	2647.5	2743.4	2907.4	3088.6	3165.9	3334.5	3505	3750	Net Plant ($mill)	5525
						7.3%	7.3%	6.0%	6.8%	6.4%	5.2%	4.7%	4.3%	5.6%	6.2%	6.5%	6.5%	Return on Total Cap'l	6.5%
						11.1%	10.7%	8.8%	9.6%	9.7%	7.1%	6.5%	5.8%	7.6%	8.9%	9.5%	9.5%	Return on Shr. Equity	10.0%
						11.3%	10.8%	8.9%	9.7%	9.9%	7.2%	6.5%	5.8%	7.7%	9.0%	10.0%	9.5%	Return on Com Equity E	10.0%
						4.3%	3.9%	1.1%	1.5%	.7%	.8%	.5%	NMF	1.4%	2.1%	2.5%	2.5%	Retained to Com Eq	3.5%
						63%	64%	87%	85%	93%	89%	93%	116%	82%	78%	77%	73%	All Div'ds to Net Prof F	67%

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1438.9 mill. **Due in 5 Yrs** $369.8 mill.
LT Debt $1282.6 mill. **LT Interest** $66.7 mill.
Incl. $50 mill. 6.5% oblig. pfd. sec. of trust subsid.
(LT interest earned: 3.9x)
Pension Assets-12/11 $839.6 mill.
Oblig. $1.32 bill.
Pfd Stock $34.3 mill. **Pfd Div'd** $2.0 mill.
1,114,657 shs. 4¼% to 5¼%, $20 par. call. $20 to $21; 120,000 shs. 7⅝%, $100 par. call. $100.
Sinking fund ends 2018.
Common Stock 96,602,192 shs.
as of 4/29/12
MARKET CAP: $2.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.5	-1.1	-.5
Avg. Indust. Use (MWH)	6403	6352	6284
Avg. Indust. Revs. per KWH (¢)	17.68	21.41	27.89
Capacity at Yearend (Mw)	2347	2325	2327
Peak Load, Winter (Mw)	1618	1562	1530
Annual Load Factor (%)	72.2	73.9	74.8
% Change Customers (yr-end)	+.5	+.5	+.3
Fixed Charge Cov. (%)	234	300	337

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	1.5%	1.5%
"Cash Flow"	-1.0%	-2.0%	4.5%
Earnings	-2.0%	-3.0%	9.0%
Dividends	--	--	2.0%
Book Value	2.0%	1.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	543.8	525.9	620.3	619.6	2309.6
2010	619.0	655.7	694.6	695.7	2665.0
2011	710.6	794.3	886.4	851.0	3242.3
2012	814.9	850	885.1	850	3400
2013	850	850	900	850	3450

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.22	.17	.37	.15	.91
2010	.29	.31	.35	.26	1.21
2011	.30	.28	.50	.36	1.44
2012	.40	.34	.49	.37	1.60
2013	.43	.36	.52	.39	1.70

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.31	.31	.31	.31	1.24
2009	.31	.31	.31	.31	1.24
2010	.31	.31	.31	.31	1.24
2011	.31	.31	.31	.31	1.24
2012	.31	.31			

BUSINESS: Hawaiian Electric Industries, Inc. is the parent company of Hawaiian Electric Company (HECO) & American Savings Bank (ASB). HECO & its subs., Maui Electric Co. (MECO) & Hawaii Electric Light Co. (HELCO), supply electricity to 446,000 customers on Oahu, Maui, Molokai, Lanai, & Hawaii. Operating companies' systems are not interconnected. Disc. int'l power sub. in '01. Elec. rev. breakdown: res'l, 33%; comm'l, 34%; large light & power, 32%; other, 1%. Generating sources: oil, 60%; purchased, 40%. Fuel costs: 60% of revs. '11 reported depr. rate (util.): 3.2%. Has 3,700 empls. Chairman: Jeffrey N. Watanabe. Pres. & CEO: Constance H. Lau. Inc.: HI. Address: 900 Richards St., P.O. Box 730, Honolulu, HI 96808-0730. Tel.: 808-543-5662. Web: www.hei.com.

Each of Hawaiian Electric Industries' utilities is now operating under a new regulatory mechanism. The company's largest utility, Hawaiian Electric Company (HECO), has been benefiting from the mechanism since 2011, and Hawaii Electric Light Company (HELCO) and Maui Electric Company (MECO) began using it this year. (MECO was granted an interim rate hike of $13.1 million, or 3.2%, based on a return of 10% on a common-equity ratio of 56.86%.) An advantage of the new mechanism is the decoupling of electric volume and revenues, so that declines in usage (stemming from the effects of the sluggish economy and conservation efforts) will no longer hurt the utilities. In addition, the utilities now benefit from annual rate adjustments for capital spending and increases in operating expenses. The new mechanism reduces, but does not eliminate, the effects of regulatory lag. HECO has a goal of earning an 8.5% return on equity in 2012. This would be an improvement over its performance in recent years, but would still fall short of its allowed ROE of 10%.

The effects of the new mechanism are the main reason why we expect earnings to improve in 2012 and climb in 2013. We estimate that share net will reach $1.60 this year—the highest tally in a decade — despite a probable decline in profits at the American Savings Bank subsidiary. ASB is likely to have lower fee income and a narrower interest-rate spread this year. We estimate a 6% earnings increase next year. However, because the payout ratio is still high, we expect no dividend increase until mid-decade.

New regulation has not eliminated the need for general rate cases. As this report went to press, HELCO was planning to file an application. An interim rate order is due 12 months after the filing date. There is no statutory time limit for the final decision.

This timely equity's dividend yield is only slightly above the utility average. However, with the stock trading within our 3- to 5-year Target Price Range, the modest dividend growth we project over that time frame probably won't be enough to produce an attractive total return.

Paul E. Debbas, CFA *August 3, 2012*

(A) Dil. EPS. Excl. gains (losses) from disc. ops.: '00, (56¢); '01, (36¢); '03, (5¢); '04, 2¢; '05, (1¢); nonrec. gain (loss): '05, 11¢; '07, (9¢). Next egs. due early Nov. (B) Div'ds histor. paid in early Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. † Sharehldr. invest. plan avail. (C) Incl. intang. In '11: $7.83/sh. (D) In mill., adj. for split. (E) Rate base: Orig. cost. Rate all'd on com. eq. in '11: HECO, 10%; in '12: HELCO, 10%; in '12: MECO, 10%; earned on avg. com. eq., '11: 9.2%. Regul. Climate: Avg. (F) Excl. div'ds paid through reinvest. plan.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	30
Earnings Predictability	70

IDACORP, INC. NYSE-IDA

RECENT PRICE	41.90	P/E RATIO	14.0 (Trailing: 12.9; Median: 15.0)	RELATIVE P/E RATIO	0.99	DIV'D YLD	3.2%	VALUE LINE

TIMELINESS 3 Lowered 5/14/10

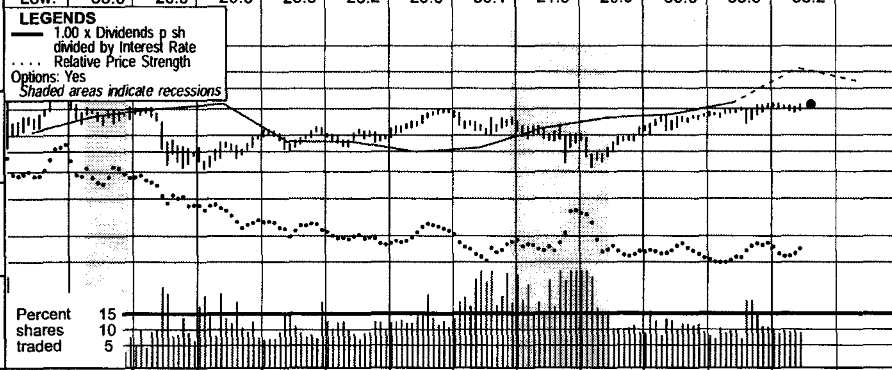
SAFETY 3 Lowered 2/14/03

TECHNICAL 4 Lowered 7/20/12

BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	49.4	41.0	30.2	32.9	32.1	40.2	39.2	35.1	32.8	37.8	42.7	43.6
Low:	33.6	20.9	20.6	25.3	26.2	29.0	30.1	21.9	20.9	30.0	33.9	38.2

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+30%)	*10%*
Low	35	(-15%)	*Nil*

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	1	0	0	0	0	0	0	0	1
Options	0	0	0	9	0	0	0	0	0
to Sell	0	0	0	9	0	1	2	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	73	78	84
to Sell	73	77	73
Hld's(000)	34642	34282	34810

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.9	-4.1
3 yr.	78.4	68.8
5 yr.	57.8	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.38	19.90	29.83	17.50	27.10	150.10	24.43	20.41	20.00	20.15	21.23	19.51	20.47	21.92	20.97	20.55	***22.40***	***23.50***	**Revenues per sh**	***24.90***
4.05	4.22	4.69	4.50	5.63	5.63	4.08	3.50	4.12	3.87	4.58	4.11	4.27	5.07	5.23	5.74	***5.60***	***6.00***	**"Cash Flow" per sh**	***6.45***
2.21	2.32	2.37	2.43	3.50	3.35	1.63	.96	1.90	1.75	2.35	1.86	2.18	2.64	2.95	3.36	***3.00***	***3.20***	**Earnings per sh** A	***3.40***
1.86	1.86	1.86	1.86	1.86	1.86	1.86	1.70	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	***1.32***	***1.40***	**Div'd Decl'd per sh** B† ■	***1.90***
2.49	2.51	2.37	2.95	3.73	4.78	3.53	3.89	4.73	4.53	5.16	6.39	5.19	5.26	6.85	6.76	***4.70***	***5.00***	**Cap'l Spending per sh**	***7.55***
18.47	18.93	19.42	20.02	21.82	23.15	23.01	22.54	23.88	24.04	25.77	26.79	27.76	29.17	31.01	33.19	***35.25***	***37.45***	**Book Value per sh** C	***40.90***
37.61	37.61	37.61	37.61	37.61	37.63	38.02	38.34	42.22	42.66	43.63	45.06	46.92	47.90	49.41	49.95	***50.00***	***50.00***	**Common Shs Outst'g** D	***53.00***
13.7	13.6	14.4	12.7	10.9	11.4	18.9	26.5	15.5	16.7	15.1	18.2	13.9	10.2	11.8	11.5	*Bold figures are*		**Avg Ann'l P/E Ratio**	***13.0***
.86	.78	.75	.72	.71	.58	1.03	1.51	.82	.89	.82	.97	.84	.68	.75	.73	*Value Line*		**Relative P/E Ratio**	***.85***
6.1%	5.9%	5.4%	6.0%	4.9%	4.9%	6.0%	6.7%	4.1%	4.1%	3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	*estimates*		**Avg Ann'l Div'd Yield**	***4.2%***

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1487.6 mill. **Due in 5 Yrs** $175.3 mill.
LT Debt $1486.6 mill. **LT Interest** $70.0 mill.
(LT interest earned: 2.5x)

Pension Assets-12/11 $390.1 mill.
Oblig. $655.4 mill.

Pfd Stock None

Common Stock 50,095,905 shs.
as of 4/27/12

MARKET CAP: $2.1 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
928.8	782.7	844.5	859.5	926.3	879.4	960.4	1049.8	1036.0	1026.8	***1120***	***1175***	**Revenues ($mill)**	***1320***
66.3	40.1	77.8	63.7	100.1	82.3	98.4	124.4	142.5	166.9	***150***	***160***	**Net Profit ($mill)**	***180***
--	--	--	16.9%	13.3%	14.3%	16.3%	15.2%	NMF	NMF	***25.0%***	***30.0%***	**Income Tax Rate**	***30.0%***
3.0%	7.5%	3.9%	4.7%	4.0%	9.7%	10.2%	10.5%	19.7%	22.8%	***25.0%***	***25.0%***	**AFUDC % to Net Profit**	***30.0%***
49.2%	50.8%	49.3%	50.0%	45.2%	48.9%	47.6%	50.2%	49.3%	45.6%	***46.0%***	***46.0%***	**Long-Term Debt Ratio**	***46.5%***
47.9%	46.4%	50.7%	50.0%	54.8%	51.1%	52.4%	49.8%	50.7%	54.4%	***54.0%***	***54.0%***	**Common Equity Ratio**	***53.5%***
1826.9	1862.5	1987.8	2048.8	2052.8	2364.2	2485.9	2807.1	3020.4	3045.2	***3265***	***3465***	**Total Capital ($mill)**	***4100***
1906.5	2088.3	2209.5	2314.3	2419.1	2616.6	2758.2	2917.0	3161.4	3406.6	***3680***	***3975***	**Net Plant ($mill)**	***5000***
5.1%	3.7%	5.3%	4.5%	6.2%	4.7%	5.3%	5.7%	6.0%	6.7%	***6.0%***	***6.0%***	**Return on Total Cap'l**	***5.5%***
7.1%	4.4%	7.7%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	***9.0%***	***9.0%***	**Return on Shr. Equity**	***8.5%***
7.0%	4.2%	7.2%	6.2%	8.9%	6.8%	7.6%	8.9%	9.3%	10.1%	***9.0%***	***9.0%***	**Return on Com Equity** E	***8.5%***
NMF	NMF	2.7%	1.3%	4.3%	2.4%	3.4%	4.8%	5.5%	6.5%	***5.0%***	***5.0%***	**Retained to Com Eq**	***4.0%***
113%	NMF	65%	80%	51%	64%	55%	46%	41%	36%	***44%***	***44%***	**All Div'ds to Net Prof**	***56%***

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.1	-3.1	+1.6
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	4.51	4.50	4.54
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	3014	2714	2973
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.6	+.4	+.7
Fixed Charge Cov. (%)	280	264	230

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '09-'11 to '15-'17**
Revenues	-10.5%	0.5%	*3.0%*
"Cash Flow"	--	5.0%	*3.0%*
Earnings	-0.5%	8.5%	*2.0%*
Dividends	-4.5%	--	*8.0%*
Book Value	3.5%	5.0%	*4.5%*

Cal-endar	QUARTERLY REVENUES($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	228.6	243.6	324.5	253.1	1049.8
2010	252.5	241.8	309.4	232.3	1036.0
2011	251.5	235.0	309.6	230.7	1026.8
2012	241.1	***250***	***350***	***278.9***	***1120***
2013	***275***	***260***	***360***	***280***	***1175***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.40	.59	1.16	.49	2.64
2010	.34	.82	1.39	.40	2.95
2011	.60	.42	2.16	.18	3.36
2012	.50	***.50***	***1.55***	***.45***	***3.00***
2013	***.55***	***.55***	***1.60***	***.50***	***3.20***

Cal-endar	QUARTERLY DIVIDENDS PAID B† ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.30	.30	.30	.30	1.20
2009	.30	.30	.30	.30	1.20
2010	.30	.30	.30	.30	1.20
2011	.30	.30	.30	.30	1.20
2012	.33	.33			

BUSINESS: IDACORP, Inc. is the holding company for Idaho Power, a utility that operates 17 hydroelectric generation developments, 2 natural gas-fired plants, and partly owns three coal plants across Idaho, Oregon, Wyoming, and Nevada. Service territory covers 24,000 square miles with estimated population of one million. Sells electricity in Idaho (95% of revenues) and Oregon (5%). Revenue breakdown: residential, 39%; commercial, 21%; industrial, 13%; other, 27%. Fuel sources: hydro, 59%; thermal, 27%; purchased power, 14%. '11 depreciation rate: 2.4%. Has 2,058 employees. Chairman: Gary G. Michael. President & CEO: J. LaMont Keen. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, ID. 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

IDACORP had a disappointing start to the year. The company reported first-quarter top- and bottom-line results that were below expectations, as a result of lower sales, warmer temperatures, and increased expenses. Moreover, both measures decreased from the year-ago period, largely due to lower accumulated deferred investment tax credits (ADITCs), which negatively impacted the bottom line by $3 million. (Idaho Power only used $0.8 million, compared to $3.9 million last year.) At yearend, IDA expects to use less than $5 million based on its 2012 ROE estimate. Recall, Idaho Power can use up to $45 million of ADITCs from 2012-2014 to achieve a minimum return of 9.5%. Thus, despite the underwhelming earnings results this quarter, IDA's ability to preserve this balance augurs well for its future performance.

The Langley Gulch power plant was completed. After conducting its "first fire" operating test in April, Idaho Power commenced commercial operation at its 300-megawatt natural gas-fired plant on June 29th. In all, the project cost a total of $398 million since 2009. The subsidiary requested that $336.7 million of these expenses be recognized in its rate base, which would raise its annualized revenues by $59.9 million. However, the Idaho Public Utilities Commission (IPUC) approved a reduced amount of $58.1 million, which was effective on July 1st. Overall, Langley Gulch will likely become a substantial part of IDA's energy portfolio, and should yield a 7.86% regulated return on investment.

Idaho Power is under contract to add more wind power, which could raise costs for customers. In the back half of the year, the company must add another 300 megawatts of wind power to the 500 megawatts already being generated. However, the expenses that Idaho Power will likely incur to produce the alternative energy have become worrisome. As a result, IDA's customers may see higher costs if contract terms are not adjusted.

Shares of IDACORP are unappealing. Investors may want to look elsewhere due to the low dividend yield, which remains below average compared to its industry peers. Average ranks in both Timeliness and Safety add to our lackluster outlook.

Michelle Jensen *August 3, 2012*

(A) EPS diluted. Excl. nonrecurring gains (loss): '00, 22¢; '03, 26¢; '05, (24¢); '06, 17¢. Next earnings report due early Aug. (B) Div'ds historically paid in early March, late May, late Aug., and late Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred debits. In '11: $20.74/sh. (D) In mill. (E) Rate Base: Net original cost. Rate allowed on com. eq. in Idaho in '08: 10.5%; earned on avg. system com. eq., '11: 10.1%. Regulatory Climate: Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

NORTHWESTERN NYSE-NWE

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
36.50	15.5 (Trailing: 14.4 Median: NMF)	1.09	4.1%	VALUE LINE

	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	28.2	32.5	35.8	36.7	29.7	26.8	30.6	36.6	38.0
Low:	24.8	25.5	30.1	24.5	16.5	18.5	23.8	27.4	33.7

TIMELINESS 3 New 5/4/12

SAFETY 3 New 5/4/12

TECHNICAL 3 Raised 8/3/12

BETA .70 (1.00 = Market)

2015-17 PROJECTIONS

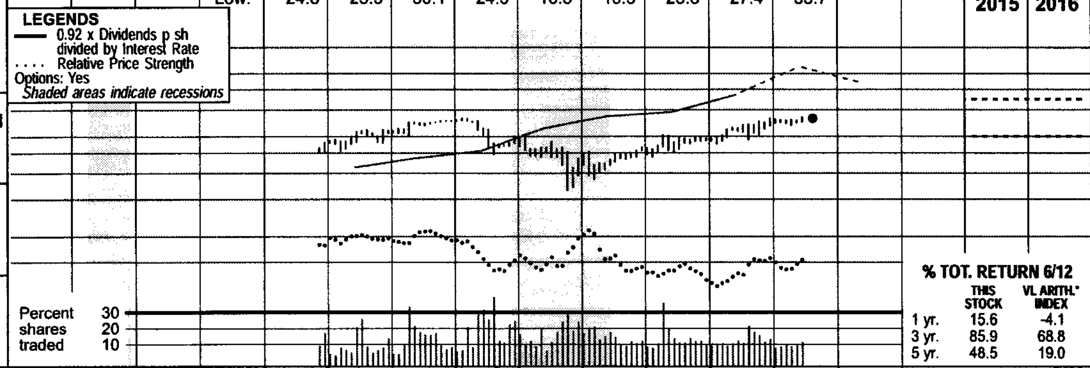
	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	30	(-20%)	Nil

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	73	74	85
to Sell	82	87	80
Hld's(000)	33751	33115	33521



% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	15.6	-4.1
3 yr.	85.9	68.8
5 yr.	48.5	19.0

NorthWestern Corporation filed for protection under Chapter 11 of the Federal Bankruptcy Code on September 14, 2003. On November 1, 2004, the company emerged from a bankruptcy reorganization. All old common shares were canceled and 35,500,000 new shares (along with 4,620,333 warrants) were issued. The stock initially traded on NASDAQ under the symbol NWEC and moved to the NYSE under the symbol NWE in May of 2008.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	32.57	31.49	30.79	35.09	31.72	30.66	30.80	**29.00**	**29.85**	Revenues per sh	**35.00**
--	--	--	4.00	3.62	3.70	4.40	4.62	4.76	5.42	**5.25**	**5.40**	"Cash Flow" per sh	**6.50**
--	--	--	1.71	1.31	1.44	1.77	2.02	2.14	2.53	**2.35**	**2.45**	Earnings per sh A	**3.00**
--	--	--	1.00	1.24	1.28	1.32	1.34	1.36	1.44	**1.48**	**1.52**	Div'd Decl'd per sh B ■ †	**1.80**
--	--	--	2.26	2.81	3.00	3.47	5.26	6.30	5.20	**8.65**	**6.60**	Cap'l Spending per sh	**4.75**
--	--	--	20.60	20.65	21.12	21.25	21.86	22.64	23.68	**24.95**	**26.05**	Book Value per sh C	**29.75**
--	--	--	35.79	35.97	38.97	35.93	36.00	36.23	36.28	**37.75**	**38.50**	Common Shs Outst'g D	**38.50**
--	--	--	17.1	26.0	21.7	13.9	11.5	12.9	12.6	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**13.0**
--	--	--	.91	1.40	1.15	.84	.77	.82	.80			Relative P/E Ratio	**.85**
--	--	--	3.4%	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%			Avg Ann'l Div'd Yield	**4.7%**
--	--	--	1165.8	1132.7	1200.1	1260.8	1141.9	1110.7	1117.3	**1095**	**1150**	Revenues ($mill)	**1350**
--	--	--	61.5	49.2	53.2	67.6	73.4	77.4	92.6	**90.0**	**95.0**	Net Profit ($mill)	**115**
--	--	--	38.5%	40.3%	37.8%	37.3%	17.2%	25.0%	9.8%	**18.0%**	**18.0%**	Income Tax Rate	**18.0%**
--	--	--	2.1%	3.3%	2.5%	2.3%	7.2%	22.7%	5.4%	**9.0%**	**8.0%**	AFUDC % to Net Profit	**4.0%**
--	--	--	44.3%	49.9%	50.1%	46.8%	56.4%	57.2%	52.2%	**53.5%**	**52.0%**	Long-Term Debt Ratio	**49.0%**
--	--	--	55.7%	50.1%	49.9%	53.2%	43.6%	42.8%	47.8%	**46.5%**	**48.0%**	Common Equity Ratio	**51.0%**
--	--	--	1324.0	1482.2	1648.4	1434.3	1803.9	1916.4	1797.1	**2030**	**2090**	Total Capital ($mill)	**2225**
--	--	--	1409.2	1491.9	1770.9	1839.7	1964.1	2118.0	2213.3	**2430**	**2570**	Net Plant ($mill)	**2825**
--	--	--	7.0%	5.2%	5.0%	7.0%	6.0%	6.0%	7.1%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.5%**
--	--	--	8.3%	6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	**9.5%**	**9.5%**	Return on Shr. Equity	**10.0%**
--	--	--	8.3%	6.6%	6.5%	8.9%	9.3%	9.4%	10.8%	**9.5%**	**9.5%**	Return on Com Equity E	**10.0%**
--	--	--	3.5%	.7%	.7%	2.3%	3.2%	3.5%	4.7%	**3.5%**	**3.5%**	Retained to Com Eq	**4.0%**
--	--	--	58%	90%	89%	74%	66%	63%	56%	**62%**	**62%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1052.4 mill. **Due in 5 Yrs** $271.0 mill.
LT Debt $937.8 mill. **LT Interest** $51.6 mill.
Incl. $32.8 mill. capitalized leases.
(LT interest earned: 2.4x)

Leases, Uncapitalized Annual rentals $2.0 mill.
Pension Assets-12/11 $432.6 mill. **Oblig.** $536.5 mill.

Pfd Stock None

Common Stock 36,390,258 shs.
as of 4/20/12
MARKET CAP: $1.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-.8	-1.0	+2.3
Avg. Indust. Use (MWH)	40831	38676	39347
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	2014
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+.7	+.6
Fixed Charge Cov. (%)	217	212	237

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	--	2.0%
"Cash Flow"	--	6.5%	4.5%
Earnings	--	--	5.0%
Dividends	--	13.0%	4.5%
Book Value	--	2.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	370.9	235.7	232.9	302.4	1141.9
2010	334.2	244.1	240.8	291.6	1110.7
2011	338.3	251.8	244.0	283.2	1117.3
2012	309.1	244.6	**245**	**296.3**	**1095**
2013	**330**	**260**	**255**	**305**	**1150**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.63	.17	.52	.70	2.02
2010	.79	.32	.40	.63	2.14
2011	.89	.30	.41	.93	2.53
2012	.88	.31	**.43**	**.73**	**2.35**
2013	**.90**	**.35**	**.45**	**.75**	**2.45**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.33	.33	.33	.33	1.32
2009	.335	.335	.335	.335	1.34
2010	.34	.34	.34	.34	1.36
2011	.36	.36	.36	.36	1.44
2012	.37	.37			

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 401,000 electric customers in Montana and South Dakota and 268,000 gas customers in Montana, South Dakota, and Nebraska. Electric revenue breakdown: residential, 41%; commercial, 50%; industrial, 5%; other, 4%. Generating sources are not provided by company. Fuel costs: 44% of revenues. '11 reported depreciation rate: 3.3%. Has 1,400 employees. Chairman: Dr. E. Linn Draper Jr. President & CEO: Robert C. Rowe. Incorporated: Delaware. Address: 3010 West 69th Street, Sioux Falls, South Dakota 57108. Telephone: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern is building two generating facilities . . . The company is constructing a 40-megawatt windfarm in Montana at an estimated cost of $86 million. Completion of the project is expected by yearend, which would enable it to qualify for federal production tax credits. NorthWestern is also building a 60-mw gas-fired peaking plant in South Dakota at an estimated cost of $65 million-$75 million. This project will probably be completed in early 2013.

. . . and is evaluating the possibility of constructing another plant. This would be gas-fired base-load generation in Montana. The new capacity would replace a purchased-power contract that is expiring in 2014.

At least one rate case is probable next year. Sometime after NorthWestern completes the gas peaker in South Dakota, the utility will put forth a rate application in the state. (This might well be for both electricity and gas.) A filing is possible in Montana, too. Any rate relief the utility obtains would not help NorthWestern's earnings until 2014, however.

We estimate that earnings will decline in 2012, followed by a partial recovery in 2013. In 2011, favorable weather conditions boosted the bottom line by $0.05 a share. This year, the first-quarter weather patterns were milder than usual. (We assume normal weather for the rest of 2012.) Also, the tax rate, though still low, will almost certainly be higher than the rate recorded in 2011. Modest growth in customer usage should produce higher profits next year. We look for a 4% bottom-line increase.

NorthWestern is doing some financing. The company plans to issue up to $100 million of common equity over the next three years through a "dribble" program. NorthWestern sold $24.3 million of stock in the second quarter, of an expected issuance of as much as $50 million in 2012. The company has also priced $150 million of long-term debt that it will issue this month.

This issue does not stand out among utilities. The dividend yield and 3- to 5-year total return potential are each about equivalent to the averages for the electric utility industry.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted EPS. Excl. gain (loss) on discontinued operations: '05, (6¢); '06, 1¢. Next earnings report due late Oct. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '11: $663.9 mill., $18.30/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '11: 10.25%; in SD in '11: none specified; in NE in '07: 10.4%; earned on avg. com. eq., '11: 10.0%. Regulatory Climate: MT, Average; SD, Above Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	85

PG&E CORP. NYSE-PCG

RECENT PRICE **44.44** | P/E RATIO **19.3** (Trailing: 15.1 Median: 15.0) | RELATIVE P/E RATIO **1.36** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 3 Lowered 11/11/11

SAFETY 3 Lowered 2/3/12

TECHNICAL 3 Raised 8/3/12

BETA .55 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	20.9	23.8	28.0	34.5	40.1	48.2	52.2	45.7	45.8	48.6	48.0	45.8
Low:	6.5	8.0	11.7	25.9	31.8	36.3	42.6	26.7	34.5	34.9	36.8	39.8

2015-17 PROJECTIONS

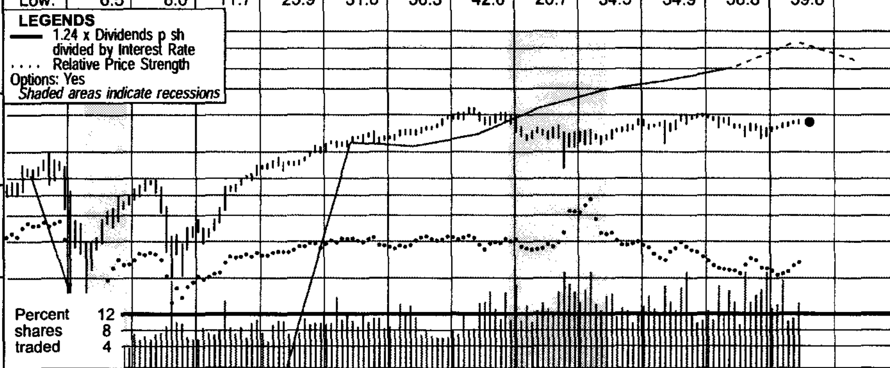
	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	35	(-20%)	-1%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	1	0	0	0	0	0	1	0	0
Options	0	0	1	0	0	0	2	0	1
to Sell	0	0	2	0	0	0	7	0	1

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	183	207	194
to Sell	198	186	210
Hld's(000)	285620	293053	322524



Target Price Range

2015	2016	2017
		120
		100
		80
		64
		48
		32
		24
		20
		16
		12
		8

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.4	-4.1
3 yr.	33.3	68.8
5 yr.	22.3	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
23.82	36.87	52.12	57.74	67.75	63.18	32.74	25.05	26.47	31.78	36.02	37.42	40.51	36.15	35.02	36.28	***35.25***	***36.30***	Revenues per sh	***42.75***
5.24	5.98	6.08	7.15	.80	5.66	1.14	4.80	5.71	7.12	7.76	8.02	8.44	8.37	8.22	8.08	***7.90***	***8.55***	"Cash Flow" per sh	***10.00***
2.16	1.57	1.88	2.24	d9.21	3.02	d2.36	2.05	2.12	2.35	2.76	2.78	3.22	3.03	2.82	2.78	***2.30***	***2.75***	Earnings per sh A	***3.75***
1.77	1.20	1.20	1.20	1.20	--	--	--	--	1.23	1.32	1.44	1.56	1.68	1.82	1.82	***1.82***	***1.82***	Div'd Decl'd per sh B ■ †	***2.00***
3.05	4.36	4.23	4.39	4.54	7.33	7.94	4.08	3.72	4.90	6.90	7.83	10.05	10.68	9.62	9.79	***11.20***	***11.05***	Cap'l Spending per sh	***12.50***
20.73	21.30	21.08	19.10	8.19	11.89	9.47	10.12	20.62	19.60	22.44	24.18	25.97	27.88	28.55	29.35	***30.25***	***31.45***	Book Value per sh C	***36.25***
403.50	417.67	382.60	360.59	387.19	363.38	381.67	416.52	418.62	368.27	348.14	353.72	361.06	370.60	395.23	412.26	***428.50***	***435.00***	Common Shs Outst'g D	***435.00***
10.9	15.5	16.8	13.1	--	4.8	--	9.5	13.8	15.4	14.8	16.8	12.1	13.0	15.8	15.5	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	***12.0***
.68	.89	.87	.75	--	.25	--	.54	.73	.82	.80	.89	.73	.87	1.01	.98			Relative P/E Ratio	***.80***
7.5%	4.9%	3.8%	4.1%	4.8%	--	--	--	--	3.4%	3.2%	3.1%	4.0%	4.3%	4.1%	4.2%			Avg Ann'l Div'd Yield	***4.5%***

CAPITAL STRUCTURE as of 3/31/12

Total Debt $13539 mill. **Due in 5 yrs** $4445 mill.
LT Debt $11767 mill. **LT Interest** $615.0 mill.
Incl. $212 mill. capitalized leases.
(LT interest earned: 3.6x)
Pension Assets-12/11 $11.0 bill. **Oblig.** $14.0 bill.
Pfd Stock $252.0 mill. **Pfd Div'd** $14.0 mill.
4,534,958 shs. 4.36% to 5%, cumulative and $25 par, redeemable from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cumulative nonredeemable and $25 par.
Common Stock 422,320,110 shs.
as of 4/24/12
MARKET CAP: $19 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
12495	10435	11080	11703	12539	13237	14628	13399	13841	14956	***15100***	***15800***	Revenues ($mill)	***18650***
d874.0	791.0	901.0	904.0	1005.0	1020.0	1198.0	1168.0	1113.0	1132.0	***985***	***1210***	Net Profit ($mill)	***1685***
--	36.7%	35.0%	37.6%	35.5%	34.6%	26.2%	31.1%	33.0%	30.3%	***32.0%***	***32.0%***	Income Tax Rate	***32.0%***
--	3.7%	3.6%	5.6%	6.7%	9.4%	9.5%	11.9%	14.4%	11.2%	***13.0%***	***11.0%***	AFUDC % to Net Profit	***9.0%***
51.5%	42.4%	45.1%	48.3%	51.7%	52.6%	52.2%	51.4%	49.6%	48.8%	***48.5%***	***46.5%***	Long-Term Debt Ratio	***48.5%***
42.8%	53.9%	53.2%	50.0%	46.8%	46.1%	46.5%	47.4%	49.3%	50.2%	***50.5%***	***52.5%***	Common Equity Ratio	***51.0%***
8438.0	7815.0	16242	14446	16696	18558	20163	21793	22863	24119	***25575***	***25950***	Total Capital ($mill)	***31000***
16928	18107	18989	19955	21785	23656	26261	28892	31449	33655	***36025***	***38325***	Net Plant ($mill)	***45800***
NMF	16.3%	7.6%	8.1%	7.6%	7.4%	7.8%	6.7%	6.2%	5.9%	***5.0%***	***6.0%***	Return on Total Cap'l	***6.5%***
NMF	17.6%	10.1%	12.1%	12.5%	11.6%	12.4%	11.0%	9.6%	9.2%	***7.5%***	***8.5%***	Return on Shr. Equity	***10.5%***
NMF	18.5%	10.3%	12.3%	12.7%	11.8%	12.6%	11.2%	9.7%	9.2%	***7.5%***	***9.0%***	Return on Com Equity E	***10.5%***
NMF	18.5%	10.3%	7.7%	6.8%	6.0%	6.8%	5.5%	3.9%	3.4%	***1.5%***	***3.0%***	Retained to Com Eq	***5.0%***
--	2%	1%	39%	47%	50%	47%	52%	61%	63%	***79%***	***66%***	All Div'ds to Net Prof	***53%***

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.8	-2.0	-.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	NMF	NMF	NMF
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	+.2	+.5	+.4
Fixed Charge Cov. (%)	296	303	295

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-5.5%	2.5%	*3.0%*
"Cash Flow"	6.0%	3.5%	*3.5%*
Earnings	--	3.5%	*4.5%*
Dividends	8.5%	16.0%	*2.0%*
Book Value	8.0%	6.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3431	3194	3235	3539	13399
2010	3475	3232	3513	3621	13841
2011	3597	3684	3860	3815	14956
2012	3641	***3700***	***3900***	***3859***	***15100***
2013	***3950***	***3800***	***4000***	***4050***	***15800***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.65	.87	.80	.71	3.03
2010	.67	.86	.66	.63	2.82
2011	.50	.91	.68	.69	2.78
2012	.66	***.54***	***.55***	***.55***	***2.30***
2013	***.60***	***.70***	***.75***	***.70***	***2.75***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.36	.39	.39	.39	1.53
2009	.39	.42	.42	.42	1.65
2010	.42	.455	.455	.455	1.79
2011	.455	.455	.455	.455	1.82
2012	.455	.455	.455		

BUSINESS: PG&E Corporation is a holding company for Pacific Gas and Electric Company and nonutility subsidiaries. Supplies electricity and gas to most of northern and central California. Has 5.1 million electric and 4.3 million gas customers. Electric revenue breakdown: residential, 40%; commercial, 38%; industrial, 12%; agricultural, 7%; other, 3%. Generating sources: nuclear, 24%; hydro, 15%; gas, 7%; purchased, 54%. Fuel costs: 36% of revenues. '11 reported depreciation rate (utility): 3.7%. Has 19,400 employees. Chairman, President & Chief Executive Officer: Anthony F. Earley, Jr. Incorporated: California. Address: One Market, Spear Tower, Suite 2400, San Francisco, California 94105. Telephone: 415-267-7000. Internet: www.pgecorp.com.

The aftermath of the pipeline explosion in San Bruno, California in September of 2010 remains a major investment consideration for PG&E. The explosion caused fatalities, injuries, and significant property damage. Since then, PG&E has incurred millions of dollars of costs and third-party claims associated with the accident, and these are continuing in 2012. (Some of the third-party claims are covered by insurance.) The company estimates that its pipeline-related expenses will amount to $450 million-$550 million this year, and that third-party liability claims will amount to as much as $225 million. Separately, PG&E made a $70 million contribution to San Bruno in the March quarter. (All figures are pretax.) We are *including* these expenses (and any insurance recoveries) in our presentation, which is one reason why we expect an earnings decline this year. Another is that average shares outstanding will be higher, as the company expects to issue $700 million of common equity in 2012. PG&E is still facing a substantial fine from the state commission, which we will *exclude* from our presentation.

We estimate that earnings will rebound in 2013. PG&E hasn't stated its expectation for pipeline-related expenses, but we believe they will not be as high as in 2012. One disadvantage, however, is that the utility's allowed return on equity is likely to be lower than it is this year.

A cost-of-capital filing is pending. PG&E proposed an allowed ROE of 11% (compared with 11.35% now) and a common-equity ratio of 52%. This would reduce annual rates by about $100 million. An order is expected by yearend, and will take effect at the start of 2013.

The utility has made its preliminary filing for its general rate case. (This proceeding is separate from the cost-of-capital case.) It plans to ask for rate increases of $1.25 billion in 2014, and $500 million in each of the following two years. A ruling is expected in 2013, with new tariffs taking effect at the start of 2014.

We don't recommend this stock. Despite the ongoing uncertainties surrounding the San Bruno explosion, the stock's yield is only average for a utility, and 3- to 5-year total return potential is low.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95; '09, 18¢; '11, (68¢); '12, (10¢); gain from disc. ops.: '08, 41¢. Incl. nonrec. loss: '00, $11.83. Next earnings report due early Aug. (B) Div'ds historically paid in mid-Jan., Apr., July and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '11: $11.48/sh. (D) In mill. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%; earned on avg. com. eq., '11: 9.5%. Regulatory Climate: Above Average.

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

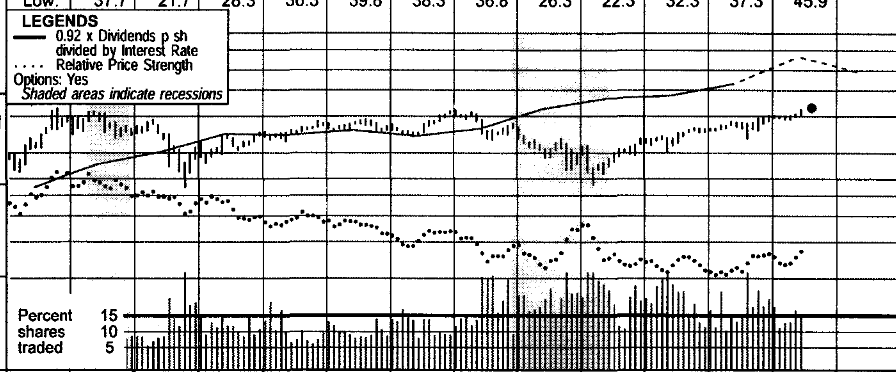
PINNACLE WEST NYSE-PNW

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
52.86	16.5	(Trailing: 17.3) (Median: 14.0)	1.16	4.1%	VALUE LINE

TIMELINESS	2 Raised 11/11/11
SAFETY	2 Raised 5/6/11
TECHNICAL	4 Lowered 6/22/12
BETA .70 (1.00 = Market)	

High:	50.7	46.7	40.5	45.8	46.7	51.0	51.7	42.9	38.0	42.7	48.9	53.9
Low:	37.7	21.7	28.3	36.3	39.8	38.3	36.8	26.3	22.3	32.3	37.3	45.9

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+15%)	7%
Low	45	(-15%)	1%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	144	166	152
to Sell	150	142	171
Hld's(000)	79647	77718	80986

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.4	-4.1
3 yr.	100.9	68.8
5 yr.	71.7	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
20.77	23.52	25.12	28.57	43.50	53.66	28.90	30.87	31.59	30.16	34.03	35.07	33.37	32.50	30.01	29.67	***30.90***	***32.00***	Revenues per sh	***33.00***
5.90	7.12	7.34	7.73	7.99	8.72	7.01	7.33	6.93	5.76	9.70	9.29	8.13	8.08	6.85	7.52	***7.80***	***8.15***	"Cash Flow" per sh	***8.75***
2.47	2.76	2.85	3.18	3.35	3.68	2.53	2.52	2.58	2.24	3.17	2.96	2.12	2.26	3.08	2.99	***3.20***	***3.45***	Earnings per sh A	***3.75***
1.03	1.13	1.23	1.33	1.43	1.53	1.63	1.73	1.83	1.93	2.03	2.10	2.10	2.10	2.10	2.10	***2.12***	***2.20***	Div'd Decl'd per sh B ■	***2.45***
2.95	3.63	3.76	4.05	7.76	12.27	9.81	7.60	5.86	6.39	7.59	9.37	9.46	7.64	7.03	8.26	***8.45***	***9.60***	Cap'l Spending per sh	***8.50***
22.51	23.90	25.50	26.00	28.09	29.46	29.44	31.00	32.14	34.57	34.48	35.15	34.16	32.69	33.86	34.98	***36.00***	***37.10***	Book Value per sh C	***41.00***
87.52	84.83	84.83	84.83	84.83	84.83	91.26	91.29	91.79	99.08	99.96	100.49	100.89	101.43	108.77	109.25	***110.00***	***111.00***	Common Shs Outst'g D	***118.50***
11.8	11.8	15.2	11.9	11.3	12.0	14.4	14.0	15.8	19.2	13.7	14.9	16.1	13.7	12.6	14.6	***Bold figures are***		Avg Ann'l P/E Ratio	***13.5***
.74	.68	.79	.68	.73	.61	.79	.80	.83	1.02	.74	.79	.97	.91	.80	.92	***Value Line***		Relative P/E Ratio	***.90***
3.5%	3.5%	2.8%	3.5%	3.8%	3.5%	4.5%	4.9%	4.5%	4.5%	4.7%	4.8%	6.2%	6.8%	5.4%	4.8%	***estimates***		Avg Ann'l Div'd Yield	***4.8%***

CAPITAL STRUCTURE as of 3/31/12
Total Debt $3659.5 mill. **Due in 5 Yrs** $1739.3 mill.
LT Debt $3341.2 mill. **LT Interest** $192.5 mill.
Incl. $65.5 mill. Palo Verde sale leaseback lessor notes.
(LT interest earned: 3.4x)
Leases, Uncapitalized Annual rentals $21.0 mill.
Pension Assets-12/11 $1.85 bill. Oblig. $2.70 bill.
Pfd Stock None

Common Stock 109,477,427 shs.
as of 4/27/12
MARKET CAP: $5.8 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
2637.3	2817.9	2899.7	2988.0	3401.7	3523.6	3367.1	3297.1	3263.6	3241.4	***3400***	***3550***	Revenues ($mill)	***3900***
215.2	230.6	235.2	223.2	317.1	298.8	213.6	229.2	330.4	328.2	***350***	***385***	Net Profit ($mill)	***445***
39.1%	31.4%	35.4%	36.2%	33.0%	33.6%	23.4%	36.9%	31.9%	34.0%	***34.0%***	***34.0%***	Income Tax Rate	***34.0%***
20.5%	6.2%	6.9%	10.4%	11.1%	14.8%	17.5%	11.2%	11.7%	12.8%	***13.0%***	***12.0%***	AFUDC % to Net Profit	***9.0%***
51.8%	50.6%	46.7%	43.2%	48.4%	47.0%	46.8%	50.4%	45.3%	44.1%	***47.5%***	***44.0%***	Long-Term Debt Ratio	***42.5%***
48.2%	49.4%	53.3%	56.8%	51.6%	53.0%	53.2%	49.6%	54.7%	55.9%	***52.5%***	***56.0%***	Common Equity Ratio	***57.5%***
5567.9	5727.5	5535.2	6033.4	6678.7	6658.7	6477.6	6686.6	6729.1	6840.9	***7565***	***7365***	Total Capital ($mill)	***8450***
6479.4	7480.1	7535.5	7577.1	7881.9	8436.4	8916.7	9257.8	9578.8	9962.3	***10385***	***10930***	Net Plant ($mill)	***12450***
5.4%	5.5%	5.6%	5.0%	6.2%	5.9%	4.7%	4.8%	6.5%	6.4%	***6.0%***	***6.5%***	Return on Total Cap'l	***6.5%***
8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	***9.0%***	***9.5%***	Return on Shr. Equity	***9.0%***
8.0%	8.1%	8.0%	6.5%	9.2%	8.5%	6.2%	6.9%	9.0%	8.6%	***9.0%***	***9.5%***	Return on Com Equity E	***9.0%***
2.9%	2.6%	2.3%	1.0%	3.4%	2.5%	.3%	.7%	3.1%	2.8%	***3.0%***	***3.5%***	Retained to Com Eq	***3.0%***
64%	68%	71%	85%	63%	70%	96%	89%	66%	68%	***66%***	***63%***	All Div'ds to Net Prof	***65%***

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.2	-1.6	+1.8
Avg. Indust. Use (MWH)	619	619	632
Avg. Indust. Revs. per KWH (¢)	8.11	7.83	7.78
Capacity at Peak (Mw)	8635	8682	8577
Peak Load, Summer (Mw)	7218	6396	7087
Annual Load Factor (%)	49.3	50.0	50.0
% Change Customers (yr-end)	+.5	+.4	+.8
Fixed Charge Cov. (%)	248	296	308

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-3.0%	-1.0%	*1.0%*
"Cash Flow"	-1.0%	--	*2.5%*
Earnings	-2.0%	1.0%	*5.0%*
Dividends	4.0%	1.5%	*2.5%*
Book Value	2.0%	--	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	625.9	836.0	1142.2	693.0	3297.1
2010	620.3	820.6	1139.1	683.6	3263.6
2011	648.9	799.8	1124.8	667.9	3241.4
2012	620.6	***879.4***	***1200***	***700***	***3400***
2013	***650***	***875***	***1300***	***725***	***3550***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	d.36	.74	2.07	d.19	2.26
2010	.07	.83	2.08	.06	3.08
2011	d.15	.78	2.24	.11	2.99
2012	d.07	***.90***	***2.30***	***.07***	***3.20***
2013	***Nil***	***1.00***	***2.35***	***.10***	***3.45***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.525	.525	.525	.525	2.10
2009	.525	.525	.525	.525	2.10
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525	.525	2.10
2012	.525	.525	.525		

BUSINESS: Pinnacle West Capital Corporation is a holding company for Arizona Public Service Company (APS), which supplies electricity to 1.1 million customers in most of Arizona, except about half of the Phoenix metro area, the Tucson metro area, and Mohave County in northwestern Arizona. Discontinued SunCor real estate subsidiary in '10. Electric revenue breakdown: residential, 47%; commercial, 39%; industrial, 5%; other, 9%. Generating sources: coal, 37%; nuclear, 27%; gas, 17%; purchased, 19%. Fuel costs: 31% of revenues. Has 6,700 employees. '11 reported deprec. rate: 3.0%. Chairman, President & CEO: Donald E. Brandt. Inc.: Arizona. Address: 400 North Fifth Street, P.O. Box 53999, Phoenix, Arizona 85072-3999. Tel.: 602-250-1000. Internet: www.pinnaclewest.com.

Pinnacle West's utility subsidiary received a base rate increase in mid-2012. Arizona Public Service's tariffs were raised by $116.3 million (4%), based on a return of 10% on a common-equity ratio of 53.94%. In addition, APS' fuel adjustment clause will now reflect the entire change in fuel and purchased-power costs, compared with 90% of any changes previously. Base rates will be frozen until mid-2016, except for a moderate increase that would occur in mid-2013. This would place the Four Corners asset acquisition (see below) in the rate base, provided that the purchase is approved by the Federal Energy Regulatory Commission and the utility reaches a new coal supply contract.

The utility hopes to complete the Four Corners purchase in December. APS would pay $294 million for another utility's 739-megawatt stake in units 4 and 5 of the coal-fired station. It would have to spend $300 million on environmental upgrades for these two units, but would avoid $600 million of environmental improvements that would have been required for units 1, 2, and 3, which would be shut down. The company would finance the purchase with debt. Note that our figures will not reflect the Four Corners acquisition until after it has been completed.

Earnings are likely to rise in 2012 and 2013. Rate relief should be the key factor each year. Management wasn't providing earnings guidance until June-quarter results were released, which was expected shortly after this report went to press.

We look for a dividend increase later this year. The rate case has been concluded, Pinnacle's earning power is improving, and the payout ratio is low enough to allow the board of directors to raise the disbursement. We estimate that the board will hike the quarterly dividend by $0.02 a share (3.8%). This would be Pinnacle's first dividend increase since the fourth quarter of 2006.

The price of this timely stock has risen 10% so far this year, far outperforming most utility equities. We think this is due to the outcome of the rate case and the prospective dividend increase. This issue's yield is about average for a utility, but total return potential to 2015-2017 is low.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted egs. Excl. nonrec. losses: '02, 77¢; '09, $1.45; excl. gains (losses) from disc. ops.: '00, 22¢; '05, (36¢); '06, 10¢; '08, 28¢; '09, (13¢); '10, 18¢; '11, 10¢. '10 EPS don't add due to change in shares, '11 due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '11: $14.32/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in '12: 10%; earned on avg. com. eq., '11: 8.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	65

PNM RESOURCES NYSE-PNM

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
20.25	16.2 (Trailing: 16.9) (Median: 16.0)	1.14	2.9%	VALUE LINE

TIMELINESS	2	Raised 12/9/11
SAFETY	3	Lowered 5/9/08
TECHNICAL	4	Lowered 6/22/12

BETA .95 (1.00 = Market)

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+25%)	9%
Low	17	(-15%)	Nil

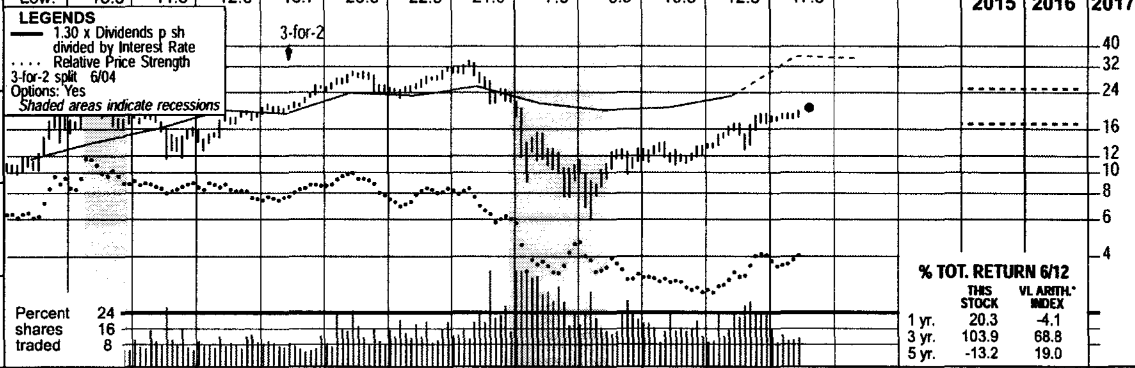
Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	103	63	84
to Sell	72	113	86
Hld's(000)	69709	69828	69113

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	25.2	20.5	19.6	26.1	30.5	32.1	34.3	21.7	13.1	14.0	19.2	20.5
Low:	15.3	11.5	12.6	18.7	23.8	22.5	21.0	7.6	5.9	10.8	12.8	17.3



% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.3	-4.1
3 yr.	103.9	68.8
5 yr.	-13.2	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
14.10	18.12	17.43	18.96	27.46	40.09	19.92	24.11	26.54	30.19	32.25	24.92	22.65	19.01	19.31	21.35	16.35	16.90	Revenues per sh	22.35
2.61	2.58	3.04	2.82	3.16	4.31	2.83	3.05	3.14	3.56	3.57	2.54	1.76	2.32	2.67	3.18	3.20	3.30	"Cash Flow" per sh	3.80
1.15	1.25	1.50	1.29	1.55	2.61	1.07	1.15	1.43	1.59	1.72	.76	.11	.58	.87	1.08	1.25	1.40	Earnings per sh A	2.05
.24	.42	.51	.53	.53	.53	.57	.61	.63	.79	.86	.91	.61	.50	.50	.50	.58	.70	Div'd Decl'd per sh B ■†	1.00
1.42	2.05	2.06	1.56	2.50	4.51	4.09	2.78	2.25	3.07	4.04	5.94	3.99	3.32	3.25	4.10	3.55	3.15	Cap'l Spending per sh	2.60
12.04	12.84	13.75	14.74	15.76	17.25	16.60	17.84	18.19	18.70	22.09	22.03	18.89	18.90	17.60	19.62	20.20	20.95	Book Value per sh C	22.20
62.66	62.66	62.66	61.05	58.68	58.68	58.68	60.39	60.46	68.79	76.65	76.81	86.53	86.67	86.67	79.65	80.00	80.00	Common Shs Outst'g D	85.00
11.0	10.0	9.8	9.5	8.5	7.3	15.1	14.7	15.0	17.1	15.6	35.6	NMF	18.1	14.0	14.5	Bold figures are		Avg Ann'l P/E Ratio	10.5
.69	.58	.51	.54	.55	.37	.82	.84	.79	.91	.84	1.89	NMF	1.21	.89	.91	Value Line		Relative P/E Ratio	.70
1.9%	3.3%	3.5%	4.4%	4.1%	2.8%	3.5%	3.6%	2.9%	2.9%	3.2%	3.4%	4.9%	4.8%	4.1%	3.2%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1671.8 mill. Due in 5 Yrs $236.8 mill.
LT Debt $1824.0 mill. LT Interest $100 mill.
(LT interest earned: 2.8x)
Pension Assets-12/11 $427.4 mill.
Oblig. $588.9 mill.

Pfd Stock $11.5 mill. Pfd Div'd $.5 mill.
115,293 shs. 4.58%, $100 par w/o mandatory redemption. Sinking fund began 2/1/84.

Common Stock 79,653,624 shs.
As of 4/27/12
MARKET CAP: $1.6 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1169.0	1455.7	1604.8	2076.8	2471.7	1914.0	1959.5	1647.7	1673.5	1700.6	1310	1350	Revenues ($mill)	1900
64.3	68.9	88.3	106.6	122.1	59.9	8.1	53.5	80.0	96.6	100	115	Net Profit ($mill)	175
24.5%	29.0%	28.2%	31.1%	24.7%	5.1%	40.4%	30.4%	32.6%	38.8%	40.0%	40.0%	Income Tax Rate	40.0%
--	--	--	--	--	--	--	6.4%	7.1%	8.8%	7.5%	7.5%	AFUDC % to Net Profit	8.0%
49.8%	47.5%	47.1%	57.4%	50.9%	42.0%	45.6%	48.7%	50.4%	51.5%	51.5%	51.0%	Long-Term Debt Ratio	51.0%
49.5%	51.9%	52.4%	42.3%	48.8%	57.6%	54.0%	51.0%	49.2%	48.1%	48.5%	48.5%	Common Equity Ratio	49.0%
1966.9	2077.3	2098.9	3044.4	3470.7	2935.8	3025.4	3214.9	3100.3	3245.6	3350	3460	Total Capital ($mill)	3900
1867.3	2194.4	2324.6	2984.1	3761.9	2935.4	3192.0	3332.4	3444.4	3627.1	3800	4000	Net Plant ($mill)	4630
4.7%	4.7%	5.3%	4.7%	4.9%	3.4%	1.9%	3.1%	4.2%	4.5%	5.0%	5.0%	Return on Total Cap'l	6.0%
6.5%	6.3%	7.9%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.5%	7.0%	Return on Shr. Equity	9.0%
6.5%	6.3%	8.0%	8.2%	7.2%	3.5%	.5%	3.2%	5.2%	6.1%	6.5%	7.0%	Return on Com Equity E	9.0%
3.1%	3.0%	4.5%	4.3%	3.7%	NMF	NMF	.4%	2.2%	3.3%	3.5%	3.5%	Retained to Com Eq	5.0%
53%	53%	44%	48%	49%	117%	NMF	86%	58%	47%	46%	49%	All Div'ds to Net Prof	50%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.2	-5.7	+2.5
Avg. Indust. Use (MWH)	N/A	N/A	N/A
Avg. Indust. Revs. per KWH (¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	2711	2631	2547
Peak Load, Summer (Mw)	1866	1973	1938
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	-.9	-.7	--
Fixed Charge Cov. (%)	156	182	201

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-3.5%	-7.5%	2.0%
"Cash Flow"	-2.5%	-4.5%	5.5%
Earnings	-7.5%	-12.0%	16.0%
Dividends	-.5%	-8.0%	12.0%
Book Value	1.5%	-1.0%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	385.9	401.1	477.7	383.0	1647.7
2010	383.5	405.8	503.7	380.5	1673.5
2011	387.7	415.5	549.5	347.9	1700.6
2012	305.4	315	395	294.6	1310
2013	310	325	410	305	1350

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.15	.01	.60	d.18	.58
2010	.06	.21	.63	d.03	.87
2011	.04	.20	.61	.22	1.08
2012	.17	.30	.60	.18	1.25
2013	.20	.35	.65	.20	1.40

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.23	.125	.125	.71
2009	.125	.125	.125	.125	.50
2010	.125	.125	.125	.125	.50
2011	.125	.125	.125	.125	.50
2012	.145	.145			

BUSINESS: PNM Resources is an investor-owned holding company of energy and energy related businesses. Primary subsidiaries include Public Service Company of New Mexico (PNM) and Texas-New Mexico Power Company (TNMP) which engage in the generation, transmission, and distribution of electricity in New Mexico and Texas. Sold competitive energy business First Choice Energy (9/11). Electric revenue breakdown '11: residential, 38%; commercial, 36%; industrial, 8%; other, 18%. Fuels: coal, 62%; nuclear, 30%; gas/oil, 8%. Fuel costs: 54% of revs. '11 depreciation rate: 3.0%. Has 1,951 employees. Chairman, President & CEO: Patricia K. Collawn. Inc.: NM. Addr.: Alvarado Square, Albuquerque, NM. 87158. Tel.: 505-241-2700. Internet: www.pnmresources.com.

PNM Resources posted a decent start to the year. The company's top- and bottom-line results of $305 million and $0.17 a share were in line with expectations. Earnings more than doubled from the year-ago tally, largely due to the sale of its competitive energy businesses, First Choice Power and Optim Energy, which put pressure on PNMR's performance last year. Moreover, share repurchases in 2011, totaling approximately $125 million, helped to boost share earnings in this year. Looking forward, we reiterate our 2012 share-net estimate of $1.25; however, we increased our 2013 projection by a nickel, to $1.40.

The Environmental Protection Agency's (EPA) best available retrofit technology (BART) requirements have led to an uphill battle. Recall, the court decided to deny PNMR's request to suspend installation of selective catalytic reduction (SCR) technology, which could cost the company more than $750 million over the next five years. Too, the governor of New Mexico sent a similar request, asking the EPA to permit a 90-day stay to allow PNMR to create an alternative plan. The motion was granted in July, and we expect a final decision later this year.

The electric utility remains engaged regarding other regulatory activity. Although PNMR is not anticipating another general rate case filing this year, the company is focused on its pending FERC rate cases, its renewable energy rider, and its 2013 renewable energy plan.

Shares of PNM Resources picked up steam since our last review. The stock price climbed to over $20 a share, hitting a high not seen since 2008. Thus, this issue is ranked to outperform the broader market averages over the coming six to 12 months.

However, PNM Resources' lackluster dividend yield may offset any positive sentiment. Despite the company's 16% quarterly dividend increase, to $0.145 a share, we are still unimpressed. PNMR's 2.9% yield is significantly below the utility industry average of 4.1%. Thus, income-seeking investors should look elsewhere right now. Moreover, PNMR's stock price is within our Target Price Range, limiting capital gains potential.

Michelle Jensen *August 3, 2012*

(A) EPS diluted. Excl. nonrecur. gains (losses): '97, 3¢; '98, net (16¢); '99, 5¢; '00, 14¢; '01, (10¢); '03, 45¢; '05, (56¢); '07, 14¢; '08, ($3.77); '10, ($1.36). Egs. may not sum due to rounding. Next egs. report due early Aug. (B) Div'ds hist. paid in mid Feb., May, Aug., Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. '11: $3.21/sh. (D) In mill., adjust. for split. (E) Rate base: net orig. cost. Elect. ROE allowed in '08: 10.1%; earned on avg. com. eq., '11: 6.1%. Regulatory Climate: Avg.

Company's Financial Strength	B
Stock's Price Stability	65
Price Growth Persistence	25
Earnings Predictability	15

PORTLAND GENERAL NYSE-POR

RECENT PRICE	26.81	P/E RATIO	14.1 (Trailing: 16.0 / Median: NMF)	RELATIVE P/E RATIO	0.99	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 3 Lowered 8/19/11

SAFETY 2 Raised 5/4/12

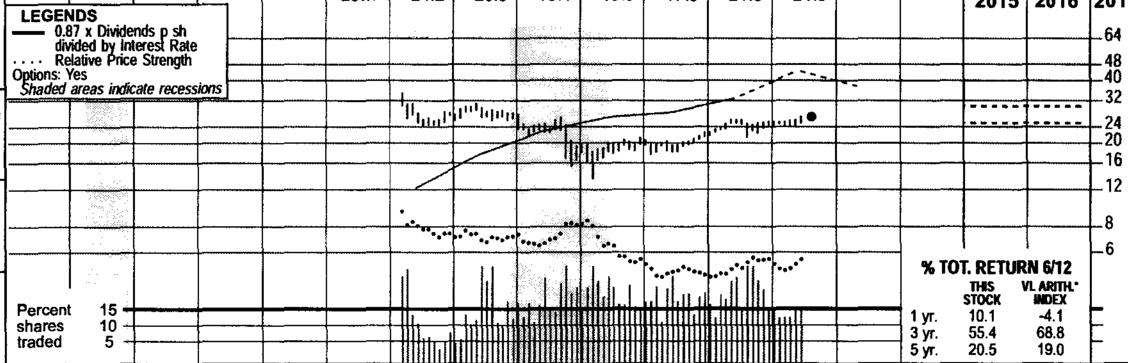
TECHNICAL 3 Raised 7/13/12

BETA .75 (1.00 = Market)

High:	35.0	31.3	27.7	21.4	22.7	26.0	27.6		
Low:	24.2	25.5	15.4	13.5	17.5	21.3	24.3		

Target Price Range
2015 | 2016 | 2017

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



% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	10.1	-4.1
3 yr.	55.4	68.8
5 yr.	20.5	19.0

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+10%)	7%
Low	25	(-5%)	3%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	119	100	124
to Sell	119	122	105
Hld's(000)	69437	67569	67722

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

2002	2003	2004	2005[G]	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	23.14	24.32	27.87	27.89	23.99	23.67	24.06	***24.50***	***25.10***	Revenues per sh	***27.50***
--	--	--	4.75	4.64	5.21	4.71	4.07	4.82	4.96	***5.10***	***5.30***	"Cash Flow" per sh	***6.25***
--	--	--	1.02	1.14	2.33	1.39	1.31	1.66	1.95	***1.90***	***1.95***	Earnings per sh A	***2.25***
--	--	--	--	.68	.93	.97	1.01	1.04	1.06	***1.08***	***1.11***	Div'd Decl'd per sh B ■ †	***1.25***
--	--	--	4.08	5.94	7.28	6.12	9.25	5.97	3.98	***3.95***	***3.30***	Cap'l Spending per sh	***4.00***
--	--	--	19.15	19.58	21.05	21.64	20.50	21.14	22.07	***22.85***	***23.60***	Book Value per sh C	***26.25***
--	--	--	62.50	62.50	62.53	62.58	75.21	75.32	75.36	***75.55***	***75.75***	Common Shs Outst'g D	***76.50***
--	--	--	--	23.4	11.9	16.3	14.4	12.0	12.4	*Bold figures are*		Avg Ann'l P/E Ratio	***12.0***
--	--	--	--	1.26	.63	.98	.96	.76	.78	*Value Line*		Relative P/E Ratio	***.80***
--	--	--	--	2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	*estimates*		Avg Ann'l Div'd Yield	***4.6%***
--	--	1454.0	1446.0	1520.0	1743.0	1745.0	1804.0	1783.0	1813.0	***1850***	***1900***	Revenues ($mill)	***2100***
--	--	92.0	64.0	71.0	145.0	87.0	95.0	125.0	147.0	***145***	***145***	Net Profit ($mill)	***175***
--	--	37.0%	40.2%	33.6%	33.8%	28.7%	28.8%	30.5%	28.3%	***30.0%***	***30.0%***	Income Tax Rate	***30.0%***
--	--	9.8%	18.8%	33.8%	17.9%	17.2%	31.6%	17.6%	5.4%	***3.0%***	***3.0%***	AFUDC % to Net Profit	***3.0%***
--	--	41.1%	42.3%	43.4%	49.9%	46.2%	50.3%	53.0%	49.6%	***47.0%***	***47.5%***	Long-Term Debt Ratio	***45.5%***
--	--	58.9%	57.7%	56.6%	50.1%	53.8%	49.7%	47.0%	50.4%	***53.0%***	***52.5%***	Common Equity Ratio	***54.5%***
--	--	2171.0	2076.0	2161.0	2629.0	2518.0	3100.0	3390.0	3298.0	***3260***	***3425***	Total Capital ($mill)	***3725***
--	--	2275.0	2436.0	2718.0	3066.0	3301.0	3858.0	4133.0	4285.0	***4345***	***4340***	Net Plant ($mill)	***4350***
--	--	5.6%	4.6%	4.7%	6.9%	5.0%	4.5%	5.4%	6.2%	***6.0%***	***5.5%***	Return on Total Cap'l	***6.0%***
--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	***8.5%***	***8.0%***	Return on Shr. Equity	***8.5%***
--	--	7.2%	5.3%	5.8%	11.0%	6.4%	6.2%	7.9%	8.8%	***8.5%***	***8.0%***	Return on Com Equity E	***8.5%***
--	--	7.2%	5.3%	3.5%	6.6%	2.0%	1.5%	3.0%	4.1%	***3.5%***	***3.5%***	Retained to Com Eq	***4.0%***
--	--	--	--	39%	40%	69%	76%	62%	54%	***56%***	***57%***	All Div'ds to Net Prof	***55%***

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1735.0 mill. **Due in 5 Yrs** $337.0 mill.
LT Debt $1635.0 mill. **LT Interest** $94.0 mill.
(LT interest earned: 2.5x)
Leases, Uncapitalized Annual rentals $9.0 mill.

Pension Assets-12/11 $487.0 mill.
Oblig. $634.0 mill.

Pfd Stock None

Common Stock 75,506,040 shs.
as of 4/26/12

MARKET CAP: $2.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.3	-3.1	+3.3
Avg. Indust. Use (MWH)	9343	12986	14932
Avg. Indust. Revs. per KWH (¢)	7.07	6.62	6.16
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw) F	3949	3582	3555
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.5	+.2
Fixed Charge Cov. (%)	179	224	273

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	--	2.5%
"Cash Flow"	--	-.5%	5.0%
Earnings	--	8.5%	5.5%
Dividends	--	NMF	3.5%
Book Value	--	2.0%	3.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	485.0	389.0	445.0	485.0	1804.0
2010	449.0	415.0	464.0	455.0	1783.0
2011	484.0	411.0	439.0	479.0	1813.0
2012	479.0	***431***	***460***	***480***	***1850***
2013	***495***	***440***	***470***	***495***	***1900***

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.47	.31	.43	.11	1.31
2010	.36	.32	.65	.34	1.66
2011	.92	.29	.36	.38	1.95
2012	.65	***.35***	***.50***	***.40***	***1.90***
2013	***.68***	***.37***	***.50***	***.40***	***1.95***

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.235	.245	.245	.245	.97
2009	.245	.245	.255	.255	1.00
2010	.255	.255	.26	.26	1.03
2011	.26	.26	.265	.265	1.05
2012	.265	.265	.27		

BUSINESS: Portland General Electric Company (PGE) provides electricity to 825,000 customers in 52 cities in a 4,000-square-mile area of Oregon, including Portland and Salem. The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 48%; commercial, 35%; industrial, 12%; other, 5%. Generating sources: coal, 19%; gas, 10%; hydro, 9%; wind, 6%; purchased, 56%. Fuel costs: 42% of revenues. '11 reported depreciation rate: 3.7%. Has 2,600 employees. Chairman: Corbin A. McNeill, Jr. Chief Executive Officer and President: Jim Piro. Incorporated: Oregon. Address: 121 SW Salmon Street, Portland, Oregon 97204. Telephone: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric has issued a request for proposals for generating resources, and another RFP is coming. The utility needs generating resources for the 2013-2017 time frame. PGE will propose building some units, and an independent evaluator hired by the state commission will review PGE's bid against proposals submitted by other companies that want to build units themselves or sell power to the company. The winning bidders will likely be announced in late 2012 or early 2013. PGE, with the approval of the Oregon commission, will also issue a separate RFP for renewable energy resources. If everything proceeds as expected, the winners of the latter RFP will be announced in late 2012 or early 2013, too.

The importance of the RFPs is that they will determine PGE's capital spending and financing plans for the next few years. We are not assuming in our figures that the company builds any major projects over that time frame, but if any of its bids are successful, then PGE's profits will probably wind up higher than our estimates and projections suggest.

We estimate that earnings will decline slightly in 2012, recover in 2013, and improve in 2014. Favorable hydro and weather conditions helped PGE in the first quarter of 2011, making the year-to-year profit comparison difficult. Our 2012 estimate of $1.90 a share is within PGE's guidance of $1.85-$2.00. Without much impetus for higher income in 2013, except for modest volume growth, only a slight bottom-line increase is probable next year. (The company has not yet provided earnings guidance for 2013.) PGE will probably file a general rate application in early 2013, with new tariffs taking effect in 2014. If this occurs, earnings growth in 2014 should be greater than in 2013.

As we had expected, the board of directors raised the dividend in the second quarter. The board boosted the annual disbursement by $0.02 cents a share (1.9%), the same increase as in each of the past two years.

This stock's dividend yield is about equal to the utility average. Our 3- to 5-year projections indicate subpar total return potential.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted EPS. '09 & '10 EPS don't add due to rounding. Next earnings report due early Aug. (B) Div'ds paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $7.88/sh. (D) In mill. (E) Rate base: Net original cost. Rate allowed on common equity in '11: 10.0%; earned on average com. eq., '11: 9.0%. Regulatory Climate: Below Average. (F) Summer peak in '09. (G) '05 per-share data are pro forma, based on shares outstanding when the stock began trading in '06.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	45

UNS ENERGY NYSE-UNS

RECENT PRICE	41.08	P/E RATIO	18.7 (Trailing: 16.0; Median: 17.0)	RELATIVE P/E RATIO	1.32	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 3 Lowered 11/11/11

SAFETY 3 New 12/31/04

TECHNICAL 3 Raised 7/20/12

BETA .75 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	26.0	20.8	24.9	24.9	34.8	37.5	40.0	34.5	33.3	36.9	39.3	42.1					
Low:	13.8	13.7	16.0	22.9	24.3	29.5	27.6	20.9	22.8	29.0	33.0	35.2					

2015-17 PROJECTIONS

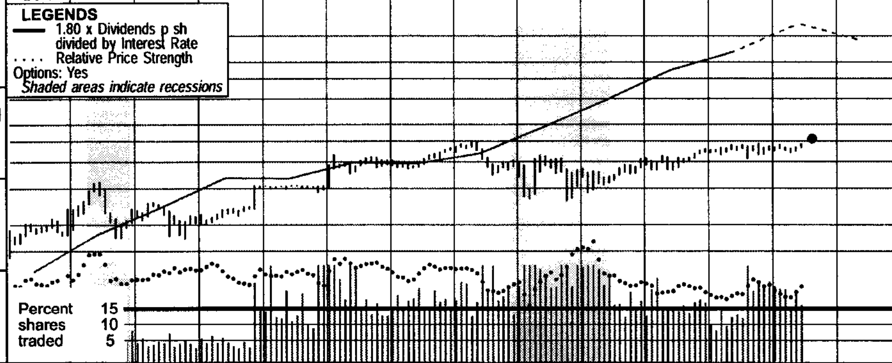
	Price	Gain	Ann'l Total Return
High	65	(+60%)	*15%*
Low	40	(-5%)	*4%*

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	74	87	80
to Sell	76	73	93
Hld's(000)	33078	32564	33499



Target Price Range

2015	2016	2017

128, 96, 80, 64, 48, 40, 32, 24, 16, 12

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.7	-4.1
3 yr.	65.5	68.8
5 yr.	43.7	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.28	22.71	23.83	24.85	31.12	43.12	25.50	28.71	34.13	35.26	37.42	39.12	39.41	38.89	39.78	40.89	***38.15***	***39.45***	**Revenues per sh**	***42.50***
6.82	5.29	3.48	3.96	4.23	5.41	4.80	5.20	5.29	5.21	5.68	5.64	4.56	7.82	7.33	7.44	***6.60***	***7.10***	**"Cash Flow" per sh**	***8.00***
3.76	2.60	.68	1.08	1.27	1.79	.97	1.30	1.31	1.30	1.85	1.55	.39	2.69	2.82	2.75	***2.20***	***2.75***	**Earnings per sh A**	***3.75***
--	--	--	--	.32	.40	.50	.60	.64	.76	.84	.90	.96	1.16	1.56	1.68	***1.72***	***1.76***	**Div'd Decl'd per sh B ■ †**	***2.25***
2.07	2.22	2.52	2.87	3.19	3.63	3.36	4.06	4.49	5.83	6.77	6.95	9.85	8.01	7.26	10.13	***8.80***	***10.50***	**Cap'l Spending per sh**	***11.70***
4.15	6.75	7.65	10.02	11.20	12.68	13.05	15.97	16.95	17.68	18.59	19.54	19.16	20.94	22.46	24.07	***23.90***	***24.90***	**Book Value per sh**	***27.45***
32.13	32.14	32.26	32.35	33.22	33.50	33.58	33.79	34.26	34.87	35.19	35.32	35.46	35.85	36.54	36.92	***38.00***	***38.00***	**Common Shs Outst'g C**	***40.00***
4.3	6.1	23.3	10.8	11.8	10.8	18.2	14.6	18.7	23.9	17.7	22.0	73.8	10.4	11.6	13.3	*Bold figures are*		**Avg Ann'l P/E Ratio**	***14.0***
.27	.35	1.21	.62	.77	.55	.99	.83	.99	1.27	.96	1.17	4.44	.69	.74	.84	*Value Line*		**Relative P/E Ratio**	***.95***
--	--	--	--	2.1%	2.1%	2.8%	3.2%	2.6%	2.5%	2.6%	2.6%	3.3%	4.1%	4.8%	4.6%	*estimates*		**Avg Ann'l Div'd Yield**	***4.3%***

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
856.2	969.9	1169.0	1229.5	1316.9	1381.4	1397.5	1394.4	1453.7	1509.5	***1450***	***1500***	**Revenues ($mill)**	***1700***
33.3	45.2	45.9	46.1	69.2	58.4	14.0	104.3	111.5	110.0	***90.0***	***105***	**Net Profit ($mill)**	***150***
33.7%	19.7%	42.5%	41.4%	38.8%	40.1%	54.8%	38.2%	41.2%	37.8%	***40.0%***	***40.0%***	**Income Tax Rate**	***40.0%***
--	2.2%	--	--	2.9%	3.4%	--	--	--	--	***Nil***	***Nil***	**AFUDC % to Net Profit**	***Nil***
81.5%	79.2%	77.1%	75.3%	72.9%	68.8%	72.9%	70.5%	68.5%	67.8%	***69.0%***	***70.0%***	**Long-Term Debt Ratio**	***72.5%***
18.5%	20.8%	22.9%	24.7%	27.1%	31.2%	27.1%	29.5%	31.5%	32.2%	***31.0%***	***30.5%***	**Common Equity Ratio**	***28.0%***
2368.8	2589.0	2540.3	2494.9	2414.1	2214.9	2506.4	2547.0	2602.8	2758.6	***2930***	***3135***	**Total Capital ($mill)**	***3950***
1668.4	2069.2	2081.1	2171.5	2259.6	2407.3	2617.7	2785.7	2961.5	3182.3	***3405***	***3645***	**Net Plant ($mill)**	***4465***
2.8%	4.9%	5.1%	5.1%	5.9%	5.7%	3.0%	5.2%	5.5%	5.3%	***5.0%***	***5.0%***	**Return on Total Cap'l**	***5.5%***
7.6%	8.4%	7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	***10.0%***	***11.0%***	**Return on Shr. Equity**	***14.0%***
7.6%	8.4%	7.9%	7.5%	10.6%	8.5%	2.1%	13.9%	13.6%	12.4%	***10.0%***	***11.0%***	**Return on Com Equity D**	***14.0%***
3.8%	4.6%	4.1%	3.2%	6.1%	3.9%	NMF	8.4%	6.7%	5.4%	***2.5%***	***4.0%***	**Retained to Com Eq**	***5.5%***
51%	45%	48%	57%	43%	54%	NMF	40%	51%	56%	***80%***	***64%***	**All Div'ds to Net Prof**	***60%***

CAPITAL STRUCTURE as of 3/31/12
Total Debt $1446.7 mill. **Due in 5 Yrs** $770.0 mill.
LT Debt $1913.0 mill. **LT Interest** $75.0 mill.
Incl. $352.7 mill. capitalized leases.
(LT interest earned: 3.4x)

Pension Assets-12/11 $245 mill. **Oblig.** $319 mill.
Pfd Stock None

Common Stock 40,260,270 shs.
as of 4/18/12
MARKET CAP: $1.7 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.4	-.8	+.4
Avg. Indust. Use (MWH)	5096	5076	5064
Avg. Indust. Revs. per KWH (¢)	7.00	6.90	7.10
Capacity at Peak (Mw)	3010	3044	3271
Peak Load, Summer (Mw)	2354	2333	2334
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.4	+.3	+.4
Fixed Charge Cov. (%)	232	268	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.0%	2.5%	*16.5%*
"Cash Flow"	5.0%	7.0%	*1.0%*
Earnings	7.0%	13.0%	*5.5%*
Dividends	20.0%	14.5%	*7.5%*
Book Value	7.0%	5.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	311.9	337.8	414.2	330.5	1394.4
2010	317.9	337.8	438.8	359.2	1453.7
2011	344.8	369.7	450.9	344.1	1509.5
2012	318.9	***355***	***435***	***341.1***	***1450***
2013	***340***	***345***	***450***	***365***	***1500***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.14	.80	1.45	.30	2.69
2010	.52	.65	1.36	.29	2.82
2011	.35	.71	1.46	.22	2.75
2012	.17	***.60***	***1.25***	***.18***	***2.20***
2013	***.35***	***.70***	***1.45***	***.25***	***2.75***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.24	.24	.24	.24	.96
2009	.29	.29	.29	.29	1.16
2010	.39	.39	.39	.39	1.56
2011	.42	.42	.42	.42	1.68
2012	.43	.43			

BUSINESS: UNS Energy Corporation, through its subsidiaries, operates as an electric utility in Arizona. Subsidiaries include Tuscon Electric Power (TEP), UNS Gas, and UNS Electric. TEP segment serves about 400,000 retail customers in southern Arizona and accounted for 77% of '11 net income. Revenue sources: residential, 42%; commercial, 21%; industrial, 34%; other, 3%. Copper mining is largest industry served. Fuels: coal, 92%; gas, 8%. '11 TEP reported depreciation rate: 3.2%. Has 2,004 employees: TEP, 1,391; UNS Gas, 187; UNS Electric, 154; Other, 272. Chrmn. & CEO: Paul J. Bonavia. Pres.: David G. Hutchens. Inc.: AZ. Address: 88 E. Broadway Blvd., Tucson, AZ. 85701. Telephone: 520-571-4000. Internet: www.unisourceenergy.com.

UNS Energy, formerly known as UniSource Energy, has filed for rate increases. The company's largest subsidiary, Tuscon Electric Power (TEP), has been in a four-year base-rate freeze, which is scheduled to end December 1, 2012, according to its 2008 settlement agreement. As anticipated, TEP filed for a rate hike on July 2nd, and expects the settlement to be completed within 13 months, with an August 1, 2013 start date. TEP is requesting $128 million in annual revenue increases, which is based on an original cost rate base of approximately $1.5 billion. All told, an increase would likely result in a 15% base-rate hike, which should help boost earnings in 2013. As a result, however, customers will see costs rise a little over 15%, as the average bill will increase by $13 a month.

The new rates are needed to provide TEP with an appropriate rate of return, which has been lacking due to significant cost changes since its last test year in 2006. Indeed, the requested rate hikes will likely cover rising service costs and the significant amount of capital investments the company incurred over the past five years. Too, the rate increases will help pay for renewable power and energy efficiency expenditures mandated by environmental regulations. Also, management hopes to see growth and demand improve, which have lagged since the recession.

In other news, the company reported underwhelming first-quarter results. In fact, both the top and bottom lines were below expectations. Revenues were $319 million, and earnings contracted over 50% from the year-ago figure. We now anticipate the full-year performance will be lackluster, as UNS is hindered by TEP's rate freeze. As a result, we have tempered our 2012 share-net estimate by a nickel, to $2.20.

These shares are best suited for income-oriented investors. Although this issue is ranked to mirror the broader market averages over the coming six to 12 months, UNS Energy's 4.2% dividend yield is impressive. Moreover, we expect management to further boost the dividend in the coming 3 to 5 years, to achieve its target payout ratio, which is 60%-70% of its net income.

Michelle Jensen *August 3, 2012*

(A) EPS diluted. Excl. nonrecur. gains (losses): '98, 19¢; '99, $1.35; '00, 48¢; '03, $2.00. Next earnings report due early Aug. Earnings may not sum due to rounding. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) In millions. (D) Rate base: fair value. Rate allowed on com. eq. in '08: 10.25%; earned on avg. com. eq., '11: 12.4%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	35

XCEL ENERGY NYSE-XEL

RECENT PRICE 28.72 | P/E RATIO 16.4 (Trailing: 17.0; Median: 14.0) | RELATIVE P/E RATIO 1.15 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Lowered 2/17/12

SAFETY 2 Raised 5/14/04

TECHNICAL 4 Raised 7/27/12

BETA .65 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	31.8	28.5	17.4	18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.3
Low:	24.2	5.1	10.4	15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.9

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	9%
Low	25	(-15%)	1%

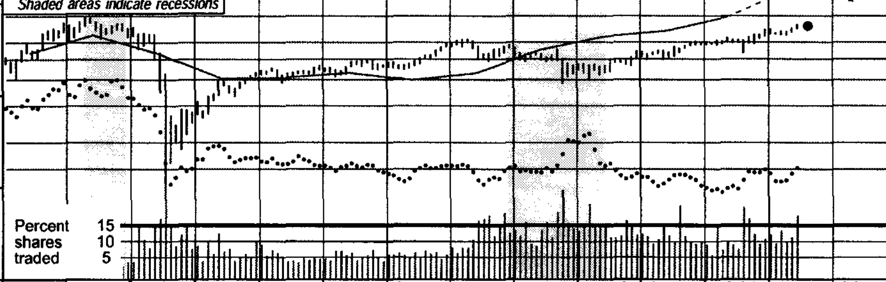
Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	206	218	208
to Sell	164	171	208
Hld's(000)	296827	298171	300995

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



Target Price Range
2015 | 2016 | 2017
64
48
40
32
24
20
16
12
8
6

% TOT. RETURN 6/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.6	-4.1
3 yr.	73.5	68.8
5 yr.	71.7	19.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
19.22	18.32	18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	**21.35**	**22.20**	Revenues per sh	**25.25**
4.33	3.92	4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	**3.95**	**4.10**	"Cash Flow" per sh	**4.75**
1.91	1.61	1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	**1.75**	**1.85**	Earnings per sh A	**2.25**
1.37	1.40	1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	**1.07**	**1.11**	Div'd Decl'd per sh B ■	**1.35**
2.99	2.90	2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	**5.40**	**6.50**	Cap'l Spending per sh	**4.75**
15.46	15.89	16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	**18.15**	**19.25**	Book Value per sh C	**21.75**
138.13	149.24	152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	**490.00**	**507.00**	Common Shs Outst'g D	**515.00**
12.5	15.5	15.2	16.6	14.3	12.4	40.8	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**13.0**
.78	.89	.79	.95	.93	.64	2.23	.66	.72	.82	.80	.89	.82	.85	.90	.90	*estimates*		Relative P/E Ratio	**.85**
5.7%	5.6%	5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%			Avg Ann'l Div'd Yield	**4.7%**

CAPITAL STRUCTURE as of 3/31/12
Total Debt $10247 mill. **Due in 5 Yrs** $2082.4 mill.
LT Debt $8598.4 mill. **LT Interest** $584.7 mill.
Incl. $191.4 mill. capitalized leases.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $185.6 mill.
Pension Assets-12/11 $2.67 bill. **Oblig.** $3.23 bill.

Pfd Stock None

Common Stock 486,943,183 shs.
as of 4/19/12
MARKET CAP: $14 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
9524.4	7937.5	8345.3	9625.5	9840.3	10034	11203	9644.3	10311	10655	**10450**	**11250**	Revenues ($mill)	**13000**
177.6	510.0	526.9	499.0	568.7	575.9	645.7	685.5	727.0	841.4	**860**	**930**	Net Profit ($mill)	**1110**
32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	**12.0%**	**12.0%**	AFUDC % to Net Profit	**8.0%**
59.6%	55.3%	55.0%	51.7%	52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	**53.5%**	**52.5%**	Long-Term Debt Ratio	**50.0%**
39.5%	43.8%	44.1%	47.3%	47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	**46.5%**	**47.5%**	Common Equity Ratio	**50.0%**
11815	11790	11801	11398	12371	12748	14800	15277	17452	17331	**19250**	**20550**	Total Capital ($mill)	**22400**
18816	13667	14096	14696	15549	16676	17689	18508	20663	22353	**23925**	**26100**	Net Plant ($mill)	**29700**
5.4%	6.1%	6.2%	6.2%	6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	**6.0%**	**6.0%**	Return on Total Cap'l	**6.5%**
3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	**9.5%**	**9.5%**	Return on Shr. Equity	**10.0%**
3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	**9.5%**	**9.5%**	Return on Com Equity E	**10.0%**
NMF	3.9%	3.9%	2.9%	3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	**4.0%**	**4.0%**	Retained to Com Eq	**3.5%**
NMF	60%	62%	69%	63%	66%	59%	61%	59%	56%	**61%**	**60%**	All Div'ds to Net Prof	**62%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.0	+3.0	+.4
Large C & I Use (MWH)	24225	24431	24286
Large C & I Revs. per KWH (¢)	5.34	5.65	5.90
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21108	20517	21898
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	--	+.4
Fixed Charge Cov. (%)	258	277	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-4.0%	-1.5%	3.0%
"Cash Flow"	-2.0%	1.0%	5.0%
Earnings	-1.0%	4.5%	6.0%
Dividends	-4.0%	3.5%	5.0%
Book Value	--	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2695	2016	2315	2618	9644.3
2010	2807	2308	2629	2567	10311
2011	2817	2438	2832	2568	10655
2012	2578	**2422**	**2850**	**2600**	**10450**
2013	**2900**	**2650**	**3000**	**2700**	**11250**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.38	.25	.48	.37	1.49
2010	.36	.29	.62	.29	1.56
2011	.42	.33	.69	.28	1.72
2012	.38	**.36**	**.69**	**.32**	**1.75**
2013	**.42**	**.36**	**.71**	**.36**	**1.85**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.23	.2375	.2375	.94
2009	.2375	.2375	.245	.245	.97
2010	.245	.245	.2525	.2525	1.00
2011	.2525	.2525	.26	.26	1.03
2012	.26	.26	.27		

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota, & Michigan & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.4 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. commercial & industrial, 35%; lg. commercial & industrial, 18%; other, 16%. Generating sources not avail. Fuel costs: 48% of revs. '11 reported depr. rate: 2.9%. Has 11,300 empls. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Web: www.xcelenergy.com.

One of Xcel Energy's utility subsidiaries is taking steps to deal with disappointing regulatory rulings in two states. The Minnesota commission denied Northern States Power's request for an accounting order that would have allowed it to defer (for future recovery) $24 million of incremental property taxes in 2012. The decision will make it tougher for the company to attain even the low end of its targeted profit range of $1.75-$1.85 a share this year. (Even so, we're keeping our estimate at $1.75 a share for now.) The company was planning to file an electric application in Minnesota in November, but is considering accelerating its rate case. The South Dakota regulators granted NSP a final electric rate hike of about $8 million (less than the interim tariff increase of $12.7 million), based on a 9.25% return on a 53.04% common-equity ratio. Considering the order, and the low ROE that NSP has been earning in the state, the utility filed another rate case shortly thereafter. It requested a $19.4 million tariff hike, based on a return of 10.65% on a common-equity ratio of 52.89%. New rates should take effect in late 2012 or early 2013.

A rate case is pending in Wisconsin, and a few more filings are expected by yearend. Regulatory activity is standard operating procedure for Xcel's utilities so that they can place their capital investments into the rate base and recover rising expenses. In Wisconsin, NSP asked for electric and gas increases of $39.1 million (6.7%) and $5.3 million, respectively, based on a return of 10.4% on a common-equity ratio of 52.5%. New tariffs are likely to take effect in early 2013. The company also plans to file electric rate cases in Texas, New Mexico, and North Dakota. Rate relief should boost earnings in 2013, and a return to normal winter weather conditions would be a plus, as well.

The board of directors boosted the common dividend by one cent a share (3.8%) quarterly. The increase was near the upper end of Xcel's dividend growth target of 2%-4% annually. We think dividend hikes will accelerate by mid-decade.

Xcel stock does not stand out among utility equities. The dividend yield and 3- to 5-year total return potential are below average for the industry.

Paul E. Debbas, CFA *August 3, 2012*

(A) Diluted EPS. Excl. nonrec. gain (loss): '02, ($6.27); '10, 5¢; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '09 EPS don't add due to rounding. Next egs. report due late Oct. (B) Div'ds histor. paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $4.91/sh. (D) In mill. (E) Rate base: Varies. Rate all'd on com. eq.: MN '09 10.88%; WI '08 10.75%; CO '10 (elec.) 10.5%; CO '07 (gas) 10.25%; TX '86 15.05%; earned on avg. com. eq., '11: 10.1%. Regulatory Climate: Average.

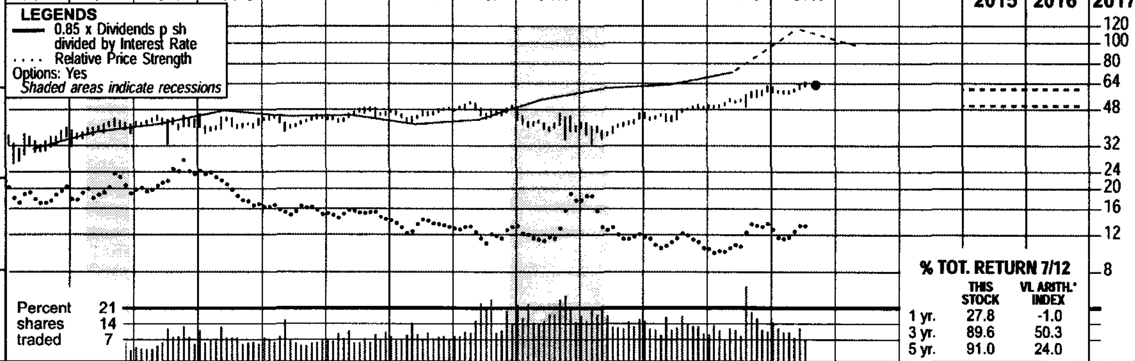
Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

CON. EDISON NYSE-ED

RECENT PRICE **63.20** | P/E RATIO **16.4** (Trailing: 17.5; Median: 14.0) | RELATIVE P/E RATIO **1.12** | DIV'D YLD **3.9%** | VALUE LINE

TIMELINESS **2** Raised 8/24/12
SAFETY **1** New 7/27/90
TECHNICAL **2** Raised 8/24/12
BETA .60 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	43.4	45.4	46.0	45.6	49.3	49.3	52.9	49.3	46.3	51.0	62.7	66.0
Low:	31.4	32.7	36.6	37.2	41.1	41.2	43.1	34.1	32.6	41.5	48.6	57.0



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(-5%)	3%
Low	50	(-20%)	-1%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	311	300	279
to Sell	189	213	273
Hld's(000)	122506	125157	121648

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.8	-1.0
3 yr.	89.6	50.3
5 yr.	91.0	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
29.62	30.24	30.46	35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	*42.30*	*43.70*	Revenues per sh	*48.25*
4.97	5.08	5.29	5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	*7.00*	*7.35*	"Cash Flow" per sh	*8.50*
2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	*3.75*	*3.90*	Earnings per sh A	*4.25*
2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	*2.42*	*2.44*	Div'd Decl'd per sh B ■	*2.50*
2.87	2.78	2.66	3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	*7.55*	*7.30*	Cap'l Spending per sh	*7.25*
24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	*40.40*	*41.90*	Book Value per sh C	*47.00*
234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	*293.00*	*293.00*	Common Shs Outst'g D	*293.00*
10.1	10.9	15.3	14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.63	.63	.80	.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.96	*Value Line*		Relative P/E Ratio	*.85*
7.0%	6.5%	4.6%	4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $11873 mill. Due in 5 Yrs $3742.0 mill.
LT Debt $9842 mill. LT Interest $515.0 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $50.0 mill.

Pension Assets-12/11 $7.80 bill. **Oblig.** $11.8 bill.

Pfd Stock None

Common Stock 292,892,396 shs. **as of 7/31/12**

MARKET CAP: $19 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
8482.0	9827.0	9758.0	11690	12137	13120	13583	13032	13325	12938	*12400*	*12800*	Revenues ($mill)	*14150*
682.1	639.0	560.0	719.0	749.0	936.0	933.0	868.0	992.0	1062.0	*1115*	*1155*	Net Profit ($mill)	*1260*
36.9%	33.7%	34.3%	33.6%	35.2%	32.6%	36.0%	34.2%	36.0%	36.1%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
2.2%	4.2%	7.7%	2.2%	1.6%	1.9%	1.7%	2.6%	2.4%	1.6%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
50.1%	50.4%	47.4%	49.6%	50.2%	45.6%	48.3%	48.5%	48.6%	46.5%	*46.5%*	*46.0%*	Long-Term Debt Ratio	*45.5%*
48.1%	48.0%	51.0%	49.0%	48.5%	53.1%	50.6%	50.4%	50.4%	52.5%	*53.5%*	*54.0%*	Common Equity Ratio	*54.5%*
12302	13369	13828	14921	16515	16687	19160	20330	21952	21794	*22025*	*22725*	Total Capital ($mill)	*25300*
13329	15225	16106	17112	18445	19914	20874	22464	23863	25093	*26350*	*27500*	Net Plant ($mill)	*30200*
7.1%	6.3%	5.6%	6.3%	6.0%	7.0%	6.2%	5.7%	5.9%	6.2%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.1%	9.6%	7.7%	9.6%	9.1%	10.3%	9.4%	8.3%	8.8%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.0%*
11.3%	9.8%	7.8%	9.7%	9.2%	10.4%	9.5%	8.4%	8.9%	9.2%	*9.0%*	*9.5%*	Return on Com Equity E	*9.0%*
4.0%	2.9%	.8%	2.6%	2.6%	3.9%	3.1%	2.5%	3.2%	3.1%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
65%	71%	89%	74%	73%	63%	67%	71%	65%	66%	*64%*	*62%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-.9	+3.6	-1.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	12242	12963	14788
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	296	331	360

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.0%	--	*1.0%*
"Cash Flow"	1.0%	4.5%	*5.5%*
Earnings	1.0%	4.5%	*4.0%*
Dividends	1.0%	1.0%	*1.0%*
Book Value	4.0%	4.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3423	2845	3489	3275	13032
2010	3462	3017	3707	3139	13325
2011	3349	2993	3629	2967	12938
2012	3078	2771	*3651*	*2900*	*12400*
2013	*3200*	*2900*	*3700*	*3000*	*12800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.66	.55	1.20	.73	3.14
2010	.80	.64	1.23	.80	3.47
2011	1.06	.56	1.30	.65	3.57
2012	.94	.73	*1.35*	*.73*	*3.75*
2013	*1.05*	*.67*	*1.38*	*.80*	*3.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.585	.585	.585	.585	2.34
2009	.59	.59	.59	.59	2.36
2010	.595	.595	.595	.595	2.38
2011	.60	.60	.60	.60	2.40
2012	.605	.605			

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R, acquired 7/99), which operates in New York, New Jersey, and Pennsylvania. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Purchases most of its power. Fuel costs: 39% of revenues. '11 reported depreciation rates: 2.8%-3.1%. Has 15,000 employees. Chairman, President & CEO: Kevin Burke. Inc.: New York. Address: 4 Irving Place, New York, NY 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's largest utility subsidiary plans to file a general rate case in November. Consolidated Edison Company of New York's rate plan expires in 2013: at the end of March for electricity and at the end of September for gas and steam. The utility will be able to update its rate base and its operating expenses, but will likely wind up with a lower allowed return on equity, due to low interest rates. (This is especially true on the electric side, where the allowed ROE is now 10.15%.) New tariffs should take effect at the start of October, 2013, so any change in rates wouldn't have much effect on the utility until 2014.

Orange and Rockland got an electric rate order that took effect at the start of July. The three-year rate plan calls for a total tariff increase of $48 million. The allowed ROE is 9.4% in the first year, 9.5% in the second, and 9.6% in the third, based on a 48% common-equity ratio.

The competitive energy business made a large asset acquisition. Consolidated Edison Development paid $266 million (from cash on hand) for a 70-megawatt solar project that is under construction in California. It is scheduled for completion in the fourth quarter of 2012. This asset appealed to the company because it came with a 25-year contract to sell power to the local utility there. ConEd is looking for solar projects that come with long-term power contracts, or are in states in which solar energy credits can be sold. As a group, the company's nonutility activities are earning a higher ROE than the regulated utility operations.

We look for respectable earnings growth this year and next. ConEd is benefiting from customer growth, especially on the gas side of its business, where customers are converting from oil to gas to heat their homes. The purchase of the solar project should help next year, too.

This timely stock is up nearly 10% since our May report, far outpacing most utility issues. There isn't any obvious reason for the rise in price. The yield is a bit below the utility average, the relative price-earnings ratio is well above its historical level, and the quotation is *higher* than the upper level of our 2015-2017 Target Price Range.

Paul E. Debbas, CFA *August 24, 2012*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 11¢; '03, 45¢; gain on discontinued operations: '08, $1.01. Next earnings report due late Oct. (B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '11: $34.24/sh. (D) In millions. (E) Rate base: net original cost. Rate allowed on com. eq. for CECONY in '10: 10.15% electric, 9.6% gas and steam; O&R in '12 (electric) 9.4%, in '09 (gas) 10.3%; earned on avg. com. eq., '11: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	85

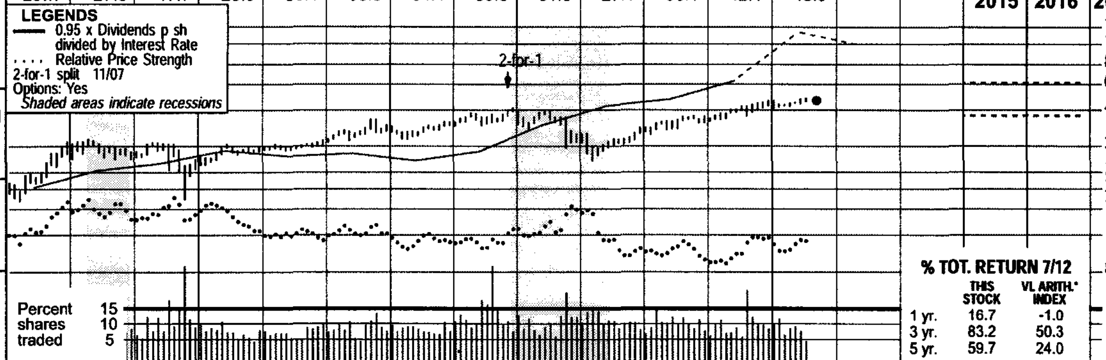
DOMINION RES. NYSE-D

RECENT PRICE	53.50	P/E RATIO	17.6 (Trailing: 20.3 / Median: 15.0)	RELATIVE P/E RATIO	1.21	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 2 Raised 8/24/12
SAFETY 2 Raised 9/11/98
TECHNICAL 2 Raised 8/24/12
BETA .65 (1.00 = Market)

High:	35.0	33.5	33.0	34.4	43.5	42.2	49.4	48.5	39.8	45.1	53.6	55.2	
Low:	27.6	17.7	25.9	30.4	33.3	34.4	39.8	31.3	27.1	36.1	42.1	48.9	

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+20%)	9%
Low	45	(-15%)	1%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	309	316	287
to Sell	317	329	374
Hld's(000)	324573	321349	322861

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.7	-1.0
3 yr.	83.2	50.3
5 yr.	59.7	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
13.36	20.44	15.65	14.81	18.84	19.94	16.58	18.58	20.55	26.00	23.61	27.17	27.93	25.26	26.16	25.23	***23.45***	***24.00***	Revenues per sh	***26.25***
3.22	3.89	2.99	3.68	3.71	3.92	4.45	3.97	4.18	3.71	4.91	5.08	5.07	4.82	5.10	5.04	***5.50***	***5.85***	"Cash Flow" per sh	***7.00***
1.33	1.50	.86	1.50	1.25	1.49	2.41	1.96	2.13	1.50	2.40	2.13	3.04	2.64	2.89	2.76	***3.00***	***3.20***	Earnings per sh A	***3.75***
1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.30	1.34	1.38	1.46	1.58	1.75	1.83	1.97	***2.11***	***2.24***	Div'd Decl'd per sh B ■ †	***2.60***
1.34	1.73	1.60	2.16	2.82	2.31	2.17	5.20	3.88	4.84	5.81	6.89	6.09	6.41	5.89	6.41	***7.45***	***8.30***	Cap'l Spending per sh	***7.75***
13.59	13.42	13.67	12.75	14.22	15.81	16.57	16.21	16.80	14.98	18.50	16.31	17.28	18.67	20.65	20.08	***21.30***	***22.50***	Book Value per sh C	***26.75***
362.44	375.60	388.92	372.64	491.60	529.40	616.20	650.00	680.00	694.00	698.00	576.80	583.20	599.00	581.00	570.00	***576.00***	***581.00***	Common Shs Outst'g D	***595.00***
14.8	12.5	24.6	14.5	19.4	20.9	12.0	15.2	15.1	24.9	16.0	20.6	13.8	12.7	14.3	17.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	***15.0***
.93	.72	1.28	.83	1.26	1.07	.66	.87	.80	1.33	.86	1.09	.83	.85	.91	1.09		*estimates*	Relative P/E Ratio	***1.00***
6.6%	6.9%	6.1%	5.9%	5.3%	4.1%	4.4%	4.3%	4.0%	3.6%	3.6%	3.3%	3.8%	5.2%	4.4%	4.1%			Avg Ann'l Div'd Yield	***4.7%***
						10218	12078	13972	18041	16482	15674	16290	15131	15197	14379	***13500***	***13950***	Revenues ($mill)	***15600***
						1378.0	1261.0	1425.0	1050.0	1704.0	1414.0	1781.0	1585.0	1724.0	1603.0	***1740***	***1870***	Net Profit ($mill)	***2300***
						33.1%	34.9%	35.4%	35.7%	35.5%	33.4%	37.1%	33.2%	38.6%	34.6%	***36.0%***	***36.0%***	Income Tax Rate	***36.0%***
						6.9%	7.9%	4.9%	9.7%	7.9%	7.3%	4.9%	4.8%	5.9%	5.3%	***5.0%***	***5.0%***	AFUDC % to Net Profit	***5.0%***
						56.2%	59.4%	57.0%	57.9%	52.9%	57.8%	59.1%	57.5%	56.3%	59.8%	***59.0%***	***58.0%***	Long-Term Debt Ratio	***56.5%***
						42.7%	39.7%	42.0%	41.1%	46.2%	41.1%	39.8%	41.5%	42.8%	39.3%	***40.5%***	***41.0%***	Common Equity Ratio	***43.0%***
						23927	26571	27190	25307	27961	22898	25290	26923	28012	29097	***30400***	***31825***	Total Capital ($mill)	***37000***
						20257	25850	26716	28940	29382	21352	23274	25592	26713	29670	***32500***	***35775***	Net Plant ($mill)	***43500***
						7.7%	6.5%	6.9%	6.1%	7.9%	8.0%	8.7%	7.5%	7.7%	7.0%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.5%***
						13.2%	11.7%	12.2%	9.9%	12.9%	14.6%	17.2%	13.9%	14.1%	13.7%	***14.0%***	***14.0%***	Return on Shr. Equity	***14.5%***
						13.3%	11.8%	12.3%	9.9%	13.1%	14.9%	17.5%	14.0%	14.2%	13.9%	***14.0%***	***14.0%***	Return on Com Equity E	***14.5%***
						6.3%	4.0%	4.8%	1.1%	5.6%	5.0%	8.4%	4.7%	5.3%	4.0%	***4.0%***	***4.5%***	Retained to Com Eq	***4.5%***
						54%	67%	62%	89%	58%	67%	52%	67%	63%	71%	***71%***	***70%***	All Div'ds to Net Prof	***68%***

CAPITAL STRUCTURE as of 6/30/12
Total Debt $20674 mill. **Due in 5 Yrs** $8016.0 mill.
LT Debt $17003 mill. **LT Interest** $884.0 mill.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $111.0 mill.
Pension Assets-12/11 $5.15 bill.
Oblig. $4.98 bill.
Pfd Stock $257.0 mill. **Pfd Div'd** $16.0 mill.
1,340,140 shs. $4.04-$7.05, $100 liq. pref., redeemable at $101.00-$112.50/sh.; 2,500,000 variable rate Money Market Preferred shs.
Common Stock 573,352,279 shs.

MARKET CAP: $31 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.2	+4.5	-3.4
Avg. Indust. Use (MWH)	14857	15162	14823
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	15917	16563	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	+.5
Fixed Charge Cov. (%)	319	378	318

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.5%	2.0%	*.5%*
"Cash Flow"	3.0%	3.0%	*6.0%*
Earnings	7.0%	6.5%	*5.0%*
Dividends	3.5%	6.5%	*6.0%*
Book Value	3.5%	3.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	4778	3450	3648	3255	15131
2010	4168	3333	3950	3746	15197
2011	4057	3341	3803	3178	14379
2012	3462	3053	***3850***	***3135***	***13500***
2013	***3650***	***3150***	***3900***	***3250***	***13950***

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.89	.78	1.00	d.01	2.64
2010	.51	.79	.98	.61	2.89
2011	.89	.58	.69	.60	2.76
2012	.86	.48	***.91***	***.75***	***3.00***
2013	***.90***	***.60***	***.95***	***.75***	***3.20***

Calendar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.395	.395	.395	.395	1.58
2009	.4375	.4375	.4375	.4375	1.75
2010	.4575	.4575	.4575	.4575	1.83
2011	.4925	.4925	.4925	.4925	1.97
2012	.5275	.5275			

BUSINESS: Dominion Resources, Inc. is a holding company for Virginia Power & North Carolina Power, which serve 2.4 mill. customers in Virginia & northeastern North Carolina. Acq'd Consolidated Natural Gas (1.3 mill. customers in Ohio & West Virginia) 1/00. Nonutility operations include independent power production & retail energy services. Electric rev. breakdown: residential, 46%; commercial, 31%; industrial, 7%; other, 16%. Generating sources: nuclear, 28%; coal, 26%; gas, 12%; other, 1%; purch., 33%. Fuel costs: 47% of revs. '11 reported depr. rates: 2.0%-4.7%. Has 15,800 employees. Chairman, President & CEO: Thomas F. Farrell II. Inc.: VA. Address: 120 Tredegar St., P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

We have cut our 2012 earnings estimate for Dominion Resources by $0.15 a share. Second-quarter results were below our expectation. The weather was milder than normal, which hurt the bottom line by an estimated $0.05 a share, and the company booked a $74 million pretax charge ($0.08 a share) for the cost of restoring customers following storms in mid-2012. Even so, profits should still advance over the 2011 tally, because . . .

Virginia Power is performing well. The service area's economy is faring better than the national economy. In addition, the utility's earning power is rising with the addition of generation and transmission projects. We expect growth from the regulated operations to produce higher profits in 2013, as well. Virginia Power completed gas-fired and coal-fired plants in 2011 and 2012, respectively. It earned a return on these projects through rate riders. The utility is now building a 1,329-megawatt gas-fired facility at an expected cost of $1.1 billion. It is scheduled for completion in late 2014. The company plans to ask the Virginia regulators for permission to construct a similar plant that would be on line in 2016. Virginia Power is building a $350 million transmission line that is scheduled for completion in 2015, and some smaller transmission projects are under way, as well.

North Carolina Power has a rate case pending. The utility filed for a tariff hike of $63.7 million, based on an 11.25% return on a 52.4% common-equity ratio. New rates should take effect at the start of 2013.

Weak power prices are a concern for Dominion. Hedging and effective cost controls can only do so much in such an operating environment. We expect no improvement in the nonregulated power-generation segment's profits in the next two years. At least the company's other nonutility operations are faring better. One key opportunity is a proposed expansion of its Cove Point liquefied natural gas facility—if Dominion can obtain regulatory approvals and fend off legal challenges.

This stock is ranked favorably for Timeliness. However, the yield and 3- to 5-year total return potential are only average, by utility standards.

Paul E. Debbas, CFA *August 24, 2012*

(A) Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 12¢; '09, (47¢); '10, $2.18; '11, (7¢); losses from disc. ops.: '04, 3¢; '06, 26¢; '07, 1¢; '10, 26¢; '12, 3¢. '09 EPS don't add due to change in shares. Next earnings report due late Oct. (B) Div'ds histor. paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '11: $9.05/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '11: 10.9%; earned on avg. com. eq., '11: 13.4%. Regulatory Climate: Avg.

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

DUKE ENERGY NYSE-DUK

RECENT PRICE 68.20 | P/E RATIO 18.2 (Trailing: 16.0; Median: NMF) | RELATIVE P/E RATIO 1.25 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 3 Lowered 11/18/11

SAFETY 2 New 6/1/07

TECHNICAL 3 Raised 8/10/12

BETA .60 (1.00 = Market)

	2009	2010	2011	2012	2013	2014
High:	63.9	61.8	53.8	55.8	66.4	71.1
Low:	50.7	40.5	35.2	46.4	50.6	60.6

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

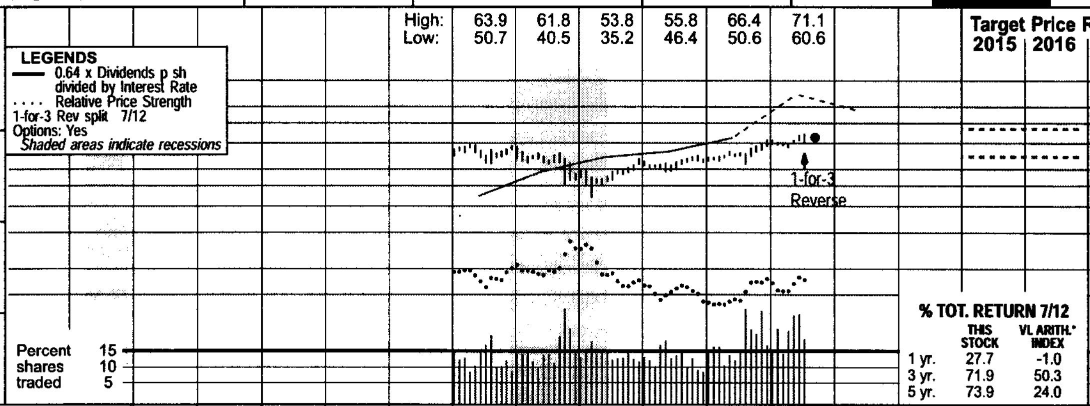
	Price	Gain	Ann'l Total Return
High	75	(+10%)	7%
Low	55	(-20%)	Nil

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	5	0	0	1	0	0	0
to Sell	1	0	7	1	1	7	0	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	400	407	393
to Sell	305	320	372
Hld's(000)	214829	220069	220614



% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	27.7	-1.0
3 yr.	71.9	50.3
5 yr.	73.9	24.0

Duke Energy Corporation, in its current configuration, began trading on January 3, 2007, the day after it spun off its midstream gas operations into a new company, Spectra Energy (NYSE: SE), to shareholders. Duke Energy shareholders received half a share of Spectra Energy for each Duke share held. In July of 2012, Duke acquired Progress Energy and effected a 1-for-3 reverse split. Data for the "old" Duke are not shown because they are not comparable.

© VALUE LINE PUB. LLC	2002	2003	2004	2005	2006	2007
Revenues per sh	--	--	--	--	25.32	30.24
"Cash Flow" per sh	--	--	--	--	7.86	8.11
Earnings per sh A	--	--	--	--	2.76	3.60
Div'd Decl'd per sh B ■ †	--	--	--	--	--	2.58
Cap'l Spending per sh	--	--	--	--	8.07	7.43
Book Value per sh C	--	--	--	--	62.30	50.40
Common Shs Outst'g D	--	--	--	--	418.96	420.62
Avg Ann'l P/E Ratio	--	--	--	--	--	16.1
Relative P/E Ratio	--	--	--	--	--	.85
Avg Ann'l Div'd Yield	--	--	--	--	--	4.4%
Revenues ($mill)	--	--	--	--	10607	12720
Net Profit ($mill)	--	--	--	--	1080.0	1522.0
Income Tax Rate	--	--	--	--	29.4%	31.9%
AFUDC % to Net Profit	--	--	--	--	6.9%	7.2%
Long-Term Debt Ratio	--	--	--	--	41.0%	30.9%
Common Equity Ratio	--	--	--	--	59.0%	69.1%
Total Capital ($mill)	--	--	--	--	44220	30697
Net Plant ($mill)	--	--	--	--	41447	31110
Return on Total Cap'l	--	--	--	--	3.1%	6.0%
Return on Shr. Equity	--	--	--	--	4.1%	7.2%
Return on Com Equity E	--	--	--	--	4.1%	7.2%
Retained to Com Eq	--	--	--	--	4.1%	2.0%
All Div'ds to Net Prof	--	--	--	--	--	72%

© VALUE LINE PUB. LLC	2008	2009	2010	2011	2012	2013	15-17
Revenues per sh	31.15	29.18	32.22	32.63	28.55	36.45	41.25
"Cash Flow" per sh	7.34	7.58	8.49	8.68	6.90	9.00	10.00
Earnings per sh A	3.03	3.39	4.02	4.14	3.80	4.45	5.00
Div'd Decl'd per sh B ■ †	2.70	2.82	2.91	2.97	3.03	3.09	3.30
Cap'l Spending per sh	10.35	9.85	10.84	9.80	7.95	9.00	3.30
Book Value per sh C	49.51	49.85	50.84	51.14	56.75	58.10	19.50
Common Shs Outst'g D	423.96	436.29	442.96	445.29	704.00	705.00	1340.0
Avg Ann'l P/E Ratio	17.3	13.3	12.7	13.8	Bold figures are		12.5
Relative P/E Ratio	1.04	.89	.81	.87	Value Line		.85
Avg Ann'l Div'd Yield	5.2%	6.2%	5.7%	5.2%	estimates		5.2%
Revenues ($mill)	13207	12731	14272	14529	20100	25700	29200
Net Profit ($mill)	1279.0	1461.0	1765.0	1839.0	2195	3145	3570
Income Tax Rate	32.5%	34.4%	32.6%	31.3%	31.5%	31.5%	31.5%
AFUDC % to Net Profit	16.0%	17.5%	22.7%	23.2%	20.0%	13.0%	11.0%
Long-Term Debt Ratio	38.7%	42.6%	44.3%	45.1%	46.5%	48.0%	51.5%
Common Equity Ratio	61.3%	57.4%	55.7%	54.9%	53.0%	52.0%	48.5%
Total Capital ($mill)	34238	37863	40457	41451	75100	79075	91500
Net Plant ($mill)	34036	37950	40344	42661	68800	71950	82400
Return on Total Cap'l	4.8%	4.9%	5.5%	5.6%	4.0%	5.0%	5.5%
Return on Shr. Equity	6.1%	6.7%	7.8%	8.1%	5.5%	7.5%	8.0%
Return on Com Equity E	6.1%	6.7%	7.8%	8.1%	5.5%	7.5%	8.0%
Retained to Com Eq	.6%	1.1%	2.1%	2.2%	1.0%	2.5%	3.0%
All Div'ds to Net Prof	89%	84%	73%	72%	80%	69%	66%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $21386 mill. **Due in 5 Yrs** $9364.0 mill.
LT Debt $18454 mill. **LT Interest** $1052.0 mill.
Incl. $283.0 mill. capitalized leases. Incl. $915.0 mill. nonrecourse LT debt of variable interest entities.
(LT interest earned: 3.3x)
Leases, Uncapitalized Annual rentals $81.0 mill.
Pension Assets-12/11 $4.74 bill. **Oblig.** $4.88 bill.

Pfd Stock None

Common Stock 704,125,200 shs. as of 8/3/12

MARKET CAP: $48 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-5.9	+7.0	-2.1
Avg. Indust. Use (MWH)	2406	2440	3062
Avg. Indust. Revs. per KWH (¢)	4.31	4.86	4.89
Capacity at Peak (Mw) F	19894	19908	19356
Peak Load, Summer (Mw) F	16246	16712	NA
Annual Load Factor (%) F	56.0	58.0	NA
% Change Customers (avg.)	+.2	+.4	+.3
Fixed Charge Cov. (%)	308	295	292

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	4.5%	4.5%
"Cash Flow"	--	1.0%	3.5%
Earnings	--	7.0%	4.5%
Dividends	--	--	2.0%
Book Value	--	-4.0%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3312	2913	3396	3110	12731
2010	3594	3287	3946	3445	14272
2011	3663	3534	3964	3368	14529
2012	3630	3577	6950	5943	20100
2013	6000	6100	7250	6350	25700

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.81	.63	1.17	.78	3.39
2010	1.02	.87	1.53	.60	4.02
2011	1.14	.99	1.35	.66	4.14
2012	1.26	.99	1.10	.45	3.80
2013	1.20	1.00	1.50	.75	4.45

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.66	.66	.69	.69	2.70
2009	.69	.69	.72	.72	2.82
2010	.72	.72	.735	.735	2.91
2011	.735	.735	.75	.75	2.97
2012	.75	.75	.765		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.1 mill. electric customers in North Carolina, Florida, Indiana, South Carolina, Ohio, & Kentucky, and over 500,000 gas customers in Ohio & Kentucky. Owns independent power plants & has international operations. Acq'd Cinergy 4/06; spun off midstream gas ops. 1/07; acq'd Progress Energy 7/12. Elec. rev. breakdown: residential, 42%; commercial, 31%; industrial, 19%; other, 8%. Generating sources: coal, 53%; nuclear, 33%; other, 2%; purch., 12%. Fuel costs: 35% of revs. '11 reported deprec. rates: 2.6%-3.5%. Has 29,250 employees. Chairman, President & CEO: James E. Rogers. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy's takeover of Progress Energy created more controversy after completion than while awaiting regulatory approval. In early July, Duke issued about $17 billion in stock for Progress, which has utilities in North and South Carolina and in Florida. *(Note: All per-share data have been adjusted for a 1-for-3 reverse split paid July 3rd.)* As Duke announced the completion of the deal, it also stated that Bill Johnson (the former Progress CEO who was slated to take over as CEO of Duke) had "resigned . . . by mutual agreement." Jim Rogers remained CEO. Subsequently, some former Progress officers and directors resigned, as well. The North Carolina commission held hearings about the unexpected management change, and a rating agency lowered its corporate credit ratings on Duke.

The controversy doesn't seem to have hurt Duke's stock—so far. It has performed in line with most electric utility equities since the closing of the deal. However, that's not to say that there won't eventually be any repercussions. The company is planning rate filings in the Carolinas later in 2012. Rate orders there have been reasonable in recent years, but it remains to be seen whether this will continue when the commissions issue their rulings next year. The merger integration process might also be hampered, too.

Duke has other worries. The Crystal River 3 nuclear unit remains out of service, as it has been since September of 2009. Repair costs would probably be more than $1 billion. Whether this is covered by insurance is in dispute. A coal gasification plant that Duke is building in Indiana went over budget by nearly $1 billion, resulting in writedowns in 2011 and 2012, and the start-up date has been delayed from September until early 2013.

Duke expects to incur $450 million-$550 million of merger-related expenses in the second half of 2012. We are *including* these in our presentation. Earnings should be much higher in 2013.

This stock's yield is about half a percentage point above the utility mean. In our view, this isn't enough to compensate investors for the uncertainties that Duke is facing. Furthermore, total return potential to 2015-2017 is unappealing.

Paul E. Debbas, CFA *August 24, 2012*

(A) Diluted EPS. Excl. nonrec. gain (losses): '08, 15¢; '09, (63¢); '10, ($1.02); '11, (30¢); '12, (60¢). Next egs. report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '11: $18.06/sh. (D) In mill., adj. for reverse split. (E) Rate base: Net orig. cost. Rates allowed on com. eq. in '12 in NC and SC: 10.5% (Duke); in '09 in OH: 10.63% (elec.); in '04 in IN: 10.3%; earned on avg. com. eq., '11: 8.1%. Regul. Climate: NC Avg.; SC, OH, IN Above Avg. (F) Carolinas only.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	75

EXELON CORP. NYSE-EXC

RECENT PRICE **38.04** | P/E RATIO **17.1** (Trailing: 12.9; Median: 13.0) | RELATIVE P/E RATIO **1.17** | DIV'D YLD **5.5%** | VALUE LINE

TIMELINESS 3 Raised 11/26/10
SAFETY 2 Lowered 11/26/10
TECHNICAL 2 Raised 8/17/12
BETA .80 (1.00 = Market)

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+45%)	14%
Low	40	(+5%)	6%

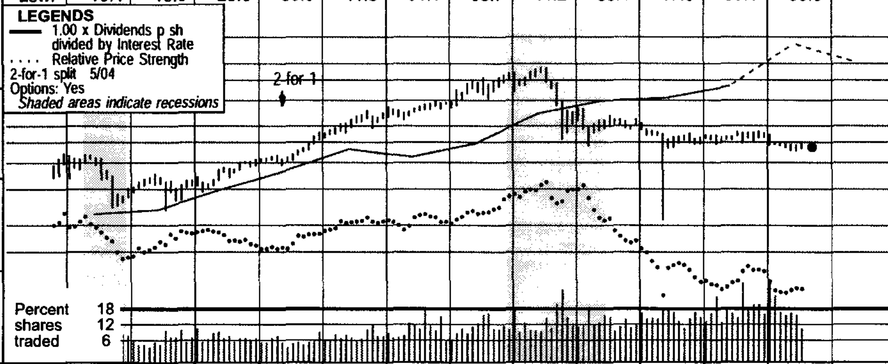
Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	10	0	0	0	1
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	372	407	425
to Sell	318	318	421
Hld's(000)	430605	437821	513584

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	35.1	28.5	33.3	44.9	57.5	63.6	86.8	92.1	59.0	49.9	45.4	43.7
Low:	19.4	18.9	23.0	30.9	41.8	51.1	58.7	41.2	38.4	17.0	39.1	36.3



Target Price Range 2015 | 2016 | 2017

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-6.6	-1.0
3 yr.	-10.9	50.3
5 yr.	-31.3	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	19.40	11.75	23.58	23.13	23.89	21.85	23.06	23.37	28.62	28.66	26.24	28.16	28.54	27.80	30.40	Revenues per sh	35.25
--	--	--	3.55	1.84	5.06	5.03	5.02	5.68	6.19	6.71	7.43	7.64	8.24	8.32	7.24	6.75	8.10	"Cash Flow" per sh	9.75
--	--	--	1.86	1.39	2.20	2.40	2.44	2.75	3.21	3.50	4.03	4.10	4.29	3.87	3.75	2.00	2.85	Earnings per sh A	3.50
--	--	--	--	--	.91	.88	.96	1.26	1.60	1.64	1.82	2.05	2.10	2.10	2.10	2.10	2.10	Div'd Decl'd per sh B ■	2.10
--	--	--	--	1.18	3.18	3.33	2.95	2.89	3.25	3.61	4.05	4.74	4.96	5.02	6.10	7.30	7.10	Cap'l Spending per sh	8.00
--	--	--	--	11.31	12.82	11.97	12.84	14.19	13.70	14.89	15.34	16.79	19.15	20.48	21.70	25.30	26.05	Book Value per sh C	28.75
--	--	--	630.20	638.01	642.01	646.63	662.00	664.20	666.00	670.00	661.00	658.00	660.00	662.00	663.00	854.00	855.00	Common Shs Outst'g D	820.00
--	--	--	--	22.4	13.2	10.5	11.8	13.0	15.4	16.5	18.2	18.0	11.5	11.0	11.3	Bold figures are		Avg Ann'l P/E Ratio	13.5
--	--	--	--	1.46	.68	.57	.67	.69	.82	.89	.97	1.08	.77	.70	.71	Value Line		Relative P/E Ratio	.90
--	--	--	--	--	3.1%	3.5%	3.4%	3.5%	3.2%	2.8%	2.5%	2.8%	4.3%	4.9%	5.0%	estimates		Avg Ann'l Div'd Yield	4.5%

CAPITAL STRUCTURE as of 3/31/12
Total Debt $18757 mill. **Due in 5 Yrs** *$6500 mill.*
LT Debt $17458 mill. **LT Interest** $978 mill.
Includes $648 mill. nonrecourse transition bonds.
(LT interest earned: 6.7x)

Leases, Uncapitalized Annual rentals $65.0 mill.
Pension Assets-12/11 $11.3 bill. **Oblig.** $13.5 bill.
Pfd Stock $280.0 mill. **Pfd Div'd** $17.0 mill.
Includes $280 mill. in preferred securities of subsidiaries.
Common Stock 852,410,272 shs.
MARKET CAP: $32 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
14955	15812	14515	15357	15655	18916	18859	17318	18644	18924	23750	26000	Revenues ($mill)	29000
1599.0	1641.0	1844.0	2162.0	2370.0	2730.0	2721.0	2844.0	2567.0	2499.0	1645	2455	Net Profit ($mill)	2920
36.7%	32.9%	27.5%	30.4%	33.7%	34.6%	32.6%	38.8%	39.2%	36.8%	32.0%	37.0%	Income Tax Rate	37.0%
1.2%	1.9%	.9%	1.0%	1.6%	1.8%	1.3%	2.3%	2.1%	3.0%	4.0%	3.0%	AFUDC % to Net Profit	3.0%
61.2%	61.1%	56.1%	56.1%	54.2%	53.9%	53.1%	47.2%	46.8%	45.7%	45.5%	45.5%	Long-Term Debt Ratio	47.0%
36.1%	38.5%	43.5%	43.5%	45.4%	45.7%	46.6%	52.4%	52.9%	54.0%	54.0%	53.5%	Common Equity Ratio	52.5%
21464	22079	21658	20972	21971	22189	23726	24112	25651	26661	40075	41525	Total Capital ($mill)	45100
17134	20630	21482	21981	22775	24153	25813	27341	29941	32570	44150	46225	Net Plant ($mill)	52000
9.4%	9.2%	10.4%	12.1%	12.5%	14.1%	13.1%	13.3%	11.4%	10.6%	5.0%	7.0%	Return on Total Cap'l	8.0%
19.2%	19.1%	19.4%	23.5%	23.6%	26.7%	24.4%	22.3%	18.8%	17.3%	7.5%	11.0%	Return on Shr. Equity	12.0%
20.1%	18.8%	19.5%	23.6%	23.7%	26.9%	24.6%	22.5%	18.9%	17.3%	7.5%	11.0%	Return on Com Equity E	12.5%
12.8%	11.5%	10.7%	11.9%	13.0%	15.3%	12.5%	11.5%	8.7%	7.7%	NMF	3.0%	Retained to Com Eq	5.0%
38%	40%	45%	50%	45%	43%	49%	49%	54%	56%	98%	74%	All Div'ds to Net Prof	60%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.9	+4.8	-2.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	8.09	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	30150	30778	NA
Nuclear Capacity Factor (%)	93.6	93.9	93.3
% Change Customers (yr-end)	-.2	+.4	+.3
Fixed Charge Cov. (%)	622	546	569

BUSINESS: Exelon Corporation is a holding company for Commonwealth Edison (3.8 mill. elec. customers in IL), PECO Energy, (1.6 mill. elec., 495,000 gas customers in PA), & Baltimore Gas and Electric (1.2 mill. elec., 655,000 gas customers in MD). Has nonregulated generating & energy-marketing ops. Acq'd Constellation Energy 3/12. Elec. rev. breakdown: res'l, 59%; small comm'l & ind'l, 23%; large comm'l & ind'l, 8%; other, 10%. Generating sources: nuclear, 82%; other, 7%; purch., 11%. Fuel costs: 38% of revs. '11 depr. rates: 2.6%-3.1% elec., 1.7% gas. Has 19,300 empls. Chairman: Mayo A. Shattuck III. Pres. & CEO: Christopher M. Crane. Inc.: PA. Address: 10 S. Dearborn St., P.O. Box 805379, Chicago, IL 60680-5379. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.0%	4.0%	4.0%
"Cash Flow"	8.5%	5.0%	3.5%
Earnings	8.0%	4.5%	-2.0%
Dividends	--	7.0%	Nil
Book Value	5.5%	7.5%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	4722	4141	4339	4116	17318
2010	4461	4398	5291	4494	18644
2011	5052	4587	5295	3990	18924
2012	4686	5954	7000	6110	23750
2013	6500	6100	7100	6300	26000

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	1.28	.99	1.14	.88	4.29
2010	1.13	.67	1.27	.79	3.87
2011	1.01	.93	.90	.91	3.75
2012	.53	.33	.60	.54	2.00
2013	.75	.65	.75	.70	2.85

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.50	.50	.50	.525	2.03
2009	.525	.525	.525	.525	2.10
2010	.525	.525	.525	.525	2.10
2011	.525	.525	.525	.525	2.10
2012	.525	.525			

Exelon's earnings will almost certainly decline considerably this year. The acquisition of Constellation Energy in March is one reason. Exelon estimates that its merger-related expenses in 2012 will amount to $325 million, but merger-related expense reductions will be $170 million. (Over time, the former will decline and the latter will increase.) We are *including* these costs in our earnings presentation. Even were it not for the Constellation deal, however, profits were headed down. Until 2012, Exelon's hedging program had insulated its nonregulated generating subsidiary from the effects of worsening conditions in the power markets, but low power prices have finally caught up with the company.

Despite the fact that Exelon might not earn the dividend in 2012, the payout is secure, in our view. The board of directors isn't considering merger-related costs when declaring dividends. Exelon's finances remain sound, too.

The benefits of the Constellation takeover should be more apparent beginning in 2013. The merger-related costs are expected to decline to $80 million, while the merger-related savings are estimated to advance to $305 million. In 2014, further improvement is likely in each of these measures, and management expects its nonregulated businesses to generate an additional $100 million of operating income through synergies. Exelon's generating business is a good fit with Constellation's retail energy-supply unit. Rate relief at Baltimore Gas and Electric should be another plus. However, weak prices in the power markets will offset these positive factors to some extent.

Baltimore G&E has filed a general rate case. The utility is seeking increases of $150.8 million for electricity and $53.4 million for gas, based on a 10.5% return on a 48.4% common-equity ratio. New tariffs are expected to take effect in February.

We think this stock has appeal for income-oriented investors. The dividend yield is more than one percentage point above the utility mean. Total return potential to 2015-2017 is also above the group average, despite the fact that we project no dividend increase over that time frame.

Paul E. Debbas, CFA *August 24, 2012*

(A) Diluted earnings. Excludes nonrecurring gain (losses): '02, (18¢); '03, ($1.06); '04, 3¢; '05, ($1.85); '06, ($1.15); '09, (20¢); '12, (25¢); gains from disc. ops.: '07, 2¢; '08, 3¢. '10 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvest. program avail. (C) Incl. deferred charges. In '11: $11.26/sh. (D) In mill., adj. for split. (E) Rate all'd on com. eq. in IL in '11: 10.5%; earned on avg. com. eq., '11: 17.9%. Regulatory Climate: PA, Avg.; IL, MD, Below Avg.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	40
Earnings Predictability	90

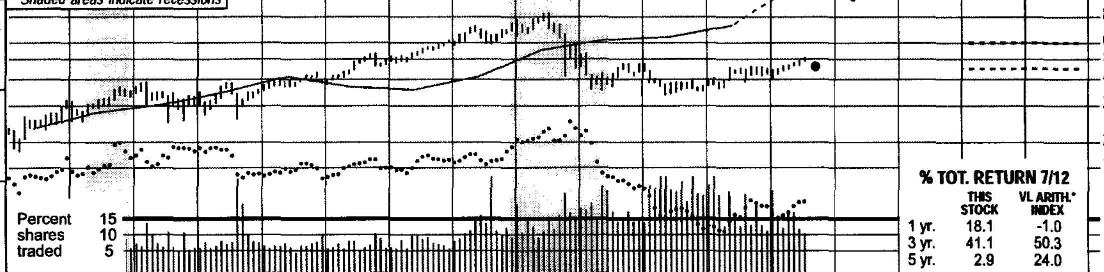
FIRSTENERGY NYSE-FE

RECENT PRICE **46.12** | P/E RATIO **16.1** (Trailing: 19.5 / Median: 15.0) | RELATIVE P/E RATIO **1.10** | DIV'D YLD **4.8%** | VALUE LINE

TIMELINESS 3 Lowered 8/3/12
SAFETY 2 Raised 6/2/06
TECHNICAL 2 Raised 8/17/12
BETA .80 (1.00 = Market)

High:	37.0	39.1	38.9	43.4	53.4	61.7	75.0	84.0	53.6	47.8	46.5	51.1	
Low:	25.1	24.8	25.8	35.2	37.7	47.8	57.8	41.2	35.3	33.6	36.1	40.4	

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



Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+30%)	11%
Low	45	(Nil)	4%

Insider Decisions

	S	O	N	D	J	F	M	A	M
to Buy	0	0	0	0	0	0	1	0	0
Options	0	0	0	0	1	0	10	0	1
to Sell	0	0	0	1	0	0	5	0	3

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	228	235	227
to Sell	208	214	240
Hld's(000)	298664	277853	291443

Percent shares traded 15 / 10 / 5

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.1	-1.0
3 yr.	41.1	50.3
5 yr.	2.9	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.19	12.26	24.72	27.19	31.31	26.88	40.83	37.31	37.76	36.35	36.03	42.00	44.70	41.70	43.76	38.87	38.75	39.20	Revenues per sh	45.50
4.83	3.66	5.33	6.89	7.28	5.48	6.45	4.79	7.60	7.55	7.22	8.34	9.04	8.80	8.50	5.75	6.75	7.10	"Cash Flow" per sh	8.00
2.10	1.94	1.95	2.50	2.69	2.84	2.54	1.47	2.77	2.84	3.82	4.22	4.38	3.32	3.25	1.88	2.80	3.10	Earnings per sh A	3.75
1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.50	1.91	1.71	1.85	2.05	2.20	2.20	2.20	2.20	2.20	2.20	Div'd Decl'd per sh B ■	2.40
.97	.89	2.75	2.69	2.74	2.86	3.35	2.60	2.57	3.66	4.12	5.36	9.47	7.23	6.44	5.45	5.80	6.40	Cap'l Spending per sh	6.00
16.41	18.07	18.77	19.63	20.72	24.86	23.92	25.13	26.04	27.86	28.30	29.45	27.17	28.08	28.03	31.75	32.35	33.30	Book Value per sh C	37.00
152.57	230.21	237.07	232.45	224.53	297.64	297.64	329.84	329.84	329.84	319.21	304.84	304.84	304.84	304.84	418.22	418.22	418.22	Common Shs Outst'g D	418.22
10.4	11.8	15.4	11.3	9.2	10.9	13.0	22.5	14.1	16.1	14.2	15.6	15.6	13.0	11.7	22.4	Bold figures are		Avg Ann'l P/E Ratio	13.5
.65	.68	.80	.64	.60	.56	.71	1.28	.74	.86	.77	.83	.94	.87	.74	1.41	Value Line		Relative P/E Ratio	.90
6.9%	6.6%	5.0%	5.3%	6.1%	4.8%	4.6%	4.5%	4.9%	3.7%	3.4%	3.1%	3.2%	5.1%	5.8%	5.2%	estimates		Avg Ann'l Div'd Yield	4.7%

CAPITAL STRUCTURE as of 3/31/12
Total Debt $18374 mill. **Due in 5 Yrs** $7641.0 mill.
LT Debt $15527 mill. **LT Interest** $916.0 mill.
Incl. $284.8 mill. 9% ($25 par) cumulative mandatorily redeemable preferred securities.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $258.0 mill.
Pension Assets-12/11 $5.87 bill. **Oblig.** $7.98 bill.
Pfd Stock None

Common Stock 418,216,437 shs.
as of 4/30/12
MARKET CAP: $19 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
12152	12307	12453	11989	11501	12802	13627	12712	13339	16258	16200	16400	Revenues ($mill)	19000
827.6	490.8	932.6	951.0	1265.0	1309.0	1342.0	1015.0	991.0	752.0	1180	1305	Net Profit ($mill)	1580
41.5%	43.9%	42.2%	42.1%	38.6%	40.3%	36.7%	19.6%	38.6%	41.3%	42.0%	42.0%	Income Tax Rate	42.0%
3.0%	6.5%	2.7%	2.0%	2.1%	2.4%	3.9%	12.8%	16.6%	9.3%	6.0%	5.0%	AFUDC % to Net Profit	6.0%
60.2%	53.1%	52.8%	46.5%	48.6%	49.7%	52.4%	58.2%	59.5%	54.2%	54.5%	55.0%	Long-Term Debt Ratio	55.0%
38.0%	45.0%	45.4%	52.4%	51.4%	50.3%	47.7%	41.8%	40.5%	45.8%	45.5%	45.0%	Common Equity Ratio	45.0%
18756	18414	18938	17527	17570	17846	17383	20467	21124	28996	29800	30800	Total Capital ($mill)	34400
12680	13269	13478	13998	14667	15383	17723	19164	19788	30337	31175	32250	Net Plant ($mill)	34800
6.3%	4.6%	6.5%	7.1%	9.0%	9.0%	9.7%	6.9%	6.3%	4.0%	5.5%	6.0%	Return on Total Cap'l	6.0%
11.1%	5.7%	10.4%	10.1%	14.0%	14.6%	16.2%	11.9%	11.6%	5.7%	8.5%	9.5%	Return on Shr. Equity	10.0%
10.5%	5.4%	10.6%	10.2%	13.9%	14.6%	16.2%	11.9%	11.6%	5.7%	8.5%	9.5%	Return on Com Equity E	10.0%
4.3%	NMF	4.9%	4.2%	7.4%	7.7%	8.1%	4.0%	3.8%	NMF	2.0%	3.0%	Retained to Com Eq	3.5%
63%	101%	55%	59%	47%	47%	50%	66%	68%	NMF	78%	71%	All Div'ds to Net Prof	64%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-8.3	+5.6	+.1
Avg. Indust. Use (MWH)	NMF	NMF	NMF
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	--	NA	NA
Fixed Charge Cov. (%)	193	253	206

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.0%	2.5%	1.5%
"Cash Flow"	1.5%	.5%	.5%
Earnings	.5%	-2.0%	5.0%
Dividends	4.0%	4.0%	1.5%
Book Value	3.0%	1.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3334	3017	3408	2953	12712
2010	3299	3128	3693	3219	13339
2011	3576	4060	4719	3903	16258
2012	4078	3869	4400	3853	16200
2013	4200	3950	4300	3950	16400

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.94	.84	.77	.77	3.32
2010	.59	.87	1.19	.61	3.25
2011	.15	.48	1.27	d.09	1.88
2012	.73	.45	.82	.80	2.80
2013	.80	.65	.85	.80	3.10

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.55	.55	.55	.55	2.20
2009	.55	.55	.55	.55	2.20
2010	.55	.55	.55	.55	2.20
2011	.55	.55	.55	.55	2.20
2012	.55	.55			

BUSINESS: FirstEnergy Corp. is a holding company for Ohio Edison, Pennsylvania Power, Cleveland Electric, Toledo Edison, Metropolitan Edison, Penelec, Jersey Central Power & Light, West Penn Power, Potomac Edison, & Mon Power. Provides electric service to over 6 million customers in OH, PA, NJ, WV, MD, & NY. Acq'd Allegheny Energy 2/11. Electric revenue breakdown by customer class not available. Generating sources: coal, 44%; nuclear, 26%; purchased, 30%. Fuel costs: 45% of revs. '11 reported depr. rates: 2.2%-3.4%. Has 17,000 employees. Chairman: George M. Smart. President & CEO: Anthony J. Alexander. COO: Richard R. Grigg. Inc.: OH. Address: 76 South Main Street, Akron, OH 44308-1890. Tel.: 800-736-3402. Internet: www.firstenergycorp.com.

Unfavorable conditions in the power markets continue to hurt FirstEnergy. That's partly why the company's share earnings have fallen significantly since 2008. Low power prices are squeezing margins from its nonregulated generating assets. June-period profits fell short of our expectation, and we have lowered our 2012 earnings estimate by $0.50 a share, to $2.80. This figure is still well above the depressed 2011 tally, but mainly because the company incurred sizable merger-related expenses, stemming from its takeover of Allegheny Energy, last year.

Various uncertainties prompted management to withdraw its earnings guidance for 2013. (The company's targeted range for 2012, on a GAAP basis, is $2.80-$3.10 a share.) The aforementioned conditions in the power markets, as well as the state of the economy, have raised uncertainty for FirstEnergy. Withdrawal of guidance usually concerns Wall Street, and the stock price is down 6% since the company reported second-quarter results in early August. We've trimmed our 2013 share-net forecast from $3.25 to $3.10.

FirstEnergy received some good news in Ohio. The company was disappointed with American Electric Power's initial plan for transition to competitive markets in the state, which FirstEnergy believed was anticompetitive. (FirstEnergy has a retail energy-supply operation that competes in Ohio and other states that allow customers to choose their provider.) AEP's revised plan, which the state regulators approved, is more competitive. In addition, FirstEnergy's own regulatory plan was extended by two years, through May of 2016.

Jersey Central Power & Light must file a rate case by November 1st. After the state's Rate Counsel complained that JCP&L was overearning its allowed return on equity of 9.75%, the Board of Public Utilities ordered the utility to file a rate case. We assume no change in rates in our estimates and projections, but this doesn't mean that we are ruling out the possibility of an unfavorable regulatory outcome.

We have a neutral stance on this equity. Its dividend yield is above average for a utility, but subpar dividend growth to 2015-2017 will likely produce a total return that is only average for the industry.

Paul E. Debbas, CFA *August 24, 2012*

(A) Dil. EPS. Excl. nonrec. gain (losses): '04, (11¢); '05, (28¢); '09, (3¢); '10, (68¢); '11, 33¢; gain (loss) from disc. ops.: '03, (33¢); '05, 5¢. '10 EPS don't add due to rounding, '11 due to chg. in shs. Next egs. report due early Nov. (B) Div'ds paid early Mar., June, Sept. & Dec. Five div'ds declared in '04. ■ Div'd reinvest. plan avail. (C) Incl. intang.: In '11: $20.25/sh. (D) In mill. (E) Rate base: Deprec. orig. cost. Rates all'd on com. eq.: 9.75%-12.9%; earn. on avg. com. eq., '11: 11.4%. Regulatory Climate: OH Above Avg.; PA, NJ Avg.; MD, WV Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	55
Earnings Predictability	75

NEXTERA ENERGY NYSE-NEE

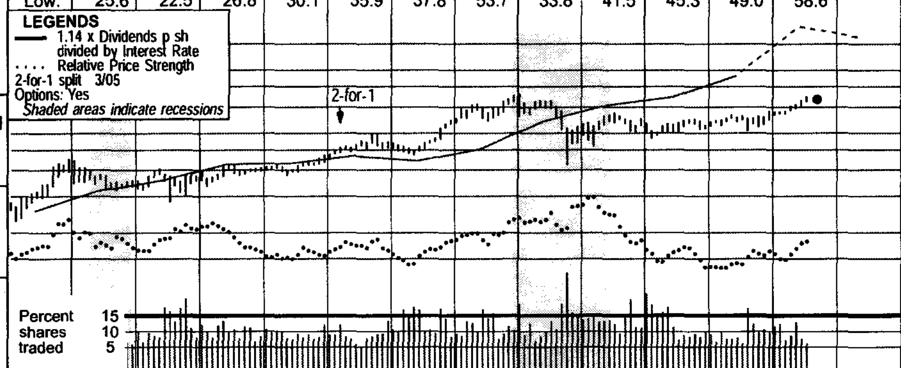
RECENT PRICE **69.59** | P/E RATIO **15.5** (Trailing: 13.5; Median: 14.0) | RELATIVE P/E RATIO **1.06** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS 2 Raised 8/3/12
SAFETY 2 Lowered 2/26/10
TECHNICAL 3 Raised 7/27/12
BETA .75 (1.00 = Market)

High:	35.8	32.7	34.0	38.1	48.1	55.6	72.8	73.8	60.6	56.3	61.2	72.2
Low:	25.6	22.5	26.8	30.1	35.9	37.8	53.7	33.8	41.5	45.3	49.0	58.6

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.14 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 3/05
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+30%)	10%
Low	65	(-5%)	2%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	335	340	338
to Sell	321	327	363
Hld's(000)	278221	282949	280141

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	33.5	-1.0
3 yr.	37.1	50.3
5 yr.	43.1	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.51	17.52	18.43	18.03	20.15	24.10	22.74	26.13	28.27	30.00	38.75	37.47	40.13	37.82	36.39	36.88	*35.70*	*36.35*	Revenues per sh	*40.50*
4.21	4.62	5.39	4.86	4.94	5.02	4.51	5.36	5.60	6.18	6.77	6.85	8.03	8.75	9.62	9.29	*8.25*	*9.95*	"Cash Flow" per sh	*11.75*
1.67	1.79	1.93	2.04	2.07	2.31	2.01	2.45	2.46	2.32	3.23	3.27	4.07	3.97	4.74	4.82	*4.55*	*4.80*	Earnings per sh A	*6.00*
.92	.96	1.00	1.04	1.08	1.12	1.16	1.20	1.30	1.42	1.50	1.64	1.78	1.89	2.00	2.20	*2.40*	*2.60*	Div'd Decl'd per sh B ■ †	*3.20*
1.33	1.52	1.71	2.41	3.70	3.28	3.44	3.75	3.75	4.09	9.22	12.32	12.80	14.52	13.89	15.93	*13.75*	*13.75*	Cap'l Spending per sh	*13.50*
12.56	13.32	14.18	15.04	15.91	17.10	17.48	18.91	20.25	21.52	24.49	26.35	28.57	31.35	34.36	35.92	*38.45*	*41.20*	Book Value per sh C	*49.25*
365.63	363.63	361.42	357.11	351.53	351.71	365.51	368.53	372.24	394.85	405.40	407.35	408.92	413.62	420.86	416.00	*423.00*	*429.00*	Common Shs Outst'g D	*430.00*
13.5	13.5	16.2	13.0	12.8	12.5	14.2	12.6	13.6	17.9	13.7	18.9	14.5	13.4	10.8	11.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.85	.78	.84	.74	.83	.64	.78	.72	.72	.95	.74	1.00	.87	.89	.69	.73	*Value Line*		Relative P/E Ratio	*.85*
4.1%	4.0%	3.2%	3.9%	4.1%	3.9%	4.1%	3.9%	3.9%	3.4%	3.4%	2.7%	3.0%	3.5%	3.9%	4.0%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $23970 mill. **Due in 5 Yrs** $9679.0 mill.
LT Debt $20582 mill. **LT Interest** $1029.0 mill.
Incl. $402.5 mill. of equity units, conv. into common by 2013 at $50/share.
(LT interest earned: 3.7x)

Pension Assets-12/11 $3.12 bill. **Oblig.** $2.12 bill.

Pfd Stock None

Common Stock 417,075,629 shs.

MARKET CAP: $29 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
8311.0	9630.0	10522	11846	15710	15263	16410	15643	15317	15341	*15100*	*15600*	Revenues ($mill)	*17400*
710.0	883.4	887.0	901.0	1281.0	1312.0	1639.0	1615.0	1957.0	2021.0	*1925*	*2065*	Net Profit ($mill)	*2620*
25.6%	29.4%	23.1%	23.8%	23.7%	21.9%	21.5%	16.8%	21.4%	22.4%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
--	--	4.2%	5.4%	3.8%	5.7%	6.6%	7.9%	4.4%	4.4%	*4.0%*	*4.0%*	AFUDC % to Net Profit	*1.0%*
46.7%	55.6%	51.6%	48.6%	49.1%	51.2%	54.2%	55.7%	55.5%	58.2%	*57.0%*	*56.0%*	Long-Term Debt Ratio	*52.5%*
51.5%	44.4%	48.4%	51.4%	50.9%	48.8%	45.8%	44.3%	44.5%	41.8%	*43.0%*	*44.0%*	Common Equity Ratio	*47.5%*
12406	15695	15564	16538	19521	22015	25514	29267	32474	35753	*37925*	*40200*	Total Capital ($mill)	*44400*
14304	20297	21226	22463	24499	28652	32411	36078	39075	42490	*46725*	*50450*	Net Plant ($mill)	*60600*
6.6%	6.7%	7.0%	6.9%	8.0%	7.5%	7.9%	6.9%	7.4%	7.0%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
10.7%	12.7%	11.8%	10.6%	12.9%	12.2%	14.0%	12.5%	13.5%	13.5%	*12.0%*	*11.5%*	Return on Shr. Equity	*12.5%*
10.9%	12.5%	11.8%	10.6%	12.9%	12.2%	14.0%	12.5%	13.5%	13.5%	*12.0%*	*11.5%*	Return on Com Equity E	*12.5%*
4.6%	6.4%	5.6%	4.2%	6.9%	6.1%	7.9%	6.5%	7.8%	7.4%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
58%	50%	53%	60%	46%	50%	44%	47%	42%	46%	*52%*	*54%*	All Div'ds to Net Prof	*53%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	--	+2.2	-1.4
Avg. Indust. Use (MWH)	325	348	343
Avg. Indust. Revs. per KWH (¢)	8.86	6.85	7.40
Capacity at Peak (Mw)	26682	25800	26538
Peak Load, Summer (Mw) F	24346	22256	21619
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	--	+.6	+.6
Fixed Charge Cov. (%)	281	315	311

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	2.5%	1.5%
"Cash Flow"	6.5%	8.5%	4.0%
Earnings	7.5%	11.0%	5.0%
Dividends	6.5%	7.5%	8.0%
Book Value	8.0%	9.0%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3705	3811	4473	3654	15643
2010	3622	3591	4691	3413	15317
2011	3134	3961	4382	3864	15341
2012	3371	3667	*4562*	*3500*	*15100*
2013	*3400*	*3800*	*4800*	*3600*	*15600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.90	.91	1.31	.85	3.97
2010	1.36	1.01	1.74	.63	4.74
2011	.64	1.38	1.20	1.61	4.82
2012	1.11	1.26	*1.28*	*.90*	*4.55*
2013	*1.05*	*1.35*	*1.40*	*1.00*	*4.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.445	.445	.445	.445	1.78
2009	.4725	.4725	.4725	.4725	1.89
2010	.50	.50	.50	.50	2.00
2011	.55	.55	.55	.55	2.20
2012	.60	.60			

BUSINESS: NextEra Energy, Inc. (formerly FPL Group, Inc.) is a holding company for Florida Power & Light (FPL), which provides electricity to 4.6 million customers in a 27,650-sq.-mi. area in eastern & southern Florida. NextEra Energy Resources is a nonregulated power generator with nuclear, gas, & wind ownership. Revenue breakdown: residential, 56%; commercial, 41%; industrial & other, 3%. Generating sources: gas, 65%; nuclear, 20%; coal, 5%; oil, 1%; purchased, 9%. Fuel costs: 41% of revs. '11 reported deprec. rates: FPL, 3.2%; NextEra, 4.0%. Has 15,000 employees. Chairman: Lewis Hay, III. President and CEO: James L. Robo. Inc.: Florida. Address: 700 Universe Blvd., Juno Beach, FL 33408. Tel.: 561-694-4000. Internet: www.nexteraenergy.com.

NextEra Energy's utility subsidiary has reached a settlement of its general rate case. The agreement, if approved by the Florida commission, would raise Florida Power & Light's rates by $378 million in January. Further tariff hikes would occur when modernization projects on three gas-fired plants are completed in 2013, 2014, and 2016. The utility's allowed return on equity would be in a range with a midpoint of 10.7%. FPL could file for rate relief if it earns an ROE of less than 9.7%, and another party could seek a rate review if the utility earns an ROE above 11.7%. FPL and the intervenors asked for a commission ruling by the end of August.

Several large capital projects are in various stages of development. The three plant modernization projects mentioned above would cost a total of about $3.5 billion. FPL is also adding 490 mw of capacity to its existing nuclear units at an expected cost of $3.1 billion. The utility will recover the cost of the nuclear uprate program through a regulatory mechanism, instead of in base rates.

Although we look for an earnings decline this year, this doesn't mean that NextEra is performing poorly. Mark-to-market accounting gains boosted the bottom line by $0.45 a share in 2011, making for a tough comparison. Even so, utility profits are benefiting from the use of regulatory amortization (i.e., reduced depreciation because depreciation taken in the past was too high), and nonutility income is benefiting from additional generating capacity, much of it wind. **We look for higher profits in 2013**, assuming that the regulators approve FPL's settlement.

This timely stock has been one of the best-performing utility issues in 2012, having risen about 15% year to date. Investors are attracted to NextEra's superior dividend growth potential and the fact that the company's nonregulated business has held up much better (even with weakness in the power markets) than those of most utilities with a major nonregulated presence. The dividend yield is fractionally below the industry average, however, and since the quotation is within our 2015-2017 Target Price Range, long-term total return potential isn't much better than the norm for the utility industry.

Paul E. Debbas, CFA — *August 24, 2012*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '00, (5¢); '02, (60¢); '03, 5¢; '11, (24¢). '11 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in mid-March, mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '11: $5.19/sh. (D) In millions, adj. for stock split. (E) Rate allowed on common equity in '10: 9%-11%; earned on avg. com. eq., '11: 13.6%. Regulatory Climate: Average. (F) Winter peak in '09.

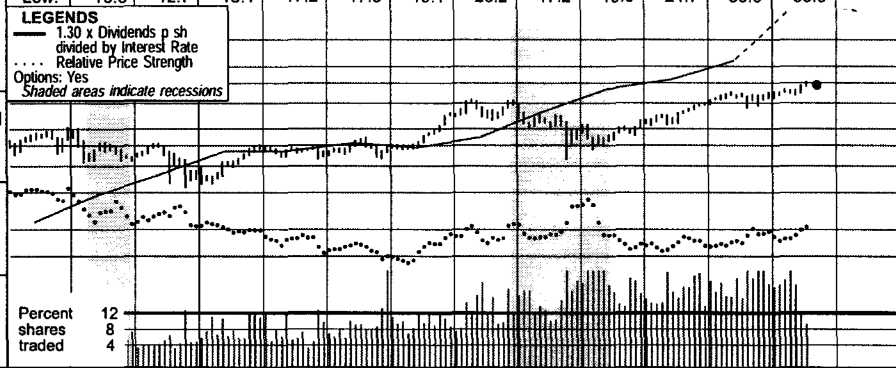
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	85

NORTHEAST UTILITIES NYSE-NU

RECENT PRICE **39.15** | P/E RATIO **18.3** (Trailing: 21.0 Median: 16.0) | RELATIVE P/E RATIO **1.25** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS 3 Lowered 8/12/11
SAFETY 2 Raised 5/25/12
TECHNICAL 2 Raised 8/24/12
BETA .70 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	24.3	20.7	20.3	20.3	22.0	28.9	33.6	31.6	26.5	32.2	36.5	40.9
Low:	16.6	12.7	13.1	17.2	17.3	19.1	26.2	17.2	19.0	24.7	30.0	33.5



Target Price Range 2015 | 2016 | 2017: 64, 48, 40, 32, 24, 20, 16, 12, 8, 6

2015-17 PROJECTIONS

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

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	146	164	165
to Sell	151	141	214
Hld's(000)	139484	134947	198414

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.3	-1.0
3 yr.	92.7	50.3
5 yr.	73.5	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
29.52	29.46	28.77	33.91	40.86	52.82	40.89	47.53	51.82	41.85	44.64	37.27	37.22	30.97	27.76	25.21	**21.00**	**25.00**	Revenues per sh	**27.75**
3.77	2.68	3.73	5.68	3.39	10.48	6.32	5.80	5.00	5.46	3.69	4.82	6.16	4.96	5.68	4.88	**4.50**	**5.45**	"Cash Flow" per sh	**6.50**
.01	d1.05	d.36	d1.14	d.20	1.37	1.08	1.24	.91	.98	.82	1.59	1.86	1.91	2.10	2.22	**2.00**	**2.60**	Earnings per sh A	**3.25**
1.38	.25	--	.10	.40	.45	.53	.58	.63	.68	.73	.78	.83	.95	1.03	1.10	**1.32**	**1.44**	Div'd Decl'd per sh B ■	**1.70**
1.85	1.85	1.79	2.50	2.88	3.40	3.86	4.31	4.85	5.89	5.49	7.14	8.06	5.17	5.41	6.08	**4.65**	**4.40**	Cap'l Spending per sh	**4.50**
17.73	16.34	15.63	15.80	15.43	16.27	17.33	17.73	17.80	18.46	18.14	18.65	19.38	20.37	21.60	22.65	**29.00**	**30.15**	Book Value per sh C	**34.50**
128.44	130.18	130.95	131.87	143.82	130.13	127.56	127.70	129.03	131.59	154.23	156.22	155.83	175.62	176.45	177.16	**314.00**	**314.00**	Common Shs Outst'g D	**314.00**
NMF	--	--	--	--	14.1	16.1	13.4	20.8	19.8	27.1	18.7	13.7	12.0	13.4	15.4	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**13.0**
NMF	--	--	--	--	.72	.88	.76	1.10	1.05	1.46	.99	.82	.80	.85	.97	*estimates*		Relative P/E Ratio	**.85**
8.9%	2.4%	--	.6%	1.9%	2.3%	3.0%	3.5%	3.3%	3.5%	3.3%	2.6%	3.2%	4.2%	3.6%	3.2%			Avg Ann'l Div'd Yield	**4.0%**
						5216.3	6069.2	6686.7	5507.3	6884.4	5822.2	5800.1	5439.4	4898.2	4465.7	**6600**	**7850**	Revenues ($mill)	**8700**
						144.2	162.7	122.1	128.5	126.2	251.5	296.2	335.6	377.8	400.3	**635**	**820**	Net Profit ($mill)	**1030**
						--	32.1%	29.8%	30.8%	--	30.3%	29.7%	34.9%	36.6%	29.9%	**35.0%**	**35.0%**	Income Tax Rate	**35.0%**
						9.2%	7.1%	6.8%	17.4%	21.5%	13.9%	15.8%	4.6%	7.1%	8.6%	**6.0%**	**4.0%**	AFUDC % to Net Profit	**4.0%**
						64.3%	63.9%	64.2%	63.2%	58.7%	59.2%	60.4%	57.2%	55.1%	53.4%	**45.0%**	**45.5%**	Long-Term Debt Ratio	**46.0%**
						33.9%	34.3%	34.0%	35.1%	39.7%	39.2%	38.1%	41.5%	43.6%	45.3%	**54.0%**	**53.5%**	Common Equity Ratio	**53.5%**
						6513.2	6591.6	6749.4	6923.2	7052.0	7431.1	7926.2	8629.5	8741.8	8856.0	**16825**	**17650**	Total Capital ($mill)	**20300**
						4728.4	5429.9	5864.2	6417.2	6242.2	7229.9	8207.9	8840.0	9567.7	10403	**16325**	**16950**	Net Plant ($mill)	**19200**
						4.1%	4.2%	2.8%	3.5%	2.9%	5.0%	5.4%	5.4%	5.8%	5.9%	**5.0%**	**5.5%**	Return on Total Cap'l	**6.0%**
						6.2%	6.8%	5.1%	5.0%	4.3%	8.3%	9.4%	9.1%	9.6%	9.7%	**7.0%**	**8.5%**	Return on Shr. Equity	**9.5%**
						6.3%	6.9%	5.1%	5.1%	4.3%	8.4%	9.6%	9.2%	9.8%	9.8%	**7.0%**	**8.5%**	Return on Com Equity E	**9.5%**
						3.2%	3.7%	1.6%	1.5%	.3%	4.3%	5.3%	4.7%	5.0%	5.0%	**2.5%**	**4.0%**	Retained to Com Eq	**4.5%**
						51%	48%	70%	72%	94%	50%	45%	50%	49%	50%	**67%**	**56%**	All Div'ds to Net Prof	**53%**

CAPITAL STRUCTURE as of 3/31/12
Total Debt $5998.8 mill. **Due in 5 Yrs** $1862.0 mill.
LT Debt $5071.5 mill. **LT Interest** $243.4 mill.
Incl. $94.4 mill. of rate reduction bonds.
(LT interest earned: 3.0x)
Leases, Uncapitalized Annual rentals $7.7 mill.
Pension Assets-12/11 $2.01 bill. **Oblig.** $3.10 bill.
Pfd Stock $116.2 mill. **Pfd Div'd** $5.6 mill.
Incl. 2,324,000 shs $1.90-$3.28 rates ($50 par) not subject to mandatory redemption.
Common Stock 313,604,078 shs.
as of 4/30/12
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.5	+1.7	-1.2
Avg. Indust. Use (MWH)	614	627	624
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.1	+.5	+.4
Fixed Charge Cov. (%)	255	284	291

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-4.0%	-9.5%	*Nil*
"Cash Flow"	-2.5%	2.0%	*4.0%*
Earnings	--	18.0%	*8.0%*
Dividends	12.5%	8.5%	*8.5%*
Book Value	3.0%	3.5%	*8.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1594	1224	1306	1315	5439.4
2010	1339	1112	1243	1204	4898.2
2011	1235	1048	1115	1068	4465.7
2012	1100	1629	*2021*	*1850*	*6600*
2013	*2050*	*1700*	*2175*	*1925*	*7850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.60	.47	.37	.48	1.91
2010	.49	.41	.57	.64	2.10
2011	.64	.44	.51	.64	2.22
2012	.56	.15	*.75*	*.54*	*2.00*
2013	*.70*	*.55*	*.80*	*.55*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.20	.20	.2125	.2125	.83
2009	.2375	.2375	.2375	.2375	.95
2010	.25625	.25625	.25625	.25625	1.02
2011	.275	.275	.275	.275	1.10
2012	.29375	.343			

BUSINESS: Northeast Utilities is the parent of utilities that have about 3 mill. elec., 500,000 gas customers. Connecticut Light & Power (CL&P) serves most of CT; Public Service Co. of New Hampshire (PSNH) supplies power to three fourths of NH's population; Western Massachusetts Electric Co. (WMECO) serves western MA; NSTAR supplies power to parts of eastern MA & gas to central & eastern MA. Acq'd NSTAR 4/12. Elec. rev. breakdown: res'l, 53%; comm'l, 30%; ind'l, 6%; other, 11%. Generating sources not avail. Fuel costs: 35% of revs. '11 reported depr. rate: 2.6%. Has 9,100 empls. Chairman: Charles W. Shivery. Pres. & CEO: Thomas J. May. Inc.: MA. Address: One Federal St., Building 111-4, Springfield, MA 01105. Tel.: 413-785-5871. Web: www.nu.com.

The profits we estimate for Northeast Utilities in 2012 aren't indicative of the company's earning potential. NU incurred expenses and reserves for customer rate credits associated with its merger with NSTAR, which was completed in April. These amounted to $0.24 a share in the first half. In addition, due to criticism following lengthy storm-related outages in 2011, Connecticut Light & Power wrote off $40 million of restoration costs and agreed to fund some energy initiatives in the state. This lowered first-half profits by $0.14 a share. At least the second half of 2012 should be much better. Most merger-related costs have already been booked, and moderate rate hikes took effect in mid-2012 at Public Service of New Hampshire and Yankee Gas.

Next year should be much better. The combined company is achieving merger-related cost reductions, which are ramping up quarter by quarter. NU is retaining these savings because electric tariffs are frozen in Connecticut through November of 2014 and in Massachusetts through December of 2015. Also, we estimate that the board will raise the quarterly dividend by 5% in the first period of 2013.

CL&P is still dealing with repercussions from the aforementioned storm-related outages. The state regulators issued a report that criticized some aspects of the utility's performance. In fact, they suggested that its allowed return on equity might be cut when rates are reset after the freeze ends. Even before the report was released, the utility proposed a five-year, $300 million system resiliency plan. CL&P is hoping for a ruling from the commission in time for the work to begin in 2013.

Transmission is an important part of NU's business. The company earns a higher ROE on transmission than on distribution. Its five-year transmission capital budget is over $3 billion. However, the Federal Energy Regulatory Commission is reviewing NU's allowed return on equity, due to complaints that it is too high.

This stock is up more than 10% since our May report. Its valuation is not compelling for either the near or long term. The subpar regulatory climate in Connecticut is another cause for concern.

Paul E. Debbas, CFA *August 24, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '02, 10¢; '03, (32¢); '04, (7¢); '05, ($1.36); '08, (19¢); '10, 9¢. '09,'10 & '11 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '11: $20.07/sh. (D) In mill. (E) Rate all'd on com. eq. in MA: '11, 9.6%; in CT: (elec.) '10, 9.4% (gas) '11, 8.83%; in NH: '10, 9.67%; earned on avg. com. eq., '11: 10.1%. Regulatory Climate: CT, Below Avg.; NH, Avg.; MA, Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	60

PEPCO HOLDINGS NYSE-POM

RECENT PRICE 19.62 | P/E RATIO 16.4 (Trailing: 19.8; Median: 14.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 5.5% | VALUE LINE

TIMELINESS 3 Raised 2/5/10

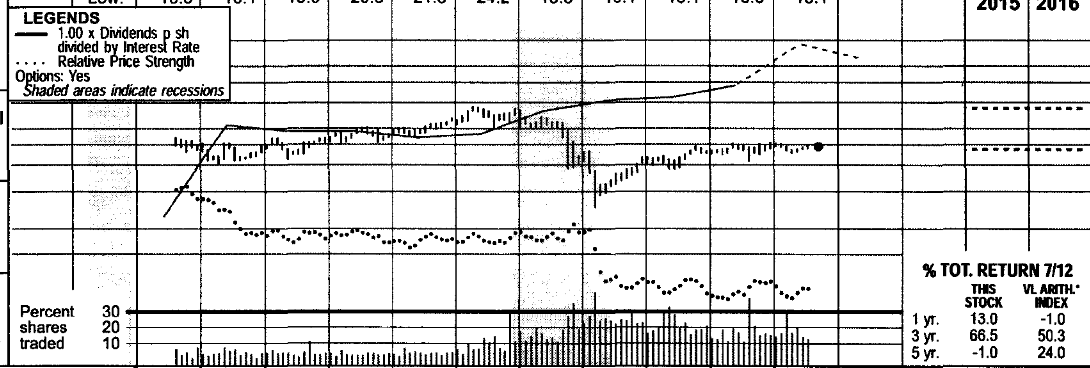
SAFETY 3 Lowered 6/6/03

TECHNICAL 2 Raised 8/24/12

BETA .75 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	21.9	20.6	21.7	24.5	27.0	30.7	29.6	18.7	19.8	20.6	20.5
Low:	18.3	16.1	16.9	20.3	21.8	24.2	15.3	10.1	15.1	16.6	18.1

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+55%)	15%
Low	19	(-5%)	4%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	130	157	156
to Sell	141	134	148
Hld's(000)	122366	118632	131009

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.0	-1.0
3 yr.	66.5	50.3
5 yr.	-1.0	24.0

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

2002	2003F	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
41.11	42.33	38.35	42.49	43.57	46.71	48.88	41.66	31.27	26.02	**25.55**	**25.60**	Revenues per sh	**27.45**
3.12	3.80	3.71	3.67	3.47	3.30	3.55	2.82	2.97	3.00	**3.00**	**3.10**	"Cash Flow" per sh	**3.70**
1.79	1.35	1.46	1.49	1.33	1.53	1.93	1.06	1.24	1.14	**1.20**	**1.30**	Earnings per sh A	**1.70**
.42	1.00	1.00	1.00	1.04	1.04	1.08	1.08	1.08	1.08	**1.08**	**1.12**	Div'd Decl'd per sh B ■	**1.16**
3.06	3.48	2.75	2.46	2.47	3.11	3.57	3.89	3.56	4.14	**4.00**	**4.00**	Cap'l Spending per sh	**3.90**
18.17	17.48	17.87	18.88	18.82	20.04	19.14	19.15	18.79	19.06	**19.40**	**19.70**	Book Value per sh C	**21.50**
164.85	171.77	188.33	189.82	191.93	200.51	218.91	222.27	225.08	227.50	**235.00**	**242.00**	Common Shs Outst'g D	**255.00**
11.3	13.4	13.6	14.9	18.1	18.2	12.2	13.7	14.0	16.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**14.0**
.62	.76	.72	.79	.98	.97	.73	.91	.89	1.05	*estimates*		Relative P/E Ratio	**.95**
2.1%	5.5%	5.0%	4.5%	4.3%	3.7%	4.6%	7.4%	6.2%	5.7%			Avg Ann'l Div'd Yield	**4.9%**
6777.3	7271.3	7221.8	8065.5	8362.9	9366.4	10700	9259.0	7039.0	5920.0	**6000**	**6200**	Revenues ($mill)	**7000**
294.9	245.2	261.3	277.4	254.4	296.5	400.0	235.0	276.0	257.0	**280**	**320**	Net Profit ($mill)	**430**
17.0%	18.3%	38.7%	38.8%	39.1%	39.3%	29.6%	31.9%	18.8%	37.2%	**40.0%**	**40.0%**	Income Tax Rate	**40.0%**
--	--	--	--	--	--	--	--	--	--	**Nil**	**Nil**	AFUDC % to Net Profit	**Nil**
58.7%	63.1%	59.7%	57.1%	54.6%	54.1%	56.2%	53.8%	49.0%	49.1%	**49.0%**	**50.0%**	Long-Term Debt Ratio	**50.0%**
36.4%	35.6%	39.6%	42.3%	45.1%	45.9%	43.8%	46.2%	51.0%	50.9%	**51.0%**	**50.0%**	Common Equity Ratio	**50.0%**
8228.9	8439.3	8494.0	8469.3	8004.0	8753.0	9568.0	9203.0	8292.0	8516.0	**8910**	**9570**	Total Capital ($mill)	**10980**
6798.0	6964.9	7088.0	7312.0	7576.6	7876.7	8314.0	8863.0	7673.0	8220.0	**7750**	**7800**	Net Plant ($mill)	**8100**
4.6%	4.8%	5.0%	5.0%	5.1%	5.1%	5.8%	4.5%	5.1%	4.5%	**4.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
8.7%	7.9%	7.6%	7.6%	7.0%	7.4%	9.5%	5.5%	6.5%	5.9%	**6.0%**	**7.0%**	Return on Shr. Equity	**8.0%**
9.2%	7.7%	7.7%	7.7%	7.0%	7.4%	9.5%	5.5%	6.5%	5.9%	**6.0%**	**7.0%**	Return on Com Equity E	**8.0%**
5.3%	2.0%	2.5%	2.4%	1.5%	2.3%	4.2%	NMF	.8%	.3%	**.5%**	**1.5%**	Retained to Com Eq	**2.5%**
46%	75%	68%	69%	78%	68%	56%	101%	87%	95%	**91%**	**85%**	All Div'ds to Net Prof	**69%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $5127 mill. **Due in 5 Yrs** $1560 mill.
LT Debt $4203 mill. **LT Interest** $250 mill.
(LT interest earned: 2.5x)

Pension Assets-12/11 $1.7 bill. **Oblig.** $2.1 bill.

Pfd Stock None

Common Stock 228,885,730 shs.
as of 7/25/12

MARKET CAP: $4.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.5	+4.1	-2.8
Avg. Resid'l Use (KWH)	10395	11253	10836
Avg. Resid'l Revs. per KWH(¢)	N/A	N/A	N/A
Capacity at Peak (Mw)	N/A	N/A	N/A
Peak Load, Summer (Mw)	N/A	N/A	N/A
Annual Load Factor (%)	N/A	N/A	N/A
% Change Customers (yr-end)	+.6	+1.1	+.7
Fixed Charge Cov. (%)	188	204	251

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-3.5%	-4.5%	-3.0%
"Cash Flow"	-4.5%	-4.0%	4.0%
Earnings	-4.5%	-4.5%	7.0%
Dividends	--	1.5%	1.0%
Book Value	0.5%	0.5%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2520	2065	2539	2135	9259
2010	1819	1636	2067	1517	7039
2011	1634	1409	1643	1234	5920
2012	1292	1179	**1900**	**1629**	**6000**
2013	**1300**	**1200**	**2000**	**1700**	**6200**

Cal-endar	EARNINGS PER SHARE AG Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.21	.11	.56	.18	1.06
2010	.16	.34	.52	.25	1.24
2011	.27	.42	.35	.10	1.14
2012	.30	.27	**.43**	**.20**	**1.20**
2013	**.30**	**.35**	**.45**	**.20**	**1.30**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.27	.27	.27	.27	1.08
2009	.27	.27	.27	.27	1.08
2010	.27	.27	.27	.27	1.08
2011	.27	.27	.27	.27	1.08
2012	.27	.27			

BUSINESS: Pepco Holdings, Inc. consists mainly of three electric utility subsidiaries: Potomac Electric Power Co., serving Washington, D.C. and adjoining areas of Maryland; Delmarva Power, which serves the peninsula area of Delaware, Maryland and Virginia; and Atlantic City Electric, serving southern New Jersey. In July 2010, Pepco sold competitive energy business (Conectiv Energy) to Calpine Corp. Electricity customers: 1.8 million; gas customers: 124,000. Electricity breakdown: residential, 30%; commercial, 49%; other, 21%. 2011 depreciation rate: 2.6%. Has approximately 5,104 employees as of 12/31/11. Chrmn., Pres. & CEO: Joseph M. Rigby. Inc.: DE. Address: 701 Ninth Street, N.W., Wash., D.C. 20068. Telephone.: 202-872-2000. Internet: www.pepcoholdings.com.

Pepco Holdings turned in a soft second-quarter showing. The Washington, DC-based utility reported earnings of $0.27 a share, below our $0.33 estimate. The miss was primarily driven by higher-than-expected operating costs related to reliability and system improvement efforts. Although we believe Pepco's heightened spending habits will provide some benefit down the road, they are likely to continue to suppress earnings growth in the near term. As a result, we have reduced our 2012 earnings estimate by $0.05 a share, to $1.20. Despite the weak second-quarter performance, management reiterated its full-year share-net guidance range of $1.15-$1.30.

The company recently received disappointing rulings in its Maryland rate cases. On July 20th, both Pepco and Delmarva Power received decisions in their distribution rate cases in Maryland. For Pepco, the commission approved an $18 million annual rate increase based on an ROE of 9.31%, while Delmarva was approved for an $11 million increase on an ROE of 9.81%. Combined, the utilities were only granted about 50% of their requested hikes.

There are currently three rate cases pending. Looking past the unfavorable regulatory treatment in Maryland, the company still has ongoing cases in DC, Delaware, and New Jersey where it is requesting a total of $154 million of incremental revenues. A decision in DC is expected sometime in the coming months, while rulings in New Jersey and Delaware are pegged for the fourth quarter.

The stock's dividend remains among the highest in the utility sector. Shares of Pepco are currently yielding an attractive 5.5%, well above the industry's 4.1% average. Encouragingly, management reiterated its commitment to maintaining its quarterly payout in Pepco's most recent conference call (August 7th). For investors seeking to add a consistent income play to their portfolios, this stock remains a top selection.

These neutrally ranked shares are well-suited for long-term accounts. Based on our current projections, total return potential to 2015-2017 is above average by utility standards.

Michael Ratty *August 24, 2012*

(A) Based on dil. shs. Excl. nonrecur. items: '01, 30¢; '03, d69¢; '04, 1¢; '05, 47¢; '06, d1¢; '08, 46¢; '10, 62¢. Next egs. rpt. due early Nov. (B) Div'ds paid in late March, June, Sep., and Dec. ■ Div'd reinvest. plan. (C) Incl. def'd chgs: '11, $4.5 bill. or $19.78/sh. (D) In mill. (E) Rate allowed in MD: 9.83% ('10-Pepco), 10.0% ('09-Delmarva); DC: 9.6% ('10-Pep.); DEL: 10.0% ('06-Del.); NJ: 10.3% ('10-ACE); Earned on '10 avg. com. eq., 6.5%. Reg. Clim.: Avg. (F) Pre-'03 results pro forma. (G) Qtrly egs. may not add due to chng. in shs.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	30
Earnings Predictability	70

SCANA CORP. NYSE-SCG

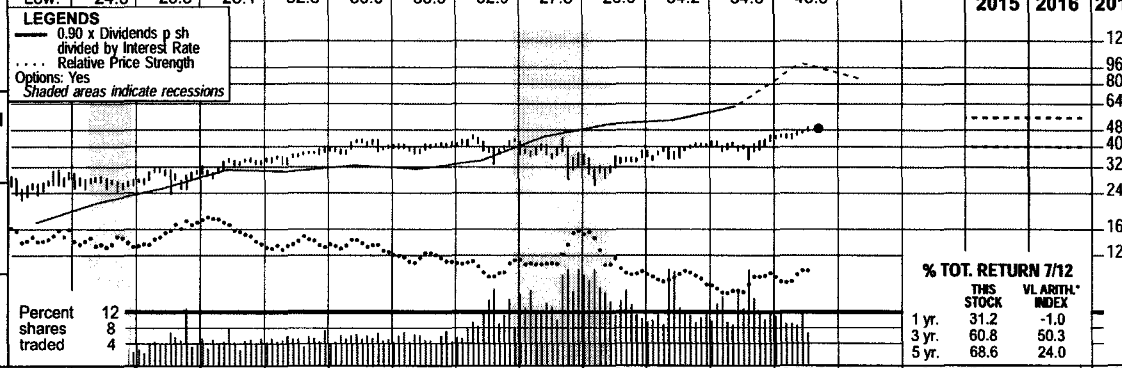
RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
49.02	14.9	(Trailing: 16.3) (Median: 13.0)	1.02	4.1%	

TIMELINESS 3 Raised 9/24/10
SAFETY 2 Lowered 9/10/99
TECHNICAL 3 Raised 8/10/12
BETA .65 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:					30.0	32.1	35.7	39.7	43.7	42.4	45.5	44.1	38.6	42.0	45.5	50.3	
Low:					24.3	23.5	28.1	32.8	36.6	36.9	32.9	27.8	26.0	34.2	34.6	43.3	

Target Price Range 2015 | 2016 | 2017

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



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	7%
Low	40	(-20%)	Nil

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	154	150	160
to Sell	136	144	139
Hld's(000)	62605	61078	64854

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	31.2	-1.0
3 yr.	60.8	50.3
5 yr.	68.6	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
14.25	14.19	15.76	15.93	32.78	32.95	26.65	30.85	34.38	41.54	39.00	39.50	45.08	34.45	36.23	33.92	*30.95*	*30.35*	Revenues per sh	*33.75*
3.75	3.53	3.62	3.15	4.43	4.55	4.56	4.95	5.26	7.41	5.67	5.72	5.85	5.65	5.93	6.01	*6.20*	*6.15*	"Cash Flow" per sh	*7.00*
2.05	1.90	2.12	1.44	2.12	2.15	2.38	2.50	2.67	2.78	2.59	2.74	2.95	2.85	2.98	2.97	*3.15*	*3.35*	Earnings per sh A	*3.75*
1.47	1.51	1.54	1.32	1.15	1.20	1.30	1.38	1.46	1.56	1.68	1.76	1.84	1.88	1.90	1.94	*1.98*	*2.02*	Div'd Decl'd per sh B ■ †	*2.15*
2.34	2.45	2.87	2.37	3.28	4.99	6.41	6.94	4.84	3.37	4.50	6.20	7.66	7.43	6.90	6.80	*10.00*	*11.10*	Cap'l Spending per sh	*9.50*
15.86	16.66	16.86	20.27	19.40	20.95	19.64	20.82	21.69	23.28	24.32	25.30	25.81	27.71	29.15	29.92	*31.30*	*33.90*	Book Value per sh C	*39.75*
106.18	107.32	103.57	103.57	104.73	104.73	110.83	110.74	113.00	115.00	117.00	117.00	118.00	123.00	127.00	130.00	*132.50*	*145.00*	Common Shs Outst'g D	*155.00*
13.1	13.4	14.5	17.5	12.5	12.6	12.2	13.0	13.6	14.4	15.4	15.0	12.7	11.6	12.9	13.7	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.82	.77	.75	1.00	.81	.65	.67	.74	.72	.77	.83	.80	.76	.77	.82	.86	*Value Line*		Relative P/E Ratio	*.85*
5.5%	5.9%	5.0%	5.2%	4.3%	4.4%	4.5%	4.2%	4.0%	3.9%	4.2%	4.3%	4.9%	5.7%	4.9%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $5477.0 mill. **Due in 5 Yrs** $864.0 mill.
LT Debt $4862.0 mill. **LT Interest** $259.0 mill.
(LT interest earned: 2.9x)

Leases, Uncapitalized Annual rentals $11.0 mill.
Pension Assets-12/11 $755.0 mill. **Oblig.** $830.1 mill.

Pfd Stock None

Common Stock 130,792,209 shs. as of 4/30/12
MARKET CAP: $6.4 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
2954.0	3416.0	3885.0	4777.0	4563.0	4621.0	5319.0	4237.0	4601.0	4409.0	*4100*	*4400*	Revenues ($mill)	*5250*
259.0	285.0	305.0	323.0	306.0	327.0	353.0	357.0	376.0	387.0	*420*	*470*	Net Profit ($mill)	*580*
32.2%	31.5%	32.5%	--	26.5%	29.2%	35.4%	32.0%	29.8%	30.3%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
13.5%	10.5%	8.5%	.9%	2.6%	4.6%	8.5%	14.3%	8.0%	5.4%	*6.0%*	*10.0%*	AFUDC % to Net Profit	*6.0%*
55.7%	57.1%	55.4%	51.4%	50.9%	48.4%	58.0%	56.8%	52.9%	54.3%	*55.0%*	*53.0%*	Long-Term Debt Ratio	*53.0%*
42.1%	40.8%	42.6%	46.6%	47.2%	49.7%	40.5%	43.2%	47.1%	45.7%	*45.0%*	*47.0%*	Common Equity Ratio	*47.0%*
5176.0	5646.0	5752.0	5739.0	6027.0	5952.0	7519.0	7891.0	7854.0	8511.0	*9220*	*10435*	Total Capital ($mill)	*13075*
5474.0	6417.0	6762.0	6734.0	7007.0	7538.0	8305.0	9009.0	9662.0	10047	*10965*	*12150*	Net Plant ($mill)	*15375*
7.0%	6.9%	7.1%	7.4%	6.8%	7.3%	6.2%	6.1%	6.5%	6.2%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
11.3%	11.8%	11.9%	11.6%	10.3%	10.6%	11.2%	10.5%	10.2%	10.0%	*10.0%*	*9.5%*	Return on Shr. Equity	*9.5%*
11.6%	12.1%	12.2%	11.8%	10.5%	10.8%	11.4%	10.2%	10.2%	10.0%	*10.0%*	*9.5%*	Return on Com Equity E	*9.5%*
5.5%	5.5%	5.6%	5.3%	3.8%	4.0%	4.4%	3.6%	3.8%	3.6%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	55%	55%	56%	65%	64%	62%	66%	63%	64%	*62%*	*60%*	All Div'ds to Net Prof	*57%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.0	+8.5	-3.4
Avg. Indust. Use (MWH)	7071	7923	8129
Avg. Indust. Revs. per KWH (¢)	6.65	6.72	6.87
Capacity at Yearend (Mw)	5611	5645	5642
Peak Load, Summer (Mw)	4557	4735	4885
Annual Load Factor (%)	58.7	60.9	57.3
% Change Customers (yr-end)	+.8	+.9	+.5
Fixed Charge Cov. (%)	255	278	279

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	-2.0%	*-.5%*
"Cash Flow"	4.0%	-1.0%	*3.0%*
Earnings	4.5%	2.0%	*4.0%*
Dividends	4.5%	4.0%	*2.0%*
Book Value	3.5%	4.5%	*5.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1343	878	921	1095	4237.0
2010	1428	939	1088	1146	4601.0
2011	1281	1000	1092	1036	4409.0
2012	1107	908	*1085*	*1000*	*4100*
2013	*1250*	*950*	*1150*	*1050*	*4400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.94	.45	.84	.62	2.85
2010	1.02	.43	.79	.74	2.98
2011	1.00	.43	.81	.75	2.97
2012	.91	.55	*.85*	*.84*	*3.15*
2013	*1.05*	*.50*	*.90*	*.90*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.44	.46	.46	.46	1.82
2009	.46	.47	.47	.47	1.87
2010	.47	.475	.475	.475	1.90
2011	.475	.485	.485	.485	1.93
2012	.485	.495	.495		

BUSINESS: SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 669,000 customers in South Carolina. Supplies gas and transmission service to 1.3 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown: residential, 42%; commercial, 31%; industrial, 17%; other, 10%. Generating sources: coal, 49%; oil & gas, 28%; nuclear, 19%; hydro, 3%; purchased, 1%. Fuel costs: 54% of revenues. '11 reported deprec. rate: 2.9%. Has 5,900 employees. Chairman, CEO & President: Kevin B. Marsh. Inc.: South Carolina. Address: 100 SCANA Parkway, Cayce, South Carolina 29033. Tel.: 803-217-9000. Internet: www.scana.com.

SCANA's utility subsidiary in South Carolina has filed an electric rate case. South Carolina Electric & Gas is seeking a rate hike of $151.5 million (6.6%), based on a return of 10.95% on a common-equity ratio of 52.18%. (This application excludes the two nuclear units that are under construction, which are dealt with in separate regulatory proceedings.) SCE&G's electric rate base isn't earning an adequate return on equity, having earned an ROE of below 9% for the 12 months ended in mid-2012. In recent years, the utility has been able to settle its general rate cases. SCE&G expects to obtain a rate order in time for new tariffs to take effect at the start of 2013.

The utility has a separate filing for its nuclear construction costs under the state's Base Load Review Act (BLRA). SCE&G's 55% share of the two units it is building are projected to cost $5.8 billion. In order to avoid rate shock and enable the utility to earn a return on construction work in progress, SCE&G files for a modest rate hike each year under the BLRA for these costs. The latest petition is for an increase of $56.7 million (2.5%). New rates are expected to take effect in October.

SCE&G is seeking an adjustment in gas rates, too. Each year, the utility files if it is overearning or underearning its allowed ROE by at least half a percentage point. Because SCE&G is now underearning its allowed ROE for gas, it requested a boost of $8.8 million (2.4%). New tariffs should take effect in November.

We have raised our 2012 share-net estimate by a nickel, to $3.15. June-quarter profits were better than we expected, as the company is benefiting from economic improvement in its service territory. Our revised estimate is at the midpoint of SCANA's guidance of $3.05-$3.25.

We forecast further bottom-line growth in 2013. We assume reasonable regulatory treatment in the aforementioned rate cases and a return to normal weather patterns in Georgia. The mild winter hurt SCANA's gas-supply operation there in the first quarter of 2012.

We aren't enthusiastic about this stock. The yield is only average for a utility, and 3- to 5-year total return potential is low.

Paul E. Debbas, CFA *August 24, 2012*

(A) Excl. nonrec. gains (losses): '97, 16¢; '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. '11 EPS don't add due to change in shs. Next earnings report due late Oct. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '11: $9.84/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SC: 10.7% elec. in '10, 10.25% gas in '05; in NC: 10.6% in '08; earned on avg. com. eq., '11: 9.9%. Regul. Clim.: Above Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	100

SOUTHERN CO. NYSE-SO

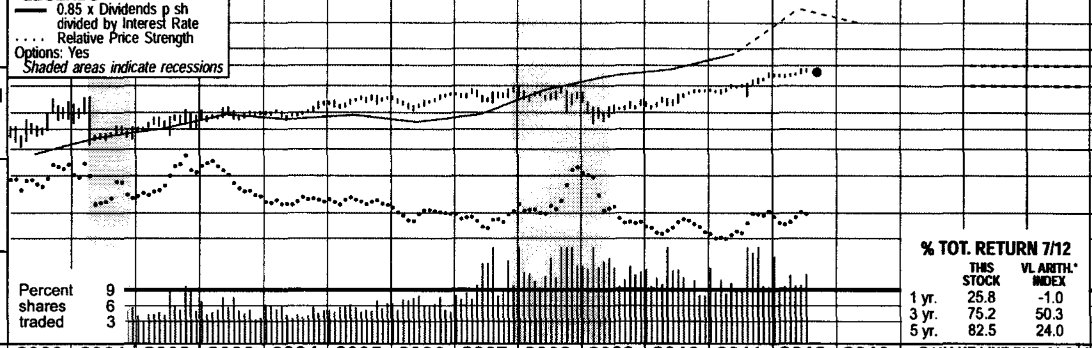
RECENT PRICE	46.60	P/E RATIO	17.4 (Trailing: 18.7, Median: 15.0)	RELATIVE P/E RATIO	1.19	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS 2 Raised 8/24/12
SAFETY 1 Raised 6/3/05
TECHNICAL 3 Raised 8/10/12
BETA .55 (1.00 = Market)

High:	35.7	31.1	32.0	34.0	36.5	37.4	39.3	40.6	37.6	38.6	46.7	48.6
Low:	20.9	23.2	27.0	27.4	31.1	30.5	33.2	29.8	26.5	30.8	35.7	43.7

Target Price Range 2015 | 2016 | 2017

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



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+5%)	6%
Low	40	(-15%)	1%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	435	435	385
to Sell	281	307	387
Hld's(000)	373196	374903	372243

Percent shares traded 9 6 3

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.8	-1.0
3 yr.	75.2	50.3
5 yr.	82.5	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.30	18.19	16.34	17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	*19.00*	*19.55*	Revenues per sh	*21.75*
3.64	3.86	4.26	4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	*5.10*	*5.45*	"Cash Flow" per sh	*6.25*
1.68	1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	*2.60*	*2.80*	Earnings per sh A	*3.25*
1.26	1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	*1.94*	*2.02*	Div'd Decl'd per sh B ■ †	*2.25*
1.82	2.68	2.87	3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	*6.25*	*5.65*	Cap'l Spending per sh	*6.75*
13.61	13.91	14.04	13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	*20.95*	*21.70*	Book Value per sh C	*25.50*
677.04	693.42	697.75	665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	*868.00*	*870.00*	Common Shs Outst'g D	*915.00*
13.8	14.0	15.7	14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.86	.81	.82	.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	1.00	*Value Line*		Relative P/E Ratio	*.95*
5.5%	5.9%	4.9%	5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $21961 mill. **Due in 5 Yrs** $7695.0 mill.
LT Debt $19051 mill. **LT Interest** $848.0 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $121.0 mill.
Pension Assets-12/11 $6.80 bill. **Oblig.** $8.08 bill.
Pfd Stock $1082 mill. **Pfd Div'd** $65.0 mill.
Incl. 1 mill. shs. 4.20%-5.44% cum. pfd. ($100 par); 12 mill. shs. 4.95%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 3 mill. shs. 6.0%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 868,690,126 shs.
MARKET CAP: $40 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
10549	11251	11902	13554	14356	15353	17127	15743	17456	17657	*16500*	*17000*	Revenues ($mill)	*20000*
1510.0	1602.1	1589.0	1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	*2340*	*2510*	Net Profit ($mill)	*3040*
25.9%	27.0%	27.0%	26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
5.4%	4.6%	5.2%	4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	*13.0%*	*13.0%*	AFUDC % to Net Profit	*13.0%*
43.1%	45.9%	53.5%	53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*53.0%*
43.4%	43.6%	44.1%	44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	*45.5%*	*45.0%*	Common Equity Ratio	*45.0%*
20086	22135	23288	24131	24618	27608	31174	34091	35438	37307	*40000*	*41700*	Total Capital ($mill)	*52200*
24642	27534	28361	29480	31092	33327	35878	39230	42002	45010	*48275*	*50900*	Net Plant ($mill)	*61500*
8.6%	8.4%	8.1%	8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
13.2%	13.4%	14.7%	14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	*12.0%*	*12.5%*	Return on Shr. Equity	*12.5%*
15.1%	14.8%	14.9%	14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	*12.5%*	*13.0%*	Return on Com Equity E	*12.5%*
4.1%	4.4%	4.7%	4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
76%	73%	69%	70%	73%	70%	74%	75%	77%	73%	*75%*	*72%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.8	+7.6	-2.7
Avg. Indust. Use (MWH)	3095	3332	3438
Avg. Indust. Revs. per KWH (¢)	6.04	6.20	6.37
Capacity at Yearend (Mw)	42932	42963	43555
Peak Load, Summer (Mw)	34471	36321	36956
Annual Load Factor (%)	60.6	62.2	59.0
% Change Customers (yr-end)	- -	+.3	-.1
Fixed Charge Cov. (%)	310	342	397

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	2.5%	*1.0%*
"Cash Flow"	2.0%	3.5%	*5.0%*
Earnings	3.0%	3.0%	*5.0%*
Dividends	3.0%	4.0%	*4.0%*
Book Value	3.5%	6.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3666	3885	4682	3510	15743
2010	4157	4208	5320	3771	17456
2011	4012	4521	5428	3696	17657
2012	3604	4181	*5015*	*3700*	*16500*
2013	*3800*	*4200*	*5200*	*3800*	*17000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.41	.61	.99	.31	2.32
2010	.60	.62	.98	.18	2.36
2011	.49	.70	1.06	.30	2.55
2012	.42	.70	*1.12*	*.36*	*2.60*
2013	*.50*	*.75*	*1.20*	*.35*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.4025	.42	.42	.42	1.66
2009	.42	.4375	.4375	.4375	1.73
2010	.4375	.455	.455	.455	1.80
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49			

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 35%; commercial, 30%; industrial, 19%; wholesale, 11%; other, 5%. Retail revenues by state: Georgia, 51%; Alabama, 33%; Florida, 9%; Mississippi, 7%. Generating sources: coal, 49%; oil & gas, 28%; nuclear, 15%; hydro, 2%; purchased, 6%. Fuel costs: 39% of revenues. '11 reported deprec. rate (utility): 3.2%. Has 26,400 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

Southern Company has two major projects under construction. Georgia Power is building two nuclear units that are scheduled to begin commercial operation in 2016 and 2017. The utility's 45.7% share of the project (about 1,000 megawatts) has a certified cost of $6.1 billion. However, some $400 million of cost overruns are in dispute between the company and the construction firms. If the final cost is above the certified cost, Georgia Power would have to seek recovery for the overage from the state commission. Mississippi Power is building a 582-mw coal gasification plant, which is scheduled for completion in 2014. The projected cost has risen to $2.88 billion (including a $62 million contingency), which is the cost cap there. The utility would have to ask the state regulators for approval to recover any costs above the cost cap.

We now estimate that earnings will advance slightly in 2012. Second-quarter profits were better than we expected, so we have raised our earnings estimate by $0.05 a share, to $2.60. Our revised estimate is now within Southern Company's guidance of $2.58-$2.70 a share.

We expect profits to increase in 2013. Georgia Power will benefit from the final increase of its three-year rate hike. In addition, the service area's economy is growing moderately. We have raised our earnings estimate by $0.05 a share because average shares outstanding will be lower than we had expected.

Southern Company won't need additional common equity this year or next. That's because the cost of environmental compliance will be less than the company had expected. Whatever equity is issued through the exercise of options will be bought back on the open market. There will be a small net increase in shares outstanding, however, because options are exercised at below-market prices.

This high-quality stock is timely. However, it is trading at an above-market price-earnings ratio, which is unusual for a utility issue. The yield is average for a utility, but with the share price near the upper bound of our 2015-2017 Target Price Range, total return potential over that time frame is minimal.

Paul E. Debbas, CFA *August 24, 2012*

(A) Diluted earnings. Excl. nonrecurring gain (loss): '03, 6¢; '09, (25¢). '10 EPS don't add due to change in shares. Next earnings report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $6.27/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 12.5%. Earned on avg. com. eq., '11: 13.0%. Regulatory Climate: AL Above Average; GA, MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

TECO ENERGY, INC. NYSE-TE

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
18.00	14.0	(Trailing: 14.5 Median: 15.0)	0.96	5.0%	VALUE LINE

TIMELINESS 3 Lowered 2/17/12
SAFETY 2 Raised 2/24/12
TECHNICAL 2 Raised 8/24/12
BETA .85 (1.00 = Market)

High:	33.0	29.0	17.0	15.5	19.3	17.7	18.6	22.0	16.7	18.1	19.7	19.4
Low:	24.8	10.0	9.5	11.3	14.9	14.4	14.8	10.5	8.4	14.5	15.8	16.9

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+40%)	12%
Low	18	(Nil)	5%

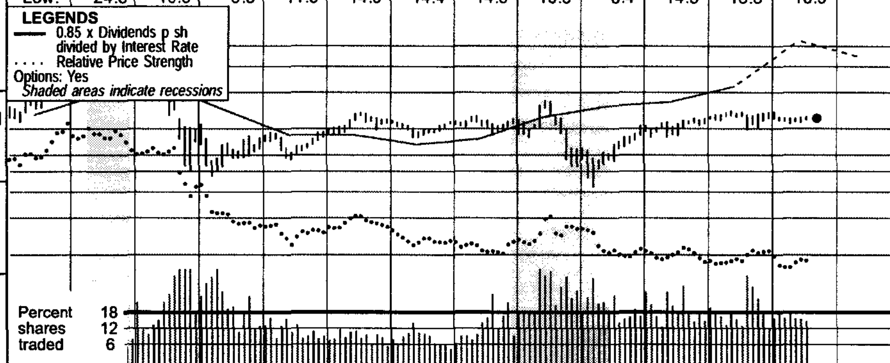
Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	137	153	160
to Sell	137	146	145
Hld's(000)	123784	122395	124759

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



Percent shares traded 18 12 6

Target Price Range

2015	2016	2017

40 32 24 16 12 10 8 6 4

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.1	-1.0
3 yr.	56.7	50.3
5 yr.	46.3	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
12.53	14.23	14.83	15.01	18.17	18.97	15.22	14.59	13.37	14.46	16.46	16.77	15.85	15.48	16.23	15.49	*14.05*	*14.70*	Revenues per sh	*16.25*
3.28	3.34	3.25	3.28	4.11	4.31	3.20	1.96	2.14	2.37	2.51	2.51	2.01	2.35	2.59	2.77	*2.80*	*2.90*	"Cash Flow" per sh	*3.50*
1.71	1.61	1.52	1.53	1.97	2.24	1.95	d.08	.71	1.00	1.17	1.27	.77	1.00	1.13	1.27	*1.25*	*1.30*	Earnings per sh A	*1.65*
1.11	1.17	1.23	1.29	1.33	1.37	1.41	.93	.76	.76	.76	.78	.80	.80	.82	.85	*.88*	*.90*	Div'd Decl'd per sh B ■	*1.00*
2.28	1.62	2.24	3.23	5.45	6.92	6.06	3.14	1.37	1.42	2.18	2.34	2.77	2.99	2.28	2.10	*2.35*	*2.45*	Cap'l Spending per sh	*3.00*
10.73	11.04	11.42	10.73	11.93	14.12	14.86	8.93	6.43	7.65	8.25	9.56	9.43	9.75	10.10	10.50	*10.85*	*11.25*	Book Value per sh C	*13.00*
117.60	130.90	132.00	132.10	126.30	139.60	175.80	187.80	199.70	208.20	209.50	210.90	212.90	213.90	214.90	215.80	*217.00*	*218.00*	Common Shs Outst'g D	*221.00*
14.3	15.4	17.8	14.2	11.9	12.9	11.0	--	19.3	17.1	13.8	13.3	21.2	12.6	14.6	14.4	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.90	.89	.93	.81	.77	.66	.60	--	1.02	.91	.75	.71	1.28	.84	.93	.91	*Value Line*		Relative P/E Ratio	*.85*
4.5%	4.7%	4.5%	5.9%	5.7%	4.8%	6.6%	7.4%	5.5%	4.4%	4.7%	4.6%	4.9%	6.3%	4.9%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*

CAPITAL STRUCTURE as of 3/31/12
Total Debt $3028.7 mill. Due in 5 Yrs $1213.0 mill.
LT Debt $2598.7 mill. LT Interest $169.1 mill.
(LT interest earned: 3.2x)

Leases, Uncapitalized Annual rentals $17.9 mill.

Pension Assets-12/11 $467.6 mill.
Oblig. $646.4 mill.

Pfd Stock None

Common Stock 215,679,828 shs.
as of 4/27/12

MARKET CAP: $3.9 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
2675.8	2740.0	2669.1	3010.1	3448.1	3536.1	3375.3	3310.5	3487.9	3343.4	*3050*	*3200*	Revenues ($mill)	*3575*
298.2	d14.7	137.4	211.0	244.4	265.8	162.4	213.9	242.9	272.6	*270*	*285*	Net Profit ($mill)	*375*
--	--	38.5%	45.1%	40.4%	40.7%	36.8%	31.6%	34.8%	36.1%	*36.0%*	*36.0%*	Income Tax Rate	*35.0%*
4.4%	--	.7%	.0%	1.6%	2.3%	5.4%	6.5%	1.2%	.6%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*5.0%*
50.5%	72.4%	75.1%	70.0%	65.0%	61.0%	61.5%	60.6%	59.2%	54.2%	*59.5%*	*58.5%*	Long-Term Debt Ratio	*55.5%*
39.7%	27.6%	24.9%	30.0%	35.0%	39.0%	38.5%	39.4%	40.8%	45.8%	*40.5%*	*41.5%*	Common Equity Ratio	*44.5%*
6585.1	6070.3	5163.9	5300.9	4941.6	5175.4	5214.3	5287.0	5317.8	4953.9	*5780*	*5890*	Total Capital ($mill)	*6525*
5464.0	5679.0	4657.9	4566.9	4766.9	4888.2	5221.3	5544.1	5841.0	5967.8	*6135*	*6320*	Net Plant ($mill)	*7225*
5.7%	2.1%	5.6%	6.5%	7.3%	7.3%	5.1%	6.0%	6.4%	7.4%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.5%*
9.1%	NMF	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	12.0%	*11.5%*	*11.5%*	Return on Shr. Equity	*13.0%*
9.9%	NMF	10.7%	13.3%	14.1%	13.2%	8.1%	10.3%	11.2%	12.0%	*11.5%*	*11.5%*	Return on Com Equity E	*13.0%*
3.2%	NMF	NMF	3.3%	5.0%	5.1%	NMF	2.1%	3.1%	3.9%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
72%	NMF	106%	75%	65%	61%	104%	80%	72%	67%	*71%*	*69%*	All Div'ds to Net Prof	*59%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.1	+2.3	-3.4
Avg. Indust. Use (Mw)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	9.63	9.35	8.94
Capacity at Peak (Mw)	4719	4684	4684
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	-.1	+.6	+.7
Fixed Charge Cov. (%)	199	270	302

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-1.0%	1.5%	*.5%*
"Cash Flow"	-4.0%	2.0%	*5.5%*
Earnings	-5.0%	3.5%	*6.5%*
Dividends	-4.5%	1.5%	*3.5%*
Book Value	-2.0%	6.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	824.0	825.2	896.3	765.0	3310.5
2010	912.3	898.8	901.8	775.0	3487.9
2011	796.1	885.7	911.4	750.2	3343.4
2012	730.0	788.4	*850*	*681.6*	*3050*
2013	*750*	*850*	*900*	*700*	*3200*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.16	.29	.30	.25	1.00
2010	.26	.35	.35	.17	1.13
2011	.24	.36	.42	.25	1.27
2012	.23	.34	*.42*	*.26*	*1.25*
2013	*.27*	*.34*	*.42*	*.27*	*1.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.195	.20	.20	.20	.80
2009	.20	.20	.20	.20	.80
2010	.20	.205	.205	.205	.82
2011	.205	.215	.215	.215	.85
2012	.22	.22			

BUSINESS: TECO Energy, Inc. is a holding company for Tampa Electric, which serves 678,000 customers in west central Florida, and Peoples Gas (acquired 6/97), which serves 340,000 customers in Florida. TECO also mines coal and has generation investments in Guatemala. Sold TECO Transport 12/07. Electric revenue breakdown: residential, 49%; commercial, 30%; industrial, 8%; other, 13%. Generating sources: coal, 58%; gas, 36%; purchased, 6%. Fuel costs: 32% of revenues. '11 reported deprec. rate (utility): 3.6%. Has 4,300 employees. Chairman: Sherrill W. Hudson. President & CEO: John B. Ramil. Incorporated: Florida. Address: TECO Plaza, 702 N. Franklin Street, Tampa, Florida 33602. Telephone: 813-228-1111. Internet: www.tecoenergy.com.

Wall Street is worried about the declining business of TECO's coal-mining subsidiary. This year, low prices of natural gas have prompted many electric utilities to use more gas and less coal to generate power. Thus, TECO Coal now expects volume of 6.0 million-6.3 million tons this year, a million tons less than it estimated in early 2012 and well below the 8.1 million tons it sold in 2011. Thanks to the expiration of a low-priced contract in 2011, margins should still be higher than a year ago. Even so, there is valid concern about TECO Coal's prospects beyond this year, although investors should note that this subsidiary also sells specialty coals that should make up about 45% of its sales mix in 2012.

We have lowered our 2012 and 2013 share-earnings estimates by a nickel each year. Upon releasing June-quarter results, management lowered its 2012 earnings guidance by $0.10 a share, to $1.20-$1.30. This was due in part to TECO Coal's prospects, but also to mild weather (through July) that has hurt Tampa Electric. Our revised 2012 estimate is at the midpoint of TECO's targeted range. The company hasn't yet provided profit guidance for 2013, but we trimmed our forecast due to our assumption that TECO Coal's income will be lower than we had expected. We still look for a dividend hike next year, but think the increase will be just modest.

TECO's utilities are performing well. Despite the unfavorable weather conditions mentioned above, Tampa Electric should still be able to earn a return on equity at or near the bottom of its allowed ROE range of 10.25%-12.25%. Peoples Gas should earn an ROE near the midpoint of its allowed range of 9.75%-11.75%. Each utility is benefiting from an improved customer growth rate and effective cost controls. No rate cases are pending, and we expect no filings in the near term.

This equity offers an attractive yield. It is about a percentage point above the utility average. Although we have lowered our sights a bit for the 3- to 5-year period, the stock still offers total return potential that is a cut above the industry norm. No matter what happens with TECO Coal, its income isn't likely to fall to zero.

Paul E. Debbas, CFA *August 24, 2012*

(A) Diluted earnings. Excl. nonrecurring gain (losses): '97, (6¢); '99, (11¢); '03, ($4.97); '07, 63¢; '10, (2¢) net; gains (loss) on discontinued ops.: '04, (77¢); '05, 31¢; '06, 1¢; '07, 7¢. Next earnings report due early Nov. (B) Div'ds paid in late Feb., May, Aug. & Nov. ■ Div'd reinvestment plan available. (C) Incl. deferred charges. In '11: $2.58/sh. (D) In millions. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09 (elec.): 10.25%-12.25%; in '09 (gas): 9.75%-11.75%; earned on avg. com. eq., '11: 12.3%. Regulatory Climate: Average.

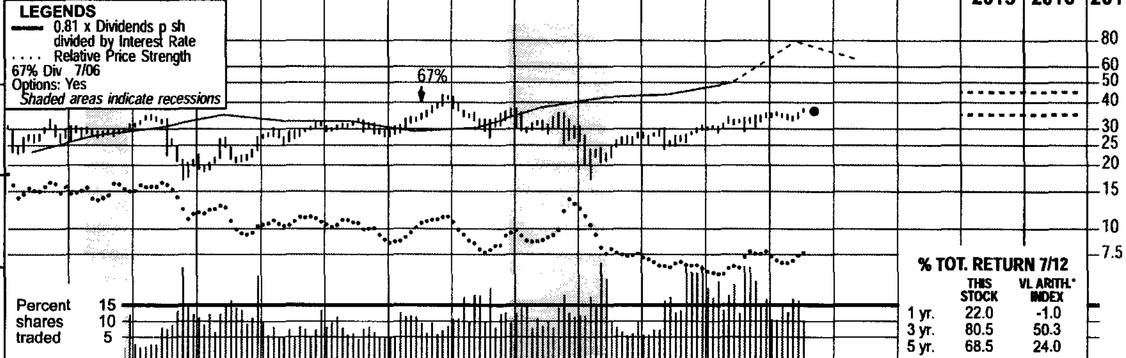
Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	70

UIL HOLDINGS NYSE-UIL

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
36.44	17.1	(Trailing: 20.2 Median: 17.0)	1.17	4.7%	VALUE LINE

TIMELINESS 3 Raised 5/14/10
SAFETY 2 Raised 2/29/08
TECHNICAL 3 Raised 7/27/12
BETA .70 (1.00 = Market)

High:	31.8	35.3	27.6	32.8	33.7	43.8	43.0	37.8	31.2	31.3	35.8	37.7
Low:	26.3	16.9	18.5	25.1	27.4	27.4	27.0	25.1	17.0	23.8	28.6	32.6



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	10%
Low	35	(-5%)	4%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	90	74	67
to Sell	53	67	81
Hld's(000)	32150	31887	33016

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.0	-1.0
3 yr.	80.5	50.3
5 yr.	68.5	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
30.89	30.64	29.34	29.01	37.54	46.15	47.55	40.39	45.87	49.88	34.03	39.23	37.69	29.91	19.75	31.01	*30.00*	*31.35*	Revenues per sh	*36.25*
4.81	5.40	5.34	4.67	5.53	6.61	5.89	4.69	4.37	4.13	4.65	5.48	5.93	5.09	3.65	5.33	*5.35*	*5.55*	"Cash Flow" per sh	*5.80*
1.90	1.96	1.80	2.23	2.56	2.53	1.85	1.24	1.54	1.30	1.86	1.87	1.89	1.94	1.99	1.95	*2.10*	*2.30*	Earnings per sh A	*2.45*
1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	1.73	*1.73*	*1.73*	Div'd Decl'd per sh B ■	*1.73*
2.01	1.44	1.63	1.48	2.31	2.01	2.41	2.19	2.04	2.25	3.09	9.92	8.57	4.12	4.03	6.48	*5.20*	*5.10*	Cap'l Spending per sh	*5.00*
18.72	18.94	19.05	19.55	20.42	21.25	20.28	20.65	22.84	22.39	18.53	18.55	18.85	19.15	21.31	21.61	*21.95*	*22.55*	Book Value per sh C	*25.50*
23.50	23.18	23.39	23.44	23.46	23.53	23.79	23.86	24.01	24.32	24.86	25.03	25.17	29.98	50.51	50.65	*51.00*	*51.00*	Common Shs Outst'g E	*51.00*
11.4	10.1	16.3	12.6	10.8	11.5	15.0	18.0	18.7	23.5	18.7	18.4	16.7	12.7	14.0	16.5	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.71	.58	.85	.72	.70	.59	.82	1.03	.99	1.25	1.01	.98	1.01	.85	.89	1.04	*Value Line*		Relative P/E Ratio	*1.05*
8.0%	8.8%	5.9%	6.2%	6.2%	5.9%	6.2%	7.7%	6.0%	5.7%	5.0%	5.0%	5.5%	7.0%	6.2%	5.4%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1131.0	963.7	1101.3	1213.1	846.0	982.0	948.7	896.6	997.7	1570.4	*1530*	*1600*	Revenues ($mill)	*1850*
44.0	29.5	36.9	31.4	45.4	46.7	48.1	54.3	70.3	99.7	*105*	*115*	Net Profit ($mill)	*125*
45.2%	53.1%	45.4%	44.1%	31.2%	39.5%	42.2%	38.0%	38.6%	38.5%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
5.1%	8.5%	1.1%	9.0%	8.0%	8.3%	8.3%	10.0%	26.3%	12.1%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*10.0%*
45.0%	50.1%	47.2%	47.2%	47.0%	50.8%	53.6%	54.0%	58.4%	58.6%	*58.0%*	*57.0%*	Long-Term Debt Ratio	*54.0%*
55.0%	49.9%	52.8%	52.8%	53.0%	49.2%	46.4%	46.0%	41.6%	41.4%	*42.0%*	*43.0%*	Common Equity Ratio	*46.0%*
877.8	988.2	1039.6	1031.5	869.2	943.6	1023.6	1247.7	2587.9	2642.7	*2670*	*2700*	Total Capital ($mill)	*2800*
517.1	548.8	563.9	592.1	647.0	878.4	1073.6	1153.0	2327.5	2570.4	*2700*	*2800*	Net Plant ($mill)	*3100*
7.3%	4.3%	4.5%	4.1%	6.5%	6.2%	6.1%	5.8%	3.7%	5.2%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	9.5%	6.5%	9.1%	*9.5%*	*10.0%*	Return on Shr. Equity	*9.5%*
9.1%	6.0%	6.7%	5.8%	9.9%	10.1%	10.1%	9.5%	6.5%	9.1%	*9.5%*	*10.0%*	Return on Com Equity D	*9.5%*
.6%	NMF	NMF	NMF	NMF	3.1%	1.0%	1.2%	1.7%	1.1%	*1.5%*	*2.0%*	Retained to Com Eq	*3.0%*
93%	NMF	112%	NMF	117%	70%	90%	88%	74%	88%	*84%*	*77%*	All Div'ds to Net Prof	*71%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1754 mill. **Due in 5 Yrs.** $310.0 mill.
LT Debt $1645 mill. **LT Interest** $75.0 mill.
(LT interest earned: 3.0x)
Leases, Uncapitalized: Ann. rentals $10.6 mill.

Pension Assets-12/11 $548 mill. **Oblig.** $792 mill.

Pfd Stock None

Common Stock 50,665,114 shs. **as of 7/31/12**

MARKET CAP: $1.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.1	+4.4	-2.8
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.7	6.3	6.4
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	-.1	Nil
Fixed Charge Cov. (%)	303	281	230

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-3.5%	-9.0%	*5.0%*
"Cash Flow"	-2.0%	1.5%	*3.5%*
Earnings	-2.0%	4.5%	*4.0%*
Dividends	--	--	*Nil*
Book Value	--	-.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	235.5	200.2	255.2	205.7	896.6
2010	220.3	207.1	236.3	334.0	997.7
2011	561.1	314.0	321.4	373.9	1570.4
2012	458.3	283.5	*360*	*428.2*	*1530*
2013	*470*	*300*	*380*	*450*	*1600*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.48	.51	.73	.22	1.94
2010	.53	.48	.63	.35	1.99
2011	1.02	.28	.24	.41	1.95
2012	.92	.23	*.35*	*.60*	*2.10*
2013	*.95*	*.30*	*.40*	*.65*	*2.30*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.432	.432	.432	.432	1.73
2009	.432	.432	.432	.432	1.73
2010	.432	.432	.432	.432	1.73
2011	.432	.432	.432	.432	1.73
2012	.432	.432			

BUSINESS: UIL Holdings, through its subsidiaries, operates as one of the largest regulated utility companies in Connecticut. Business consists of electric distribution/transmission operations of The United Illuminating Company and natural gas transportation/distribution operations of The Southern Connecticut Gas Company, The Connecticut Natural Gas Company, and The Berkshire Gas Company. Revenue distribution by class: residential, 48%; commercial, 28%; industrial, 5%; other, 19%. Fuel costs: 39% of revenues; O&M costs, 24%. Has 1,868 employees as of 12/11. President & Chief Executive Officer: James P. Torgerson. Inc.: CT. Address: 157 Church Street, P.O. Box 1564, New Haven, CT. 06506-0901. Telephone: 203-499-2000. Internet: www.uil.com.

UIL Holdings reported weaker-than-expected second-quarter results. The Connecticut-based utility posted earnings of $0.23 a share during the period, significantly below our $0.33 estimate. The miss was primarily driven by unfavorable weather conditions, which has seemed to be a recurring theme among several utilities this earnings season. Despite the soft quarterly showing, management reaffirmed its full-year earnings guidance range of $2.00-$2.15 a share. We have lowered our 2012 share-net estimate by a nickel, to $2.10.

Given recent regulatory uncertainty, UIL is still considering when to file its electric distribution rate case. Since the restructuring last year of Connecticut's utility regulatory body (PURA), UIL has been reluctant to file its electric rate case due to a lack of visibility. Now that the composition of the board has been settled, we anticipate the company will make the filing sometime in the first half of 2013. However, nothing has been officially stated at this juncture. Based on our current estimates, we assume UIL's electric business will earn its allowed ROE in 2012 and 2013.

Continued progress in gas conversions is a positive. UIL has converted nearly 4,700 customers through the first half of 2012, roughly a 46% increase over the comparable period of 2011. Management noted it remains on pace to hit its goal of 10,200 by year's end, as well as its 30,000-35,000 target by the end of 2013. We look for gas conversions and other cost savings to help the gas utilities earn their allowed ROEs by 2014.

The stock maintains a neutral ranking for Timeliness (3). In our view, the equity remains an attractive selection for investors seeking to add some stability to their portfolios. With Above-Average rankings for Safety (2) and Financial Strength (B++), UIL represents a solid low-risk play within the utility sector. Indeed, its dividend yield also ranks among the best in the industry, offering shareholders a nice income component, as well.

Based on our current projections, total return potential for UIL to 2015-2017 is right around the utility industry average.

Michael Ratty *August 24, 2012*

(A) EPS basic. Excl. nonrecur. gains (losses): '96, 17¢; '00, 4¢; '03, (26¢); '04, $2.14; '06, ($5.07); '10, (47¢). Next egs. report due early Nov. (B) Div'ds historically paid in early Jan., early April, early July, and early Oct. ■ Div'd reinvest. plan avail. (C) Incl. deferred charges. In '11: $370.2 mill. or $7.32/sh. (D) Rate base: orig. cost. Rate allowed on common equity in '09: 8.75%. Earned on average common equity in '11: 9.1%. Regul. Clim.: Below Average. (E) In millions. Adjust for stock dividend.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	70
Earnings Predictability	80

ALLETE NYSE-ALE

RECENT PRICE **40.54** | P/E RATIO **16.5** (Trailing: 18.1 / Median: NMF) | RELATIVE P/E RATIO **1.15** | DIV'D YLD **4.6%** | VALUE LINE

High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.5	
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	38.0	

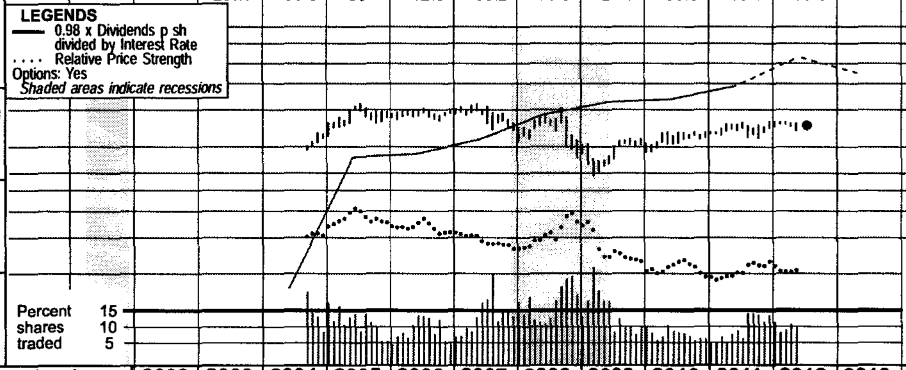
TIMELINESS 3 Lowered 8/12/11

SAFETY 2 New 10/1/04

TECHNICAL 3 Raised 5/11/12

BETA .70 (1.00 = Market)

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



Target Price Range

2015	2016	2017

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

Percent shares traded 15 / 10 / 5

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	35	(-15%)	1%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	75	81	76
to Sell	50	52	65
Hld's(000)	21519	22270	22589

% TOT. RETURN 5/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.5	-9.6
3 yr.	70.9	64.7
5 yr.	3.4	13.3

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (now KAR Auction Services, NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	**25.45**	**26.65**	Revenues per sh	**29.75**
--	--	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	**5.00**	**5.45**	"Cash Flow" per sh	**6.50**
--	--	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	**2.45**	**2.65**	Earnings per sh A	**3.50**
--	--	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	**1.84**	**1.88**	Div'd Decl'd per sh B ■ †	**2.00**
--	--	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	**11.45**	**7.70**	Cap'l Spending per sh	**3.25**
--	--	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	**29.80**	**30.70**	Book Value per sh C	**34.50**
--	--	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	**38.50**	**39.00**	Common Shs Outst'g D	**40.50**
--	--	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	*Bold figures are*		Avg Ann'l P/E Ratio	**12.0**
--	--	1.33	.95	.89	.79	.84	1.07	1.02	.93	*Value Line*		Relative P/E Ratio	**.80**
--	--	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	**4.8%**
--	--	751.4	737.4	767.1	841.7	801.0	759.1	907.0	928.2	**980**	**1040**	Revenues ($mill)	**1200**
--	--	38.5	68.0	77.3	87.6	82.5	61.0	75.3	93.8	**95.0**	**105**	Net Profit ($mill)	**140**
--	--	38.8%	28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	**25.0%**	**25.0%**	Income Tax Rate	**25.0%**
--	--	1.8%	.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	**9.0%**	**5.0%**	AFUDC % to Net Profit	**2.0%**
--	--	38.2%	39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	**44.5%**	**44.0%**	Long-Term Debt Ratio	**40.0%**
--	--	61.8%	60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	**55.5%**	**56.0%**	Common Equity Ratio	**60.0%**
--	--	1020.7	990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	**2060**	**2135**	Total Capital ($mill)	**2350**
--	--	883.1	860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	**2325**	**2515**	Net Plant ($mill)	**2850**
--	--	5.1%	8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	**5.5%**	**6.0%**	Return on Total Cap'l	**7.0%**
--	--	6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	**8.0%**	**8.5%**	Return on Shr. Equity	**10.0%**
--	--	6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	**8.0%**	**8.5%**	Return on Com Equity E	**10.0%**
--	--	4.7%	5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	**2.0%**	**2.5%**	Retained to Com Eq	**4.0%**
--	--	23%	54%	57%	51%	61%	93%	81%	66%	**75%**	**71%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 3/31/12
Total Debt $863.6 mill. **Due in 5 Yrs** $222.6 mill.
LT Debt $856.5 mill. **LT Interest** $43.9 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $10.9 mill.

Pension Assets-12/11 $432.4 mill.
Oblig. $597.5 mill.

Pfd Stock None

Common Stock 38,142,329 shs.

MARKET CAP: $1.5 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-25.6	+29.1	+5.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	2.98	5.20	NA
Capacity at Peak (Mw)	1757	1812	NA
Peak Load, Winter (Mw) F	1414	1604	1599
Annual Load Factor (%)	81.2	79.0	NA
% Change Customers (avg.)	+1.4	+1.0	NA
Fixed Charge Cov. (%)	296	334	344

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	-1.0%	*3.5%*
"Cash Flow"	--	3.0%	*7.0%*
Earnings	--	.5%	*7.5%*
Dividends	--	12.0%	*2.0%*
Book Value	--	5.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	199.6	164.7	178.8	216.0	759.1
2010	233.6	211.2	224.1	238.1	907.0
2011	242.2	219.9	226.9	239.2	928.2
2012	240.0	*230*	*250*	*260*	*980*
2013	*265*	*245*	*260*	*270*	*1040*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.55	.29	.49	.56	1.89
2010	.68	.57	.56	.38	2.19
2011	1.07	.48	.57	.53	2.65
2012	.66	*.54*	*.65*	*.60*	*2.45*
2013	*.75*	*.55*	*.70*	*.65*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.43	.43	.43	.43	1.72
2009	.44	.44	.44	.44	1.76
2010	.44	.44	.44	.44	1.76
2011	.445	.445	.445	.445	1.78
2012	.46	.46			

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric revenue breakdown: taconite mining/processing, 24%; paper/wood products, 9%; other industrial, 10%; residential, 13%; commercial, 14%; wholesale, 13% other, 17%. Has real estate operation in FL. Discont. water-utility ops. in '01. Spun off automotive remarketing operation in '04. Generating sources: coal & lignite, 60%; hydro, 3%; other, 2%; purchased, 35%. '11 deprec. rate: 3.0%. Has 1,400 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

We estimate that ALLETE's earnings will decline this year. This is partly due to a tough comparison, as tax benefits boosted the bottom line by $0.26 a share in the first half of 2011. In addition, a milder-than-usual winter lowered profits by $0.05 a share. What's more, pension expense is up. (Minnesota Power, ALLETE's main utility subsidiary, is asking the state regulators for a tracking mechanism for pension costs.) Our 2012 share-net estimate is at the low end of the company's targeted range of $2.45-$2.65.

Earnings should recover in 2013. We assume normal first-quarter weather conditions. More importantly, Minnesota Power is building two wind projects, which are scheduled for completion by year-end 2012. Each of these will provide 105 megawatts of capacity at an expected cost of $160 million. Because state regulatory law allows current-cost recovery of renewable-energy projects (i.e., without a formal rate case), these will benefit earnings in 2013.

The utility will soon seek regulatory approvals for a large environmental project. Minnesota Power's proposed upgrades to the Boswell 4 coal-fired unit would cost $300 million-$400 million. Like the aforementioned renewable-energy projects, this would also qualify for current-cost recovery. If the needed approvals are granted, construction would begin in 2013, with completion of the project expected in 2015.

The long-term profit picture looks good. The mining-based economy in northern Minnesota is already faring well, and some of the utility's customers have announced expansions or are considering them. In addition, Minnesota Power has significant opportunities for transmission spending, both on its own and through equity investments in American Transmission Company (in which the company has an 8% stake). These would be well above the utility's current five-year capital budget, which includes $113 million for transmission, so our long-term profit projection might prove understated.

This stock offers a dividend yield that is about half a percentage point above the utility average. Total return potential to 2015-2017 is only average for a utility, however.

Paul E. Debbas, CFA *June 22, 2012*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due late July. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '11: $9.22/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '11: 9.1%. Regulatory Climate: Average. (F) Summer peak in '10.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	70

ALLIANT ENERGY NYSE-LNT

RECENT PRICE **44.64** | P/E RATIO **14.9** (Trailing: 16.5, Median: 14.0) | RELATIVE P/E RATIO **0.98** | DIV'D YLD **4.1%** | VALUE LINE

TIMELINESS 2 Raised 8/24/12
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Raised 8/3/12
BETA .70 (1.00 = Market)

High:	33.2	31.0	25.1	28.8	30.6	40.0	46.5	42.4	31.5	37.7	44.5	47.7
Low:	27.5	14.3	15.0	23.5	25.6	27.5	34.9	22.8	20.3	29.2	33.9	41.9

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

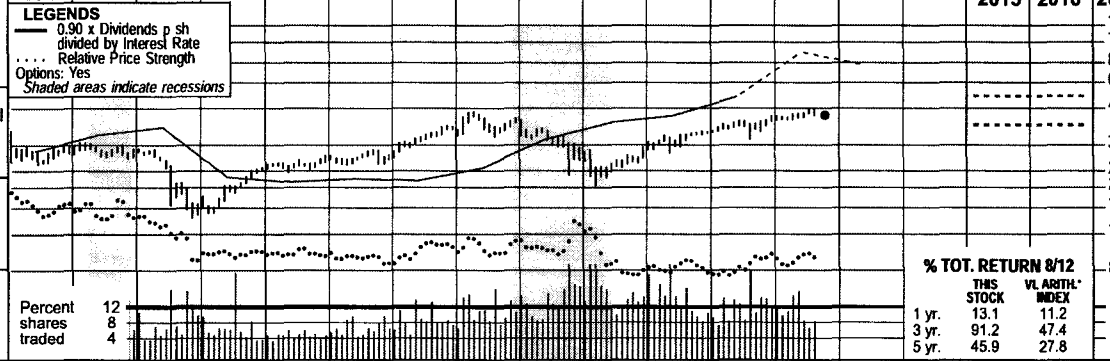
	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	40	(-10%)	2%

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	150	129	121
to Sell	127	147	150
Hld's(000)	60603	61552	62065



% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	11.2
3 yr.	91.2	47.4
5 yr.	45.9	27.8

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
28.26	28.19	25.56	28.02	28.93	31.15	33.33	31.02	30.81	33.02	***28.85***	***30.35***	Revenues per sh	***39.15***
4.52	4.19	4.69	5.46	4.33	5.12	4.56	4.21	5.21	5.65	***5.90***	***6.20***	"Cash Flow" per sh	***7.30***
1.18	1.57	1.85	2.21	2.06	2.69	2.54	1.89	2.75	2.75	***2.95***	***3.10***	Earnings per sh A	***3.60***
2.00	1.00	1.02	1.05	1.15	1.27	1.40	1.50	1.58	1.70	***1.80***	***1.90***	Div'd Decl'd per sh B ■ †	***2.20***
7.12	7.69	5.55	4.51	3.42	4.91	7.96	10.87	7.82	6.22	***9.00***	***6.95***	Cap'l Spending per sh	***7.40***
19.89	21.37	22.13	20.85	22.83	24.30	25.56	25.07	26.09	27.14	***29.75***	***30.80***	Book Value per sh C	***32.60***
92.30	110.96	115.74	117.04	116.13	110.36	110.45	110.66	110.89	111.02	***111.00***	***112.00***	Common Shs Outst'g D	***115.00***
19.9	12.7	14.0	12.6	16.8	15.1	13.4	13.9	12.5	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	***13.0***
1.09	.72	.74	.67	.91	.80	.81	.93	.80	.92	*Value Line*		Relative P/E Ratio	***.85***
8.5%	5.0%	3.9%	3.8%	3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	*estimates*		Avg Ann'l Div'd Yield	***4.7%***
2608.8	3128.2	2958.7	3279.6	3359.4	3437.6	3681.7	3432.8	3416.1	3665.3	***3200***	***3400***	Revenues ($mill)	***4500***
113.1	176.6	229.5	337.8	260.1	320.8	280.0	208.6	303.9	304.4	***325***	***345***	Net Profit ($mill)	***420***
24.2%	28.9%	26.7%	19.0%	43.8%	44.4%	33.4%	--	30.1%	14.7%	***30.0%***	***30.0%***	Income Tax Rate	***30.0%***
6.8%	11.7%	8.1%	3.0%	3.1%	2.4%	--	--	8.8%	6.0%	***6.0%***	***6.0%***	AFUDC % to Net Profit	***6.0%***
56.4%	44.8%	45.0%	41.6%	31.4%	32.4%	36.3%	44.3%	46.3%	45.7%	***45.5%***	***46.0%***	Long-Term Debt Ratio	***47.0%***
39.2%	50.0%	50.2%	53.1%	62.9%	61.9%	58.6%	51.2%	49.5%	50.9%	***51.5%***	***51.0%***	Common Equity Ratio	***50.5%***
4679.1	4738.4	5104.7	4599.1	4218.4	4329.5	4815.6	5423.0	5840.8	5921.2	***6405***	***6755***	Total Capital ($mill)	***7455***
3729.2	4432.6	5284.6	4866.2	4944.9	4679.9	5353.5	6203.0	6730.6	7037.1	***7400***	***7600***	Net Plant ($mill)	***8200***
4.1%	5.7%	6.1%	8.9%	7.5%	8.6%	7.0%	5.1%	6.6%	6.7%	***6.5%***	***6.5%***	Return on Total Cap'l	***7.0%***
5.5%	6.8%	8.2%	12.6%	9.0%	11.0%	9.1%	6.9%	9.7%	9.5%	***9.5%***	***9.5%***	Return on Shr. Equity	***10.5%***
5.8%	6.7%	8.2%	13.1%	9.1%	11.3%	9.3%	6.8%	9.9%	10.1%	***10.0%***	***10.0%***	Return on Com Equity E	***11.0%***
NMF	2.5%	3.8%	8.1%	4.0%	5.9%	3.8%	.9%	3.8%	3.4%	***3.5%***	***3.5%***	Retained to Com Eq	***4.0%***
NMF	67%	58%	42%	59%	50%	62%	88%	64%	66%	***66%***	***66%***	All Div'ds to Net Prof	***64%***

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2917.0 mill. **Due in 5 Yrs** $649.2 mill.
LT Debt $2752.8 mill. **LT Interest** $155.0 mill.
(LT interest earned: 4.4x)

Pension Assets-12/11 $1081.4 mill. **Oblig.** $897.4 mill.
Pfd Stock $205.1 mill. **Pfd Div'd** $16.0 mill.
449,765 shs. $100 par; 6,599,460 shs. $25 par

Common Stock 110,976,142 shs.

MARKET CAP: $5.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.8	+2.8	+.9
Avg. Indust. Use (MWH)	10948	11213	11054
Avg. Indust. Revs. per KWH (¢)	6.33	6.80	6.51
Capacity at Peak (Mw)	5491	5425	5734
Peak Load, Summer (Mw)	5491	5425	5734
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	+.2	+.2
Fixed Charge Cov. (%)	256	306	237

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.0%	3.0%	*3.5%*
"Cash Flow"	-2.0%	-.5%	*6.5%*
Earnings	2.0%	5.0%	*6.5%*
Dividends	-3.0%	8.0%	*5.5%*
Book Value	.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	949.9	742.3	885.7	854.9	3432.8
2010	890.2	741.6	951.7	832.6	3416.1
2011	945.0	819.5	1021.6	879.2	3665.3
2012	765.7	690.3	***1020***	***724***	***3200***
2013	***790***	***750***	***1100***	***760***	***3400***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.30	.34	.77	.48	1.89
2010	.45	.44	1.31	.55	2.75
2011	.68	.44	1.12	.51	2.75
2012	.50	.58	***1.30***	***.57***	***2.95***
2013	***.55***	***.55***	***1.35***	***.65***	***3.10***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.35	.35	.35	.35	1.40
2009	.375	.375	.375	.375	1.50
2010	.395	.395	.395	.395	1.58
2011	.425	.425	.425	.425	1.70
2012	.45	.45	.45		

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 47%; IA, 50%; MN, 3%. Elect. rev.: residential, 37%; commercial, 23%; industrial, 28%; wholesale, 7%; other, 5%. Fuel sources, 2011: coal, 52%; nuclear, 17%; gas, 2%; other, 29%. Fuel costs: 45% of revs. 2011 depreciation rate: 4.6%. Estimated plant age: 10 years. Has 4,262 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy posted solid bottom-line performance for the second quarter. The utility business benefited from greater electric sales to residential and commercial customers. Higher income from subsidiary Interstate Power and Light's (IPL's) tax benefit rider also contributed, and so did lower operating costs. Looking forward, we expect decent results from the utilities going forward, assuming a stable economy and normal weather. Favorable earnings comparisons ought to continue in the coming quarters, and we project a nice share-net improvement for full-year 2012.

There have been some developments on the regulatory front. IPL, along with two parties representing Iowa consumers, has filed a proposed settlement with the Iowa Utilities Board (IUB) in its natural gas rate case. The three parties have agreed to increase IPL's natural gas service revenue by roughly $10.5 million. A time line for review of the settlement proposal by the IUB is unknown, though the original rate case was expected to be completed by April of 2013. IPL had previously requested a rate hike of $14.8 million, to recover natural gas system improvements and to compensate for higher costs. Elsewhere, subsidiary Wisconsin Power and Light has received approval from the Public Service Commission of Wisconsin to reduce retail gas base rates by 7% in 2013 and freeze gas rates in the following year. The utility has also requested to reduce overall retail electric rates by 2.5% next year, due to lower expected electric fuel costs. It will probably receive approval for the plan by yearend.

This stock is ranked to outperform the broader market for the coming six to 12 months. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. In addition, Alliant earns favorable marks for Safety, Financial Strength, and Price Stability. From the recent quotation, this issue has unimpressive, though fairly well-defined, total return potential for the coming years. Income-oriented investors may find this equity's healthy dividend yield attractive. However, investors seeking strong capital appreciation potential are probably better served elsewhere.

Michael Napoli, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢; '09, (88¢); '10, (15¢); '11, (1¢). Next egs. rpt. due in November. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '11: $92.1 mill., $0.83/sh. (D) In mill. (E) Rate base: Orig. cost. Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

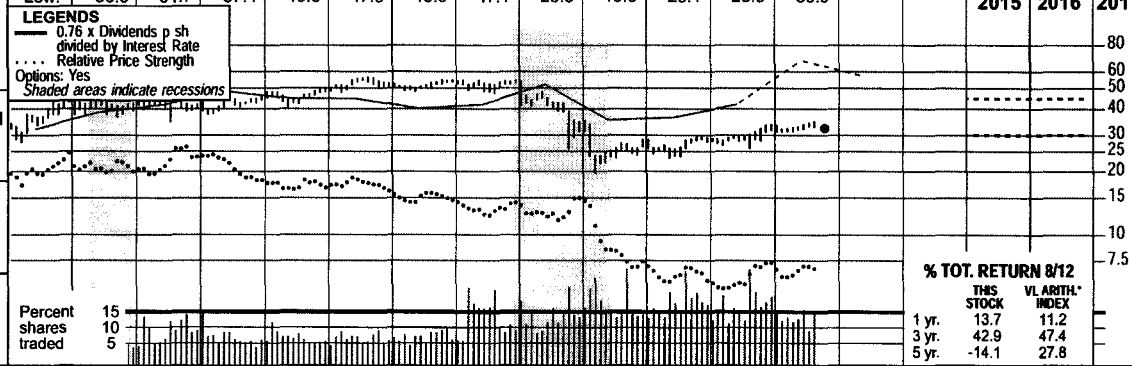
AMEREN NYSE-AEE

RECENT PRICE **32.50** | P/E RATIO **11.6** (Trailing: 9.6 / Median: 15.0) | RELATIVE P/E RATIO **0.76** | DIV'D YLD **5.0%** | VALUE LINE

TIMELINESS 3 Lowered 3/2/12
SAFETY 3 Lowered 6/26/09
TECHNICAL 3 Lowered 9/7/12
BETA .80 (1.00 = Market)

High:	46.0	45.3	46.5	50.4	56.8	55.2	55.0	54.3	35.3	29.9	34.1	35.3
Low:	36.5	34.7	37.4	40.6	47.5	48.0	47.1	25.5	19.5	23.1	25.5	30.9

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+40%)	12%
Low	30	(-10%)	3%

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	181	170	169
to Sell	158	176	164
Hld's(000)	143204	147715	132680

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.7	11.2
3 yr.	42.9	47.4
5 yr.	-14.1	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.13	24.24	24.18	25.68	28.10	32.64	24.93	28.20	26.43	33.12	33.30	36.23	36.92	29.87	31.77	31.04	**28.45**	**28.65**	Revenues per sh	**30.50**
5.12	4.96	5.36	5.36	6.11	6.33	5.28	6.29	5.57	6.10	6.02	6.76	6.44	6.06	6.33	5.87	**5.90**	**5.85**	"Cash Flow" per sh	**6.50**
2.86	2.44	2.82	2.81	3.33	3.41	2.66	3.14	2.82	3.13	2.66	2.98	2.88	2.78	2.77	2.47	**2.40**	**2.25**	Earnings per sh A	**2.50**
2.51	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	2.54	1.54	1.54	1.56	**1.61**	**1.65**	Div'd Decl'd per sh B ■	**1.80**
3.18	2.77	2.37	4.16	6.77	7.99	5.11	4.19	4.13	4.63	4.99	6.96	9.75	7.51	4.66	4.50	**5.75**	**5.50**	Cap'l Spending per sh	**6.00**
23.06	22.00	22.27	22.52	23.30	24.26	24.93	26.73	29.71	31.09	31.86	32.41	32.80	33.08	32.15	32.64	**31.90**	**32.40**	Book Value per sh C	**34.50**
102.12	137.22	137.22	137.22	137.22	138.05	154.10	162.90	195.20	204.70	206.60	208.30	212.30	237.40	240.40	242.60	**242.65**	**246.00**	Common Shs Outst'g D	**255.00**
13.8	15.5	14.2	13.5	11.0	12.1	15.8	13.5	16.3	16.7	19.4	17.4	14.2	9.3	9.7	11.9	*Bold figures are*		Avg Ann'l P/E Ratio	**14.5**
.86	.89	.74	.77	.72	.62	.86	.77	.86	.89	1.05	.92	.85	.62	.62	.75	*Value*	*Line*	Relative P/E Ratio	**.95**
6.3%	6.7%	6.3%	6.7%	6.9%	6.2%	6.1%	6.0%	5.5%	4.9%	4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	*estim*	*ates*	Avg Ann'l Div'd Yield	**5.0%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $6887.0 mill. **Due in 5 Yrs** $1664.0 mill.
LT Debt $6678.0 mill. **LT Interest** $430.0 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $38.0 mill.
Pension Assets-12/11 $2.88 bill. **Oblig.** $3.87 bill.
Pfd Stock $142.0 mill. **Pfd Div'd** $8.0 mill.
807,595 shs. $3.50 to $5.50 cum. (no par), $100 stated value, redeemable at $102.176-$110/sh.; 616,323 shs. 4.00% to 6.625%, $100 par, redeemable at $100-$104/sh.
Common Stock 242,634,671 shs. **as of 7/31/12**
MARKET CAP: $7.9 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
3841.0	4593.0	5160.0	6780.0	6880.0	7546.0	7839.0	7090.0	7638.0	7531.0	**6900**	**7050**	Revenues ($mill)	**7750**
393.0	517.0	541.0	628.0	547.0	629.0	615.0	624.0	669.0	602.0	**595**	**560**	Net Profit ($mill)	**655**
38.9%	36.8%	34.3%	35.6%	32.7%	33.5%	33.7%	34.7%	36.8%	37.3%	**36.0%**	**36.0%**	Income Tax Rate	**36.0%**
2.8%	1.9%	1.8%	2.9%	.7%	.8%	4.6%	5.8%	7.8%	5.6%	**6.0%**	**7.0%**	AFUDC % to Net Profit	**7.0%**
46.0%	47.3%	45.5%	44.9%	43.8%	45.0%	47.8%	49.7%	48.2%	45.3%	**46.5%**	**46.0%**	Long-Term Debt Ratio	**45.0%**
51.4%	50.6%	52.6%	53.3%	54.6%	53.4%	50.8%	49.1%	50.9%	53.7%	**52.5%**	**53.5%**	Common Equity Ratio	**54.0%**
7468.0	8606.0	11036	11932	12063	12654	13712	15991	15185	14738	**14675**	**14950**	Total Capital ($mill)	**16200**
8914.0	10917	13297	13572	14286	15069	16567	17610	17853	18127	**18675**	**19150**	Net Plant ($mill)	**20600**
6.5%	7.4%	6.0%	6.5%	5.7%	6.2%	5.7%	5.3%	6.0%	5.6%	**5.5%**	**5.0%**	Return on Total Cap'l	**5.5%**
9.7%	11.4%	9.0%	9.5%	8.1%	9.0%	8.6%	7.8%	8.5%	7.5%	**7.5%**	**7.0%**	Return on Shr. Equity	**7.5%**
9.9%	11.6%	9.1%	9.7%	8.1%	9.2%	8.7%	7.8%	8.6%	7.5%	**7.5%**	**7.0%**	Return on Com Equity E	**7.5%**
.2%	2.2%	.9%	1.7%	.2%	1.3%	1.0%	3.5%	3.8%	2.8%	**2.5%**	**2.0%**	Retained to Com Eq	**2.0%**
98%	81%	91%	83%	97%	86%	88%	56%	56%	63%	**67%**	**73%**	All Div'ds to Net Prof	**71%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.1	+8.5	-1.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.45	4.63	4.93
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	266	293	295

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	.5%	- -	*Nil*
"Cash Flow"	.5%	.5%	*1.0%*
Earnings	-1.5%	-1.5%	*-1.0%*
Dividends	-5.0%	-9.5%	*2.5%*
Book Value	3.5%	1.0%	*1.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1916	1684	1815	1675	7090.0
2010	1940	1725	2267	1706	7638.0
2011	1904	1781	2268	1578	7531.0
2012	1658	1660	**2050**	**1532**	**6900**
2013	**1750**	**1700**	**2000**	**1600**	**7050**

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.66	.77	1.04	.34	2.78
2010	.43	.64	1.49	.21	2.77
2011	.29	.57	1.50	.11	2.47
2012	d.11	.87	**1.39**	**.25**	**2.40**
2013	**.30**	**.55**	**1.15**	**.25**	**2.25**

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.635	.635	.635	.635	2.54
2009	.385	.385	.385	.385	1.54
2010	.385	.385	.385	.385	1.54
2011	.385	.385	.385	.40	1.56
2012	.40	.40			

BUSINESS: Ameren Corp. is a holding company formed through the merger of Union Electric and CIPSCO. Acquired CILCORP 1/03; Illinois Power 10/04. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 811,000 gas customers in Illinois. Electric revenue breakdown: residential, 48%; commercial, 31%; industrial, 11%; other, 10%. Generating sources: coal, 67%; nuclear, 9%; hydro, 1%; gas, 1%; purchased, 22%. Fuel costs: 41% of revenues. '11 reported depreciation rates: 3%-4%. Has 9,300 employees. Chairman, President & CEO: Thomas R. Voss. Incorporated: Missouri. Address: One Ameren Plaza, 1901 Chouteau Avenue, P.O. Box 66149, St. Louis, Missouri 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren is awaiting an order on its electric rate case in Missouri. The utility is seeking a rate increase of $376 million (14.6%), based on a return of 10.75% on a common-equity ratio of 52%. Ameren also wants the commission to establish a tracking mechanism for storm costs and an accrual mechanism for assets that are in service, but not yet reflected in customer rates. The commission's staff is recommending a $210 million tariff hike, based on a 9% ROE, but is against the two regulatory mechanisms. The staff also recommends a change to the fuel adjustment clause so that only 85% of these costs would be reflected (versus 95% now). The commission's order is due in December, with new rates taking effect in January.
An electric rate case is pending in Illinois, too. This is the first one under a new state law that provides for recovery of electric distribution spending through a formula. The commission's decision is due in late September, and earnings this year will reflect a true-up for the 2012 rate base and the actual cost of service.
More-frequent rate cases in Missouri and the new law in Illinois should reduce the effects of regulatory lag. This has been a problem for the past several years, which is one reason why returns on equity have generally been mediocre.
The merchant-generation subsidiary is dealing with unfavorable industrywide conditions. Low wholesale power prices are hurting owners of nonregulated generating assets. In addition, coal-fired facilities are facing more-stringent emissions rules. As a result, this segment has closed some units, reduced the employee headcount, and cut its capital budget. This business is still covering its cash needs, but is only slightly profitable. Next year will likely be worse, due to lower hedged prices. All told, we estimate lower earnings in 2012 and 2013, even if the outcome of the aforementioned rate matters is reasonable for Ameren.
This stock has appeal for income-oriented investors. The yield is nearly a percentage point above the utility average. Although we project little overall earnings improvement between now and 2015-2017, dividends will likely be raised over that time thanks to growth in *utility* income.
Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecur. gain (losses): '03, 11¢; '05, (11¢); '10, ($2.19); '11, (32¢); '12, ($1.55). '09 EPS don't add due to change in shs., '11 due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $8.33/sh. (D) In mill. (E) Rate base: Orig. cost deprec. Rate allowed on com. eq. in MO in '10: 10.1%; in IL in '10: 9.9%-10.3% electric, in '12: 9.06% gas; earned on avg. com. eq., '11: 7.6%. Reg. Climate: MO, Avg.; IL, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	10
Earnings Predictability	90

AMERICAN ELEC. PWR. NYSE-AEP

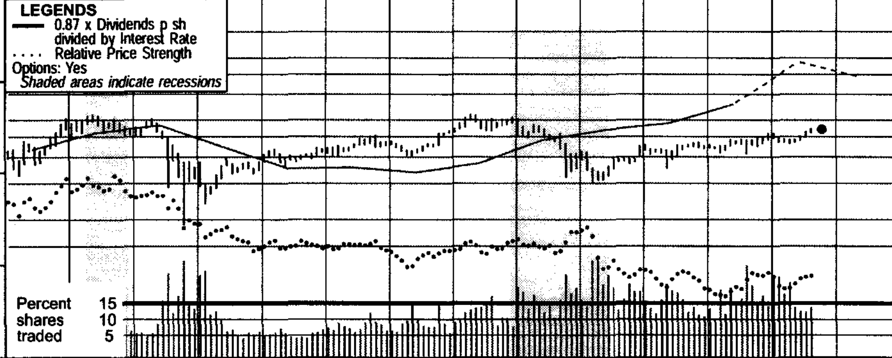
RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
43.43	13.8	(Trailing: 14.1, Median: 13.0)	0.91	4.5%	

TIMELINESS 3 Lowered 5/4/12
SAFETY 3 Lowered 10/4/02
TECHNICAL 3 Lowered 9/14/12
BETA .70 (1.00 = Market)

High:	51.2	48.8	31.5	35.5	40.8	43.1	51.2	49.1	36.5	37.9	41.7	44.0
Low:	39.3	15.1	19.0	28.5	32.3	32.3	41.7	25.5	24.0	28.2	33.1	37.0

Target Price Range 2015 | 2016 | 2017

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



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	10%
Low	40	(-10%)	3%

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	339	323	312
to Sell	208	279	254
Hld's(000)	299983	298208	270699

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.7	11.2
3 yr.	58.7	47.4
5 yr.	23.0	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.07	32.43	33.08	35.63	42.53	190.10	42.96	36.82	35.51	30.76	31.82	33.41	35.56	28.22	30.01	31.27	*30.65*	*32.30*	Revenues per sh	*36.50*
6.31	6.47	6.03	6.36	5.11	7.65	6.99	5.76	5.89	5.96	6.67	6.80	6.84	6.32	6.29	6.83	*6.90*	*7.10*	"Cash Flow" per sh	*8.25*
3.14	3.28	2.81	2.69	1.04	3.27	2.86	2.53	2.61	2.64	2.86	2.86	2.99	2.97	2.60	3.13	*3.10*	*3.10*	Earnings per sh A	*3.50*
2.40	2.40	2.40	2.40	2.40	2.40	2.40	1.65	1.40	1.42	1.50	1.58	1.64	1.64	1.71	1.85	*1.90*	*1.96*	Div'd Decl'd per sh B ■	*2.15*
3.07	4.00	4.13	4.47	5.51	5.69	5.08	3.44	4.28	6.11	8.89	8.88	9.83	6.19	5.07	5.74	*6.80*	*7.75*	Cap'l Spending per sh	*7.50*
24.15	24.62	25.24	25.79	25.01	25.54	20.85	19.93	21.32	23.08	23.73	25.17	26.33	27.49	28.33	30.33	*31.60*	*32.80*	Book Value per sh C	*36.75*
188.24	189.99	191.82	194.10	322.02	322.24	338.84	395.02	395.86	393.72	396.67	400.43	406.07	478.05	480.81	483.42	*486.00*	*489.00*	Common Shs Outst'g D	*500.00*
13.2	13.4	17.0	14.3	34.3	13.9	12.7	10.7	12.4	13.7	12.9	16.3	13.1	10.0	13.4	11.9	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.83	.77	.88	.82	2.23	.71	.69	.61	.66	.73	.70	.87	.79	.67	.85	.75	*Value Line*		Relative P/E Ratio	*.90*
5.8%	5.5%	5.0%	6.2%	6.7%	5.3%	6.6%	6.1%	4.3%	3.9%	4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $18510 mill. **Due in 5 Yrs** $6372 mill.
LT Debt $15319 mill. **LT Interest** $844 mill.
Incl. $2389 mill. securitized bonds.
(LT interest earned: 3.4x)

Leases, Uncapitalized Annual rentals $316 mill.
Pension Assets-12/11 $4.30 bill. **Oblig.** $4.99 bill.
Pfd Stock None

Common Stock 484,902,556 shs. as of 7/26/12
MARKET CAP: $21 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
14555	14545	14057	12111	12622	13380	14440	13489	14427	15116	*14900*	*15800*	Revenues ($mill)	*18200*
976.0	984.0	1038.0	1036.0	1131.0	1147.0	1208.0	1365.0	1248.0	1513.0	*1490*	*1500*	Net Profit ($mill)	*1725*
25.2%	38.8%	33.1%	29.3%	33.0%	31.1%	31.3%	29.7%	34.8%	31.7%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
--	3.8%	3.6%	5.4%	9.9%	9.8%	9.9%	10.9%	10.4%	10.6%	*12.0%*	*12.0%*	AFUDC % to Net Profit	*12.0%*
56.0%	60.6%	56.2%	54.8%	56.7%	58.3%	59.1%	54.4%	53.1%	50.7%	*50.5%*	*50.0%*	Long-Term Debt Ratio	*49.0%*
43.1%	38.7%	43.1%	44.9%	43.0%	41.4%	40.7%	45.4%	46.7%	49.3%	*49.5%*	*50.0%*	Common Equity Ratio	*51.0%*
16393	20333	19584	20222	21902	24342	26290	28958	29184	29747	*30950*	*32125*	Total Capital ($mill)	*35900*
21684	22029	22801	24284	26781	29870	32987	34344	35674	36971	*38425*	*40250*	Net Plant ($mill)	*45100*
7.5%	6.6%	7.0%	6.6%	6.7%	6.3%	6.2%	6.2%	5.7%	6.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
13.5%	12.3%	12.1%	11.3%	11.9%	11.3%	11.2%	10.3%	9.1%	10.3%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.5%*
13.7%	12.4%	12.2%	11.3%	12.0%	11.4%	11.3%	10.4%	9.1%	10.3%	*10.0%*	*9.5%*	Return on Com Equity E	*9.5%*
2.4%	4.5%	5.7%	5.2%	5.7%	5.1%	5.1%	4.6%	3.1%	4.2%	*4.0%*	*3.5%*	Retained to Com Eq	*3.5%*
82%	64%	54%	54%	53%	55%	55%	56%	66%	60%	*62%*	*64%*	All Div'ds to Net Prof	*62%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.4	+4.5	+1.2
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.83	4.95	4.95
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	265	257	286

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-10.5%	-2.0%	*3.5%*
"Cash Flow"	--	1.0%	*4.0%*
Earnings	2.0%	1.5%	*3.0%*
Dividends	-3.0%	4.0%	*3.5%*
Book Value	1.0%	5.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3458	3202	3547	3282	13489
2010	3569	3360	4064	3434	14427
2011	3730	3609	4333	3444	15116
2012	3625	3551	*4300*	*3424*	*14900*
2013	*3850*	*3750*	*4450*	*3750*	*15800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.89	.68	.93	.49	2.97
2010	.72	.35	1.16	.37	2.60
2011	.83	.73	1.17	.41	3.13
2012	.80	.75	*1.10*	*.45*	*3.10*
2013	*.85*	*.75*	*1.05*	*.45*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.41	.41	.41	.41	1.64
2009	.41	.41	.41	.41	1.64
2010	.41	.42	.42	.46	1.71
2011	.46	.46	.46	.47	1.85
2012	.47	.47	.47		

BUSINESS: American Electric Power Company, Inc. (AEP), through 10 operating utilities, serves about 5.3 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, and West Virginia. Electric revenue breakdown: residential, 37%; commercial, 23%; industrial, 21%; wholesale, 16%; other, 3%. Sold 50% stake in Yorkshire Holdings (British utility) '01; sold SEEBOARD (British utility) '02; sold Houston Pipeline '05. Generating sources not available. Fuel costs: 35% of revenues. '11 reported depr. rates: 1.3%-9.3%. Has 18,700 employees. Chairman: Michael G. Morris. President & CEO: Nicholas K. Akins. Inc.: NY. Address: 1 Riverside Plaza, Columbus, OH 43215-2373. Tel.: 614-716-1000. Internet: www.aep.com.

American Electric Power will be making a transition to competitive markets in Ohio in the next few years. The Public Utilities Commission of Ohio (PUCO) issued a new plan in the third quarter. The PUCO overturned the previous transition plan earlier this year after some customers complained about much higher bills. AEP's base generation rates will be frozen (but there will be a fuel adjustment clause), and the utility will be able to collect a nonbypassable retail stability rider and a capacity charge to help compensate for the effects of customer switching to other suppliers. AEP will make another filing to separate its generating units in Ohio into a nonutility affiliate, except for two units that will be transferred to two regulated companies. Management was disappointed with certain aspects of the transition plan that the PUCO ordered, and has asked the regulators for a rehearing. Because the new plan will make it easier for other providers to compete in AEP's service territory, we have lowered our 2013 earnings estimate by $0.15 a share, to $3.10, which would be flat with our estimated 2012 tally.

Two rate cases are pending. Indiana Michigan Power filed for a $146.3 million rate hike in Indiana, based on an 11.15% return on equity. The commission's staff is recommending an increase of just $28 million, based on a 9.2% ROE. An order is expected by yearend. Another AEP subsidiary, SWEPCO, asked the Texas commission for an increase of $83.1 million, based on an 11.25% ROE. Rates should go into effect in the first quarter of 2013.

The regulated operations are faring well. There is less regulatory activity than usual because most of AEP's utilities are earning their allowed ROEs, or are close to doing so. In addition, the company's transmission business should increase its contribution to the bottom line in the coming years, as there are plenty of opportunities to invest capital. Because the regulated picture is generally bright, we think the board of directors will raise the dividend in the fourth quarter, as it did in each of the past two years.

This stock's yield and 2015-2017 total return potential are similar to the utility norms.

Paul E. Debbas, CFA *September 21, 2012*

(A) Excl. nonrec. gains (losses): '02, ($3.86); '03, ($1.92); '04, 24¢; '05, (62¢); '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; gains (losses) on disc. ops.: '02, (57¢); '03, (32¢); '04, 15¢; '05, 7¢; '06, 2¢; '08, 3¢; '09, (1¢). '09 EPS don't add due to change in shs., '11 due to rounding. Next egs. due late Oct. (B) Div'ds historically paid early Mar., June, Sept. & Dec. ■ Div'd reinv. plan avail. (C) Incl. intang. In '11: $18.77/sh. (D) In mill. (E) Rate base: various. Rates all'd on com. eq.: 9.96%-10.9%; earned on avg. com. eq., '10: 9.3%. Regul. Clim.: Avg.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	90

CLECO CORPORATION NYSE-CNL

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
41.49	16.0 (Trailing: 14.5 Median: 14.0)	1.05	3.3%	VALUE LINE

TIMELINESS 3 Lowered 12/16/11

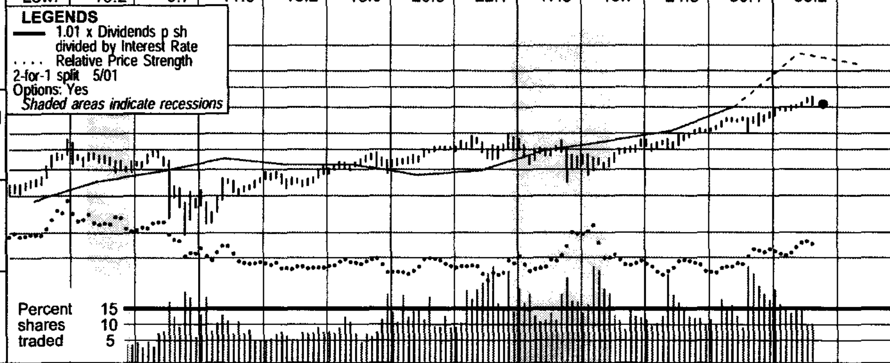
SAFETY 1 Raised 6/22/12

TECHNICAL 3 Raised 7/13/12

BETA .65 (1.00 = Market)

High:	27.3	24.9	18.4	20.8	24.4	26.2	29.8	28.4	28.1	31.8	38.3	45.3
Low:	19.2	9.7	11.0	16.2	18.9	20.5	22.1	17.3	18.7	24.3	30.1	36.2

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	6%
Low	40	(-5%)	3%

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	101	94	109
to Sell	91	108	74
Hld's(000)	42516	43902	43036

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.9	11.2
3 yr.	85.3	47.4
5 yr.	112.0	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
9.70	10.16	11.46	17.12	18.23	23.55	15.33	18.54	15.03	18.41	17.38	17.19	17.99	14.17	18.98	18.53	*16.40*	*17.20*	Revenues per sh	*21.25*
2.11	2.18	2.28	2.36	2.77	2.94	3.05	2.98	2.56	2.76	2.63	2.69	3.71	3.78	5.12	5.28	*5.20*	*5.30*	"Cash Flow" per sh	*6.50*
1.12	1.09	1.12	1.19	1.46	1.51	1.52	1.26	1.32	1.42	1.36	1.32	1.70	1.76	2.29	2.59	*2.60*	*2.55*	Earnings per sh A	*3.25*
.77	.79	.81	.83	.85	.87	.90	.90	.90	.90	.90	.90	.90	.90	.98	1.12	*1.30*	*1.40*	Div'd Decl'd per sh B ■ †	*1.90*
1.43	1.73	2.09	3.99	2.52	1.10	1.91	1.58	1.61	3.19	4.11	8.51	5.59	4.15	4.68	3.25	*3.95*	*2.15*	Cap'l Spending per sh	*2.25*
8.30	8.68	9.07	9.44	10.04	10.69	11.77	10.09	10.83	13.69	15.22	16.85	17.65	18.50	21.76	23.55	*24.60*	*25.80*	Book Value per sh C	*30.25*
44.91	44.93	44.97	44.88	44.99	44.96	47.04	47.18	49.62	49.99	57.57	59.94	60.04	60.26	60.53	60.29	*61.00*	*61.00*	Common Shs Outst'g D	*61.00*
11.9	12.5	14.4	13.4	13.2	14.6	12.2	12.4	13.8	15.0	17.3	19.6	14.1	13.2	12.3	13.3	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.75	.72	.75	.76	.86	.75	.67	.71	.73	.80	.93	1.04	.85	.88	.78	.84	*Value Line*		Relative P/E Ratio	*.85*
5.8%	5.8%	5.0%	5.2%	4.4%	3.9%	4.8%	5.8%	5.0%	4.2%	3.8%	3.5%	3.8%	3.9%	3.5%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1332.9 mill. **Due in 5 Yrs** $209.9 mill.
LT Debt $1244.4 mill. **LT Interest** $75.9 mill.
Incl. $15.7 million capitalized leases.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $12.4 mill.
Pension Assets-12/11 $312.4 mill. **Oblig.** $362.0 mill.

Pfd Stock None

Common Stock 60,714,810 shs.
as of 7/26/12
MARKET CAP: $2.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
721.2	874.6	745.8	920.2	1000.7	1030.6	1080.2	853.8	1148.7	1117.3	*1000*	*1050*	Revenues ($mill)	*1300*
74.2	61.2	66.1	75.0	74.7	79.6	102.1	106.3	139.5	157.8	*160*	*160*	Net Profit ($mill)	*205*
36.9%	37.2%	35.2%	39.2%	36.0%	24.3%	15.3%	8.3%	44.1%	30.6%	*30.5%*	*30.5%*	Income Tax Rate	*30.5%*
12.6%	5.8%	7.5%	4.3%	14.2%	57.9%	82.8%	93.5%	12.2%	4.3%	*5.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
60.0%	64.4%	44.5%	46.3%	40.9%	43.2%	51.1%	54.2%	51.5%	48.5%	*47.0%*	*46.0%*	Long-Term Debt Ratio	*42.0%*
38.2%	33.8%	53.1%	52.0%	57.8%	56.7%	48.9%	45.8%	48.5%	51.5%	*53.0%*	*54.0%*	Common Equity Ratio	*58.0%*
1448.7	1408.5	1011.6	1315.9	1515.6	1780.5	2167.7	2436.4	2717.9	2756.9	*2835*	*2910*	Total Capital ($mill)	*3175*
1566.2	1417.1	1060.0	1188.7	1304.9	1725.9	2045.3	2247.0	2784.2	2893.9	*2980*	*2945*	Net Plant ($mill)	*2775*
7.1%	6.7%	8.9%	7.1%	6.3%	5.6%	6.1%	5.9%	6.6%	7.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*8.0%*
12.8%	12.2%	11.8%	10.6%	8.3%	7.9%	9.6%	9.5%	10.6%	11.1%	*10.5%*	*10.0%*	Return on Shr. Equity	*11.5%*
13.1%	12.5%	11.9%	10.7%	8.3%	7.8%	9.6%	9.5%	10.6%	11.1%	*10.5%*	*10.0%*	Return on Com Equity E	*11.5%*
5.6%	3.5%	3.9%	4.1%	3.0%	2.6%	4.5%	4.7%	6.1%	6.3%	*5.5%*	*4.5%*	Retained to Com Eq	*5.0%*
58%	72%	68%	62%	65%	68%	53%	51%	42%	43%	*50%*	*54%*	All Div'ds to Net Prof	*56%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.0	+5.9	+.4
Avg. Indust. Use (MWH)	3532	3657	3904
Avg. Indust. Revs. per KWH (¢)	6.48	7.68	7.58
Capacity at Peak (Mw)	2355	2559	2544
Peak Load, Summer (Mw)	2242	2348	2355
Annual Load Factor (%)	53.5	55.8	56.2
% Change Customers (avg.)	+.7	+.7	+.6
Fixed Charge Cov. (%)	138	294	415

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-1.5%	.5%	*3.5%*
"Cash Flow"	6.0%	12.5%	*5.5%*
Earnings	5.0%	10.0%	*6.5%*
Dividends	1.5%	2.0%	*11.5%*
Book Value	8.0%	10.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	213.0	207.2	241.5	192.1	853.8
2010	272.3	275.9	343.9	256.6	1148.7
2011	253.7	272.9	351.6	239.1	1117.3
2012	222.8	240.1	*312.1*	*225*	*1000*
2013	*235*	*255*	*330*	*230*	*1050*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.11	.45	.99	.21	1.76
2010	.56	.58	.82	.33	2.29
2011	.48	.52	1.08	.51	2.59
2012	.50	.77	*.98*	*.35*	*2.60*
2013	*.50*	*.60*	*1.10*	*.35*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.225	.225	.225	.225	.90
2009	.225	.225	.225	.225	.90
2010	.225	.25	.25	.25	.98
2011	.25	.28	.28	.3125	1.12
2012	.3125	.3125	.3375		

BUSINESS: Cleco Corporation is a holding company for Cleco Power, which supplies electricity to about 281,000 customers in central Louisiana. Through a subsidiary, has 775 megawatts of wholesale capacity. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 14%; other, 10%. Largest industrial customers are paper mills and other wood-product industries. Generating sources: coal & lignite, 34%; gas & oil, 29%; petroleum coke, 23%; purchased, 14%. Fuel costs: 40% of revenues. '11 reported deprec. rate (utility): 2.8%. Has 1,200 employees. Chairman: J. Patrick Garrett. President & CEO: Bruce A. Williamson. Inc.: Louisiana. Address: 2030 Donahue Ferry Road, P.O. Box 5000, Pineville, LA 71361-5000. Tel.: 318-484-7400. Internet: www.cleco.com.

Cleco's board of directors has raised the dividend again. This was the fourth increase since 2010, after a span of several years without a boost. The latest dividend hike was $0.025 a share (8%) quarterly. Cleco is targeting a payout ratio of 50%-60%. The company's cash flow is very healthy, giving the board the ability to continue raising the disbursement.

The utility is awaiting the outcome of a request for proposals (RFP). Most notably, the RFP includes a proposal to transfer Cleco's last nonregulated generating asset, the Coughlin gas-fired plant, to Cleco Power, its regulated utility subsidiary. (Cleco Power is now buying electricity from Coughlin under a three-year contract that began earlier this year.) The winning bidders, selected by an independent monitor, will probably be announced in late 2012. If the asset transfer is one of the winners, the Louisiana Public Service Commission and the Federal Energy Regulatory Commission would still have to approve it. This would probably occur in 2014.

We estimate that earnings will be about flat in 2012 and decline slightly in 2013. In the first half of 2012, Cleco booked $0.19 a share of income from the contractual expiration of indemnifications related to nonregulated generating units that were sold in 2010 and 2011. We *include* this income in our presentation, even though the company is excluding it from its earnings guidance of $2.34-$2.44 a share. We figure that, without any such income in 2013, profits will fall a bit. Beyond 2013, we aren't assuming that the aforementioned asset transfer will occur.

By utility standards, top-quality Cleco stock has a high valuation. The stock has outperformed most utility equities so far this year. Its dividend yield is about a percentage point below the industry average, and its price-earnings ratio is above the market multiple. The quotation is within our 2015-2017 Target Price Range, making total return potential low. In our view, the valuation reflects not only Cleco's strong dividend growth prospects, but some takeover speculation, as well. We don't advise investors to purchase this stock based on the possibility of an acquisition.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted earnings. Excl. nonrec. gains (losses): '00, 5¢; '02, (5¢), '03, ($2.05); '05, $2.11; '07, $1.22; '10, $1.91; '11, 63¢; losses from discont. ops.: '00, 14¢; '01, 4¢. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Feb., May, Aug. and Nov. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $10.61/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '09: 11.7%; earned on avg. com. eq., '11: 11.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

CMS ENERGY CORP. NYSE-CMS

RECENT PRICE 23.28 | P/E RATIO 13.8 (Trailing: 16.5 Median: 15.0) | RELATIVE P/E RATIO 0.91 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 2 Raised 8/3/12

SAFETY 3 Raised 12/29/06

TECHNICAL 3 Lowered 9/14/12

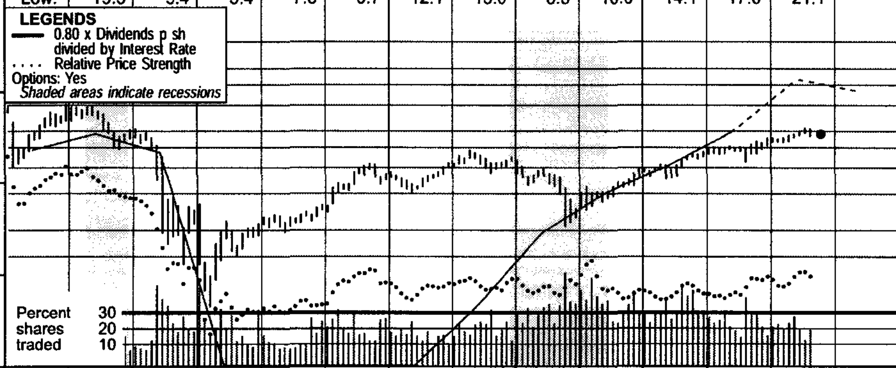
BETA .75 (1.00 = Market)

High: 31.8 24.8 10.7 10.6 16.8 17.0 19.5 17.5 16.1 19.3 22.4 25.0

Low: 19.5 5.4 3.4 7.8 9.7 12.1 15.0 8.3 10.0 14.1 17.0 21.1

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

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+30%)	11%
Low	20	(-15%)	2%

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	146	165	172
to Sell	157	148	162
Hld's(000)	227756	225413	200454

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	22.1	11.2
3 yr.	94.7	47.4
5 yr.	70.1	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
45.70	47.49	47.56	52.59	74.24	72.16	60.28	34.21	28.06	28.52	30.57	28.95	30.13	27.23	25.77	25.59	23.45	24.25	Revenues per sh	27.00
7.18	7.39	6.60	7.87	7.61	5.24	d.09	2.39	2.87	3.43	3.22	3.08	3.88	3.47	3.70	3.65	3.75	3.90	"Cash Flow" per sh	4.25
2.45	2.61	2.24	2.85	2.53	1.27	d2.99	d.29	.74	1.10	.64	.64	1.23	.93	1.33	1.45	1.55	1.65	Earnings per sh A	1.85
1.02	1.14	1.26	1.39	1.46	1.46	1.09	--	--	--	--	.20	.36	.50	.66	.84	.96	1.02	Div'd Decl'd per sh B ■	1.20
6.95	7.05	11.98	9.69	8.51	9.49	5.18	3.32	2.69	2.69	3.01	5.61	3.50	3.59	3.29	3.47	5.45	4.85	Cap'l Spending per sh	4.50
17.95	19.61	20.63	21.17	19.48	14.21	7.86	9.84	10.63	10.53	10.03	9.46	10.88	11.42	11.19	11.92	12.50	13.25	Book Value per sh C	15.50
94.81	100.79	108.11	116.04	121.20	132.99	144.10	161.13	195.00	220.50	222.78	225.15	226.41	227.89	249.60	254.10	258.00	258.00	Common Shs Outst'g D	266.00
12.5	13.5	19.9	13.9	9.6	20.8	--	--	12.4	12.6	22.2	26.8	10.9	13.6	12.5	13.6	Bold figures are		Avg Ann'l P/E Ratio	13.0
.78	.78	1.03	.79	.62	1.07	--	--	.66	.67	1.20	1.42	.66	.91	.80	.86	Value Line		Relative P/E Ratio	.85
3.3%	3.2%	2.8%	3.5%	6.0%	5.5%	7.5%	--	--	--	--	1.2%	2.7%	4.0%	4.0%	4.3%	estimates		Avg Ann'l Div'd Yield	4.9%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $7684.0 mill. **Due in 5 Yrs** $3309.0 mill.
LT Debt $6378.0 mill. **LT Interest** $351.0 mill.
Incl. $157.0 mill. capitalized leases.
(LT interest earned: 2.4x)
Leases, Uncapitalized Annual rentals $27.0 mill.
Pension Assets-12/11 $1.63 bill. **Oblig.** $2.07 bill.
Pfd Stock $44.0 mill. **Pfd Div'd** $2.0 mill.
Incl. 441,599 shs. $4.16-$4.50 $100 par, cum., callable at $103.25-$110.00.
Common Stock 263,700,000 shs.

MARKET CAP: $6.1 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
8687.0	5513.0	5472.0	6288.0	6810.0	6519.0	6821.0	6205.0	6432.0	6503.0	6050	6300	Revenues ($mill)	7200
d414.0	d40.0	144.0	247.0	158.0	168.0	300.0	231.0	356.0	384.0	420	455	Net Profit ($mill)	525
--	NMF	18.6%	25.6%	--	37.6%	31.6%	34.6%	38.1%	36.8%	37.0%	37.0%	Income Tax Rate	37.0%
--	--	--	15.4%	6.3%	3.6%	1.3%	13.0%	2.2%	2.6%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
84.4%	78.2%	75.3%	73.5%	71.7%	70.5%	69.4%	67.9%	70.1%	66.9%	66.0%	64.5%	Long-Term Debt Ratio	60.5%
15.0%	18.3%	21.5%	23.4%	24.9%	25.9%	27.4%	29.0%	29.5%	32.6%	33.5%	35.0%	Common Equity Ratio	39.5%
7532.0	8652.0	9640.0	9913.0	8961.0	8212.0	8993.0	8977.0	9473.0	9279.0	9600	9825	Total Capital ($mill)	10500
5234.0	6944.0	8636.0	7845.0	7976.0	8728.0	9190.0	9682.0	10069	10633	11500	12200	Net Plant ($mill)	14400
NMF	2.7%	4.4%	5.0%	4.5%	4.5%	5.4%	4.7%	5.8%	6.3%	6.0%	6.5%	Return on Total Cap'l	7.0%
NMF	NMF	6.1%	9.4%	6.2%	6.9%	10.9%	8.0%	12.5%	12.5%	13.0%	13.0%	Return on Shr. Equity	12.5%
NMF	NMF	6.2%	9.9%	6.4%	7.2%	11.7%	8.5%	12.5%	12.6%	13.0%	13.0%	Return on Com Equity E	12.5%
NMF	NMF	6.2%	9.9%	6.4%	5.1%	8.4%	4.1%	6.9%	5.6%	5.5%	5.5%	Retained to Com Eq	5.0%
NMF	NMF	11%	6%	10%	35%	31%	54%	46%	55%	59%	59%	All Div'ds to Net Prof	61%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.6	+5.4	+.4
Avg. Indust. Use (MWH)	1076	1027	1086
Avg. Indust. Revs. per KWH (¢)	7.29	8.27	8.21
Capacity at Peak (Mw)	8954	9246	8588
Peak Load, Summer (Mw)	7421	8190	8930
Annual Load Factor (%)	55.9	55.3	50.8
% Change Customers (yr-end)	-.9	-.3	-.1
Fixed Charge Cov. (%)	159	215	237

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-9.0%	-2.0%	.5%
"Cash Flow"	-6.5%	2.5%	3.0%
Earnings	-5.5%	8.5%	7.0%
Dividends	-7.5%	--	10.0%
Book Value	-4.5%	2.0%	5.0%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2104	1225	1263	1613	6205.0
2010	1967	1340	1443	1682	6432.0
2011	2055	1364	1464	1620	6503.0
2012	1743	1333	1424	1550	6050
2013	1900	1350	1450	1600	6300

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.31	.28	.29	.05	.93
2010	.35	.26	.53	.21	1.33
2011	.51	.26	.53	.15	1.45
2012	.36	.37	.57	.25	1.55
2013	.50	.35	.55	.25	1.65

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec. 31	Full Year
2008	.09	.09	.09	.09	.36
2009	.125	.125	.125	.125	.50
2010	.15	.15	.15	.21	.66
2011	.21	.21	.21	.21	.84
2012	.24	.24	.24		

BUSINESS: CMS Energy Corporation is a holding company for Consumers Energy, which supplies electricity and gas to lower Michigan (excluding Detroit). Has 1.8 million electric, 1.7 million gas customers. Has 1,166 megawatts of nonregulated generating capacity. Sold Palisades nuclear plant in '07. Electric revenue breakdown: residential, 42%; commercial, 31%; industrial, 20%; other, 7%. Generating sources: coal, 42%; gas, 5%; hydro, 1%; purchased, 52%. Fuel costs: 54% of revenues. '11 reported deprec. rates: 3.0% electric, 2.9% gas, 7.4% other. Has 7,700 employees. Chairman: David W. Joos. President & CEO: John G. Russell. Incorporated: Michigan. Address: One Energy Plaza, Jackson, Michigan 49201. Tel.: 517-788-0550. Internet: www.cmsenergy.com.

Rate increases should enable CMS Energy's earnings to advance in 2012 and 2013. In June, electric and gas tariff hikes for the company's utility subsidiary, Consumers Energy, went into effect. (Electric and gas rates were increased by $118.5 million and $16 million, respectively.) Our earnings estimate is at the upper end of management's targeted range of $1.52-$1.55 a share, despite a mild winter and a $0.03-a-share charge that CMS took for an early retirement program in the second quarter. (A hotter-than-normal July will help in this regard.) We forecast a profit increase of 6% in 2013, in line with the company's goal of 5%-7% bottom-line growth annually.

Frequent rate hikes are needed in order to place capital investment in the rate base. Typically, these increases are modest, thanks in part to effective expense control. Consumers Energy has not yet determined the timing of its next electric and gas rate applications, but we think they will come within the next few months. (The earliest that the utility may file a gas case is December 1st, due to a stipulation in its previous rate order.) Consumers Energy will be able to self-implement rate increases six months after filing its cases, and an order from the Michigan Public Service Commission is due 12 months after the filing.

Consumers Energy is spending $235 million to add 100 megawatts of wind capacity. The project should be completed by yearend. This will bring the utility closer to meeting a state regulation of having 10% of its generating capacity from renewable sources by 2015.

Finances are adequate. The fixed-charge coverage and common-equity ratio are below those of most utilities, but at least these measures are getting better. Also, CMS is benefiting from tax-loss carryforwards. The company is far different from what it was 10 years ago, when it was in the red and cut its dividend.

By electric utility standards, this stock has a dividend yield and 3- to 5-year total return potential that are about average. It has a favorable rank for Timeliness. Like many utility issues, the share price is within our 2015-2017 Target Price Range.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '05, ($1.61); '06, ($1.08); '07, ($1.26); '09, (7¢); '10, 3¢; '11, 12¢; '12, (14¢); gains (losses) on disc. ops.: '05, 7¢; '06, 3¢; '07, (40¢); '09, 8¢; '10, (8¢); '11, 1¢; '12, 3¢. '10 EPS don't add due to change in shs. Next earnings report due late Oct. (B) Div'ds historically paid late Feb., May, Aug. & Nov. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $9.70/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '12: 10.3%; earned on avg. com. eq., '11: 12.9%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	45

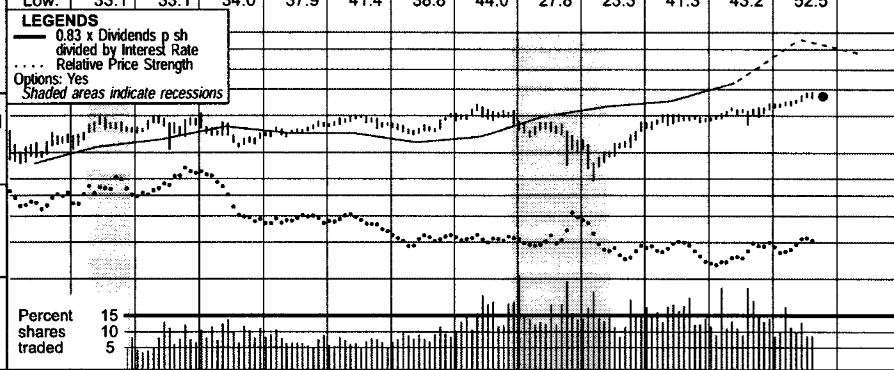
DTE ENERGY CO. NYSE-DTE

RECENT PRICE	59.61	P/E RATIO	14.8 (Trailing: 16.0; Median: 14.0)	RELATIVE P/E RATIO	0.97	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 2 Raised 8/17/12
SAFETY 3 Lowered 10/5/01
TECHNICAL 3 Lowered 9/14/12
BETA .75 (1.00 = Market)

High:	47.1	47.7	49.5	45.5	48.3	49.2	54.7	45.3	45.0	49.1	55.3	62.6
Low:	33.1	33.1	34.0	37.9	41.4	38.8	44.0	27.8	23.3	41.3	43.2	52.5

Target Price Range 2015 | 2016 | 2017



120 100 80 64 48 32 24 20 16 12 8

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+15%)	8%
Low	50	(-15%)	Nil

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	4	4	0	7	3	0	6	0
to Sell	0	6	3	0	7	3	0	6	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	167	207	180
to Sell	158	140	188
Hld's(000)	95785	98702	90537

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.6	11.2
3 yr.	93.4	47.4
5 yr.	57.4	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
25.12	25.94	29.10	32.60	39.24	48.71	40.30	41.76	40.84	50.74	50.93	54.28	57.23	48.45	50.51	52.57	*51.45*	*53.10*	Revenues per sh	*59.50*
7.10	7.42	7.61	8.40	8.59	6.98	8.31	6.95	6.81	8.14	8.19	8.48	8.26	9.38	9.78	9.57	*9.75*	*10.15*	"Cash Flow" per sh	*12.00*
2.80	2.88	3.05	3.33	3.27	2.15	3.83	2.85	2.55	3.27	2.45	2.66	2.73	3.24	3.74	3.67	*3.85*	*3.95*	Earnings per sh A	*4.75*
2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.08	2.12	2.12	2.12	2.18	2.32	*2.42*	*2.52*	Div'd Decl'd per sh B ■	*2.80*
3.66	3.14	3.83	5.10	5.25	6.80	5.88	4.45	5.19	5.99	7.92	7.96	8.42	6.26	6.49	8.77	*10.95*	*10.50*	Cap'l Spending per sh	*10.25*
23.73	24.55	25.49	26.95	28.15	28.48	27.26	31.36	31.85	32.44	33.02	35.86	36.77	37.96	39.67	41.41	*43.15*	*44.70*	Book Value per sh C	*49.75*
145.12	145.10	145.07	145.04	142.65	161.13	167.46	168.61	174.21	177.81	177.14	163.23	163.02	165.40	169.43	169.25	*175.00*	*177.00*	Common Shs Outst'g D	*181.00*
11.2	10.3	13.3	11.6	10.3	19.3	11.3	13.7	16.0	13.8	17.4	18.3	14.8	10.4	12.3	13.5	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.70	.59	.69	.66	.67	.99	.62	.78	.85	.73	.94	.97	.89	.69	.78	.85	*Value Line*		Relative P/E Ratio	*.85*
6.6%	6.9%	5.1%	5.3%	6.1%	5.0%	4.8%	5.3%	5.0%	4.6%	4.9%	4.4%	5.2%	6.3%	4.8%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $8099.0 mill. **Due in 5 Yrs** $3232.0 mill.
LT Debt $7212.0 mill. **LT Interest** $400.0 mill.
Incl. $13.0 mill. capitalized leases, $280.0 mill. Trust Preferred Securities, and $391.0 mill. securitized bonds.
(LT interest earned: 3.5x)
Leases, Uncapitalized Annual rentals $37.0 mill.
Pension Assets-12/11 $2.89 bill. **Oblig.** $4.20 bill.
Pfd Stock None
Common Stock 171,754,812 shs.

MARKET CAP: $10 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
6749.0	7041.0	7114.0	9022.0	9022.0	8861.0	9329.0	8014.0	8557.0	8897.0	*9000*	*9400*	Revenues ($mill)	*10750*
632.0	480.0	443.0	576.0	437.0	453.0	445.0	532.0	630.0	624.0	*670*	*710*	Net Profit ($mill)	*865*
--	--	27.1%	26.0%	23.9%	25.1%	34.9%	31.6%	32.7%	35.9%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
4.9%	1.3%	.7%	1.0%	5.0%	7.1%	11.2%	2.6%	1.6%	1.6%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*5.0%*
63.0%	59.2%	57.8%	55.1%	56.1%	54.4%	56.4%	54.0%	51.3%	50.6%	*50.5%*	*50.0%*	Long-Term Debt Ratio	*51.0%*
37.0%	40.8%	42.2%	44.9%	43.9%	45.6%	43.6%	46.0%	48.7%	49.4%	*49.5%*	*50.0%*	Common Equity Ratio	*49.0%*
12350	12956	13154	12849	13323	12824	13736	13648	13811	14196	*15250*	*15900*	Total Capital ($mill)	*18500*
9813.0	10324	10491	10830	11451	11408	12231	12431	12992	13746	*14625*	*15375*	Net Plant ($mill)	*17300*
7.3%	5.6%	5.2%	6.3%	5.1%	5.3%	5.0%	5.7%	6.3%	5.9%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	8.9%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.5%*
13.8%	9.1%	8.0%	10.0%	7.5%	7.7%	7.4%	8.5%	9.4%	8.9%	*8.5%*	*9.0%*	Return on Com Equity E	*9.5%*
6.4%	2.5%	1.6%	3.7%	1.2%	1.5%	1.7%	2.9%	4.0%	3.4%	*3.0%*	*3.0%*	Retained to Com Eq	*4.0%*
53%	72%	80%	63%	84%	80%	77%	65%	57%	62%	*62%*	*63%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-5.6	-.6	+.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NMF	NMF	NMF
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	10627	11687	12547
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	-.8	-.4	--
Fixed Charge Cov. (%)	223	262	282

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	1.0%	*3.0%*
"Cash Flow"	2.0%	4.5%	*4.0%*
Earnings	2.0%	5.0%	*5.0%*
Dividends	.5%	1.5%	*4.0%*
Book Value	3.5%	4.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2255	1688	1950	2121	8014.0
2010	2453	1792	2139	2173	8557.0
2011	2431	2028	2265	2173	8897.0
2012	2249	2025	*2376*	*2350*	*9000*
2013	*2450*	*2100*	*2450*	*2400*	*9400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.09	.51	.92	.72	3.24
2010	1.38	.51	.96	.90	3.74
2011	1.04	.67	1.07	.89	3.67
2012	.91	.86	*1.10*	*.98*	*3.85*
2013	*1.10*	*.75*	*1.10*	*1.00*	*3.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.53	.53	.53	.53	2.12
2009	.53	.53	.53	.53	2.12
2010	.53	.53	.53	.56	2.15
2011	.56	.56	.5875	.5875	2.30
2012	.5875	.5875	.5875	.62	

BUSINESS: DTE Energy Company is a holding company for The Detroit Edison Company, which supplies electricity in Detroit and a 7,600-square-mile area in southeastern Michigan, and Michigan Consolidated Gas (MichCon). Customers: 2.1 mill. electric, 1.3 mill. gas. Acquired MCN Energy 6/01. Has various nonutility operations. Electric revenue breakdown: residential, 42%; commercial, 33%; industrial, 14%; other, 11%. Generating sources: coal, 67%; nuclear, 17%; gas, 1%; purchased, 15%. Fuel costs: 40% of revenues. '11 reported deprec. rates: 3.3% electric, 2.3% gas. Has 9,800 employees. Chairman, President & CEO: Gerard M. Anderson. Inc.: Michigan. Address: One Energy Plaza, Detroit, Michigan 48226-1279. Tel.: 313-235-4000. Internet: www.dteenergy.com.

DTE Energy's electric utility subsidiary has asked the Michigan Public Service Commission (MPSC) for an accounting order. Detroit Edison believes it will need rate relief in 2014. However, in order to delay the filing of its next general rate case, the utility proposes deferring $127 million of regulatory liabilities (which otherwise would have been passed on to customers), and then amortizing them into pretax income starting in 2014. If the MPSC turns down Detroit Edison's request, then the utility will probably file a rate case next year.

DTE's gas utility subsidiary has a general rate case pending. MichCon filed for a tariff hike of $76.7 million, based on a return of 11% on a common-equity ratio of 52%. The utility is also asking the MPSC to grant regulatory mechanisms for the recovery of $387 million of infrastructure capital programs and the decoupling of revenues from volume. A recommendation from the MPSC's staff was expected shortly after this report went to press. MichCon will self-implement a rate increase in November, and the MPSC's order is due six months later.

We have raised our 2012 earnings estimate by $0.20 a share. A hotter-than-usual second quarter raised net profit by $21 million ($0.12 a share), and the hot weather continued into July. Our revised estimate of $3.85 a share is still within DTE's targeted range of $3.65-$3.95. We figure that rate relief at MichCon and an improved showing from the company's nonregulated activities will lead to higher income in 2013. Our estimate is $3.95 a share.

The board of directors has raised the dividend. The increase was $0.13 a share (5.5%) annually. We had looked for a healthy boost in the payout, but the raise was even better than we had expected.

DTE expects to monetize some assets in the fourth quarter. The company is placing its Barnett Shale acreage up for sale. DTE is targeting about $300 million of proceeds from these asset sales in 2012, which it will probably reinvest in nonregulated operations.

This timely issue has an average dividend yield for a utility. Total return potential to 2015-2017 is unimpressive.

Paul E. Debbas, CFA September 21, 2012

(A) Diluted EPS. Excl. nonrec. gains (losses): '03, (16¢); '05, (2¢); '06, 1¢; '07, $1.96; '08, 50¢; '11, 51¢; gains (losses) on disc. ops.: '03, 40¢; '04, (6¢); '05, (20¢); '06, (2¢); '07, $1.20; '08, 13¢. '10 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in mid-Jan., Apr., July and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '11: $42.59/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '11: 10.5% elec.; in '10: 11% gas; earned on avg. com. eq., '11: 9.1%. Regulatory Climate: Avg.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	75

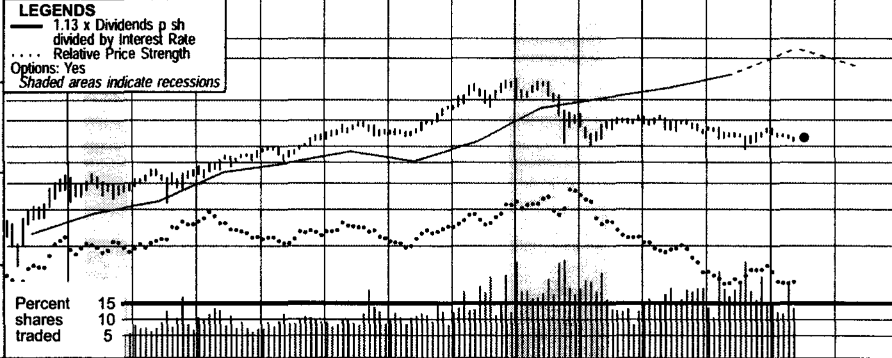
ENTERGY CORP. NYSE-ETR

RECENT PRICE	66.24	P/E RATIO	13.8 (Trailing: 10.1 Median: 14.0)	RELATIVE P/E RATIO	0.97	DIV'D YLD	5.0%	VALUE LINE

TIMELINESS 3 Lowered 2/10/12
SAFETY 2 New 12/26/08
TECHNICAL 3 Raised 5/11/12
BETA .70 (1.00 = Market)

High:	44.7	46.8	57.2	68.7	79.2	94.0	125.0	127.5	86.6	84.3	74.5	73.7
Low:	32.6	32.1	42.3	50.6	64.5	66.8	89.6	61.9	59.9	68.7	57.6	63.0

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	85	(+30%)	11%
Low	60	(-10%)	3%

Insider Decisions

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

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	216	223	224
to Sell	194	197	212
Hld's(000)	144030	142805	140958

% TOT. RETURN 5/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-0.4	-9.6
3 yr.	-1.0	64.7
5 yr.	-30.2	13.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
30.75	38.89	46.57	35.51	45.61	43.59	37.34	40.17	46.69	46.61	53.94	59.47	69.15	56.82	64.27	63.67	**59.30**	**61.70**	Revenues per sh	**68.50**
5.84	6.20	6.11	5.06	6.49	6.41	7.62	7.43	8.33	8.18	10.69	11.73	12.89	13.29	16.54	17.53	**15.00**	**15.70**	"Cash Flow" per sh	**17.25**
2.48	2.25	2.22	2.25	2.97	3.08	3.68	3.69	3.93	4.40	5.36	5.60	6.20	6.30	6.66	7.55	**4.80**	**4.70**	Earnings per sh A	**5.25**
1.80	1.80	1.50	1.20	1.22	1.28	1.34	1.60	1.89	2.16	2.16	2.58	3.00	3.00	3.24	3.32	**3.32**	**3.32**	Div'd Decl'd per sh B ■ †	**3.40**
2.45	3.45	4.63	4.84	6.80	6.25	6.88	6.85	6.51	6.72	9.44	10.29	13.92	12.99	13.33	15.21	**14.05**	**12.30**	Cap'l Spending per sh	**12.50**
28.51	27.23	28.79	28.81	31.89	33.78	35.24	38.02	38.26	35.71	40.45	40.71	42.07	45.54	47.53	50.81	**50.90**	**52.15**	Book Value per sh C	**57.50**
232.96	245.84	246.83	247.08	219.60	220.73	222.42	228.90	216.83	216.83	202.67	193.12	189.36	189.12	178.75	176.36	**177.00**	**171.00**	Common Shs Outst'g D	**171.00**
11.1	11.6	12.9	13.2	10.1	12.5	11.5	13.8	15.1	16.3	14.3	19.3	16.6	12.0	11.6	9.1	*Bold figures are*		Avg Ann'l P/E Ratio	**14.0**
.70	.67	.67	.75	.66	.64	.63	.79	.80	.87	.77	1.02	1.00	.80	.74	.57	*Value Line*		Relative P/E Ratio	**.95**
6.5%	6.9%	5.2%	4.1%	4.1%	3.3%	3.2%	3.1%	3.2%	3.0%	2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	*estimates*		Avg Ann'l Div'd Yield	**4.7%**

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
8305.0	9195.0	10124	10106	10932	11484	13094	10746	11488	11229	**10500**	**10550**	Revenues ($mill)	**11700**
878.4	874.2	933.1	943.1	1160.9	1160.0	1240.5	1251.1	1270.3	1367.4	**870**	**850**	Net Profit ($mill)	**955**
25.1%	35.9%	28.2%	37.2%	27.6%	30.7%	32.7%	33.6%	32.7%	17.3%	**34.0%**	**34.0%**	Income Tax Rate	**34.0%**
6.4%	8.7%	7.0%	8.0%	5.5%	5.8%	5.6%	7.4%	7.4%	8.9%	**13.0%**	**13.0%**	AFUDC % to Net Profit	**12.0%**
45.7%	44.8%	44.7%	51.9%	51.2%	54.3%	58.2%	55.3%	56.3%	52.2%	**53.5%**	**55.0%**	Long-Term Debt Ratio	**57.5%**
50.6%	53.2%	52.9%	45.5%	46.7%	43.9%	40.2%	43.1%	42.1%	46.4%	**45.0%**	**43.5%**	Common Equity Ratio	**41.5%**
15499	16361	15696	17013	17539	17902	19795	19985	20166	19324	**19975**	**20525**	Total Capital ($mill)	**23700**
17195	18299	18696	19197	19438	20974	22429	23389	23848	25609	**26350**	**26650**	Net Plant ($mill)	**27200**
7.3%	6.8%	7.4%	6.8%	8.0%	7.9%	7.5%	7.6%	7.7%	8.5%	**5.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
10.4%	9.7%	10.8%	11.5%	13.6%	14.2%	15.0%	14.0%	14.4%	14.8%	**9.5%**	**9.0%**	Return on Shr. Equity	**9.5%**
10.9%	9.8%	11.0%	11.9%	13.8%	14.4%	15.3%	14.3%	14.7%	15.0%	**9.5%**	**9.5%**	Return on Com Equity E	**9.5%**
7.1%	5.6%	5.8%	6.0%	8.3%	8.0%	8.1%	7.6%	7.6%	8.4%	**3.0%**	**3.0%**	Retained to Com Eq	**3.5%**
37%	44%	48%	51%	41%	46%	48%	48%	49%	45%	**70%**	**71%**	All Div'ds to Net Prof	**63%**

CAPITAL STRUCTURE as of 3/31/12
Total Debt $12619 mill. **Due in 5 Yrs** $2516.0 mill.
LT Debt $12158 mill. **LT Interest** $463.0 mill.
Incl. $1049 mill. of securitization bonds.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $84.9 mill.
Pension Assets-12/11 $3.40 bill. **Oblig.** $5.19 bill.
Pfd Stock $280.5 mill. **Pfd Div'd** $20.0 mill.
6,115,105 shs. $4.20 to $7.88, $100 par; 1,000,000 shs. 11.50%, all without sinking fund.
Common Stock 177,159,198 shs.
as of 4/30/12
MARKET CAP: $12 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-1.5	+8.4	+1.1
Avg. Indust. Use (MWH)	874	936	NA
Avg. Indust. Revs. per KWH(¢)	5.60	5.70	5.65
Capacity at Peak (Mw)	23578	24310	NA
Peak Load, Summer (Mw)	21009	21799	22387
Annual Load Factor (%)	60.0	62.0	NA
% Change Customers (yr-end)	+1.1	+.9	+.5
Fixed Charge Cov. (%)	355	342	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.0%	4.5%	2.0%
"Cash Flow"	10.0%	11.5%	1.5%
Earnings	9.5%	8.5%	-4.5%
Dividends	10.0%	9.0%	1.0%
Book Value	4.5%	4.5%	3.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2789	2521	2937	2499	10746
2010	2760	2863	3332	2533	11488
2011	2541	2803	3396	2489	11229
2012	2384	**2716**	**3000**	**2400**	**10500**
2013	**2450**	**2700**	**3000**	**2400**	**10550**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.20	1.14	2.32	1.64	6.30
2010	1.12	1.65	2.62	1.26	6.66
2011	1.38	1.76	3.53	.87	7.55
2012	.40	**1.40**	**2.00**	**1.00**	**4.80**
2013	**.85**	**1.30**	**1.70**	**.85**	**4.70**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.75	.75	.75	.75	3.00
2009	.75	.75	.75	.75	3.00
2010	.75	.83	.83	.83	3.24
2011	.83	.83	.83	.83	3.32
2012	.83	.83			

BUSINESS: Entergy Corporation supplies electricity to 2.7 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans. Distributes gas to 191,000 customers in Louisiana. Has a nonutility nuclear subsidiary that owns six units. Electric revenue breakdown: residential, 39%; commercial, 26%; industrial, 25%; other, 10%. Generating sources: nuclear, 36%; gas, 22%; coal, 13%; purchased, 29%. Fuel costs: 36% of revenues. '11 reported depreciation rate: 2.6%. Has 14,700 employees. Chairman & CEO: J. Wayne Leonard. President & COO: Richard J. Smith. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy will soon file for regulatory approval for its planned sale of its transmission assets to ITC Holdings. ITC is the sole publicly traded transmission-only company, and Entergy decided to sell because transmission is capital-intensive and makes up less than 10% of its total assets. The company would receive $1.775 billion in cash, which it would use for debt reduction. ITC would issue enough stock to Entergy shareholders so that they would own 50.1% of ITC, thereby making the asset sale tax-free for Entergy. The transaction must be approved by regulators in Texas, Louisiana, New Orleans (separate from the rest of the state), Arkansas, and Mississippi, plus the Federal Energy Regulatory Commission. ITC stockholders must approve it, too. The deal will likely be concluded in 2013.

Some of Entergy's nonregulated nuclear plants are still facing various concerns. The state of Vermont, which wants the company to shut Vermont Yankee, is embroiled in litigation with Entergy. A court order was favorable for the company, but this matter is far from over. Due to the uncertainty about Vermont Yankee, Entergy took a nonrecurring charge of $1.26 a share in the March quarter to write down the unit. In New York, officials want the company to build cooling towers at Indian Point, but Entergy favors a much less costly alternative. In Michigan, the Nuclear Regulatory Commission will conduct supplementary inspections of Palisades due to operating problems. At least Entergy got some good news when the NRC extended the operating license of Pilgrim in Massachusetts.

Earnings are headed down this year. The comparison is tough because Entergy benefited from favorable weather patterns and a low tax rate in 2011. In addition, lower margins on wholesale power sales are hurting the bottom line. We look for another earnings decline in 2013.

A rate case is pending in Texas. Entergy is seeking a $104.8 million hike, based on a 10.6% return on a 49.92% common-equity ratio. An order is expected in July.

This stock's yield is nearly a percentage point above the utility average. Its 3- to 5-year total return potential is only about average for the industry, however.

Paul E. Debbas, CFA *June 22, 2012*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '97, ($1.22); '98, 78¢; '01, 15¢; '02, ($1.04); '03, 33¢ net; '05, (21¢); '12, ($1.26). '10 EPS don't add due to rounding. Next earnings report due late July. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan available. † Shareholder investment plan available. (C) Incl. deferred charges. In '11: $34.05/sh. (D) In mill. (E) Rate base: net orig. cost. Allowed return on equity (blended): 10.5%; earned on avg. com. eq., '11: 15.4%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	95

GREAT PLAINS EN'GY NYSE-GXP

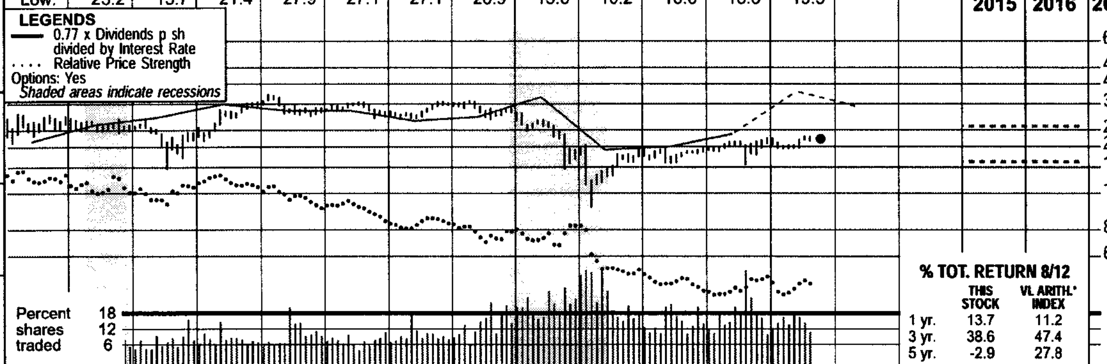
RECENT PRICE	P/E RATIO	(Trailing: 17.3) (Median: 15.0)	RELATIVE P/E RATIO	DIV'D YLD	VALUE LINE
21.76	14.3	Trailing: 17.3; Median: 15.0	0.94	4.0%	

TIMELINESS 3 Lowered 3/9/12
SAFETY 3 Lowered 12/26/08
TECHNICAL 3 Raised 8/10/12
BETA .75 (1.00 = Market)

High:	27.6	27.0	32.8	35.7	32.8	32.8	33.4	29.3	20.5	19.9	22.1	22.5
Low:	23.2	15.7	21.4	27.9	27.1	27.1	26.9	15.6	10.2	16.6	16.3	19.5

Target Price Range
2015 | 2016 | 2017

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



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+15%)	7%
Low	17	(-20%)	-1%

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	115	105	114
to Sell	110	116	106
Hld's(000)	94551	102697	107362

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.7	11.2
3 yr.	38.6	47.4
5 yr.	-2.9	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
14.60	14.47	15.17	14.50	18.02	23.61	26.91	31.04	33.13	34.85	33.30	37.89	14.00	14.51	16.62	17.03	*15.65*	*16.30*	Revenues per sh	*19.50*
3.90	3.91	4.21	3.63	4.63	4.70	4.40	4.69	4.75	4.54	3.86	4.24	3.09	3.27	4.12	3.51	*3.45*	*3.70*	"Cash Flow" per sh	*4.75*
1.69	1.69	1.89	1.26	2.05	1.59	2.04	2.27	2.46	2.18	1.62	1.86	1.16	1.03	1.53	1.25	*1.35*	*1.40*	Earnings per sh A	*1.75*
1.59	1.62	1.64	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	.83	.83	.84	*.86*	*.88*	Div'd Decl'd per sh B ■	*1.10*
1.66	2.05	1.97	2.97	6.67	4.38	1.91	2.19	2.66	4.49	6.05	6.15	8.86	6.49	4.76	3.40	*4.15*	*5.15*	Cap'l Spending per sh	*4.00*
14.71	14.19	14.41	13.97	14.88	12.59	13.58	13.82	15.35	16.37	16.70	18.18	21.39	20.62	21.26	21.74	*21.70*	*22.20*	Book Value per sh C	*24.00*
61.91	61.91	61.91	61.91	61.91	61.91	69.20	69.26	74.37	74.74	80.35	86.23	119.26	135.42	135.71	136.14	*153.50*	*153.50*	Common Shs Outst'g D	*153.50*
15.9	17.0	15.7	20.0	12.4	15.9	11.1	12.2	12.6	14.0	18.3	16.3	20.5	16.0	12.1	16.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*12.0*
1.00	.98	.82	1.14	.81	.81	.61	.70	.67	.75	.99	.87	1.23	1.07	.77	1.02	*estimates*		Relative P/E Ratio	*.80*
5.9%	5.6%	5.5%	6.6%	6.5%	6.6%	7.3%	6.0%	5.4%	5.5%	5.6%	5.5%	7.0%	5.0%	4.5%	4.1%			Avg Ann'l Div'd Yield	*5.3%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $3804.5 mill. **Due in 5 Yrs** $1079.6 mill.
LT Debt $3013.4 mill. **LT Interest** $172.3 mill.
(LT interest earned: 2.2x)

Leases, Uncapitalized Annual rentals $19.7 mill.
Pension Assets-12/11 $591.1 mill.
Oblig. $980.6 mill.
Pfd Stock $39.0 mill. **Pfd Div'd** $1.6 mill.
390,000 shs. 3.80% to 4.50% (all $100 par & cum.), callable from $101 to $103.70.
Common Stock 153,430,889 shs.
as of 8/6/12
MARKET CAP: $3.3 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1861.9	2149.5	2464.0	2604.9	2675.3	3267.1	1670.1	1965.0	2255.5	2318.0	*2400*	*2500*	Revenues ($mill)	*3000*
129.2	159.0	178.8	164.2	127.6	159.2	119.5	135.6	211.7	174.4	*205*	*215*	Net Profit ($mill)	*280*
27.2%	34.2%	24.1%	18.7%	27.0%	30.7%	34.5%	25.0%	31.7%	32.7%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
1.0%	1.8%	2.0%	2.1%	8.4%	10.6%	46.8%	57.0%	25.7%	3.9%	*1.0%*	*5.0%*	AFUDC % to Net Profit	*2.0%*
53.5%	53.8%	44.8%	47.5%	30.6%	40.7%	49.7%	53.2%	50.2%	47.8%	*47.0%*	*48.5%*	Long-Term Debt Ratio	*44.5%*
44.7%	44.4%	53.4%	50.9%	67.5%	57.9%	49.6%	46.2%	49.2%	51.6%	*52.5%*	*51.0%*	Common Equity Ratio	*55.0%*
2102.8	2154.6	2137.1	2403.3	1988.4	2709.8	5146.2	6044.5	5867.6	5741.2	*6345*	*6700*	Total Capital ($mill)	*6700*
2604.1	2700.9	2734.5	2765.6	3066.2	3444.5	6081.3	6651.1	6892.3	7053.5	*7365*	*7810*	Net Plant ($mill)	*8475*
7.7%	9.0%	10.1%	8.2%	7.9%	7.5%	3.5%	3.9%	5.3%	4.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.5%*
13.2%	16.0%	15.1%	13.0%	9.2%	9.9%	4.6%	4.8%	7.2%	5.8%	*6.0%*	*6.5%*	Return on Shr. Equity	*7.5%*
13.6%	16.4%	15.5%	13.3%	9.4%	10.1%	4.6%	4.8%	7.3%	5.8%	*6.0%*	*6.5%*	Return on Com Equity E	*7.5%*
2.3%	4.4%	5.1%	3.2%	NMF	.9%	NMF	.9%	3.4%	2.0%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
83%	73%	68%	76%	104%	91%	NMF	81%	54%	66%	*62%*	*63%*	All Div'ds to Net Prof	*61%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	+18.1	+5.6	-1.7
Avg. Indust. Use (MWH)	1367	1429	1463
Avg. Indust. Revs. per KWH (¢)	5.47	5.89	6.11
Capacity at Peak (Mw)	6336	6272	6697
Peak Load, Summer (Mw)	5347	5531	5690
Annual Load Factor (%)	51.3	52.8	50.5
% Change Customers (avg.)	-1.2	+.2	--
Fixed Charge Cov. (%)	144	218	211

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-1.5%	-14.0%	*3.5%*
"Cash Flow"	-1.5%	-3.5%	*4.5%*
Earnings	-2.5%	-9.5%	*5.5%*
Dividends	-6.5%	-13.0%	*5.0%*
Book Value	4.5%	5.5%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	419.2	480.5	587.7	477.6	1965.0
2010	506.9	552.0	728.8	467.8	2255.5
2011	492.9	565.1	773.7	486.3	2318.0
2012	479.7	603.6	*816.7*	*500*	*2400*
2013	*550*	*600*	*800*	*550*	*2500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.05	.28	.57	.10	1.03
2010	.15	.47	.96	d.04	1.53
2011	.01	.31	.91	.01	1.25
2012	d.07	.41	*.91*	*.10*	*1.35*
2013	*.10*	*.30*	*.90*	*.10*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.415	.415	.415	.415	1.66
2009	.2075	.2075	.2075	.2075	.83
2010	.2075	.2075	.2075	.2075	.83
2011	.2075	.2075	.2075	.2125	.84
2012	.2125	.2125	.2125		

BUSINESS: Great Plains Energy Incorporated is a holding company for Kansas City Power & Light and two other subsidiaries, which supply electricity to 824,000 customers in western Missouri (71% of revenues) and eastern Kansas (29%). Acq'd Aquila 7/08. Sold Strategic Energy (energy-marketing subsidiary) in '08. Electric revenue breakdown: residential, 41%; commercial, 38%; industrial, 8%; other, 13%. Generating sources: coal, 71%; nuclear, 11%; wind, 2%; gas & oil, 1%; purchased, 15%. Fuel costs: 30% of revs. '11 reported deprec. rate (utility): 3.0%. Has 3,100 employees. Chairman: Michael J. Chesser. President & CEO: Terry Bassham. Inc.: Missouri. Address: 1200 Main St., Kansas City, MO 64105. Tel.: 816-556-2200. Internet: www.greatplainsenergy.com.

As usual, Great Plains Energy's utility subsidiaries have rate cases pending. The company's utilities have not been earning their allowed returns on equity in recent years, so they have been filing rate applications frequently in order to reduce the effects of regulatory lag and weak volume. Great Plains' utilities asked the Missouri commission for tariff hikes totaling $189.2 million, based on a return of 10.4% on a 52.5% common-equity ratio. The company is also asking the state regulators to grant it tracking mechanisms to recover rising property taxes and earn a return on transmission expenditures. New rates are expected to go into effect in late January. Kansas City Power & Light asked the Kansas commission for a rate increase of $63.6 million, based on a 10.4% return on a 51.8% common-equity ratio. New tariffs are expected to take effect at the start of 2013. Even if the utilities receive reasonable rate orders, they are likely to underearn their allowed ROEs again next year.

We have raised our 2012 earnings estimate by $0.15 a share, to $1.35. Favorable weather conditions helped lift June-period results, and the higher-than-normal temperatures continued into the third quarter. Our revised estimate is still within management's targeted range of $1.20-$1.40.

We look for only a moderate share-earnings increase in 2013. We assume reasonable regulatory treatment, but we also base our forecast on a return to normal weather patterns. Also, average shares outstanding will be higher due to the 17.1 million shares that Great Plains issued in June of 2012 for the conversion of some debt into equity.

The Wolf Creek nuclear unit has room for improvement. The plant, 47%-owned by KCP&L, had a refueling outage in 2011 that was much longer than expected, and then had an unplanned outage in the first quarter of 2012. Its next refueling outage is scheduled for the first quarter of 2013.

We are not enthusiastic about this stock. The yield (even assuming a dividend hike in the fourth quarter) is only about equal to the utility average, and with the quotation well within our 2015-2017 Target Price Range, total return potential is unimpressive.

Paul E. Debbas, CFA *September 21, 2012*

(A) Excl. nonrec. gains (losses): '00, 49¢; '01, ($2.01); '02, (5¢); '03, 29¢; '04, (7¢); '09, 12¢; gain (losses) on discont. ops.: '03, (13¢); '04, 10¢; '05, (3¢); '08, 35¢; '09, (1¢). '09-'11 EPS don't add due to change in shares or rounding. Next earnings report due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '11: $9.01/sh. (D) In mill. (E) Rate base: Fair value. Rate allowed on com. eq. in MO in '11: 10%; in KS in '10: 10%; earned on avg. com. eq., '11: 6.0%. Regulatory Climate: Average.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	5
Earnings Predictability	70

MGE ENERGY INC. NDQ-MGEE

RECENT PRICE 51.23 | P/E RATIO 18.2 (Trailing: 19.5 Median: 16.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 2 Raised 9/7/12
SAFETY 1 New 1/3/03
TECHNICAL 3 Raised 7/27/12
BETA .60 (1.00 = Market)

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+5%)	5%
Low	45	(-10%)	1%

Insider Decisions

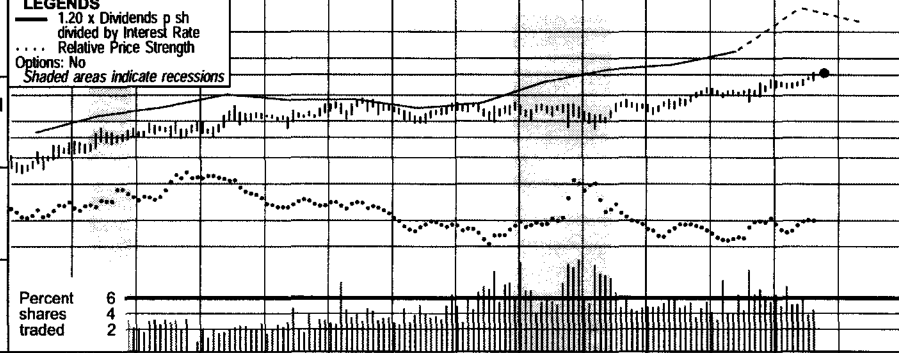
	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	1	3	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	35	38	44
to Sell	51	46	38
Hld's(000)	7491	7553	7542

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	27.8	30.1	35.8	36.4	38.8	37.0	37.2	36.5	38.2	43.6	47.8	51.7
Low:	20.9	24.6	25.0	27.6	30.5	29.2	29.4	27.9	27.3	32.1	37.1	43.0

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: No
Shaded areas indicate recessions



Percent shares traded 6 4 2

Target Price Range 2015 | 2016 | 2017

80 60 50 40 30 25 20 15 10 7.5

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	21.3	11.2
3 yr.	56.1	47.4
5 yr.	82.9	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.75	16.46	15.53	16.96	19.50	19.55	19.75	21.89	20.84	25.10	24.20	24.49	26.02	23.10	23.04	23.64	23.05	23.80	Revenues per sh	27.65
2.41	3.26	3.59	3.81	3.89	3.78	3.33	2.94	2.88	3.00	3.52	3.69	4.02	3.98	4.14	4.41	4.55	4.85	"Cash Flow" per sh	5.85
.82	1.40	1.38	1.48	1.67	1.62	1.69	1.71	1.77	1.57	2.06	2.27	2.38	2.21	2.50	2.64	2.75	2.90	Earnings per sh A	3.30
1.28	1.29	1.30	1.31	1.32	1.33	1.34	1.35	1.36	1.37	1.39	1.41	1.43	1.46	1.49	1.52	1.56	1.62	Div'd Decl'd per sh B ■	1.84
1.36	1.35	1.92	3.16	4.44	2.47	4.45	4.52	4.70	4.19	4.41	6.21	4.62	3.53	2.63	2.82	3.45	3.65	Cap'l Spending per sh	4.25
11.14	11.25	11.34	11.49	12.05	12.67	12.94	14.34	16.59	16.81	17.89	19.49	20.88	21.71	22.72	23.84	25.00	26.20	Book Value per sh	30.65
16.08	16.08	16.08	16.16	16.62	17.07	17.57	18.34	20.39	20.45	20.98	21.95	22.90	23.11	23.11	23.11	23.20	23.30	Common Shs Outst'g C	23.50
28.1	14.5	16.2	14.0	11.7	14.8	16.0	17.5	18.0	22.4	15.9	15.0	14.2	15.1	15.0	15.8	Bold figures are		Avg Ann'l P/E Ratio	15.0
1.76	.84	.84	.80	.76	.76	.87	1.00	.95	1.19	.86	.80	.85	1.01	.95	.99	Value Line		Relative P/E Ratio	1.00
5.5%	6.3%	5.8%	6.3%	6.7%	5.5%	5.0%	4.5%	4.3%	3.9%	4.3%	4.1%	4.2%	4.4%	4.0%	3.6%	estimates		Avg Ann'l Div'd Yield	3.7%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $362.8 mill. Due in 5 Yrs $18.2 mill.
LT Debt $360.2 mill. LT Interest $20.0 mill.
(LT interest earned: 5.8x)

Leases, Uncapitalized Annual rentals $2.4 mill.
Pension Assets-12/11 $173.3 mill.
Obligation $283.7 mill.

Pfd Stock None

Common Stock 23,113,638 shs.
as of 7/31/12
MARKET CAP: $1.2 billion (Mid-Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
347.1	401.5	424.9	513.4	507.5	537.6	596.0	533.8	532.6	546.4	535	555	Revenues ($mill)	650
29.2	30.6	33.8	32.1	42.4	48.8	52.8	51.0	57.7	60.9	65.0	67.5	Net Profit ($mill)	77.5
39.1%	39.4%	37.9%	38.2%	37.9%	36.3%	35.5%	35.6%	36.9%	37.1%	38.0%	35.0%	Income Tax Rate	35.0%
--	--	--	--	--	--	--	--	2.2%	2.0%	2.0%	2.0%	AFUDC % to Net Profit	2.0%
45.8%	43.5%	37.4%	39.3%	38.7%	35.2%	36.3%	39.0%	38.9%	39.6%	38.5%	36.5%	Long-Term Debt Ratio	34.0%
54.2%	56.5%	62.6%	60.7%	61.3%	64.8%	63.7%	61.0%	61.1%	60.4%	61.5%	63.5%	Common Equity Ratio	66.0%
419.5	465.3	540.5	566.2	612.6	660.1	750.6	822.7	859.4	911.9	940	960	Total Capital ($mill)	1095
451.5	537.5	607.4	667.7	728.4	844.0	901.2	939.8	968.0	995.6	1050	1100	Net Plant ($mill)	1200
8.1%	7.8%	7.1%	6.6%	7.8%	8.1%	7.7%	6.9%	7.6%	7.8%	8.0%	8.0%	Return on Total Cap'l	8.0%
12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	10.2%	11.0%	11.1%	8.5%	8.5%	Return on Shr. Equity	8.5%
12.8%	11.6%	10.0%	9.3%	11.3%	11.4%	11.0%	10.2%	11.0%	11.1%	11.0%	11.0%	Return on Com Equity D	11.0%
2.6%	2.5%	2.3%	1.2%	3.7%	4.3%	4.4%	3.4%	4.4%	4.7%	2.5%	2.5%	Retained to Com Eq	3.0%
79%	79%	77%	87%	67%	62%	60%	66%	60%	57%	77%	77%	All Div'ds to Net Prof	74%

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.0	+4.1	+0.8
Avg. Indust. Use (MWH)	2536	2679	2632
Avg. Indust. Revs. per KWH (¢)	6.67	7.51	7.38
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	802	770
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	NA	NA	NA

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.0%	--	2.5%
"Cash Flow"	1.0%	6.0%	6.0%
Earnings	4.5%	6.5%	5.0%
Dividends	1.0%	1.5%	3.5%
Book Value	6.5%	6.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	181.1	107.6	109.3	135.8	533.8
2010	159.7	109.1	127.9	135.9	532.6
2011	164.6	117.3	133.6	130.9	546.4
2012	149.3	117.2	132	136.5	535
2013	160	120	135	140	555

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.65	.43	.55	.58	2.21
2010	.62	.50	.86	.52	2.50
2011	.77	.55	.91	.41	2.64
2012	.69	.62	.86	.58	2.75
2013	.75	.62	.90	.63	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.355	.355	.3617	.3617	1.43
2009	.3617	.3617	.3684	.3684	1.46
2010	.3684	.3684	.3751	.3751	1.49
2011	.3751	.3751	.3826	.3826	1.52
2012	.3826	.3826	.3951		

BUSINESS: MGE Energy Inc. is a holding company for Madison Gas and Electric, which provides electric service to approximately 139,000 customers in a 316-square-mile area of Dane County and gas service to 144,000 customers in 1,631 square miles in seven counties in Wisconsin. Electric revenue breakdown, '11: residential, 33%; commercial, 52%; industrial, 5%; public authorities and other, 10%. Generating sources, '11: coal, 55%; purchased power, 38%; natural gas and other, 7%. Fuel costs: 23% of revenues. '11 reported depreciation rate: electric, 3.2%; gas, 1.6%. Has 712 employees. Chairman, President & CEO: Gary J. Wolter. Inc.: Wisconsin. Address: 133 South Blair St., Madison, WI 53703. Telephone: 608-252-7000. Internet: www.mge.com.

Shares of MGE Energy have advanced nicely in value over the past three months. The company reported solid results for the second quarter. The top line roughly matched the prior-year results, supported by a modest increase in electric sales volume, as warmer-than-normal weather drove customer demand higher. Growth in the electric and nonregulated lines was roughly offset by a decrease in gas revenue. Regardless, operating expenses declined, and share earnings increased roughly 13%.

Healthy performance will probably continue going forward. The utility should continue to benefit from favorable demographics within its service territory. A relatively strong economy ought to drive population growth and demand for power in and around Madison, Wisconsin. We expect favorable results from the electric business going forward, though the company's gas operations should continue to experience weakness. Overall, we look for solid bottom-line growth for the current year. This trend will probably continue from 2013 onward.

The company has been active on the regulatory front. MGE has requested a 5.8% hike in electric rates and a 2.6% increase in gas rates. The company cited costs associated with infrastructure and environmental improvements as reasons for the request. It has asked that these rates become effective on January 1st of 2013.

The board of directors has increased the dividend by about 3%. Beginning with the September payout, the quarterly dividend is now $0.3951. Moderate dividend growth will probably continue in the coming years.

This stock is ranked to outperform the broader equity markets for the coming six to 12 months. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. Moreover, MGE earns good marks for Safety, Financial Strength, Price Stability, and Earnings Predictability. The stock also has below-average volatility (Beta: 0.60). However, despite the solid profits and steady dividends we expect 3 to 5 years out, total return potential is below the *Value Line* median.

Michael Napoli, CFA *September 21, 2012*

(A) Excl. nonrecurring loss: '96, 42¢. Next earnings report due in November.
(B) Dividends historically paid in mid-March, June, September, and December. ■ Dvd. reinvestment plan available. (C) In millions.
(D) Rate allowed on common equity in '11: 10.4%; earned on average common equity, '11: 10.3%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

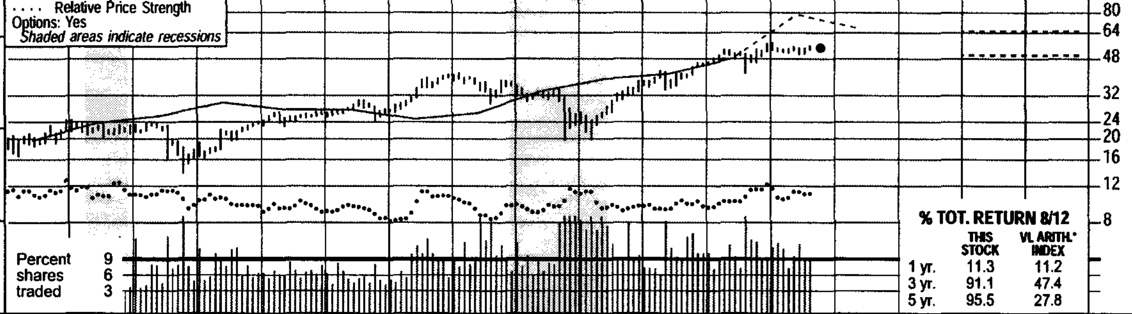
OGE ENERGY CORP. NYSE-OGE

RECENT PRICE	54.32	P/E RATIO	15.7 (Trailing: 15.5; Median: 14.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	3.0%	VALUE LINE

TIMELINESS 3 Lowered 4/27/12
SAFETY 2 Raised 7/1/05
TECHNICAL 3 Lowered 9/14/12
BETA .75 (1.00 = Market)

High:	24.7	24.2	24.3	27.0	30.6	40.6	41.3	36.2	37.8	46.2	57.2	57.5
Low:	20.0	13.7	16.0	22.8	24.4	26.3	29.1	19.6	19.7	33.9	40.6	50.2

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



Target Price Range

2015	2016	2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+20%)	*8%*
Low	50	(-10%)	*-1%*

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	118	116	125
to Sell	118	119	112
Hld's(000)	50222	52502	50733

Percent shares traded 9 6 3

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.3	11.2
3 yr.	91.1	47.4
5 yr.	95.5	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
17.18	18.23	20.02	27.90	42.33	40.80	38.52	43.24	54.74	65.65	43.92	41.37	43.54	29.58	38.08	39.92	*37.90*	*38.70*	Revenues per sh	*45.50*
3.31	3.38	3.90	4.06	4.15	3.61	3.75	3.65	3.74	3.89	4.47	4.79	4.80	5.37	6.02	6.63	*6.85*	*7.25*	"Cash Flow" per sh	*8.25*
1.62	1.61	2.04	1.94	1.89	1.29	1.43	1.73	1.78	1.83	2.45	2.64	2.49	2.66	2.99	3.45	*3.50*	*3.65*	Earnings per sh A	*4.00*
1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.34	1.37	1.40	1.43	1.46	1.52	*1.59*	*1.66*	Div'd Decl'd per sh B ■	*1.90*
2.00	2.03	1.86	2.33	2.30	2.89	2.99	2.07	3.02	3.30	5.34	6.08	8.02	8.74	8.73	12.95	*11.20*	*11.40*	Cap'l Spending per sh	*4.50*
11.91	12.19	12.91	13.09	13.66	13.34	12.53	13.75	14.28	15.19	17.59	18.31	20.29	21.04	23.46	26.13	*27.95*	*29.95*	Book Value per sh C	*35.75*
80.76	80.77	80.80	77.86	77.92	77.99	78.50	87.40	90.00	90.60	91.20	91.80	93.50	97.00	97.60	98.10	*99.00*	*99.50*	Common Shs Outst'g D	*101.00*
12.3	14.0	13.3	12.1	10.6	17.4	14.1	11.8	14.1	14.9	13.7	13.8	12.4	10.8	13.3	14.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.77	.81	.69	.69	.69	.89	.77	.67	.74	.79	.74	.73	.75	.72	.85	.91	*Value Line*		Relative P/E Ratio	*.95*
6.7%	5.9%	4.9%	5.7%	6.6%	5.9%	6.6%	6.5%	5.3%	4.9%	4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $3334.2 mill. **Due in 5 Yrs** $1156.7 mill.
LT Debt $2737.5 mill. **LT Interest** $155.6 mill.
(LT interest earned: 4.4x)

Leases, Uncapitalized Annual rentals $6.8 mill.

Pension Assets-12/11 $589.8 mill.
Oblig. $697.7 mill.

Pfd Stock None

Common Stock 98,656,135 shs.

MARKET CAP: $5.4 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
3023.9	3779.0	4926.6	5948.2	4005.6	3797.6	4070.7	2869.7	3716.9	3915.9	*3750*	*3850*	Revenues ($mill)	*4600*
111.7	141.8	157.8	166.1	226.1	244.2	231.4	258.3	295.3	342.9	*365*	*385*	Net Profit ($mill)	*425*
36.4%	35.4%	34.5%	30.2%	34.8%	32.3%	30.4%	31.7%	34.9%	30.7%	*31.0%*	*31.0%*	Income Tax Rate	*31.0%*
.8%	.4%	1.1%	1.3%	3.8%	1.6%	1.7%	9.1%	5.7%	9.0%	*7.0%*	*5.0%*	AFUDC % to Net Profit	*2.0%*
60.4%	54.4%	52.6%	49.5%	45.6%	44.4%	53.3%	50.6%	50.8%	51.6%	*51.5%*	*51.5%*	Long-Term Debt Ratio	*51.0%*
39.6%	45.6%	47.4%	50.5%	54.4%	55.6%	46.7%	49.4%	49.2%	48.4%	*48.5%*	*48.5%*	Common Equity Ratio	*49.0%*
2485.8	2637.7	2709.7	2726.6	2950.1	3025.5	4058.6	4129.7	4652.5	5300.4	*5705*	*6115*	Total Capital ($mill)	*7350*
3204.3	3309.5	3581.0	3567.4	3867.5	4246.3	5249.8	5911.6	6464.4	7474.0	*8250*	*9025*	Net Plant ($mill)	*9350*
6.6%	7.1%	7.4%	7.6%	9.1%	9.5%	7.0%	7.9%	7.8%	7.8%	*8.0%*	*8.0%*	Return on Total Cap'l	*7.5%*
11.4%	11.8%	12.3%	12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	*12.5%*	*12.0%*	Return on Shr. Equity	*11.0%*
11.4%	11.8%	12.3%	12.1%	14.1%	14.5%	12.2%	12.7%	12.9%	13.4%	*12.5%*	*12.0%*	Return on Com Equity E	*11.0%*
1.2%	3.6%	3.4%	3.4%	6.6%	7.1%	5.4%	6.0%	6.7%	7.7%	*7.0%*	*6.5%*	Retained to Com Eq	*6.0%*
89%	70%	73%	72%	53%	51%	55%	53%	48%	43%	*43%*	*43%*	All Div'ds to Net Prof	*45%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.4	+6.6	+3.4
Avg. Indust. Use (MWH)	684	729	752
Avg. Indust. Revs. per KWH (¢)	4.69	5.44	5.37
Capacity at Peak (Mw)	7084	7029	7115
Peak Load, Summer (Mw)	6418	6626	7057
Annual Load Factor (%)	52.0	53.8	52.2
% Change Customers (yr-end)	+.8	+.8	+.8
Fixed Charge Cov. (%)	338	409	427

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-.5%	-8.0%	*4.0%*
"Cash Flow"	4.5%	8.5%	*5.5%*
Earnings	6.0%	8.5%	*4.5%*
Dividends	1.0%	2.0%	*4.5%*
Book Value	6.0%	8.5%	*7.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	606.6	644.1	845.3	773.7	2869.7
2010	875.8	887.2	1125.4	828.5	3716.9
2011	840.5	978.1	1212.1	885.2	3915.9
2012	840.7	855.0	*1200*	*854.3*	*3750*
2013	*850*	*850*	*1250*	*900*	*3850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.18	.72	1.40	.35	2.66
2010	.25	.78	1.65	.31	2.99
2011	.25	1.04	1.80	.37	3.45
2012	.38	.95	*1.82*	*.35*	*3.50*
2013	*.35*	*1.00*	*1.95*	*.35*	*3.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.3475	.3475	.3475	.3475	1.39
2009	.355	.355	.355	.355	1.42
2010	.3625	.3625	.3625	.3625	1.45
2011	.375	.375	.375	.375	1.50
2012	.3925	.3925	.3925		

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 794,000 customers in Oklahoma (88% of electric revenues) and western Arkansas (9%); wholesale is (3%). Owns 81.3% of Enogex pipeline subsidiary. Acquired Transok 6/99. Electric revenue breakdown: residential, 43%; commercial, 24%; industrial, 18%; other, 15%. Generating sources: coal, 49%; gas, 33%; wind, 2%; purchased, 16%. Fuel costs: 58% of revenues. '11 reported depreciation rate (utility): 2.9%. Has 3,500 employees. Chairman, President & CEO: Peter B. Delaney. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. Telephone: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary has received a rate increase. Oklahoma Gas and Electric's tariffs were raised by $4.3 million (less than 1%), based on a 10.2% return on a 53% common-equity ratio. The rate hike was well below the $73.3 million OG&E had requested. Still, the decision wasn't as unfavorable as it might appear. The utility will now be able to file for recovery of some transmission projects through a rate rider, similar to the regulatory mechanisms it has for other kinds of capital expenditures (such as wind capacity). OG&E expects to spend nearly $1 billion on transmission in the next five years.

The utility isn't earning its allowed ROE in Arkansas. OG&E will soon seek recovery of a wind project through a surcharge on customers' bills. If this doesn't narrow the gap between its allowed and earned ROEs, the utility will probably file a general rate case.

The Enogex pipeline subsidiary acquired some gas-gathering assets earlier this month. It paid $80.5 million for properties in northwestern Oklahoma and the Texas panhandle. This is a key growth region for Enogex. In fact, the company plans to invest another $250 million in midstream gas infrastructure there through the end of next year. Enogex expects its minority partner to invest $60 million in the fourth quarter of 2012. This would reduce OGE's stake in Enogex to about 80%, from 81.3% today.

We estimate an earnings increase this year and next. The economy in OG&E's service area is stronger than the national economy, and OGE is benefiting from ongoing investment at Enogex. The bottom-line growth this year will likely be slight, however, because the extremely hot summer of 2011 makes for a tough comparison.

We expect a dividend increase at the board meeting in the fourth quarter. This is when the directors usually review the disbursement. We estimate a 4.5% raise in the annual payout, to $1.64 a share.

This stock's yield is more than a percentage point below the utility average. With the quotation within our 2015-2017 Target Price Range, total return potential is low.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecurring losses: '02, 39¢; '03, 14¢; '04, 6¢; gains on discontinued ops.: '02, 12¢; '04, 1¢; '05, 49¢; '06, 39¢. '09 & '11 EPS don't add to total due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in late Jan., Apr., July & Oct. ■ Div'd reinvestment plan avail. (C) Incl. deferred charges. In '11: $6.98/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in OK in '12: 10.2%; in AR in '09: 10.25%; earned on avg. com. eq., '11: 13.1%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	95
Earnings Predictability	95

WESTAR ENERGY NYSE-WR

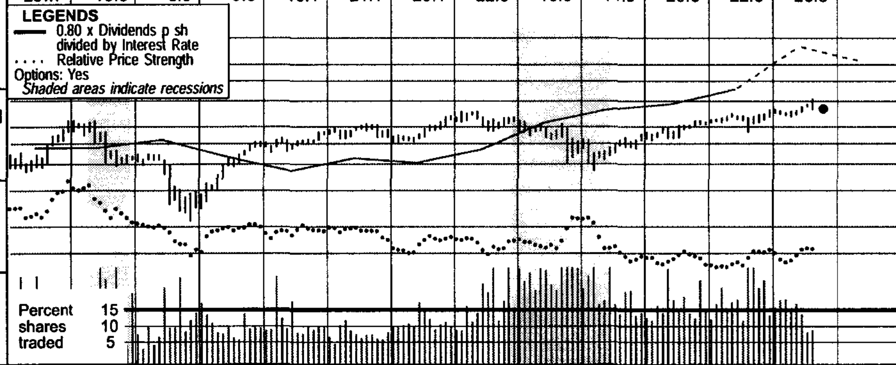
RECENT PRICE 29.31 | P/E RATIO 14.7 (Trailing: 16.0 / Median: 14.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 4.6% | VALUE LINE

TIMELINESS 2 Raised 8/24/12
SAFETY 2 Raised 4/1/05
TECHNICAL 3 Raised 8/10/12
BETA .75 (1.00 = Market)

High:	25.9	18.0	20.5	22.9	25.0	27.2	28.6	25.9	22.3	25.9	29.0	33.0	
Low:	15.6	8.5	9.8	18.1	21.1	20.1	22.8	16.0	14.9	20.6	22.6	26.8	

Target Price Range 2015 | 2016 | 2017

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



2015-17 PROJECTIONS

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

Insider Decisions

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

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	118	129	126
to Sell	83	93	103
Hld's(000)	69839	69508	69803

Percent shares traded 15 10 5

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	14.6	11.2
3 yr.	65.6	47.4
5 yr.	56.3	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.67	32.90	30.86	30.21	33.80	31.20	24.77	20.06	17.02	18.23	18.37	18.09	16.98	17.04	18.34	17.27	**17.70**	**18.30**	Revenues per sh	**20.15**
5.52	3.47	6.35	7.51	6.96	5.32	4.77	3.77	3.12	3.28	3.94	3.77	3.14	3.59	4.24	3.97	**4.20**	**4.40**	"Cash Flow" per sh	**5.05**
2.60	d.46	2.13	1.48	.89	d.58	1.00	1.48	1.17	1.55	1.88	1.84	1.31	1.28	1.80	1.79	**1.95**	**2.05**	Earnings per sh A	**2.40**
2.07	2.10	2.14	2.14	1.44	1.20	1.20	.87	.80	.92	.98	1.08	1.16	1.20	1.24	1.28	**1.32**	**1.36**	Div'd Decl'd per sh B■†	**1.48**
3.09	3.22	2.77	4.09	4.40	3.37	1.89	2.06	2.19	2.45	3.95	7.84	8.65	5.26	4.82	5.55	**6.70**	**7.05**	Cap'l Spending per sh	**7.85**
25.14	30.79	29.40	27.83	27.20	25.97	13.68	14.23	16.13	16.31	17.62	19.14	20.18	20.59	21.25	22.20	**23.60**	**25.40**	Book Value per sh C	**28.35**
64.63	65.41	65.91	67.40	70.08	70.08	71.51	72.84	86.03	86.84	87.39	95.46	108.31	109.07	112.13	125.70	**127.00**	**128.00**	Common Shs Outst'g E	**134.00**
11.7	--	18.4	17.2	20.6	--	14.0	10.8	17.4	14.8	12.2	14.1	17.0	14.9	13.0	14.8	Bold figures are		Avg Ann'l P/E Ratio	**12.5**
.73	--	.96	.98	1.34	--	.76	.62	.92	.79	.66	.75	1.02	.99	.83	.94	Value Line		Relative P/E Ratio	**.85**
6.8%	6.3%	5.5%	8.4%	7.9%	5.8%	8.6%	5.5%	3.9%	4.0%	4.3%	4.2%	5.2%	6.3%	5.3%	4.8%	estimates		Avg Ann'l Div'd Yield	**4.9%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $3436.7 mill. **Due in 5 Yrs** $753.9 mill.
LT Debt $3042.5 mill. **LT Interest** $160.0 mill.
(LT interest earned: 3.1x)

Pension Assets-12/11 $481 mill. **Oblig.** $876 mill.

Pfd Stock None

Common Stock 126,315,391 shs.
as of 7/31/12
MARKET CAP: $3.7 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1771.1	1461.1	1464.5	1583.3	1605.7	1726.8	1839.0	1858.2	2056.2	2171.0	**2250**	**2340**	Revenues ($mill)	**2700**
72.0	108.1	100.1	134.9	165.3	168.4	136.8	141.3	203.9	214.0	**250**	**265**	Net Profit ($mill)	**325**
53.4%	43.1%	25.0%	31.0%	25.4%	27.5%	24.8%	29.4%	29.0%	30.4%	**30.0%**	**30.0%**	Income Tax Rate	**30.0%**
--	5.0%	--	--	--	10.4%	--	--	10.4%	10.0%	**10.0%**	**10.0%**	AFUDC % to Net Profit	**10.0%**
71.6%	66.2%	53.8%	52.1%	50.0%	50.6%	49.8%	53.4%	53.6%	49.5%	**49.0%**	**49.5%**	Long-Term Debt Ratio	**50.0%**
22.9%	33.2%	45.5%	47.2%	49.3%	48.9%	49.7%	46.1%	46.0%	50.0%	**51.0%**	**50.5%**	Common Equity Ratio	**50.0%**
4272.4	3127.3	3049.2	3000.4	3124.2	3738.3	4400.1	4866.8	5180.9	5531.0	**5900**	**6450**	Total Capital ($mill)	**7600**
3995.4	3909.5	3911.0	3947.7	4071.6	4803.7	5533.5	5771.7	6309.5	6745.4	**7200**	**7500**	Net Plant ($mill)	**8500**
4.4%	7.0%	5.5%	6.2%	6.7%	5.8%	4.2%	4.4%	5.5%	5.2%	**5.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
5.9%	10.2%	7.1%	9.4%	10.6%	9.1%	6.2%	6.2%	8.5%	7.6%	**8.5%**	**8.0%**	Return on Shr. Equity	**8.5%**
7.3%	10.3%	7.1%	9.5%	10.7%	9.2%	6.2%	6.3%	8.5%	7.7%	**8.5%**	**8.0%**	Return on Com Equity D	**8.5%**
NMF	4.9%	3.2%	4.3%	5.5%	4.3%	1.2%	.8%	3.1%	2.2%	**2.5%**	**3.0%**	Retained to Com Eq	**3.5%**
120%	53%	56%	55%	49%	53%	80%	87%	63%	72%	**67%**	**66%**	All Div'ds to Net Prof	**60%**

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-2.0	+6.2	+1.0
Avg. Indust. Use (MWH)	5145	5468	5589
Avg. Indust. Revs. per KWH (¢)	5.67	5.82	6.22
Capacity at Peak (Mw)	6807	6756	6784
Peak Load, Summer (Mw)	4545	5485	5549
Annual Load Factor (%)	54.5	55.0	55.5
% Change Customers (yr-end)	+.9	+.3	+.1
Fixed Charge Cov. (%)	226	267	297

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-6.0%	-1.0%	*2.5%*
"Cash Flow"	-6.0%	1.5%	*4.5%*
Earnings	--	1.0%	*6.5%*
Dividends	-4.5%	7.0%	*3.0%*
Book Value	-3.0%	6.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	421.8	467.8	528.5	440.1	1858.2
2010	459.8	495.2	644.4	456.8	2056.2
2011	481.7	524.9	678.2	486.2	2171.0
2012	475.7	566.3	***690***	***518***	***2250***
2013	***520***	***575***	***710***	***535***	***2340***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.10	.35	.73	.10	1.28
2010	.27	.47	1.01	.05	1.80
2011	.27	.38	.98	.16	1.79
2012	.21	.48	***1.02***	***.24***	***1.95***
2013	***.25***	***.46***	***1.08***	***.26***	***2.05***

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.27	.29	.29	.29	1.14
2009	.29	.30	.30	.30	1.19
2010	.30	.31	.31	.31	1.23
2011	.31	.32	.32	.32	1.27
2012	.32	.33	.33		

BUSINESS: Westar Energy, Inc., formerly Western Resources, is the parent of Kansas Gas & Electric Company. Westar supplies electricity to 688,000 customers in Kansas. Electric revenue sources: residential and rural, 42%; commercial, 37%; industrial, 21%. Sold investment in ONEOK in 2003 and 85% ownership in Protection One in 2004. 2011 depreciation rate: 4.2%. Estimated plant age: 14 years. Fuels: coal, 51%; nuclear, 8%; gas, 41%. Has 2,424 employees. BlackRock, Inc. owns 5.9% of common; off. & dir., less than 1% (3/12 proxy). Chairman: Charles Q. Chandler IV. Chief Executive Officer and President: Mark A. Ruelle. Inc.: Kansas. Address: 818 South Kansas Avenue, Topeka, Kansas 66612. Telephone: 785-575-6300. Internet: www.westarenergy.com.

Westar Energy reported strong results for the second quarter. The top line advanced at a moderate clip. The company benefited from healthy demand resulting from warmer weather during the period. Solid growth from the Retail businesses and an impressive advance in Transmission revenue more than offset a decline in Wholesale revenue. Healthy top-line results were partly offset by greater operating costs, however. Even so, share net of $0.48 compared favorably with the prior-year tally.

Favorable comparisons ought to continue in the coming quarters. A rate increase of $50 million was approved and implemented earlier in the year. This ought give retail sales a boost. Healthy growth should continue in the Transmission business, though weakness may well persist in the Wholesale line. Overall, we expect higher revenues and share earnings for the company for full-year 2012. Growth ought to continue in 2013.

Investment in operations ought to pay off going forward. All of the company's large projects remain on schedule and within budget. Westar has finished an upgrade of air quality equipment at its Lawrence Energy Center, and an additional improvement is slated for completion by the end of the year. Major environmental projects at the Jeffrey and LaCygne energy centers are also progressing well. The Prairie Wind joint venture is also coming along nicely. Westar has acquired the majority of the rights of way, and has begun clearing. The project is expected to be completed in late 2014.

This stock is favorably ranked for year-ahead performance. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. Moreover, Westar earns good marks for Safety, Price Stability, and Earnings Predictability. In addition, the stock has below-average volatility (Beta: 0.75). Overall, Westar has unimpressive, but fairly well-defined, total return potential for the pull to 2015-2017. Conservative, income-seeking investors may find this issue attractive, considering the healthy dividend yield. Subscribers looking for strong capital appreciation can probably find better choices elsewhere.

Michael Napoli, CFA *September 21, 2012*

(A) EPS diluted from 2010 onward. Excl. nonrecur gains (losses): '96, ($0.19); '97, $7.97; '98, ($1.45); '99, ($1.31); '00, $1.07; '01, 27¢; '02, ($12.06); '03, 77¢; '08, 39¢; '11, 14¢. Next egs. rep't due in November. (B) Div'ds paid in early Jan., April, July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. reg. assets. In 2011: $8.32/sh. (D) Rate base determined: fair value; Rate allowed on common equity in '12: 10.0%; earned on avg. com. eq., '11: 8.2%. Regul. Clim.: Avg. (E) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	80

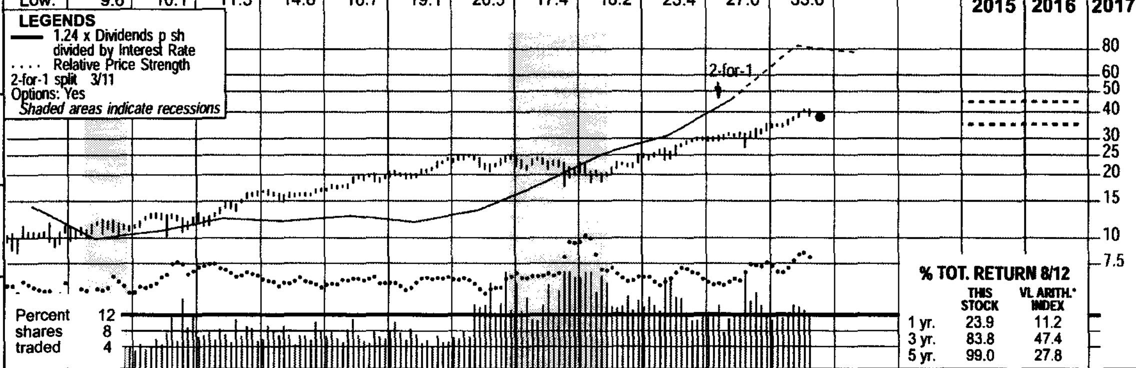
WISCONSIN ENERGY NYSE-WEC

RECENT PRICE 37.87 | P/E RATIO 16.0 (Trailing: 16.5 Median: 14.0) | RELATIVE P/E RATIO 1.05 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 3 Lowered 1/13/12
SAFETY 1 Raised 3/23/12
TECHNICAL 3 Raised 8/3/12
BETA .65 (1.00 = Market)

High:	12.3	13.2	16.8	17.3	20.4	24.3	25.2	24.8	25.3	30.5	35.4	41.5
Low:	9.6	10.1	11.3	14.8	16.7	19.1	20.5	17.4	18.2	23.4	27.0	33.6

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-10%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	4	0	2	0	2	3	4	5	0
to Sell	4	0	2	0	4	3	4	6	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	188	191	187
to Sell	175	178	178
Hld's(000)	158257	157172	146079

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.9	11.2
3 yr.	83.8	47.4
5 yr.	99.0	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
7.94	7.93	8.56	9.56	14.14	17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	*18.45*	*19.75*	Revenues per sh	*22.50*
2.13	1.48	2.06	2.26	2.24	2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	*3.90*	*4.15*	"Cash Flow" per sh	*5.00*
.99	.27	.83	.94	.54	.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	*2.30*	*2.35*	Earnings per sh A	*2.75*
.75	.77	.78	.78	.69	.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	*1.20*	*1.36*	Div'd Decl'd per sh B ■	*1.80*
1.77	1.56	1.76	2.22	2.64	3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	*3.30*	*3.10*	Cap'l Spending per sh	*3.00*
8.71	8.25	8.23	8.44	8.50	8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	*18.00*	*18.65*	Book Value per sh C	*20.50*
223.36	225.73	231.21	237.81	237.29	230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	*230.50*	*230.50*	Common Shs Outst'g D	*230.50*
14.3	NMF	18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.90	NMF	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.89	.89	.89	.90	*Value Line*		Relative P/E Ratio	*.95*
5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $5191.8 mill. **Due in 5 Yrs** $1802.6 mill.
LT Debt $4297.5 mill. **LT Interest** $244.3 mill.
Incl. $120.0 mill. capitalized leases.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $16.3 mill.
Pension Assets-12/11 $1.26 bill. **Oblig.** $1.33 bill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101; 44,498 shs. 6%, $100 par.
Common Stock 230,447,077 shs.

MARKET CAP: $8.7 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	4431.0	4127.9	4202.5	4486.4	*4250*	*4550*	Revenues ($mill)	*5200*
270.8	269.2	221.2	304.8	313.7	337.7	359.8	378.4	455.6	514.0	*535*	*550*	Net Profit ($mill)	*640*
37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	37.6%	36.5%	35.4%	33.9%	*36.0%*	*36.5%*	Income Tax Rate	*36.5%*
4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	27.2%	25.0%	18.6%	16.4%	*9.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	54.8%	51.9%	50.6%	53.6%	*54.0%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	44.8%	47.7%	49.0%	46.0%	*46.0%*	*46.5%*	Common Equity Ratio	*47.0%*
5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	7442.0	7473.1	7764.5	8608.0	*9040*	*9300*	Total Capital ($mill)	*10025*
4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	8517.0	9070.5	9601.5	10160	*10555*	*10870*	Net Plant ($mill)	*11525*
7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	6.3%	6.4%	7.5%	7.5%	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.9%	12.9%	*13.0%*	*12.5%*	Return on Shr. Equity	*13.5%*
12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	12.0%	12.9%	*13.0%*	*13.0%*	Return on Com Equity E	*13.5%*
8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	7.0%	6.2%	7.0%	6.8%	*6.0%*	*5.5%*	Retained to Com Eq	*5.0%*
35%	35%	45%	34%	35%	35%	35%	42%	41%	47%	*52%*	*57%*	All Div'ds to Net Prof	*65%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-8.1	+6.0	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.57	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5812	5908	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.3	+.2
Fixed Charge Cov. (%)	281	312	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.0%	3.0%	*3.5%*
"Cash Flow"	3.5%	4.0%	*7.0%*
Earnings	9.0%	10.0%	*6.5%*
Dividends	3.0%	14.0%	*13.5%*
Book Value	6.5%	7.0%	*4.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1396.2	842.5	821.9	1067.3	4127.9
2010	1248.6	890.9	973.2	1089.8	4202.5
2011	1328.7	991.7	1052.8	1113.2	4486.4
2012	1191.2	944.7	*964.1*	*1150*	*4250*
2013	*1350*	*1000*	*1000*	*1200*	*4550*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.60	.27	.25	.48	1.60
2010	.55	.37	.47	.53	1.92
2011	.72	.41	.55	.49	2.18
2012	.74	.51	*.56*	*.49*	*2.30*
2013	*.80*	*.45*	*.56*	*.54*	*2.35*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.135	.135	.135	.135	.54
2009	.169	.169	.169	.169	.68
2010	.20	.20	.20	.20	.80
2011	.26	.26	.26	.26	1.04
2012	.30	.30	.30		

BUSINESS: Wisconsin Energy Corporation is a holding company for We Energies, which provides electric, gas & steam service in Wisconsin. Customers: 1.1 mill. elec., 1.1 mill. gas. Acq'd WICOR 4/00. Discontinued pump-manufacturing operations in '04. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 36%; small commercial & industrial, 31%; large commercial & industrial, 24%; other, 9%. Generating sources: coal, 54%; gas, 7%; hydro, 1%; wind, 1%; purchased, 37%. Fuel costs: 42% of revs. '11 reported deprec. rate (utility): 2.8%. Has 4,600 employees. Chairman, President & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy has a rate case pending in Wisconsin. The company's utilities in the state are seeking electric rate increases of $172.6 million (6.2%) in 2013 and $37.1 million in 2014, a gas rate decrease of $17.1 million in 2013, and small tariff hikes for steam. The staff of the Wisconsin commission is not contesting the 10.4%-10.5% returns on equity that the utilities are requesting. New rates should go into effect at the start of 2013.

An electric rate hike in Michigan took effect in late June. The regulators boosted Wisconsin Electric's tariffs by $9.2 million (5.2%), based on a 10.1% ROE. This was above the $7.7 million raise that the utility self-implemented six months earlier.

Earnings will likely advance at a mid-single-digit clip in 2012. This year, the utility avoided a rate increase by suspending $140.1 million of regulatory amortization. Average shares outstanding are down slightly, as well. We have raised our earnings estimate by a nickel a share due to favorable weather conditions. Our revised estimate is at the midpoint of Wisconsin Energy's targeted range of $2.28-$2.32 a share.

We have cut our 2013 earnings estimate by $0.05 a share. Wisconsin Energy's stock-repurchase authorization has $200 million remaining. We had estimated that the stock would be bought back next year, but are no longer doing so due to the high share price, which is up about 10% so far this year.

Wisconsin Energy has signaled that its dividends will probably be raised by more than 10% in 2013 and 2014. Over the past several years, the company has had a payout ratio that is well below the industry average. The board wants to change this, and is targeting a payout ratio of about 60% by 2014.

The high expected dividend growth is reflected in this stock's valuation. The dividend yield is nearly a full percentage point below the utility mean, and the relative price-earnings ratio is higher than it has been historically. Despite the strong dividend growth we project over the 3- to 5-year period, total return potential is unexciting because the quotation is already within our 2015-2017 Target Price Range.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (5¢); '00, 10¢ net; '02, (44¢); '03, (10¢) net; '04, (42¢); gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 6¢. '11 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $7.29/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '10: 10.4%-10.5%; earned on avg. com. eq., '11: 13.1%. Regulat. Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

Dr. Avera workpaper WP-32 is a separate file in Excel format.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In re the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

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

A. My name is Daniel K. Arbough. I am the Treasurer for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky. As Treasurer for the Companies, I am responsible for the Companies' relationships with rating agencies and banks.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to certain of the arguments presented in the testimony of Dr. J. Randall Woolridge, on behalf of the Attorney General, and Lane Kollen, on behalf of the Kentucky Industrial Utility Customers ("KIUC"). Specifically, my testimony will (1) address why the hypothetical capital structure Dr. Woolridge has proposed is inappropriate; (2) demonstrate that Mr. Kollen's claims regarding the Money Pool LG&E and KU participate in are unfounded; (3) explain the reasons why LG&E's and KU's capital structures do not presently contain short-term debt; (4) and respond to Mr. Kollen's assertions regarding other "considerations" the Commission should study in setting the Companies' return on equity.

Capital Structures

Q. Does Dr. Woolridge propose to adjust LG&E's and KU's capital structures?

A. Yes. Dr. Woolridge has recommended an adjustment to LG&E's and KU's capital structures that would reduce the utilities' common equity ratio to 50%, thereby increasing long-term debt to 50%, as well.[1] These adjustments would impose an artificial capital structure on the Companies.

Q. Why does Dr. Woolridge propose to adjust the Companies' capital structures?

A. Dr. Woolridge alleges that LG&E's and KU's capital structures presently contain too much equity as compared to PPL Corporation's capital structure.[2] Dr. Woolridge also makes a similar argument with regard to the Companies' capital structures as compared to the capital structures for the holding companies in his Electric Proxy Group.[3]

Q. Do you agree with Dr. Woolridge's adjustments to LG&E's and KU's capital structures?

A. No. Dr. Woolridge's adjustments to decrease the Companies' equity ratios to 50% are inappropriate for three reasons. First, LG&E's and KU's current capital structures are comparable to its capital structures throughout the last decade, with its objective targets and independent methodologies unchanged. Second, Dr. Woolridge unreasonably compares LG&E's and KU's capital structures with those of other holding companies, as opposed to the utilities within the holding companies. Third, the similarity between Standard & Poor's and Moody's credit ratings for the Companies demonstrates that the capital structure of LG&E's and KU's parent company has minimal impact on the Companies' ratings.

Q. To your first point, please explain whether LG&E's and KU's capital structures are consistent with its previous ratios and targets.

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[1] Case No. 2012-00221, Direct Testimony of Dr. J. Randall Woolridge of October 3, 2012 ("Woolridge KU Direct"), p. 17; Case No. 2012-00222, Direct Testimony of Dr. J. Randall Woolridge of October 3, 2012 ("Woolridge LG&E Direct"), p. 19.

[2] Woolridge KU Direct, p. 15-16; Woolridge LG&E Direct, p. 16-17.

[3] Woolridge KU Direct, p. 16-18; Woolridge LG&E Direct, p. 17-18.

A. As I explained in my direct testimony, LG&E's and KU's capital structures are established in accordance with the independent, objective criteria set forth by Standard and Poor's to achieve a rating in the "A" range. In order to obtain an "A" rating, LG&E and KU must achieve an "Intermediate" risk profile, which will require the Companies to maintain a maximum debt/capital ratio (as adjusted by Standard and Poor's) of 45%, or a maximum debt/capital ratio of 50% to achieve a "Significant" risk profile, which will allow the Companies to obtain an "A-" rating. At March 31, 2012, the end of the test year, LG&E's capital structure, including Standard and Poor's adjustments, included 50.7% common equity and 49.3% debt, while KU's included 51.4% common equity and 48.6% debt. These equity ratios are consistent with the ratios needed for the Companies to obtain a rating in the "A" range.

It is important to note that the Companies' target "A" range rating is certainly not new, as this has been their target for well over a decade. Moreover, the methodology the Companies utilize with regard to managing its capital structures has not changed. Although the exact percentages, of course, vary, LG&E's and KU's adjusted equity ratios have remained stable and consistent over the last decade. Arbough Rebuttal Exhibit 1 demonstrates this history. To change this financial policy in conjunction with a rate case decision would be viewed very negatively by the rating agencies and investors based on my experience in dealing directly with these important stakeholders.

Q. Are the Companies' target "A" ratings beneficial to debt expense?

A. Yes, as both LG&E's and KU's debt expense are among the lowest in the country, which they monitor relative to a peer group of utilities. As I explained in my direct testimony, LG&E's 3.96% cost of debt (combined taxable and tax-exempt debt) was the third lowest of any utility company in the peer group for the twelve months ending March 2012. Similarly, KU's 3.75% cost of debt (combined taxable and tax-exempt debt) was the second lowest of any utility company in the peer group. As shown in Arbough Rebuttal Exhibit 2, as of June 30, 2012, KU's cost of debt is now the lowest of the peer group of companies monitored, and LG&E's cost is now the second lowest in the peer group. These results demonstrate the efficiency of KU's and LG&E's capital structures in obtaining outstanding debt rates as compared to their peers, as well as the strong financial policy of and management by the Companies.

Q. Does Dr. Woolridge provide evidence that LG&E's and KU's equity ratios are higher than other utilities' equity ratios?

A. No, because Dr. Woolridge does not compare the Companies' capital structures with other utilities. Instead, as conceded by Dr. Woolridge, the average 46.00% common equity ratio for the companies in his Electric Proxy Group is based on the "capital structure ratios for the *holding companies*"[4] in his Group, instead of other utilities. Similarly, Dr. Woolridge states that the mean common equity ratio for his Gas Proxy Group is 49.76%, which was based as "in the case of the Electric Proxy Group" on "the capital structure ratios for the *holding companies*."[5] In his direct testimony, however, in Exhibit WEA-9, Dr. Avera shows that the utility operating companies within his peer group have an average common equity ratio of 53.8.%[6]

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[4] Woolridge KU Direct, p. 16-17; Woolridge LG&E Direct, p. 18 (emphasis added).
[5] Woolridge LG&E Direct, p. 18 (emphasis added).
[6] Direct Testimony of William E. Avera of June 29, 2012 in Case Nos. 2012-00221 and 2012-00222.

It should also be noted that when PPL Corporation acquired LG&E and KU, PPL Corporation contributed approximately $1.6 billion in equity to LG&E and KU Energy LLC ("LKE"), which is the Companies' holding company and immediate parent, in order to deleverage LKE's capital structure by paying off debt incurred from non-regulated businesses. None of the $1.6 billion has been passed on to either LG&E or KU, which is further evidence that the capital structure of PPL Corporation and LKE does not affect the Companies in the manner Mr. Kollen has asserted.

Q. Does Dr. Woolridge claim that PPL Corporation's capitalization has a direct impact to LG&E and KU?

A. Yes. Dr. Woolridge alleges that PPL Corporation's capital structure, which is somewhat different than LG&E's and KU's, has a "direct impact on the bond ratings and capital costs" of LG&E and KU.[7] Dr. Woolridge suggests that because credit rating agencies allegedly place more importance on PPL Corporation's capital structure, which has less equity, than LG&E's and KU's capital structures, which contain more equity, in establishing the Companies' ratings, there is no reason for the Companies to have a higher equity ratio than PPL Corporation.[8]

Q. What evidence does Dr. Woolridge use to make this claim?

A. Dr. Woolridge cites Standard and Poor's recent report for PPL Corporation, which states that it bases its ratings for LG&E and KU on the consolidated credit profile of

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[7] Woolridge KU Direct, p. 16; Woolridge LG&E Direct, p. 17.

[8] It is important to note that PPL Corporation financed a portion of two major acquisitions, including the acquisition of LG&E and KU, with equity units. These securities appear as debt on the balance sheet, but the rating agencies attribute significant equity credit to these securities. At year-end 2011, the equity units included as debt on the balance sheet associated with the LKE acquisition total $1.15 billion, while the units associated with the WPD Midlands acquisition total $978 million.

its ultimate parent, PPL Corporation.[9] Currently, LG&E's and KU's rating from Standard and Poor's is BBB.

Q. Is Dr. Woolridge's claim accurate?

A. No. While Standard and Poor's does consider the consolidated credit profile when rating a vertically integrated utility, Moody's, which is also an independent credit rating agency, places much less emphasis on the consolidated entity. Moody's instead rates both LG&E and KU from the bottom up. Currently, LG&E's and KU's rating from Moody's is Baa1, which is only one notch higher than the comparable BBB rating from Standard and Poor's. The fact that the two ratings are very comparable, despite the fact that Standard and Poor's considers PPL Corporation's capital structure through its "top down" review, while Moody's rates the Companies through its "bottom up" review, demonstrates that PPL Corporation's capital structure does not have a significant impact on LG&E's and KU's ratings. As such, it remains important that LG&E and KU maintain capital structures consistent with their target of achieving ratings in the "A" range.

Money Pool Participation

Q. Did Mr. Kollen claim that LG&E and KU have borrowed excess funds in order to loan it to affiliates in its Money Pool?

A. Yes, Mr. Kollen has taken discrete and unrelated events identified in data responses and incorrectly advanced a correlation between LG&E's and KU's borrowings and its

[9] Woolridge KU Direct, p. 16; Woolridge LG&E Direct, p. 17.

participation in a money pool.[10] Quite simply, the two are not connected in the manner Mr. Kollen claims.

Q. Has LG&E and KU had excess cash from their recent borrowings?

A. Yes. As explained in my direct testimony, in 2010 LG&E and KU took advantage of the very favorable long-term interest rates to refinance debt as part of the PPL Corporation transaction. The majority of the refinanced debt was used to repay existing unsecured promissory notes, with the remaining proceeds of the issuances used to fund capital projects and for other purposes.

The amount of capital expenditures LG&E and KU actually incurred in 2011, as opposed to the budgeted level of capital expenditures on which, in part, the refinancing was based, was considerably less. Specifically, LG&E incurred $128 million less in capital expenditures than expected, and KU incurred $178 million less. The fact that the Companies incurred less than the budgeted amount of capital expenditures is attributable to several factors, including decreased construction costs, permitting issues and contract delays that postponed construction schedules. In addition, bonus depreciation legislation has been passed that allows LG&E and KU to accelerate the tax depreciation of new capital assets. This has resulted in additional cash flow to each utility of between $40 million and $50 million.

Q. Please explain LG&E's and KU's involvement with its Money Pool.

A. LG&E and KU have been part of a Money Pool since 1999, which is a mechanism that allows the Companies to coordinate and provide for certain of their short-term cash and working capital requirements. The Money Pool was implemented after the

[10] Direct Testimony and Exhibits of Lane Kollen on behalf of the Kentucky Industrial Utility Customers, Inc. in Case Nos. 2012-00221 and 2012-00222, filed October 3, 2012, p. 29-32 ("Kollen Direct").

LG&E and KU merger, and has thus been in place for well over a decade. It did not begin or change as a result of the PPL transaction.

The Money Pool agreement, which was provided during discovery,[11] sets forth the Companies' clearly delineated borrowing and lending restrictions. While LG&E and KU can loan funds to one another and can borrow from its immediate parent LKE, neither LKE nor any other affiliate of PPL Corporation can borrow from LG&E or KU. Thus, Mr. Kollen's claim that "excess funds were loaned to other affiliates at extremely low interest rates"[12] is simply inaccurate, as the only affiliate to which LG&E can lend funds is KU and the only affiliate to which KU can lend funds is LG&E.

Q. How often did LG&E and KU borrow or receive funds in the test year through the Money Pool?

A. Very rarely. On one day during the test year, LG&E borrowed funds from LKE via the Money Pool. Otherwise, LG&E and KU did not borrow or receive any other funds. This again demonstrates that Mr. Kollen's assertions regarding the Companies' involvement in the Money Pool is incorrect.

Q. Did LG&E and KU invest all of their remaining cash from the 2010 refinancing in the Money Pool?

A. Absolutely not. Neither KU nor LG&E invested any funds in the Money Pool during the test year. Moreover, as demonstrated in Arbough Rebuttal Exhibit 3, KU has not invested any funds in the Money Pool at any point during this year. LG&E has had minimal investments in the Money Pool during this year, investing funds only on

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[11] See the Response to the Attorney General's Request No. 1-242 in Case No. 2012-00221 and the Response to the Attorney General's Request No. 1-285 in Case No. 2012-00222.
[12] Kollen Direct, p. 29.

fourteen days thus far when KU had short-term borrowing needs. The substantial majority of the cash was invested in money market mutual funds or insured bank accounts, which the Companies consider prudent investments.

Q. Based on your testimony, is it fair to say that the amount of bonds issued by LG&E and KU in 2010 had nothing to do with the Money Pool?

A. Yes, because there is no correlation between the Companies' remaining cash from the refinancing in 2010 and their participation in the Money Pool. As I have explained, these are separate issues that have no causal relationship. As such, I recommend that the Commission deny Mr. Kollen's adjustment to reduce LG&E's and KU's capitalization as the adjustment is based upon his completely mistaken understanding of the Companies' participation in the Money Pool.

Use of Short-Term Debt

Q. Does Mr. Kollen claim that LG&E and KU have insufficient short-term debt?

A. Yes. Although Mr. Kollen has not proposed an adjustment with regard to this issue, he claims that LG&E and KU have utilized insufficient short-term debt in this proceeding and in Environmental Cost Recovery ("ECR") proceedings.[13] These arguments are similar to those presented by the KIUC in Case Nos. 2011-00161 and 2011-00162.

Q. Why have LG&E and KU recently not utilized short-term debt?

A. In making financing decisions, the Companies utilize various sources of debt and equity, which helps protect LG&E and KU, as well as its ratepayers, from market volatility. When LG&E and KU refinanced its short-term debt with long-term debt in 2010, it was able to procure very low interest rates, which means that the

[13] Kollen Direct, p. 34.

Companies' customers will benefit from the low debt costs for many years. As I explained above, a portion of the funds were to be used for capital expenditures, such as ECR construction projects.

The fact that short-term debt rates are presently lower than long-term debt rates neither implies that the Companies' capital structures are imprudent nor provides any reasoned basis to impute a hypothetical capital structure. LG&E and KU successfully took advantage of low interest rates in procuring long-term debt costs that are favorable to the Companies and its ratepayers, which is demonstrated by the fact that as of June 30, 2012, KU had the lowest debt costs among its peer group and LG&E had the second lowest. This is not to say that LG&E and KU will not utilize short-term debt in the future. The Companies will monitor their capital needs and market conditions and utilize the various forms of debt and equity, including short-term debt, as appropriate.

Q. Should the Commission reject Mr. Kollen's alternative proposal for short-term debt?

A. Yes. Mr. Kollen does not propose an adjustment for short-term debt in this proceeding, but states that if the Commission does not intend to revisit the issue in the Companies' next ECR proceedings, it should impute 10% of the Companies' debt to short-term debt in these cases.[14] This is an arbitrary adjustment for which Mr. Kollen fails to provide any reasoned or substantive support. The adjustment also conflicts with prior Commission orders recognizing that in the utility industry capital expenditures are financed by numerous sources of capital, and that it is generally not

[14] Kollen Direct, p. 37.

possible to match a capital expenditure with a specific source of capital.[15] Accepting such an adjustment creates a fiction with regard to the Companies' capital structure which is not warranted because LG&E and KU have prudently incurred debt costs that protect the Companies from market volatility. Moreover, the adjustment ignores the other changes in the amounts, forms and costs of capital that will occur as the Companies issue short-term debt in the future. Mr. Kollen's adjustment selects only the lowest cost form of capital without regard to the associated increases in and costs of other changes in the Companies' capital structures that will occur outside the test period.

<u>Double Leveraging</u>

Q. Does Mr. Kollen identify other "considerations" for the Commission with regard to LG&E's and KU's return on equity?

A. Yes, principally the concept of double leveraging. Mr. Kollen has not proposed an adjustment for this concept, but has instead presented the idea for the Commission's consideration. Mr. Kollen states that double leveraging should be considered because the Companies are held by LKE, which finances its equity investment in the Companies' through a mix of debt and equity.[16]

Q. What is the double leverage approach to utility rate making?

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[15] *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Amended Compliance Plan for Purposes of Recovering the Costs of New and Additional Pollution Control Facilities and to Amend its Environmental Surcharge Tariff* (Case No. 2000-439) Order, April 18, 2001 ("Concerning the financing of utility plant, it has long been recognized in the utility industry that capital expenditures are financed by numerous sources of capital, and that it is generally not possible to match a capital expenditure with a specific source of capital. KIUC has acknowledged that neither it nor KU stated that the 2001 Plan capital expenditures will be financed exclusively with short-term debt. Absent such evidence, the Commission cannot find it reasonable or appropriate to set the rate of return on the 2001 Plan rate base at the cost of KU's short-term debt, either during the CWIP phase or after the facilities are in service.").

[16] Kollen Direct, p. 39.

A. Generally, proponents of double leveraging claim that a utility's required rate of return on equity should be determined by calculating the parent company's weighted average cost of capital and then equating the utility's cost of equity to the parent's weighted average cost of capital. It is important to understand this is only a general description of the theory, as Mr. Kollen did not provide an explanation of how he thinks the concept should be applied with regard to the Companies.

Q. To your knowledge, has the Commission accepted the theory of double leveraging for LG&E or KU?

A. No, not to my knowledge. This is not surprising because the concept of double leveraging conflicts with the Commission's long and well established policies and orders regarding the stand-alone treatment of and protection for utilities that are held by a parent company.[17] Although Mr. Kollen is correct that double leveraging and consolidated tax savings, the latter of which the Commission has repeatedly rejected, are two separate concepts, both are based upon the same premise, which is that a utility's rates should be affected by the financial position of its parent company.

Q. Please explain in more detail how double leveraging conflicts with the stand-alone methodology.

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[17] *In the Matter of: Joint Application of PPL Corporation, E.ON AG, E.ON US Investments Corp., E.ON U.S. LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities* (Case No. 2010-00204) Order, September 30, 2010; *In the Matter of: Joint Application to E.ON AG, Powergen PLC, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Acquisition* (Case No. 2001-00104) Order, August 6, 2001*; In the Matter of: Joint Application of Powergen PLC, LG&E Energy Corp., Louisville Gas and Electric Company, and Kentucky Utilities Company for Approval of a Merger* (Case No. 2000-095) Order, May 15, 2000; *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger* (Case No. 97-300) Order, September 12, 1997; *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Herewith* (Case No. 89-374) Order, May 25, 1990; *In the Matter of: Application of Kentucky Utilities Company to Enter into an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Herewith* (Case No. 10296) Order, October 6, 1988.

A. The stand-alone methodology, which has been employed by the Commission in a number of decisions involving LG&E and KU, affirms that a utility's rates are set to recover the just and reasonable costs of actually providing utility service.[18] The methodology is based upon the following three closely related accounting and regulatory principles: (1) cost causation; (2) the benefits-burden relationship; and (3) prevention of cross-subsidies of, or by, affiliates. The double leverage approach, however, violates these regulatory principles by ignoring the core notion that an investment's required rate of return depends on its particular risks, as further discussed by Dr. Avera in his rebuttal testimony.

Q. How does the double leverage approach conflict with the stand-alone policy?

A. As I mentioned above, the double leverage approach departs from the principle of the prevention of cross-subsidies of, or by, affiliates. As the Commission is aware, there are a host of statutes and regulations utilities must follow with regard to affiliate transactions. The purpose of these requirements is to ensure that a utility's ratepayers are not negatively affected by the activities and business risks of a utility's parent or subsidiary companies. Double leveraging selectively disregards this separation by creating an economic fiction that a utility's cost of equity is equal to parent's weighted average cost of capital. Under this approach, the utility is unduly affected by its parent company's business activities, which can lead to a cost of equity that

[18] *See, e.g., In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates* (Case No. 2009-00548) July 30, 2012 Order, p.22-24; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates* (Case No. 2009-00549) July 30, 2012 Order, p. 24-25.

greatly understates the utility's actual cost of equity. For these reasons, the Commission should disregard Mr. Kollen's suggestion.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2ND day of November 2012.

(SEAL)

Notary Public

My Commission Expires:

July 21, 2015

Arbough Rebuttal Exhibit 1

Equity/ Capital Ratio History

	KU 3/31/2012	KU 12/31/2011	KU 12/31/2010	KU 12/31/2009	KU 12/31/2008	KU 12/31/2007	KU 12/31/2006	KU 12/31/2005	KU 12/31/2004	KU 9/30/2003
LTD	1,841	1,841	1,840	1,682	1,532	1,264	843	816	726	663
Money Pool			10	45	16	23	97	70	35	99
Imputed Debt (per S&P)	184	184	169	174	159	189	189	125	125	125
Total Debt	2,025	2,025	2,019	1,901	1,707	1,476	1,129	1,010	886	887
Total Equity	2,138	2,128	2,075	1,952	1,744	1,435	1,193	1,022	969	909
Total Capitalization	4,163	4,153	4,094	3,853	3,451	2,911	2,322	2,032	1,855	1,796
Equity / Capital % including imputed debt	51.4%	51.2%	50.7%	50.7%	50.5%	49.3%	51.4%	50.3%	52.2%	50.6%
Equity / Capital % excluding imputed debt	53.7%	53.6%	52.9%	53.1%	53.0%	52.7%	55.9%	53.6%	56.0%	54.4%

	LG&E 3/31/2012	LG&E 12/31/2011	LG&E 12/31/2010	LG&E 12/31/2009	LG&E 12/31/2008	LG&E 12/31/2007	LG&E 12/31/2006	LG&E 12/31/2005	LG&E 12/31/2004	LG&E 9/30/2003
LTD	1,106	1,106	942	896	896	984	820	821	872	662
Money Pool			175	170	222	78	68	141	58	57
Imputed Debt (per S&P)	242	242	222	232	124	161	161			
Total Debt	1,348	1,348	1,339	1,298	1,242	1,223	1,049	962	930	719
Total Equity	1,387	1,377	1,336	1,253	1,234	1,161	1,094	1,027	953	767
Total Capitalization	2,735	2,725	2,675	2,551	2,476	2,384	2,143	1,989	1,883	1,486
Equity / Capital % including imputed debt	50.7%	50.5%	49.9%	49.1%	49.8%	48.7%	51.0%	51.6%	50.6%	51.6%
Equity / Capital % excluding imputed debt	55.6%	55.5%	54.5%	54.0%	52.5%	52.2%	55.2%	51.6%	50.6%	51.6%

Arbough Rebuttal Exhibit 2

Utilty Cost of Debt Comparison
12 Months Ending June 2012

Rank	Company	Per Public Data
1.	**KU**	**3.741%**
2.	**LG&E**	**3.777%**
3.	Duke Energy Indiana Inc.	3.818%
4.	Duke Energy Ohio	3.990%
5.	Dayton Power and Light	4.185%
6.	Indiana Michigan Power Company	4.819%
7.	AEP Texas Central Company	4.870%
8.	PECO Energy Company	5.107%
9.	Detroit Edison	5.161%
10.	NiSource	5.272%
11.	Appalachian Power Company	5.330%
12.	Metropolitan Edison Company	5.347%
13.	Public Service Electric and Gas Company	5.374%
14.	AEP Texas North Company	5.435%
15.	Pennsylvania Electric Company	5.506%
16.	Union Electric Company	5.570%
17.	Jersey Central Power & Light Co.	5.673%
18.	PPL Electric Utilities	5.728%
19.	Commonwealth Edison	5.743%
20.	Kentucky Power Company	6.502%
21.	Ohio Power Company	6.664%
22.	Michigan Consolidated Gas Company	6.866%
23.	Toledo Edison Company	7.002%
24.	Ameren Energy Generating Company	7.039%
25.	Ohio Edison Company	7.695%
26.	Ameren Illinois Company	7.841%

Arbough Rebuttal Exhibit 3

	KU Inv	KU MP Inv	KU Cash	Cash and Short Term Investments
12/31/2011	$ -	$ -	$ 32,974,632.25	$ 32,974,632.25
1/1/2012	$ -	$ -	$ 32,974,632.25	$ 32,974,632.25
1/2/2012	$ -	$ -	$ 32,974,632.25	$ 32,974,632.25
1/3/2012	$ -	$ -	$ 32,051,831.80	$ 32,051,831.80
1/4/2012	$ -	$ -	$ 38,714,543.13	$ 38,714,543.13
1/5/2012	$ 10,000,000.00	$ -	$ 33,607,716.87	$ 43,607,716.87
1/6/2012	$ 8,000,000.00	$ -	$ 32,881,878.02	$ 40,881,878.02
1/7/2012	$ 8,000,000.00	$ -	$ 32,881,878.02	$ 40,881,878.02
1/8/2012	$ 8,000,000.00	$ -	$ 32,881,878.02	$ 40,881,878.02
1/9/2012	$ 9,000,000.00	$ -	$ 34,404,004.10	$ 43,404,004.10
1/10/2012	$ 12,000,000.00	$ -	$ 36,425,360.39	$ 48,425,360.39
1/11/2012	$ 18,000,000.00	$ -	$ 35,175,139.93	$ 53,175,139.93
1/12/2012	$ -	$ -	$ 23,224,145.76	$ 23,224,145.76
1/13/2012	$ -	$ -	$ 10,509,037.77	$ 10,509,037.77
1/14/2012	$ -	$ -	$ 10,509,037.77	$ 10,509,037.77
1/15/2012	$ -	$ -	$ 10,509,037.77	$ 10,509,037.77
1/16/2012	$ -	$ -	$ 10,509,037.77	$ 10,509,037.77
1/17/2012	$ -	$ -	$ 3,123,934.56	$ 3,123,934.56
1/18/2012	$ -	$ -	$ 9,297,102.94	$ 9,297,102.94
1/19/2012	$ -	$ -	$ 14,755,880.65	$ 14,755,880.65
1/20/2012	$ -	$ -	$ 11,243,012.64	$ 11,243,012.64
1/21/2012	$ -	$ -	$ 11,243,012.64	$ 11,243,012.64
1/22/2012	$ -	$ -	$ 11,243,012.64	$ 11,243,012.64
1/23/2012	$ -	$ -	$ 18,248,178.02	$ 18,248,178.02
1/24/2012	$ -	$ -	$ 23,164,081.86	$ 23,164,081.86
1/25/2012	$ -	$ -	$ 12,479,639.88	$ 12,479,639.88
1/26/2012	$ -	$ -	$ 15,863,752.10	$ 15,863,752.10
1/27/2012	$ -	$ -	$ 19,012,323.20	$ 19,012,323.20
1/28/2012	$ -	$ -	$ 19,012,323.20	$ 19,012,323.20
1/29/2012	$ -	$ -	$ 19,012,323.20	$ 19,012,323.20
1/30/2012	$ -	$ -	$ 21,651,446.98	$ 21,651,446.98
1/31/2012	$ -	$ -	$ 29,709,830.87	$ 29,709,830.87
2/1/2012	$ -	$ -	$ 32,437,794.20	$ 32,437,794.20
2/2/2012	$ -	$ -	$ 14,344,516.42	$ 14,344,516.42
2/3/2012	$ -	$ -	$ 17,742,821.50	$ 17,742,821.50
2/4/2012	$ -	$ -	$ 17,742,821.50	$ 17,742,821.50
2/5/2012	$ -	$ -	$ 17,742,821.50	$ 17,742,821.50
2/6/2012	$ -	$ -	$ 20,874,252.14	$ 20,874,252.14
2/7/2012	$ -	$ -	$ 26,608,911.74	$ 26,608,911.74
2/8/2012	$ -	$ -	$ 35,186,820.68	$ 35,186,820.68
2/9/2012	$ 7,200,000.00	$ -	$ 33,585,939.86	$ 40,785,939.86
2/10/2012	$ 7,200,000.00	$ -	$ 36,938,009.84	$ 44,138,009.84
2/11/2012	$ 7,200,000.00	$ -	$ 36,938,009.84	$ 44,138,009.84

2/12/2012	$	7,200,000.00	$	-	$	36,938,009.84	$	44,138,009.84
2/13/2012	$	7,200,000.00	$	-	$	41,224,804.02	$	48,424,804.02
2/14/2012	$	12,200,000.00	$	-	$	42,150,446.95	$	54,350,446.95
2/15/2012	$	12,200,000.00	$	-	$	37,811,693.74	$	50,011,693.74
2/16/2012	$	22,200,000.00	$	-	$	38,882,837.09	$	61,082,837.09
2/17/2012	$	22,200,000.00	$	-	$	39,921,110.39	$	62,121,110.39
2/18/2012	$	22,200,000.00	$	-	$	39,921,110.39	$	62,121,110.39
2/19/2012	$	22,200,000.00	$	-	$	39,921,110.39	$	62,121,110.39
2/20/2012	$	22,200,000.00	$	-	$	39,921,110.39	$	62,121,110.39
2/21/2012	$	-	$	-	$	35,419,088.20	$	35,419,088.20
2/22/2012	$	15,000,000.00	$	-	$	31,987,974.95	$	46,987,974.95
2/23/2012	$	18,000,000.00	$	-	$	32,596,002.84	$	50,596,002.84
2/24/2012	$	18,000,000.00	$	-	$	36,442,276.91	$	54,442,276.91
2/25/2012	$	18,000,000.00	$	-	$	36,442,276.91	$	54,442,276.91
2/26/2012	$	18,000,000.00	$	-	$	36,442,276.91	$	54,442,276.91
2/27/2012	$	3,000,000.00	$	-	$	35,263,393.72	$	38,263,393.72
2/28/2012	$	10,000,000.00	$	-	$	35,216,060.85	$	45,216,060.85
2/29/2012	$	13,000,000.00	$	-	$	36,629,239.84	$	49,629,239.84
3/1/2012	$	17,200,000.00	$	-	$	35,991,883.60	$	53,191,883.60
3/2/2012	$	17,200,000.00	$	-	$	32,988,659.92	$	50,188,659.92
3/3/2012	$	17,200,000.00	$	-	$	32,988,659.92	$	50,188,659.92
3/4/2012	$	17,200,000.00	$	-	$	32,988,659.92	$	50,188,659.92
3/5/2012	$	17,200,000.00	$	-	$	35,037,148.06	$	52,237,148.06
3/6/2012	$	20,200,000.00	$	-	$	37,064,711.26	$	57,264,711.26
3/7/2012	$	31,200,000.00	$	-	$	33,505,957.39	$	64,705,957.39
3/8/2012	$	31,200,000.00	$	-	$	24,685,309.24	$	55,885,309.24
3/9/2012	$	27,200,000.00	$	-	$	27,778,093.23	$	54,978,093.23
3/10/2012	$	27,200,000.00	$	-	$	27,778,093.23	$	54,978,093.23
3/11/2012	$	27,200,000.00	$	-	$	27,778,093.23	$	54,978,093.23
3/12/2012	$	19,700,000.00	$	-	$	34,260,011.02	$	53,960,011.02
3/13/2012	$	26,700,000.00	$	-	$	33,705,550.31	$	60,405,550.31
3/14/2012	$	33,700,000.00	$	-	$	35,202,785.46	$	68,902,785.46
3/15/2012	$	28,700,000.00	$	-	$	34,114,260.91	$	62,814,260.91
3/16/2012	$	32,600,000.00	$	-	$	33,041,761.14	$	65,641,761.14
3/17/2012	$	32,600,000.00	$	-	$	33,041,761.14	$	65,641,761.14
3/18/2012	$	32,600,000.00	$	-	$	33,041,761.14	$	65,641,761.14
3/19/2012	$	19,100,000.00	$	-	$	33,307,993.57	$	52,407,993.57
3/20/2012	$	25,100,000.00	$	-	$	33,730,325.63	$	58,830,325.63
3/21/2012	$	25,100,000.00	$	-	$	37,019,999.50	$	62,119,999.50
3/22/2012	$	33,800,000.00	$	-	$	36,161,065.13	$	69,961,065.13
3/23/2012	$	33,800,000.00	$	-	$	39,099,616.39	$	72,899,616.39
3/24/2012	$	33,800,000.00	$	-	$	39,099,616.39	$	72,899,616.39
3/25/2012	$	33,800,000.00	$	-	$	39,099,616.39	$	72,899,616.39
3/26/2012	$	28,500,000.00	$	-	$	36,116,239.22	$	64,616,239.22
3/27/2012	$	28,500,000.00	$	-	$	38,185,087.46	$	66,685,087.46

3/28/2012	$	32,500,000.00	$	-	$	38,823,566.45	$	71,323,566.45
3/29/2012	$	16,600,000.00	$	-	$	32,745,357.06	$	49,345,357.06
3/30/2012	$	19,000,000.00	$	-	$	31,645,502.02	$	50,645,502.02
3/31/2012	$	19,000,000.00	$	-	$	31,645,502.02	$	50,645,502.02
4/1/2012	$	19,000,000.00	$	-	$	31,645,502.02	$	50,645,502.02
4/2/2012	$	12,000,000.00	$	-	$	34,171,796.73	$	46,171,796.73
4/3/2012	$	17,000,000.00	$	-	$	35,753,838.38	$	52,753,838.38
4/4/2012	$	17,000,000.00	$	-	$	38,219,143.58	$	55,219,143.58
4/5/2012	$	19,200,000.00	$	-	$	38,622,438.02	$	57,822,438.02
4/6/2012	$	19,200,000.00	$	-	$	42,111,314.88	$	61,311,314.88
4/7/2012	$	19,200,000.00	$	-	$	42,111,314.88	$	61,311,314.88
4/8/2012	$	19,200,000.00	$	-	$	42,111,314.88	$	61,311,314.88
4/9/2012	$	25,400,000.00	$	-	$	37,608,147.72	$	63,008,147.72
4/10/2012	$	17,400,000.00	$	-	$	35,063,286.54	$	52,463,286.54
4/11/2012	$	24,400,000.00	$	-	$	33,149,209.30	$	57,549,209.30
4/12/2012	$	28,000,000.00	$	-	$	34,924,372.44	$	62,924,372.44
4/13/2012	$	31,700,000.00	$	-	$	32,164,705.12	$	63,864,705.12
4/14/2012	$	31,700,000.00	$	-	$	32,164,705.12	$	63,864,705.12
4/15/2012	$	31,700,000.00	$	-	$	32,164,705.12	$	63,864,705.12
4/16/2012	$	20,500,000.00	$	-	$	33,406,017.34	$	53,906,017.34
4/17/2012	$	33,400,000.00	$	-	$	32,774,118.00	$	66,174,118.00
4/18/2012	$	38,400,000.00	$	-	$	31,919,338.31	$	70,319,338.31
4/19/2012	$	24,400,000.00	$	-	$	29,955,364.30	$	54,355,364.30
4/20/2012	$	19,400,000.00	$	-	$	35,223,272.59	$	54,623,272.59
4/21/2012	$	19,400,000.00	$	-	$	35,223,272.59	$	54,623,272.59
4/22/2012	$	19,400,000.00	$	-	$	35,223,272.59	$	54,623,272.59
4/23/2012	$	26,700,000.00	$	-	$	33,760,693.98	$	60,460,693.98
4/24/2012	$	30,000,000.00	$	-	$	36,877,599.43	$	66,877,599.43
4/25/2012	$	12,000,000.00	$	-	$	37,242,879.41	$	49,242,879.41
4/26/2012	$	52,267,000.00	$	-	$	24,353.68	$	52,291,353.68
4/27/2012	$	52,912,000.00	$	-	$	32,116.15	$	52,944,116.15
4/28/2012	$	52,912,000.00	$	-	$	32,116.15	$	52,944,116.15
4/29/2012	$	52,912,000.00	$	-	$	32,116.15	$	52,944,116.15
4/30/2012	$	48,157,000.00	$	-	$	333,693.58	$	48,490,693.58
5/1/2012	$	22,245,000.00	$	-	$	366,976.45	$	22,611,976.45
5/2/2012	$	22,914,000.00	$	-	$	25,023.69	$	22,939,023.69
5/3/2012	$	26,254,000.00	$	-	$	24,910.87	$	26,278,910.87
5/4/2012	$	30,834,000.00	$	-	$	30,095.83	$	30,864,095.83
5/5/2012	$	30,834,000.00	$	-	$	30,095.83	$	30,864,095.83
5/6/2012	$	30,834,000.00	$	-	$	30,095.83	$	30,864,095.83
5/7/2012	$	32,766,000.00	$	-	$	478,666.37	$	33,244,666.37
5/8/2012	$	22,268,000.00	$	-	$	24,269.76	$	22,292,269.76
5/9/2012	$	26,355,000.00	$	-	$	29,393.63	$	26,384,393.63
5/10/2012	$	28,720,000.00	$	-	$	23,849.61	$	28,743,849.61
5/11/2012	$	28,720,000.00	$	-	$	123,910.18	$	28,843,910.18

5/12/2012	$	28,720,000.00	$	-	$	123,910.18	$	28,843,910.18
5/13/2012	$	28,720,000.00	$	-	$	123,910.18	$	28,843,910.18
5/14/2012	$	30,008,000.00	$	-	$	497,570.41	$	30,505,570.41
5/15/2012	$	22,005,000.00	$	-	$	22,481.14	$	22,027,481.14
5/16/2012	$	28,205,000.00	$	-	$	22,929.37	$	28,227,929.37
5/17/2012	$	9,715,000.00	$	-	$	26,914.85	$	9,741,914.85
5/18/2012	$	10,358,000.00	$	-	$	27,833.38	$	10,385,833.38
5/19/2012	$	10,358,000.00	$	-	$	27,833.38	$	10,385,833.38
5/20/2012	$	10,358,000.00	$	-	$	27,833.38	$	10,385,833.38
5/21/2012	$	8,603,000.00	$	-	$	491,960.87	$	9,094,960.87
5/22/2012	$	18,403,000.00	$	-	$	25,490.02	$	18,428,490.02
5/23/2012	$	22,273,000.00	$	-	$	24,743.14	$	22,297,743.14
5/24/2012	$	24,073,000.00	$	-	$	44,069.80	$	24,117,069.80
5/25/2012	$	3,508,000.00	$	-	$	23,614.19	$	3,531,614.19
5/26/2012	$	3,508,000.00	$	-	$	23,614.19	$	3,531,614.19
5/27/2012	$	3,508,000.00	$	-	$	23,614.19	$	3,531,614.19
5/28/2012	$	3,508,000.00	$	-	$	23,614.19	$	3,531,614.19
5/29/2012	$	5,974,000.00	$	-	$	316,221.34	$	6,290,221.34
5/30/2012	$	11,066,000.00	$	-	$	24,176.64	$	11,090,176.64
5/31/2012	$	5,361,000.00	$	-	$	26,957.96	$	5,387,957.96
6/1/2012	$	9,001,000.00	$	-	$	27,818.45	$	9,028,818.45
6/2/2012	$	9,001,000.00	$	-	$	27,818.45	$	9,028,818.45
6/3/2012	$	9,001,000.00	$	-	$	27,818.45	$	9,028,818.45
6/4/2012	$	12,651,000.00	$	-	$	642,902.95	$	13,293,902.95
6/5/2012	$	19,584,000.00	$	-	$	27,324.64	$	19,611,324.64
6/6/2012	$	23,387,000.00	$	-	$	24,359.14	$	23,411,359.14
6/7/2012	$	26,729,000.00	$	-	$	24,827.57	$	26,753,827.57
6/8/2012	$	8,954,000.00	$	-	$	1,299,922.38	$	10,253,922.38
6/9/2012	$	8,954,000.00	$	-	$	1,299,922.38	$	10,253,922.38
6/10/2012	$	8,954,000.00	$	-	$	1,299,922.38	$	10,253,922.38
6/11/2012	$	11,570,000.00	$	-	$	25,344.22	$	11,595,344.22
6/12/2012	$	15,923,000.00	$	-	$	24,374.65	$	15,947,374.65
6/13/2012	$	18,078,000.00	$	-	$	24,432.41	$	18,102,432.41
6/14/2012	$	20,521,000.00	$	-	$	24,924.64	$	20,545,924.64
6/15/2012	$	12,168,000.00	$	-	$	24,456.22	$	12,192,456.22
6/16/2012	$	12,168,000.00	$	-	$	24,456.22	$	12,192,456.22
6/17/2012	$	12,168,000.00	$	-	$	24,456.22	$	12,192,456.22
6/18/2012	$	15,527,000.00	$	-	$	360,244.95	$	15,887,244.95
6/19/2012	$	8,513,000.00	$	-	$	24,269.78	$	8,537,269.78
6/20/2012	$	11,647,000.00	$	-	$	24,298.20	$	11,671,298.20
6/21/2012	$	14,898,000.00	$	-	$	24,551.28	$	14,922,551.28
6/22/2012	$	19,030,000.00	$	-	$	24,472.09	$	19,054,472.09
6/23/2012	$	19,030,000.00	$	-	$	24,472.09	$	19,054,472.09
6/24/2012	$	19,030,000.00	$	-	$	24,472.09	$	19,054,472.09
6/25/2012	$	807,000.00	$	-	$	374,145.10	$	1,181,145.10

6/26/2012	$	7,765,000.00	$	-	$	24,606.13	$	7,789,606.13
6/27/2012	$	13,076,000.00	$	-	$	25,465.29	$	13,101,465.29
6/28/2012	$	-	$	-	$	24,155.74	$	24,155.74
6/29/2012	$	-	$	-	$	24,267.03	$	24,267.03
6/30/2012	$	-	$	-	$	24,267.03	$	24,267.03
7/1/2012	$	-	$	-	$	24,267.03	$	24,267.03
7/2/2012	$	-	$	-	$	335,472.47	$	335,472.47
7/3/2012	$	2,843,000.00	$	-	$	24,519.23	$	2,867,519.23
7/4/2012	$	2,843,000.00	$	-	$	24,519.23	$	2,867,519.23
7/5/2012	$	7,418,000.00	$	-	$	25,342.30	$	7,443,342.30
7/6/2012	$	9,603,000.00	$	-	$	23,698.25	$	9,626,698.25
7/7/2012	$	9,603,000.00	$	-	$	23,698.25	$	9,626,698.25
7/8/2012	$	9,603,000.00	$	-	$	23,698.25	$	9,626,698.25
7/9/2012	$	1,722,000.00	$	-	$	565,654.21	$	2,287,654.21
7/10/2012	$	8,682,000.00	$	-	$	24,820.30	$	8,706,820.30
7/11/2012	$	12,049,000.00	$	-	$	24,485.47	$	12,073,485.47
7/12/2012	$	16,605,000.00	$	-	$	24,773.36	$	16,629,773.36
7/13/2012	$	2,747,000.00	$	-	$	24,908.51	$	2,771,908.51
7/14/2012	$	2,747,000.00	$	-	$	24,908.51	$	2,771,908.51
7/15/2012	$	2,747,000.00	$	-	$	24,908.51	$	2,771,908.51
7/16/2012	$	11,000.00	$	-	$	345,448.29	$	356,448.29
7/17/2012	$	11,000.00	$	-	$	24,979.38	$	35,979.38
7/18/2012	$	11,000.00	$	-	$	25,350.41	$	36,350.41
7/19/2012	$	11,000.00	$	-	$	23,713.81	$	34,713.81
7/20/2012	$	11,000.00	$	-	$	46,606.34	$	57,606.34
7/21/2012	$	11,000.00	$	-	$	46,606.34	$	57,606.34
7/22/2012	$	11,000.00	$	-	$	46,606.34	$	57,606.34
7/23/2012	$	11,000.00	$	-	$	342,535.74	$	353,535.74
7/24/2012	$	8,751,000.00	$	-	$	24,551.04	$	8,775,551.04
7/25/2012	$	1,020,000.00	$	-	$	24,913.93	$	1,044,913.93
7/26/2012	$	4,193,000.00	$	-	$	24,356.16	$	4,217,356.16
7/27/2012	$	5,642,000.00	$	-	$	25,292.23	$	5,667,292.23
7/28/2012	$	5,642,000.00	$	-	$	25,292.23	$	5,667,292.23
7/29/2012	$	5,642,000.00	$	-	$	25,292.23	$	5,667,292.23
7/30/2012	$	8,575,000.00	$	-	$	645,720.79	$	9,220,720.79
7/31/2012	$	20,000.00	$	-	$	24,659.27	$	44,659.27
8/1/2012	$	4,670,000.00	$	-	$	24,555.53	$	4,694,555.53
8/2/2012	$	8,854,000.00	$	-	$	24,640.59	$	8,878,640.59
8/3/2012	$	11,998,000.00	$	-	$	24,215.92	$	12,022,215.92
8/4/2012	$	11,998,000.00	$	-	$	24,215.92	$	12,022,215.92
8/5/2012	$	11,998,000.00	$	-	$	24,215.92	$	12,022,215.92
8/6/2012	$	11,188,000.00	$	-	$	616,336.82	$	11,804,336.82
8/7/2012	$	17,106,000.00	$	-	$	24,769.06	$	17,130,769.06
8/8/2012	$	7,972,000.00	$	-	$	24,333.48	$	7,996,333.48
8/9/2012	$	14,127,000.00	$	-	$	25,062.71	$	14,152,062.71

8/10/2012	$	15,855,000.00	$	-	$	24,672.07	$	15,879,672.07
8/11/2012	$	15,855,000.00	$	-	$	24,672.07	$	15,879,672.07
8/12/2012	$	15,855,000.00	$	-	$	24,672.07	$	15,879,672.07
8/13/2012	$	22,544,000.00	$	-	$	25,265.35	$	22,569,265.35
8/14/2012	$	28,538,000.00	$	-	$	24,534.64	$	28,562,534.64
8/15/2012	$	19,532,000.00	$	-	$	24,519.68	$	19,556,519.68
8/16/2012	$	23,663,000.00	$	-	$	34,432.81	$	23,697,432.81
8/17/2012	$	24,612,000.00	$	-	$	25,404.63	$	24,637,404.63
8/18/2012	$	24,612,000.00	$	-	$	25,404.63	$	24,637,404.63
8/19/2012	$	24,612,000.00	$	-	$	25,404.63	$	24,637,404.63
8/20/2012	$	19,360,000.00	$	-	$	608,443.22	$	19,968,443.22
8/21/2012	$	29,316,000.00	$	-	$	24,974.49	$	29,340,974.49
8/22/2012	$	39,539,000.00	$	-	$	24,715.75	$	39,563,715.75
8/23/2012	$	43,371,000.00	$	-	$	25,127.73	$	43,396,127.73
8/24/2012	$	45,706,000.00	$	-	$	25,677.78	$	45,731,677.78
8/25/2012	$	45,706,000.00	$	-	$	25,677.78	$	45,731,677.78
8/26/2012	$	45,706,000.00	$	-	$	25,677.78	$	45,731,677.78
8/27/2012	$	27,426,000.00	$	-	$	437,332.94	$	27,863,332.94
8/28/2012	$	35,762,000.00	$	-	$	24,706.75	$	35,786,706.75
8/29/2012	$	39,838,000.00	$	-	$	24,774.10	$	39,862,774.10

	LGE Inv	LGE MP Inv	LGE Cash	Cash and Short Term Investments
12/31/2011	$ -	$ -	$ 30,342,580.70	$ 30,342,580.70
1/1/2012	$ -	$ -	$ 30,342,580.70	$ 30,342,580.70
1/2/2012	$ -	$ -	$ 30,342,580.70	$ 30,342,580.70
1/3/2012	$ -	$ -	$ 27,548,596.54	$ 27,548,596.54
1/4/2012	$ -	$ -	$ 32,154,986.26	$ 32,154,986.26
1/5/2012	$ -	$ -	$ 36,033,540.48	$ 36,033,540.48
1/6/2012	$ -	$ -	$ 37,184,052.58	$ 37,184,052.58
1/7/2012	$ -	$ -	$ 37,184,052.58	$ 37,184,052.58
1/8/2012	$ -	$ -	$ 37,184,052.58	$ 37,184,052.58
1/9/2012		$ -	$ 37,476,997.42	$ 37,476,997.42
1/10/2012	$ 8,400,000.00	$ -	$ 37,001,778.76	$ 45,401,778.76
1/11/2012	$ 10,500,000.00	$ -	$ 38,349,486.11	$ 48,849,486.11
1/12/2012	$ 10,500,000.00	$ -	$ 25,888,288.68	$ 36,388,288.68
1/13/2012	$ -	$ -	$ 15,184,765.04	$ 15,184,765.04
1/14/2012	$ -	$ -	$ 15,184,765.04	$ 15,184,765.04
1/15/2012	$ -	$ -	$ 15,184,765.04	$ 15,184,765.04
1/16/2012	$ -	$ -	$ 15,184,765.04	$ 15,184,765.04
1/17/2012	$ -	$ -	$ 724,618.11	$ 724,618.11
1/18/2012	$ -	$ -	$ 5,962,389.94	$ 5,962,389.94
1/19/2012	$ -	$ -	$ 10,560,500.08	$ 10,560,500.08
1/20/2012	$ -	$ -	$ 14,292,631.79	$ 14,292,631.79
1/21/2012	$ -	$ -	$ 14,292,631.79	$ 14,292,631.79
1/22/2012	$ -	$ -	$ 14,292,631.79	$ 14,292,631.79
1/23/2012	$ -	$ -	$ 8,875,677.98	$ 8,875,677.98
1/24/2012	$ -	$ -	$ 12,745,639.91	$ 12,745,639.91
1/25/2012	$ -	$ -	$ 209,983.00	$ 209,983.00
1/26/2012	$ -	$ -	$ 165,383.52	$ 165,383.52
1/27/2012	$ -	$ -	$ 1,537,120.75	$ 1,537,120.75
1/28/2012	$ -	$ -	$ 1,537,120.75	$ 1,537,120.75
1/29/2012	$ -	$ -	$ 1,537,120.75	$ 1,537,120.75
1/30/2012	$ -	$ -	$ 4,697,990.65	$ 4,697,990.65
1/31/2012	$ -	$ -	$ 14,575,162.74	$ 14,575,162.74
2/1/2012	$ -	$ -	$ 17,456,019.97	$ 17,456,019.97
2/2/2012	$ -	$ -	$ 21,346,563.47	$ 21,346,563.47
2/3/2012	$ -	$ -	$ 25,435,121.47	$ 25,435,121.47
2/4/2012	$ -	$ -	$ 25,435,121.47	$ 25,435,121.47
2/5/2012	$ -	$ -	$ 25,435,121.47	$ 25,435,121.47
2/6/2012	$ -	$ -	$ 27,845,541.75	$ 27,845,541.75
2/7/2012	$ 1,600,000.00	$ -	$ 34,105,790.39	$ 35,705,790.39
2/8/2012	$ 11,100,000.00	$ -	$ 30,988,544.55	$ 42,088,544.55

2/9/2012	$	18,100,000.00	$	-	$	29,379,718.10	$	47,479,718.10
2/10/2012	$	18,100,000.00	$	-	$	29,387,127.96	$	47,487,127.96
2/11/2012	$	18,100,000.00	$	-	$	29,387,127.96	$	47,487,127.96
2/12/2012	$	18,100,000.00	$	-	$	29,387,127.96	$	47,487,127.96
2/13/2012	$	18,100,000.00	$	-	$	30,491,495.17	$	48,591,495.17
2/14/2012	$	23,100,000.00	$	-	$	31,292,348.81	$	54,392,348.81
2/15/2012	$	9,100,000.00	$	-	$	34,630,392.81	$	43,730,392.81
2/16/2012	$	14,100,000.00	$	-	$	35,760,870.70	$	49,860,870.70
2/17/2012	$	17,900,000.00	$	-	$	33,236,674.07	$	51,136,674.07
2/18/2012	$	17,900,000.00	$	-	$	33,236,674.07	$	51,136,674.07
2/19/2012	$	17,900,000.00	$	-	$	33,236,674.07	$	51,136,674.07
2/20/2012	$	17,900,000.00	$	-	$	33,236,674.07	$	51,136,674.07
2/21/2012	$	7,300,000.00	$	-	$	38,061,964.29	$	45,361,964.29
2/22/2012	$	8,800,000.00	$	-	$	39,373,969.77	$	48,173,969.77
2/23/2012	$	15,000,000.00	$	-	$	37,110,816.72	$	52,110,816.72
2/24/2012	$	18,400,000.00	$	-	$	38,167,858.65	$	56,567,858.65
2/25/2012	$	18,400,000.00	$	-	$	38,167,858.65	$	56,567,858.65
2/26/2012	$	18,400,000.00	$	-	$	38,167,858.65	$	56,567,858.65
2/27/2012	$	3,400,000.00	$	-	$	34,838,731.98	$	38,238,731.98
2/28/2012	$	6,400,000.00	$	-	$	36,847,959.63	$	43,247,959.63
2/29/2012	$	16,500,000.00	$	-	$	35,442,150.97	$	51,942,150.97
3/1/2012	$	16,500,000.00	$	-	$	37,547,611.35	$	54,047,611.35
3/2/2012	$	18,700,000.00	$	-	$	37,230,264.22	$	55,930,264.22
3/3/2012	$	18,700,000.00	$	-	$	37,230,264.22	$	55,930,264.22
3/4/2012	$	18,700,000.00	$	-	$	37,230,264.22	$	55,930,264.22
3/5/2012	$	20,700,000.00	$	-	$	35,605,997.24	$	56,305,997.24
3/6/2012	$	27,700,000.00	$	-	$	34,119,549.42	$	61,819,549.42
3/7/2012	$	32,100,000.00	$	-	$	37,436,745.15	$	69,536,745.15
3/8/2012	$	39,400,000.00	$	-	$	20,836,912.82	$	60,236,912.82
3/9/2012	$	30,400,000.00	$	-	$	28,961,034.50	$	59,361,034.50
3/10/2012	$	30,400,000.00	$	-	$	28,961,034.50	$	59,361,034.50
3/11/2012	$	30,400,000.00	$	-	$	28,961,034.50	$	59,361,034.50
3/12/2012	$	22,400,000.00	$	-	$	34,348,643.21	$	56,748,643.21
3/13/2012	$	27,400,000.00	$	-	$	36,413,890.77	$	63,813,890.77
3/14/2012	$	33,500,000.00	$	-	$	33,448,384.00	$	66,948,384.00
3/15/2012	$	14,500,000.00	$	-	$	36,025,847.79	$	50,525,847.79
3/16/2012	$	14,500,000.00	$	-	$	38,181,781.43	$	52,681,781.43
3/17/2012	$	14,500,000.00	$	-	$	38,181,781.43	$	52,681,781.43
3/18/2012	$	14,500,000.00	$	-	$	38,181,781.43	$	52,681,781.43
3/19/2012	$	24,500,000.00	$	-	$	40,068,540.73	$	64,568,540.73
3/20/2012	$	36,500,000.00	$	-	$	35,430,242.89	$	71,930,242.89
3/21/2012	$	43,700,000.00	$	-	$	33,327,219.61	$	77,027,219.61
3/22/2012	$	43,700,000.00	$	-	$	34,226,311.22	$	77,926,311.22
3/23/2012	$	43,700,000.00	$	-	$	35,093,755.57	$	78,793,755.57
3/24/2012	$	43,700,000.00	$	-	$	35,093,755.57	$	78,793,755.57

3/25/2012	$	43,700,000.00	$	-	$	35,093,755.57	$	78,793,755.57
3/26/2012	$	21,700,000.00	$	-	$	35,903,419.07	$	57,603,419.07
3/27/2012	$	26,900,000.00	$	-	$	35,649,557.10	$	62,549,557.10
3/28/2012	$	30,900,000.00	$	-	$	35,073,847.82	$	65,973,847.82
3/29/2012	$	16,300,000.00	$	-	$	37,041,223.87	$	53,341,223.87
3/30/2012	$	16,300,000.00	$	-	$	39,881,343.34	$	56,181,343.34
3/31/2012	$	16,300,000.00	$	-	$	39,881,343.34	$	56,181,343.34
4/1/2012	$	16,300,000.00	$	-	$	39,881,343.34	$	56,181,343.34
4/2/2012	$	16,300,000.00	$	-	$	36,252,333.84	$	52,552,333.84
4/3/2012	$	20,300,000.00	$	-	$	37,839,379.19	$	58,139,379.19
4/4/2012	$	25,400,000.00	$	-	$	35,086,607.85	$	60,486,607.85
4/5/2012	$	25,400,000.00	$	-	$	31,095,360.49	$	56,495,360.49
4/6/2012	$	25,400,000.00	$	-	$	33,848,355.92	$	59,248,355.92
4/7/2012	$	25,400,000.00	$	-	$	33,848,355.92	$	59,248,355.92
4/8/2012	$	25,400,000.00	$	-	$	33,848,355.92	$	59,248,355.92
4/9/2012	$	27,800,000.00	$	-	$	32,968,854.40	$	60,768,854.40
4/10/2012	$	19,800,000.00	$	-	$	33,674,212.54	$	53,474,212.54
4/11/2012	$	23,800,000.00	$	-	$	35,273,316.14	$	59,073,316.14
4/12/2012	$	27,300,000.00	$	-	$	34,244,443.13	$	61,544,443.13
4/13/2012	$	27,300,000.00	$	-	$	37,122,331.41	$	64,422,331.41
4/14/2012	$	27,300,000.00	$	-	$	37,122,331.41	$	64,422,331.41
4/15/2012	$	27,300,000.00	$	-	$	37,122,331.41	$	64,422,331.41
4/16/2012	$	10,300,000.00	$	-	$	34,184,177.46	$	44,484,177.46
4/17/2012	$	12,300,000.00	$	-	$	37,364,662.65	$	49,664,662.65
4/18/2012	$	22,400,000.00	$	-	$	31,587,652.79	$	53,987,652.79
4/19/2012	$	36,400,000.00	$	-	$	35,332,927.09	$	71,732,927.09
4/20/2012	$	28,700,000.00	$	-	$	39,012,072.91	$	67,712,072.91
4/21/2012	$	28,700,000.00	$	-	$	39,012,072.91	$	67,712,072.91
4/22/2012	$	28,700,000.00	$	-	$	39,012,072.91	$	67,712,072.91
4/23/2012	$	35,700,000.00	$	-	$	35,913,105.03	$	71,613,105.03
4/24/2012	$	39,000,000.00	$	-	$	37,164,078.24	$	76,164,078.24
4/25/2012	$	19,200,000.00	$	-	$	33,665,345.24	$	52,865,345.24
4/26/2012	$	53,855,000.00	$	-	$	24,617.93	$	53,879,617.93
4/27/2012	$	55,707,000.00	$	-	$	28,620.34	$	55,735,620.34
4/28/2012	$	55,707,000.00	$	-	$	28,620.34	$	55,735,620.34
4/29/2012	$	55,707,000.00	$	-	$	28,620.34	$	55,735,620.34
4/30/2012	$	52,312,000.00	$	-	$	318,864.34	$	52,630,864.34
5/1/2012	$	59,712,000.00	$	-	$	40,954.42	$	59,752,954.42
5/2/2012	$	60,595,000.00	$	-	$	25,372.66	$	60,620,372.66
5/3/2012	$	63,645,000.00	$	-	$	24,389.55	$	63,669,389.55
5/4/2012	$	64,985,000.00	$	-	$	29,606.69	$	65,014,606.69
5/5/2012	$	64,985,000.00	$	-	$	29,606.69	$	65,014,606.69
5/6/2012	$	64,985,000.00	$	-	$	29,606.69	$	65,014,606.69
5/7/2012	$	67,097,000.00	$	-	$	175,506.94	$	67,272,506.94
5/8/2012	$	57,505,000.00	$	-	$	24,800.65	$	57,529,800.65

5/9/2012	$	61,561,000.00	$	-	$	23,819.95	$	61,584,819.95
5/10/2012	$	63,638,000.00	$	-	$	23,980.65	$	63,661,980.65
5/11/2012	$	64,747,000.00	$	-	$	23,889.70	$	64,770,889.70
5/12/2012	$	64,747,000.00	$	-	$	23,889.70	$	64,770,889.70
5/13/2012	$	64,747,000.00	$	-	$	23,889.70	$	64,770,889.70
5/14/2012	$	65,303,000.00	$	-	$	193,315.93	$	65,496,315.93
5/15/2012	$	42,807,000.00	$	-	$	22,504.60	$	42,829,504.60
5/16/2012	$	46,022,000.00	$	-	$	22,257.35	$	46,044,257.35
5/17/2012	$	71,092,000.00	$	-	$	27,687.50	$	71,119,687.50
5/18/2012	$	68,957,000.00	$	-	$	1,284,723.24	$	70,241,723.24
5/19/2012	$	68,957,000.00	$	-	$	1,284,723.24	$	70,241,723.24
5/20/2012	$	68,957,000.00	$	-	$	1,284,723.24	$	70,241,723.24
5/21/2012	$	67,937,000.00	$	-	$	885,225.98	$	68,822,225.98
5/22/2012	$	69,880,000.00	$	-	$	24,712.53	$	69,904,712.53
5/23/2012	$	72,003,000.00	$	-	$	24,285.08	$	72,027,285.08
5/24/2012	$	71,878,000.00	$	-	$	27,797.25	$	71,905,797.25
5/25/2012	$	46,833,000.00	$	-	$	803,619.75	$	47,636,619.75
5/26/2012	$	46,833,000.00	$	-	$	803,619.75	$	47,636,619.75
5/27/2012	$	46,833,000.00	$	-	$	803,619.75	$	47,636,619.75
5/28/2012	$	46,833,000.00	$	-	$	803,619.75	$	47,636,619.75
5/29/2012	$	51,000,000.00	$	-	$	933,712.20	$	51,933,712.20
5/30/2012	$	55,598,000.00	$	-	$	23,889.52	$	55,621,889.52
5/31/2012	$	56,738,000.00	$	-	$	25,362.54	$	56,763,362.54
6/1/2012	$	52,648,000.00	$	-	$	25,530.13	$	52,673,530.13
6/2/2012	$	52,648,000.00	$	-	$	25,530.13	$	52,673,530.13
6/3/2012	$	52,648,000.00	$	-	$	25,530.13	$	52,673,530.13
6/4/2012	$	52,608,000.00	$	-	$	380,793.90	$	52,988,793.90
6/5/2012	$	57,370,000.00	$	-	$	27,481.74	$	57,397,481.74
6/6/2012	$	61,130,000.00	$	-	$	26,579.33	$	61,156,579.33
6/7/2012	$	64,636,000.00	$	-	$	25,444.39	$	64,661,444.39
6/8/2012	$	49,572,000.00	$	-	$	25,648.17	$	49,597,648.17
6/9/2012	$	49,572,000.00	$	-	$	25,648.17	$	49,597,648.17
6/10/2012	$	49,572,000.00	$	-	$	25,648.17	$	49,597,648.17
6/11/2012	$	51,804,000.00	$	-	$	248,671.96	$	52,052,671.96
6/12/2012	$	56,209,000.00	$	-	$	25,148.19	$	56,234,148.19
6/13/2012	$	58,286,000.00	$	-	$	25,195.88	$	58,311,195.88
6/14/2012	$	59,534,000.00	$	-	$	24,602.58	$	59,558,602.58
6/15/2012	$	42,049,000.00	$	-	$	25,185.76	$	42,074,185.76
6/16/2012	$	42,049,000.00	$	-	$	25,185.76	$	42,074,185.76
6/17/2012	$	42,049,000.00	$	-	$	25,185.76	$	42,074,185.76
6/18/2012	$	38,022,000.00	$	-	$	211,006.95	$	38,233,006.95
6/19/2012	$	60,320,000.00	$	-	$	24,161.24	$	60,344,161.24
6/20/2012	$	61,068,000.00	$	-	$	23,836.02	$	61,091,836.02
6/21/2012	$	59,640,000.00	$	-	$	24,930.45	$	59,664,930.45
6/22/2012	$	58,393,000.00	$	-	$	24,976.70	$	58,417,976.70

6/23/2012	$	58,393,000.00	$	-	$	24,976.70	$	58,417,976.70
6/24/2012	$	58,393,000.00	$	-	$	24,976.70	$	58,417,976.70
6/25/2012	$	30,576,000.00	$	-	$	299,828.20	$	30,875,828.20
6/26/2012	$	36,220,000.00	$	-	$	24,969.31	$	36,244,969.31
6/27/2012	$	40,805,000.00	$	-	$	24,567.82	$	40,829,567.82
6/28/2012	$	19,415,000.00	$	8,082,000.00	$	23,953.38	$	27,520,953.38
6/29/2012	$	23,283,000.00	$	6,336,000.00	$	1,771,042.70	$	31,390,042.70
6/30/2012	$	23,283,000.00	$	6,336,000.00	$	1,771,042.70	$	31,390,042.70
7/1/2012	$	23,283,000.00	$	6,336,000.00	$	1,771,042.70	$	31,390,042.70
7/2/2012	$	17,863,000.00	$	7,206,000.00	$	122,801.31	$	25,191,801.31
7/3/2012	$	30,155,000.00	$	-	$	25,273.82	$	30,180,273.82
7/4/2012	$	30,155,000.00	$	-	$	25,273.82	$	30,180,273.82
7/5/2012	$	33,023,000.00	$	-	$	24,227.62	$	33,047,227.62
7/6/2012	$	38,196,000.00	$	-	$	25,325.11	$	38,221,325.11
7/7/2012	$	38,196,000.00	$	-	$	25,325.11	$	38,221,325.11
7/8/2012	$	38,196,000.00	$	-	$	25,325.11	$	38,221,325.11
7/9/2012	$	39,223,000.00	$	-	$	215,547.46	$	39,438,547.46
7/10/2012	$	45,794,000.00	$	-	$	25,340.45	$	45,819,340.45
7/11/2012	$	46,964,000.00	$	-	$	25,019.99	$	46,989,019.99
7/12/2012	$	49,336,500.00	$	-	$	24,972.12	$	49,361,472.12
7/13/2012	$	38,310,500.00	$	-	$	25,199.00	$	38,335,699.00
7/14/2012	$	38,310,500.00	$	-	$	25,199.00	$	38,335,699.00
7/15/2012	$	38,310,500.00	$	-	$	25,199.00	$	38,335,699.00
7/16/2012	$	17,881,500.00	$	6,694,000.00	$	148,485.91	$	24,723,985.91
7/17/2012	$	27,778,500.00	$	33,000.00	$	24,702.16	$	27,836,202.16
7/18/2012	$	30,245,500.00	$	15,166,000.00	$	24,991.60	$	45,436,491.60
7/19/2012	$	43,925,500.00	$	6,212,000.00	$	24,633.24	$	50,162,133.24
7/20/2012	$	44,355,500.00	$	6,212,000.00	$	783,085.37	$	51,350,585.37
7/21/2012	$	44,355,500.00	$	6,212,000.00	$	783,085.37	$	51,350,585.37
7/22/2012	$	44,355,500.00	$	6,212,000.00	$	783,085.37	$	51,350,585.37
7/23/2012	$	47,616,500.00	$	335,000.00	$	25,215.90	$	47,976,715.90
7/24/2012	$	50,537,500.00	$	-	$	25,605.60	$	50,563,105.60
7/25/2012	$	29,314,500.00	$	-	$	24,599.48	$	29,339,099.48
7/26/2012	$	33,954,500.00	$	-	$	24,979.71	$	33,979,479.71
7/27/2012	$	32,780,500.00	$	-	$	812,811.81	$	33,593,311.81
7/28/2012	$	32,780,500.00	$	-	$	812,811.81	$	33,593,311.81
7/29/2012	$	32,780,500.00	$	-	$	812,811.81	$	33,593,311.81
7/30/2012	$	37,885,500.00	$	-	$	25,298.74	$	37,910,798.74
7/31/2012	$	39,017,500.00	$	1,479,000.00	$	24,818.07	$	40,521,318.07
8/1/2012	$	48,239,500.00	$	-	$	25,555.40	$	48,265,055.40
8/2/2012	$	51,736,500.00	$	-	$	24,604.39	$	51,761,104.39
8/3/2012	$	55,855,500.00	$	-	$	24,417.60	$	55,879,917.60
8/4/2012	$	55,855,500.00	$	-	$	24,417.60	$	55,879,917.60
8/5/2012	$	55,855,500.00	$	-	$	24,417.60	$	55,879,917.60
8/6/2012	$	55,929,500.00	$	-	$	418,506.37	$	56,348,006.37

8/7/2012	$	59,943,500.00	$	-	$	24,622.47	$	59,968,122.47
8/8/2012	$	53,763,500.00	$	-	$	24,559.21	$	53,788,059.21
8/9/2012	$	57,827,500.00	$	-	$	24,814.96	$	57,852,314.96
8/10/2012	$	57,775,500.00	$	-	$	24,545.42	$	57,800,045.42
8/11/2012	$	57,775,500.00	$	-	$	24,545.42	$	57,800,045.42
8/12/2012	$	57,775,500.00	$	-	$	24,545.42	$	57,800,045.42
8/13/2012	$	59,563,500.00	$	-	$	206,393.69	$	59,769,893.69
8/14/2012	$	63,877,500.00	$	-	$	24,380.74	$	63,901,880.74
8/15/2012	$	52,572,500.00	$	-	$	24,470.89	$	52,596,970.89
8/16/2012	$	50,833,500.00	$	-	$	25,310.97	$	50,858,810.97
8/17/2012	$	60,122,500.00	$	-	$	24,936.43	$	60,147,436.43
8/18/2012	$	60,122,500.00	$	-	$	24,936.43	$	60,147,436.43
8/19/2012	$	60,122,500.00	$	-	$	24,936.43	$	60,147,436.43
8/20/2012	$	57,792,500.00	$	-	$	241,207.94	$	58,033,707.94
8/21/2012	$	65,653,500.00	$	-	$	24,288.14	$	65,677,788.14
8/22/2012	$	60,379,500.00	$	-	$	24,270.09	$	60,403,770.09
8/23/2012	$	63,510,500.00	$	-	$	24,906.68	$	63,535,406.68
8/24/2012	$	60,547,500.00	$	-	$	25,699.20	$	60,573,199.20
8/25/2012	$	60,547,500.00	$	-	$	25,699.20	$	60,573,199.20
8/26/2012	$	60,547,500.00	$	-	$	25,699.20	$	60,573,199.20
8/27/2012	$	39,263,500.00	$	-	$	205,341.95	$	39,468,841.95
8/28/2012	$	45,682,500.00	$	-	$	24,923.42	$	45,707,423.42
8/29/2012	$	48,381,500.00	$	-	$	25,459.97	$	48,406,959.97

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF
VALERIE L. SCOTT
CONTROLLER
KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

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

A. My name is Valerie L. Scott. I am the Controller for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address matters raised in the testimony of certain witnesses for intervenors. Specifically, I will address (1) the normalization adjustment for Storm Damage Expenses; (2) the normalization adjustment for Injuries and Damages Expenses; and (3) LG&E's amortization of a regulatory asset related to the 2011 Windstorm.

<u>Adjustments to Storm Damage Expenses and Injuries and Damages Expenses</u>

Q. Did intervenors propose adjustments to the Companies' normalization adjustments for Storm Damage Expenses and Injuries and Damages Expenses?

A. Yes. Both KIUC witness Lane Kollen and Kroger witness Kevin Higgins propose changes to the Commission-approved methodology for calculating the normalization of (1) Storm Damage Expenses and (2) Injuries and Damages Expenses.

Q. Are the intervenors' proposed changes consistent between Storm Damage Expenses and Injuries and Damages Expenses?

A. Yes, they are generally consistent. Therefore, I discuss the two adjustments together.

Q. How did the Companies calculate their normalized level of Storm Damage Expenses and Injuries and Damages Expenses?

A. Pursuant to this Commission's orders approving a normalization methodology based on a ten-year historic average, the Companies calculated their adjustments based on experience over the most recent ten years. Because a full year's data is not available for the current year, the Companies used the test period (or twelve months ending March 31, 2012) to extrapolate for the current year. As I stated in my direct testimony, the Commission has approved or accepted this methodology in its rate case orders over the last ten years.[1]

Q. Do you have any general comments about Mr. Kollen's proposed adjustments?

A. Yes. Mr. Kollen's proposals may lead to confusion because he discusses the base amounts of adjustments in certain places, while discussing the grossed-up revenue requirement impact of adjustments in other places. For example, the dollar amounts in the table on page 5 of Mr. Kollen's testimony are grossed up for purposes of Mr. Kollen's revenue requirement calculation. The Companies' witnesses, however, do not gross up individual adjustments. Instead, Reference Schedule 1.34 collectively grosses up all adjustments proposed by the Companies, and is then included in Blake Exhibit 8. Therefore, Mr. Kollen's proposed adjustments are not always directly comparable to the Companies.

How does Mr. Kollen propose calculating the normalization adjustments?

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[1] *In the Matter of: An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433; *In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434; *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Electric Base Rates*, Case No. 2008-00251; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates,* Case No. 2008-00252; *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Base Rates*, Case No. 2009-00548; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Electric and Gas Base Rates*, Case No. 2009-00549. The Commission approved similar adjustments in the 2003 and 2009 rate cases, and approved a settlement with similar adjustments in the 2008 rate cases.

A. Mr. Kollen submits that the Companies "double count" expenses incurred during nine months of the test year because these expenses are included in both the 2011 calendar-year average and the test year ending March 31, 2012.[2] Therefore, Mr. Kollen proposes that the ten-year average be calculated based on the last ten years ending March 31.[3] Mr. Kollen's proposal would reduce KU's Storm Damage Expenses, as updated by KU's response to KIUC 2-2, by $204,000, and increase KU's Injuries and Damages Expenses by $23,000.[4] For LG&E, Mr. Kollen's proposal reduces Storm Damage Expenses by $380,000, and increases Injuries and Damages Expenses by $180,000.[5]

Q. How does Mr. Higgins propose calculating the normalization adjustments?

A. Mr. Higgins likewise disagrees with the Companies' approved methodology, asserting that the overlap between the nine months common to calendar year 2011 and the test year ending March 31, 2012, is not reasonable. Mr. Higgins's proposal differs, however, in that he would use the ten most recent calendar years for which complete information is available (i.e., calendar years 2002–2011).[6] Mr. Higgins's proposal would reduce KU's Storm Damage Expenses by $297,000 and its Injuries and Damages Expenses by about $35,000. For LG&E, Mr. Higgins's proposal would reduce Storm Damage Expenses by $458,000, increase LG&E Electric's Injuries and Damages Expenses by about $179,000, and reduce LG&E Gas's Injuries and Damages Expenses by about $18,000.[7]

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[2] Direct Testimony of Lane Kollen at 15, 16.
[3] *Id.*
[4] *Id.* at 15, 17.
[5] *Id.*
[6] Direct Testimony of Kevin C. Higgins at 8, 9.
[7] *Id.* at Higgins Exhibit 1, 2.

Q. Please comment on the results of the two different approaches advocated by Mr. Kollen and Mr. Higgins.

A. The modifications advocated by Mr. Kollen and Mr. Higgins as theoretical improvements in the accuracy of the methodology produce divergent results without any material improvement and provide insufficient justification to support a departure from the traditional methodology the Companies have used, and the Commission approved, for calculating these normalization adjustments.

Q. Is the Companies' methodology for calculating normalization adjustments consistent with past Commission orders?

A. Yes. The Companies' proposals are consistent with the practice used in their last three rate cases, wherein the twelve-month test period was substituted for the current year. Noticeably absent from the testimony of Mr. Kollen or Mr. Higgins is any mention of the Commission's approval of this normalization methodology, and thus any demonstration why the well-established and long-standing precedent should be reversed in these cases.

Q. Has the Commission approved of the Companies' methodology?

A. Yes. In the 2003 rate cases, the Commission found the Companies' methodologies for calculating Storm Damage Expenses and Injuries and Damages Expenses to be reasonable.[8] The Companies utilized the same methodology in the 2008 and 2009 rate cases.[9]

Q. Should the Companies' proposed adjustments be approved by the Commission?

[8] Case No. 2003-00433, Order at 38, 41 (June 30, 2004); Case No. 2003-00434, Order at 34, 36 (June 30, 2004).
[9] Case Nos. 2008-00251 and 2008-00252; Case Nos. 2009-00548 and 2009-00549.

A. Yes. The Companies have consistently utilized the same methodology in calculating these adjustments. It bears mentioning, though, that the approaches advanced by the Companies, Mr. Kollen, and Mr. Higgins all result in a relatively minimal difference and no improvement over the methodology approved in the Commission's orders over the last ten years. The Commission's precedent should not be summarily dismissed by such an inadequate showing.

Q. Should the Commission decide to modify its approved methodology for calculating the normalization adjustments for storms and injuries and damages, do you have a recommendation?

A. Yes. Should the Commission determine to modify its previously approved methodology for calculating these two normalization adjustments, it should do so only prospectively. In doing so, the Commission should make clear that the methodology should be followed in the future on a consistent basis. Doing so will allow certainty in future cases and prevent switching methodologies over time to achieve a desired result.

2011 WINDSTORM AMORTIZATION PERIOD (LG&E ONLY)

Q. Does Mr. Kollen propose an amortization period for the recovery of costs resulting from the 2011 Windstorm which struck LG&E Electric's service territory?[10]

A. Yes. Mr. Kollen proposes a ten-year amortization period,[11] while LG&E proposes a five-year amortization period.

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[10] *See In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving the Establishment of a Regulatory Asset* (December 27, 2011 Order).
[11] Kollen Direct at 17.

Q. Should the Commission adopt Mr. Kollen's proposal?

A. No. The Commission found five-year amortization periods to be reasonable for the recovery of storm-related regulatory assets in Case No. 2003-00434 and Case No. 6220.[12]

Mr. Kollen notes that the Commission approved settlement agreements in the Companies' last rate cases which included a ten-year amortization period for costs related to the 2008 Windstorm and 2009 Winter Storm.[13] However, the ten-year amortization period was negotiated as part of a comprehensive settlement. Thus, consideration was given in exchange for, and thus supported, the extension of the five-year period to a ten-year period in that case. The ten-year period was not accepted by the Commission as an adjudicated determination. In a past LG&E Gas case, the Commission wrote that it was "appropriate to consider the time lapse between the last rate case and the current case and the time period over which the expenditures were deferred in determining a reasonable amortization period."[14] The shorter period of time here indicates that LG&E's five-year proposal is reasonable.

Additionally, the amount of the deferred 2011 Windstorm costs is not comparable to the 2008 Windstorm and the 2009 Winter Storm. The deferred amount of the 2011 Windstorm is about $8 million, resulting in a much lower amortization cost per year using a five-year period. In the Companies' last rate cases, using a five-year amortization period for the 2008 and 2009 storms, KU proposed adjustments of

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[12] Case No. 2003-00434, Order at 40; *In the Matter of: General Adjustment in Electric and Gas Rates of Louisville Gas and Electric Company*, Case No. 6220, Order (Feb. 28, 1975).

[13] Kollen Direct at 18.

[14] *In the Matter of: The Application of Louisville Gas and Electric Company to Adjust Its Gas Rates and to Increase Its Charges for Disconnecting Service, Reconnecting Service and Returned Checks*, Case No. 2000-080, Order at 38 (Sept. 27, 2000).

approximately $12 million, and LG&E proposed adjustments of approximately $13 million.[15] Amortization of the 2011 Windstorm totals much less than that proposed for the storms in the last cases. In fact, the total 2011 Windstorm regulatory asset of $8 million is less than one year of amortization approved for the 2008 and 2009 storms. The Commission should reject KIUC's proposed adjustment.

Q. Does this conclude your testimony?

A. Yes, it does.

[15] Case Nos. 2009-00548 and 2009-00549, Reference Schedules 1.27 and 1.28.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott

Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2ND day of November 2012.

Sonna R. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

Table of Contents

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. I previously submitted direct testimony on behalf of Louisville Gas and Electric Company on June 29, 2012.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of Kentucky Industrial Utility Customers, Inc. (KIUC) witnesses Michael J. Majoros, Jr. and Lane Kollen.

Q. What are the subjects of your rebuttal testimony?

A. The subjects of my rebuttal testimony relate to the most appropriate parameters for establishing depreciation rates. The first subject is the appropriate practices for conducting life analyses for transmission, distribution and general plant assets. The second subject is the proper interim survivor curves for production plant accounts. The third subject relates to the application and improved precision of the terminal component of the net salvage percentage for production plant. The fourth subject is the unsupported changes to net salvage percents for transmission, distribution and general plant accounts. The final two subjects relate to the issues of recording a regulatory liability for net salvage, and the recording of costs of replacements as cost of removal rather than capital additions.

II. LIFE ANALYSIS

Q. Please explain the issue related to life analyses for mass accounts.

A. In this section I will address the unrealistic manner in which service life estimates were made by Mr. Majoros. Specifically, I will explain the process for life analysis I employed and why my estimates have provided the best representation of future expectations for Louisville Gas and Electric property. I will follow by showing why the process employed by Mr. Majoros is inappropriate and how the results of his analysis are unreasonable.

Q. Please explain the process used for life analysis.

A. The estimates I have made for the depreciation study are based in part on the most commonly used statistical analysis of aged retirements known as the Retirement Rate Method. This method is applied to assets in the transmission, distribution and general classes of plant and is described in great length in the Depreciation Study[1]. The Retirement Rate Method was used on all accounts in the above classes of plant except for certain accounts in general plant where vintage amortization was continued.

In addition to the statistical analysis, I have incorporated judgment based on a number of factors to arrive at the most appropriate average service life and dispersion curve for each of the accounts studied. These results were provided in pages III-4 through III-13 of the Depreciation Study. The statistical support for these estimates is presented in the section of the Depreciation Study entitled "Service Life Statistics," and set forth on pages III-16 through III-352.

Q. How does Mr. Majoros's analysis differ from yours?

A. The main difference is that Mr. Majoros has performed no analysis other than to accept the best-fit curves selected by computer software. He has incorporated no other information into his analysis, and has instead simply accepted the results of the statistical analysis, whether these results are reasonable or not.

[1] Please refer to pages II-10 through II-19 of the Depreciation Study

Q. So Mr. Majoros did not incorporate any information or judgment other than the statistical analysis?

A. No, he did not. On page 20 of his direct testimony, he states that his recommended lives "are the best-fits using the actual data from Mr. Spanos' studies." In other words, he simply selected the best mathematical fit curve for each account, without consideration of any other factors or assessment of the reasonableness of his results.

Q. Is the acceptance of the mathematical curve fitting results an acceptable practice for depreciation analysis?

A. No, it is not. As I describe in the Depreciation Study, the service life estimates I have selected were based on "judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management, and the survivor curve estimates from previous studies of this company and other electric utilities." It is standard practice in the industry to consider each of these factors. However, Mr. Majoros only considered one factor – the statistical analysis of data.

Q. Do any authoritative depreciation texts support your assertion that a Depreciation Study should incorporate factors other than statistical analysis"?

A. Yes, all depreciation texts are clear that service life estimates are forecasts of *future* expectations. As a result, blind reliance on the statistical analysis of *historical* data is inappropriate for life estimation.

One such text is the National Association of Regulatory Public Utility Commissioners' publication "Public Utility Depreciation Practices" ("NARUC Manual"). Chapter VIII of the NARUC Manual discusses life analysis. I have included this chapter in its entirety as Attachment JJS-R1.

Q. Is Mr. Majoros familiar with the NARUC Manual?

A. Yes, he is. He cites it on page 20 of his direct testimony. Yet he completely ignores the manual's recommendation that "depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions."[2]

Q. Does the NARUC Manual support Mr. Majoros's dependence solely on mathematical analysis for his life estimates?

A. No. To the contrary, the NARUC Manual is clear that "several factors should be considered in estimating property life. Some of these factors are:

1. Observable trends reflected in historical data
2. Potential changes in the type of property installed
3. Changes in the physical environment,
4. Changes in management requirements,
5. Changes in government requirements, and
6. Obsolescence due to the introduction of new technologies."[3]

Q. On page II-24 of the Depreciation Study, you indicate that the service life estimates were based on "judgment which considered a number of factors." Does the NARUC Manual discuss "judgment"?

A. Yes, it does. The NARUC Manual discusses the use of "informed judgment" in detail on page 128, explaining that "the use of informed judgment can be a major factor in forecasting." It goes on to explain that:

> "Judgment is not necessarily limited to forecasting and is used in situations where little current data are available. The analysis gathers what is known about a particular situation and modifies and refines the data to reflect the actual circumstances. The analyst's role in performing the study is to review the results and determine if they represent the mortality characteristics of the property. Using judgment, the analyst considers such things as personal experience, maintenance policies, past company studies, and other company owned equipment to determine if the stub curve represents this class of property."

[2] NARUC Manual, p. 126
[3] NARUC Manual, page 129

Q. Did Mr. Majoros incorporate any judgment to "review the results and determine if they represent the mortality characteristics of the property"?

A. No, he did not. To the contrary, Mr. Majoros seems to be critical of my study for incorporating any judgment at all. For example, on page 22 of his direct testimony, while discussing the life analysis for production plant interim survivor curves, Mr. Majoros states that "unfortunately, [I] then overlaid [my] judgment on those data to make [my] estimates." Mr. Majoros demonstrates either a clear lack of understanding or deliberate avoidance of the Depreciation Study process with statements such as this. As the NARUC Manual makes clear, judgment is an important part of life analysis. Its inclusion is not "unfortunate," but is instead an integral factor in the selection of proper life estimates.

Q. Does the lack of judgment in Mr. Majoros's study lead to any problems with his results.

A. Absolutely. Had he performed even a cursory review of his results, it would have revealed that they did not represent the "mortality characteristics of the property" being studied. In fact, many of his estimates are so far from being representative of the property being studied that they border on absurd.

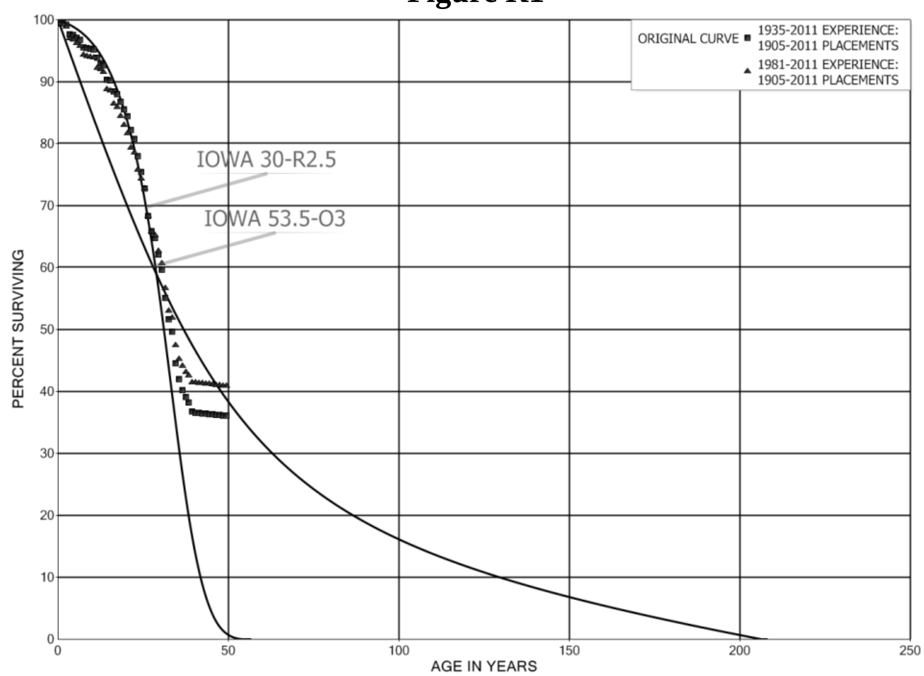
Q. Can you provide an example of the inappropriateness of the results of Mr. Majoros's analysis?

A. Yes. For Louisville Gas and Electric, Account 370, Meters, provides one of the most egregious examples of the inappropriateness of Mr. Majoros's recommendations. The assets in Account 370 are related to meters for distribution plant. Mr. Majoros's life estimate for this account is the 53.5-O3 Iowa survivor curve. That is, Mr. Majoros's study anticipates meters in this account, the largest percentage of which are standard, not new technology, residential meters at customer homes, will last on average 54 years and a maximum of 205 years. Even with a basic understanding of the meter industry, any semblance of reasonable judgment would conclude that this is too long a life for this type of property.

But a more thorough evaluation of the survivor curve selected by Mr. Majoros confirms the unreasonableness of his estimate. The Iowa survivor curves describe not only the average life of a group of property, but also the dispersion of lives around the average. Thus, the survivor curve estimate describes the range of lives expected to be experienced by the entire group. When one examines the implications of the survivor curve selected by Mr. Majoros, it becomes clear how ridiculous the 53.5-O3 selection truly is. The maximum life of an O3 survivor curve is almost four times the average life. Thus, Mr. Majoros is projecting that some of the meters in this account will be in service for over two hundred years!

Figure R1 below shows the 30-R2.5 estimate from the Depreciation Study compared to Mr. Majoros's estimate of the 53.5-O3. The graph of his estimate further emphasizes the absurdity of his selection. As the figure shows, Mr. Majoros anticipates approximately forty percent of the property in this account to last over 50 years, and almost a fifth to last longer than 100 years. It should be clear that Louisville Gas and Electric would not be able to provide reliable service to customers if it were to keep a significant number of meters in service for over 100 years. Yet this is precisely what Mr. Majoros is recommending.

Figure R1



Q. Do Mr. Majoros's other estimates have similar problems?

A. Yes. Almost all of his estimates exhibit the problems one would expect when basing an estimate solely on the blind adherence to statistics. Mr. Majoros selected survivor curves entirely based on the results of statistical analysis, and as a result ignored other factors, such as those noted in the NARUC Manual including "personal experience, maintenance policies, past company studies, and other company owned equipment."[4]

Q. One of the factors you list is "past company studies." Has Mr. Majoros taken past studies into account?

A. No, he has not. This is one of the best illustrations of how unreasonable his methodology is. Attachment JJS-R2 provides a comparison of the currently approved survivor curves and the estimates I have made for the depreciation study to the estimates proposed by Mr. Majoros. As the table shows, while the estimates I have proposed tend to represent gradual changes from the prior estimates, Mr. Majoros offers a radical departure from the previous study. In many accounts he proposes increases in average service life of 20, 30, 40 or even hundreds of years. For example, for Account 356, Overhead Conductors and Devices he proposes an increase of 104.9 years, or in percentage terms an increase of 310%. Other accounts are even more dramatic, with the largest increase in years being 234 years, and in percentage terms being a 490% percent increase. This is very peculiar given Mr. Majoros's involvement in the last proceeding.

Q. On page 6 of Mr. Majoros's testimony, he states you participated in Case No. 2003-00433 for Louisville Gas and Electric. Is this accurate?

A. No. I have conducted a depreciation study for Louisville Gas and Electric in Case No. 2007-00564 and in this proceeding.

Q. Is there significance to your clarification of Mr. Majoros's testimony?

A. Yes. First, it emphasizes the consistency of the life analyses that I conducted which was approved in the last proceeding and which Mr. Majoros had no issues with during that case. The comparison schedule of 2006 and 2011 life parameters is set forth in

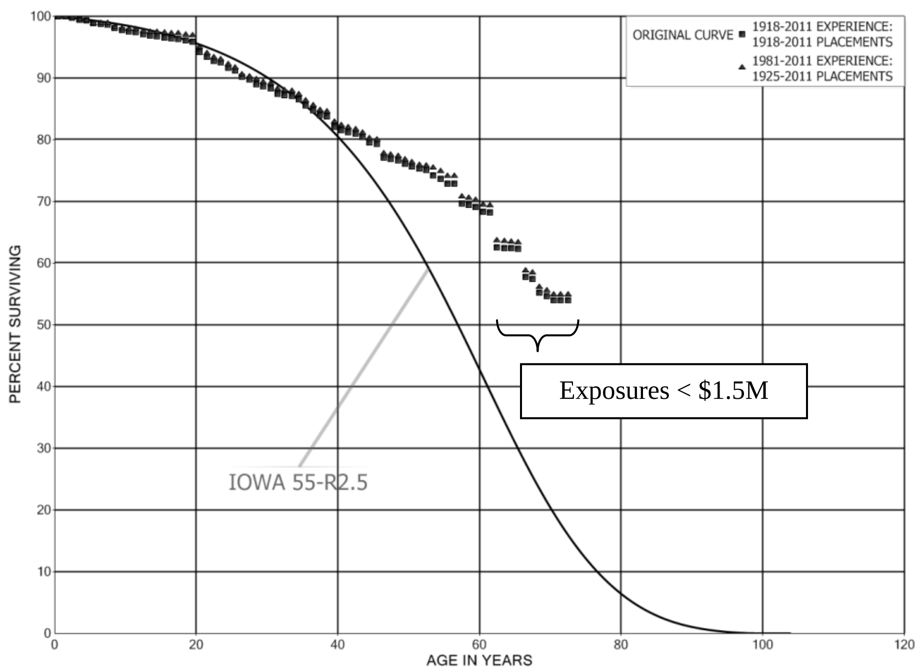
[4] NARUC Manual, p. 128

Attachment JJS-R2. Second, it demonstrates that Mr. Majoros is only focused on lowering depreciation rates as he now recommends lives drastically different from his position in the last case with no justification. The life characteristics of utility assets do not change that much from year to year without some explanation. Mr. Majoros does not offer any explanation for such large changes.

Q. Can you provide other examples of unreasonable estimates presented by Mr. Majoros?

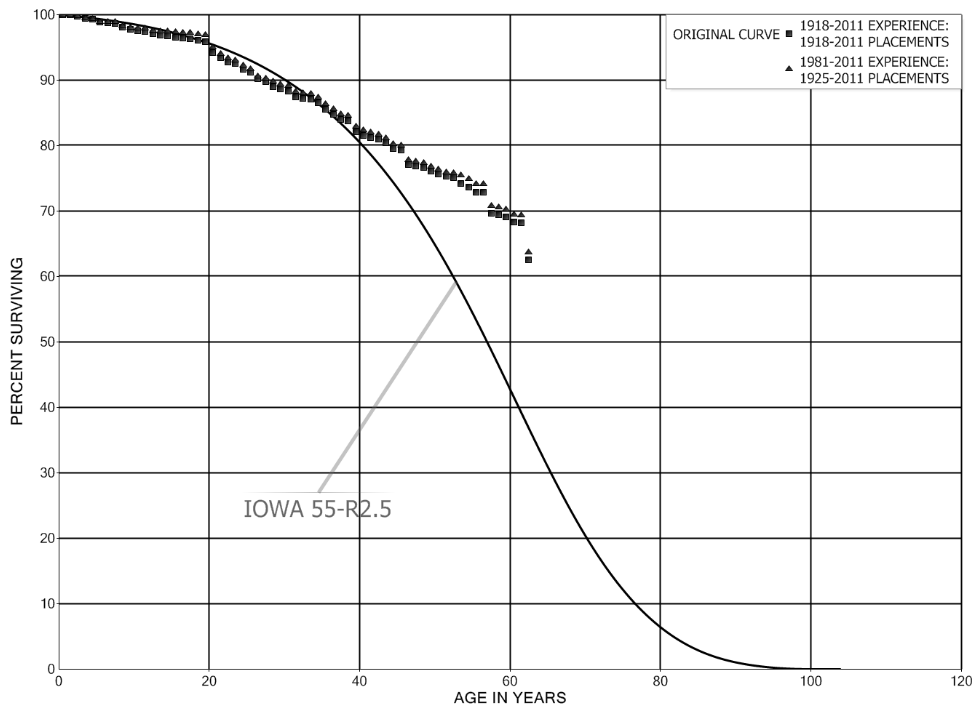
A. Yes, I can. For Account 353, Station Equipment, the approved estimate from the prior Depreciation Study was the 55-R2.5. Figure R2 below shows this estimate plotted against all points from the original life tables developed for the current study based on data through 2011.

Figure R2



As the chart shows, the current data indicates similar judgment was utilized. Based on the data, the points on the original life tables that represent significant exposures are those through age 62.5. Figure R3 below shows the life table through age 62.5, along with the estimate I have made for this study. You will notice it is the same estimate, as an understanding of the station equipment assets is a critical factor. As the chart shows, the 55-R2.5 represents a very good fit of the data through age 40, and recognizes a trend towards an increase in retirement percentages after this age. The increase in future retirement expectations is due to the change in type of assets being installed today.

Figure R3



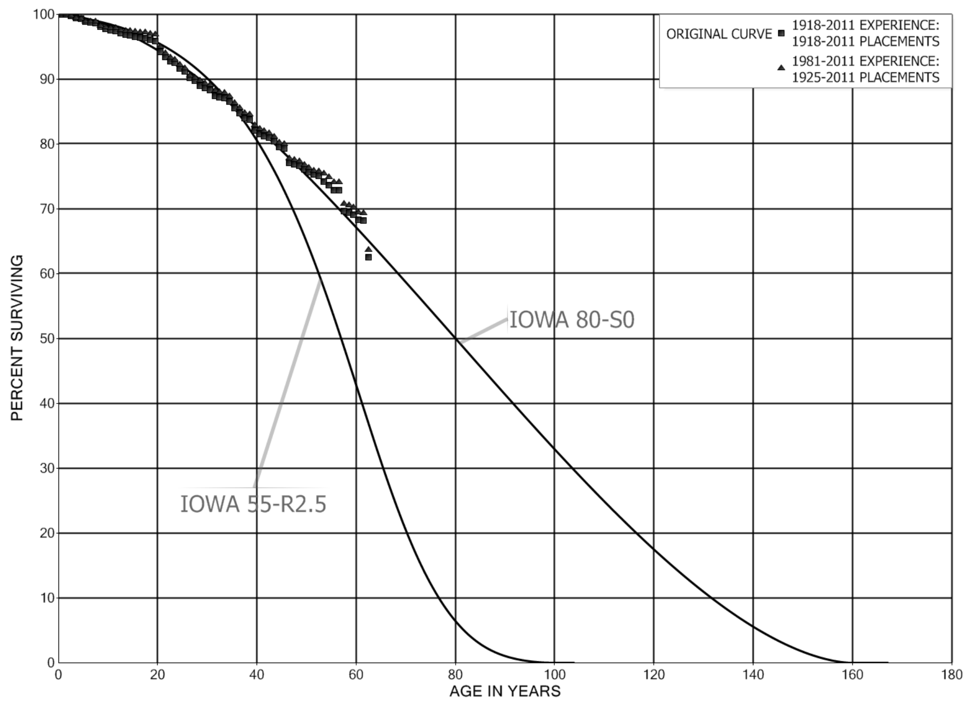
Q. What is Mr. Majoros's estimate?

A. Mr. Majoros estimates the 80-S0, which is an increase in average service life of 145%. This is an extreme estimate for a number of reasons. First, it is a huge increase over the prior estimate. Second, the 80-S0 curve produces a maximum life of 165 years which is unrealistic for station equipment, given that the primary assets are transformers, breakers and relays. Finally, in order to arrive at such an enormous increase, Mr. Majoros must assume that the level of retirements over the final 60 years for station equipment will be the same for the next 100 years. This is an example of why judgment is a critical component of an estimate.

Q. Can you explain this assumption made by Mr. Majoros?

A. Yes. Figure R4 below shows the 55-R2.5 estimate I have made and the 80-S0 estimate of Mr. Majoros plotted against the original life table through age 62.5. Note that the X-axis has changed in order to fit Mr. Majoros's curve on the graph.

Figure R4



As the chart shows, both estimates are a reasonable interpretation of the data through approximately 40 years of age. However, after this point they diverge significantly. Mr. Majoros assumes the level of retirements for the first 40 years will be the same for the next 125 years. He does not consider wear and tear will increase, nor does he consider technological obsolescence or reliability concerns, to be factors. It also is peculiar that Mr. Majoros estimates an average life of 80 years for transmission station equipment, but basically the same assets in distribution Account 362, Station Equipment, he estimates an average life of 55 years.

Q. Can you elaborate on the implications of both your and Mr. Majoros's estimate?

A. Based on the Company's historical data, roughly 40% of the assets in this account have been retired by age 63. The curve I have proposed forecasts that an increase in retirements will occur in the future. This is a reasonable expectation.

Mr. Majoros, however, has forecast that assets that reach age 60 will continue to last at the same rate with a maximum life for this curve to approximate 165 years. He presents no justification whatsoever for such a large deviation from prior Depreciation Studies for Louisville Gas and Electric, the comparable assets in distribution plant and from studies of similar property for any other utility.

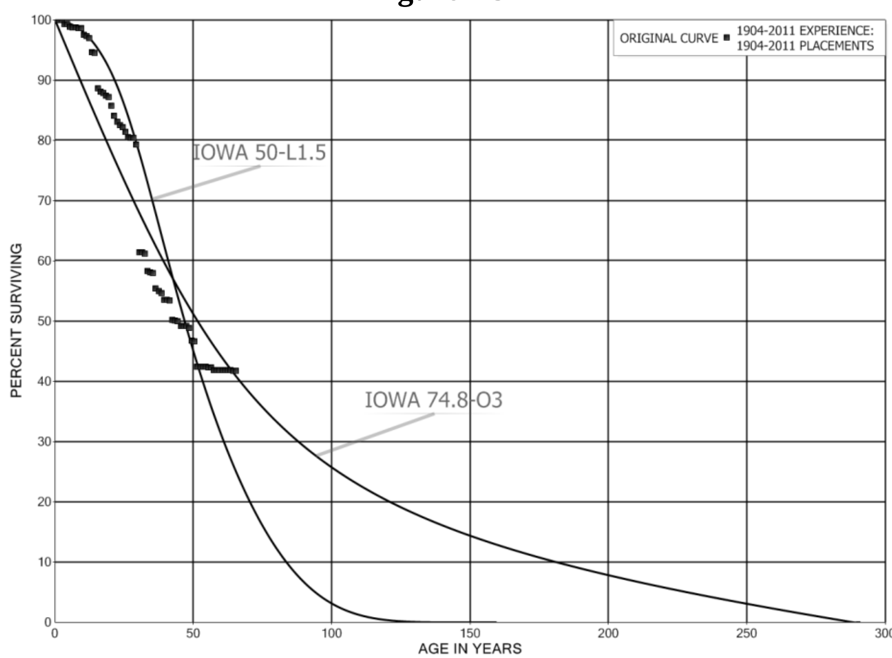
Q. Does Mr. Majoros's failure to incorporate informed judgment affect his estimate for this account?

A. Absolutely. Figure R4 should make clear the extreme results that come from a study such as Mr. Majoros's that incorporates no information at all other than the results of mathematical curve matching. The extensive judgment required for a thorough depreciation study - should have led Mr. Majoros to reconsider such an extreme estimate as he made for this account.

Q. Can you provide another example of the inappropriateness of Mr. Majoros's estimates?

A. Yes. Figure R5 below shows a comparison of my and Mr. Majoros's estimates to the representative data points for Account 361, Structures and Improvements.

Figure R5



As the chart shows, while Mr. Majoros's estimate provides a reasonable fit of the data through approximately age 64, it extends well to the right of both the original data and my curve for subsequent ages. This portion of the curve proposed by Mr. Majoros reflects the extreme nature of his estimate.

Q. Why do you consider Mr. Majoros's estimate to be extreme?

A. His estimate forecasts that the maximum life for structures and improvements will exceed 290 years. He further forecast that approximately 15 percent of the account will be in service for more than 150 years, and just under 10 percent will be in service for longer than 200 years. This is highly unreasonable even for buildings.

Q. What was the previous estimate for this account?

A. The previous estimate for this account was the 60-R3. Thus, Mr. Majoros has increased the average service life by 14.8 years, even though the newer assets being installed are prefabricated steel or modular instead of masonry.

Q. What was the basis for his estimate?

A. His estimate is based on the results of mathematical curve matching of the points between ages 21 and 87. This is different from the selection of most of his estimates, in which the range of fit he used started at age zero, not age 21.

Q. What is the impact of using a different fit range?

A. The mathematical best fit curve for ages 0 through 87 is the 59.1-L0.5. Thus, by using a slightly different fit range, Mr. Majoros has added 15.7 years to the average service life for this account.

Q. Does Mr. Majoros offer any justification for selecting the 74.8-O3 over the 59.1-L0.5?

A. No. One can only conclude that he opted to use the 74.8-O3 because it has a longer life. This flies in the face of Mr. Majoros's accusations of "bias" in my study, and offers further evidence of a clear bias for longer lives in his estimates. As I showed above, this curve represents life characteristics that are completely unreasonable for the type of property for this account. Yet Mr. Majoros ignored these considerations – and any other considerations – and selected the survivor curve that would achieve his goal of minimizing depreciation expense.

Q. Does Mr. Majoros incorporate any other information into his estimate?

A. No, he does not. In fact, as his workpapers show, he ignored his own software's best fits, which represented much shorter average service lives than he proposed.

Q. So Mr. Majoros ignored the results of his own Depreciation Software?

A. Yes he did. Attachment JJS-R3 shows Mr. Majoros's workpapers for this account. As the Attachment JJS-R3 page 3 shows, the best fit from Mr. Majoros's software was the 53-O1. This is a much shorter average service life than the estimate Mr. Majoros provided, and is in fact shorter than the approved estimate and produces higher depreciation expense than my estimate. Further, Attachment JJS-R3 page 3 sets forth the results of the curve fitting from Mr. Majoros's software for this account. With the exception of curves never used for this account (SQ, O3 and O4), the best fit average service lives range from 44 to 59 years. Attachment JJS-R3 page 2 sets forth my best fit statistics which Mr. Majoros claims to use and one can conclude that almost all reasonable curves have a best fit average service life in the mid-fifties. That is, all are in the range of my estimate, and considerably shorter than the average service life Mr. Majoros proposed for this account.

Q. If Mr. Majoros's own software indicated that the best fit curves were closer to the estimate you proposed, why did Mr. Majoros recommend such a long life for this account?

A. Again, one can only conclude that his intention is to reduce depreciation expense by as much as possible. Even in the face of evidence from his own software that a 74.8-O3 survivor curve was far too long for this account, Mr. Majoros ignored any other considerations and selected a survivor curve with an extremely long life, far outside the range of other estimates for this type of property, and far outside the range of common sense. Unfortunately, this is just another example of the major flaws in the estimates proposed by Mr. Majoros.

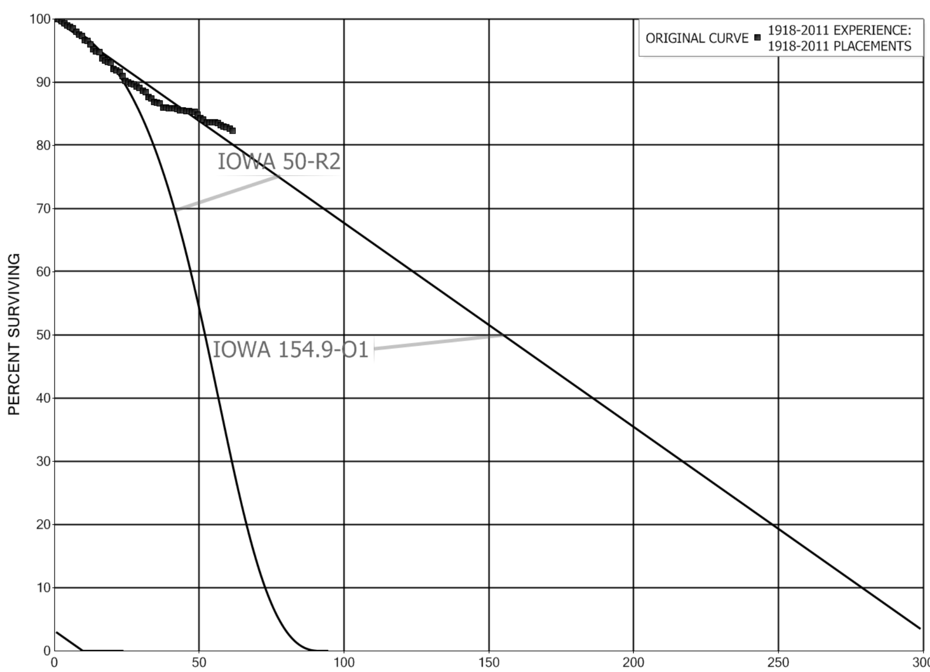
Q. Mr. Majoros argues that your Depreciation Study demonstrates "a systematic downward bias." Is this a correct statement?

A. No, it is not. As discussed above, the Depreciation Study I performed for the Company is based on informed judgment incorporating a number of factors, including a statistical life analysis. Mr. Majoros's estimates are based only on the statistical analysis of historical data. No other factors were considered in his analysis. The purported "systematic downward bias" Mr. Majoros alleges is the result of using the proper informed judgment considering multiple objective data points. Mr. Majoros's estimates in contrast are flawed, because he simply relies on blind acceptance of mathematical curve matching. As I have explained in detail, the sole dependence on statistics is not an acceptable practice in conducting a Depreciation Study, and results in improper – and in many cases absurd – results.

Q. Can you provide other examples of unreasonable life estimates provided by Mr. Majoros?

A. Yes. Figure R6 below shows a comparison of Mr. Majoros's estimate and my estimate for Account 356, Overhead Conductors and Devices compared with the original life table for this account.

Figure R6



As the chart shows, while Mr. Majoros's estimate fits the data reasonably well through age 55, it ignores the fact that for these assets, one would expect retirements to increase for later ages. With this history, Mr. Majoros represents an extremely long life with a 154.9-O1 survivor curve. His estimate forecasts that almost two-thirds of the assets in the account will be in service for more than 100 years, and some assets will last over 300 years. These are exceptionally long lives for this type of property.

Q. What is the approved estimate for this account?

A. The approved estimate for this account is the 50-R2. Thus, Mr. Majoros has more than tripled the average service life for this account.

Q. Does Mr. Majoros exhibit any bias in his estimates?

A. Yes, he does. While his estimates are primarily based on the best mathematical fitting results from the statistical analysis, there are certain exceptions in which he does not accept the best fit results. Not coincidentally, this occurs in cases where the best fit mathematical matches represent average service lives that are shorter than those I have proposed. For example, Account 333.00, Water Wheels, Turbines and Generators, has a mathematical best fit interim survivor curve of 74.1-S6, however, I have recommended a 100-S2 interim survivor curve. Mr. Majoros, without an explanation, recommends a 100-S2 interim survivor curve. By failing to maintain consistency in his analysis, it should be clear that Mr. Majoros is exhibiting a bias towards longer lives, and therefore lower depreciation expense.

Q. In order to help understand the extensive processes required for conducting a detailed life analysis, I have provided an example to highlight the differences between your methodology and that of Mr. Majoros.

A. I will use Account 362, Station Equipment, as an example.

Q. Please describe the curve fitting process you utilize.

A. First, original life tables for an account are developed from the Company's historical data. As an example, the original life for Account 362, Station Equipment is shown in Table R1 below. The percent surviving amounts in the last column are developed based

Table R1

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

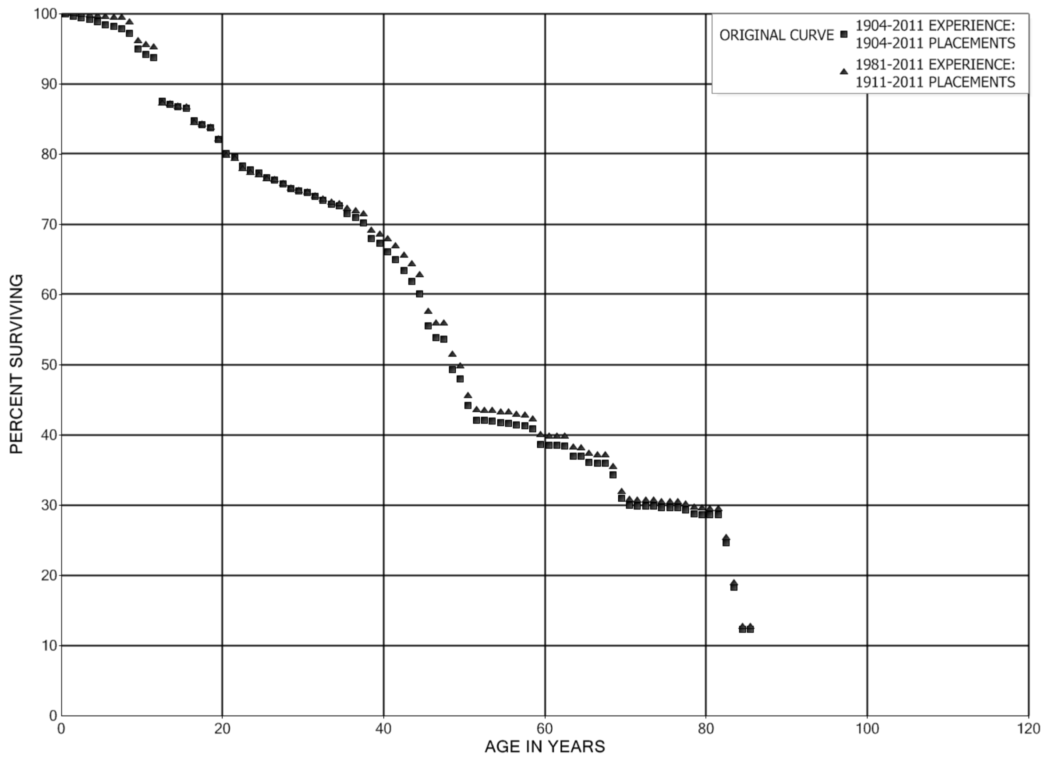
AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	146,155,841	90,988	0.0006	0.9994	100.00
0.5	133,530,839	374,954	0.0028	0.9972	99.94
1.5	122,652,364	334,229	0.0027	0.9973	99.66
2.5	115,073,034	295,165	0.0026	0.9974	99.39
3.5	114,123,285	301,686	0.0026	0.9974	99.13
4.5	111,398,587	563,504	0.0051	0.9949	98.87
5.5	106,969,934	250,101	0.0023	0.9977	98.37
6.5	103,550,454	360,195	0.0035	0.9965	98.14
7.5	100,579,317	674,650	0.0067	0.9933	97.80
8.5	96,836,326	2,180,110	0.0225	0.9775	97.14
9.5	94,745,381	744,274	0.0079	0.9921	94.95
10.5	90,301,729	477,392	0.0053	0.9947	94.21
11.5	89,310,331	5,922,916	0.0663	0.9337	93.71
12.5	79,044,166	360,240	0.0046	0.9954	87.50
13.5	77,536,282	303,670	0.0039	0.9961	87.10
14.5	75,353,047	237,520	0.0032	0.9968	86.76
15.5	72,465,311	1,492,725	0.0206	0.9794	86.48
16.5	67,298,068	387,990	0.0058	0.9942	84.70
17.5	65,464,536	384,200	0.0059	0.9941	84.21
18.5	61,795,226	1,185,288	0.0192	0.9808	83.72
19.5	55,409,190	1,411,091	0.0255	0.9745	82.11
20.5	48,639,548	284,811	0.0059	0.9941	80.02
21.5	47,745,549	792,176	0.0166	0.9834	79.55
22.5	46,171,694	315,226	0.0068	0.9932	78.23
23.5	45,639,207	256,946	0.0056	0.9944	77.70
24.5	45,105,916	409,015	0.0091	0.9909	77.26
25.5	44,054,361	130,999	0.0030	0.9970	76.56
26.5	43,407,997	341,067	0.0079	0.9921	76.33
27.5	41,467,683	374,918	0.0090	0.9910	75.73
28.5	40,404,973	163,553	0.0040	0.9960	75.05
29.5	38,117,532	140,349	0.0037	0.9963	74.74
30.5	37,299,315	261,124	0.0070	0.9930	74.47
31.5	36,473,019	248,354	0.0068	0.9932	73.95
32.5	33,574,673	280,978	0.0084	0.9916	73.44
33.5	28,462,914	104,644	0.0037	0.9963	72.83
34.5	26,099,056	397,646	0.0152	0.9848	72.56
35.5	24,263,342	154,070	0.0063	0.9937	71.46
36.5	22,809,105	263,317	0.0115	0.9885	71.00
37.5	20,632,795	663,969	0.0322	0.9678	70.18
38.5	18,868,772	179,995	0.0095	0.9905	67.92

PLACEMENT BAND 1904-2011 EXPERIENCE BAND 1904-2011

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	18,021,398	322,144	0.0179	0.9821	67.28
40.5	16,743,568	299,488	0.0179	0.9821	66.07
41.5	15,576,339	348,920	0.0224	0.9776	64.89
42.5	14,034,281	355,392	0.0253	0.9747	63.44
43.5	12,958,890	369,435	0.0285	0.9715	61.83
44.5	11,972,806	919,486	0.0768	0.9232	60.07
45.5	10,263,888	301,875	0.0294	0.9706	55.46
46.5	9,652,190	45,209	0.0047	0.9953	53.83
47.5	9,029,562	719,880	0.0797	0.9203	53.57
48.5	8,237,229	221,180	0.0269	0.9731	49.30
49.5	7,894,411	629,288	0.0797	0.9203	47.98
50.5	7,198,686	339,653	0.0472	0.9528	44.15
51.5	6,301,634	7,940	0.0013	0.9987	42.07
52.5	5,902,656	16,586	0.0028	0.9972	42.02
53.5	4,663,532	14,833	0.0032	0.9968	41.90
54.5	3,865,371	11,718	0.0030	0.9970	41.77
55.5	3,495,982	20,740	0.0059	0.9941	41.64
56.5	2,787,703	8,772	0.0031	0.9969	41.39
57.5	2,247,655	24,248	0.0108	0.9892	41.26
58.5	1,997,446	107,453	0.0538	0.9462	40.82
59.5	1,839,910	7,567	0.0041	0.9959	38.62
60.5	1,760,167	360	0.0002	0.9998	38.46
61.5	1,729,830	2,844	0.0016	0.9984	38.45
62.5	1,591,658	58,690	0.0369	0.9631	38.39
63.5	1,526,073	2,374	0.0016	0.9984	36.98
64.5	1,366,498	30,565	0.0224	0.9776	36.92
65.5	1,330,702	4,784	0.0036	0.9964	36.09
66.5	1,325,917	1,731	0.0013	0.9987	35.96
67.5	1,324,122	58,635	0.0443	0.9557	35.92
68.5	1,219,161	121,385	0.0996	0.9004	34.33
69.5	1,088,802	35,688	0.0328	0.9672	30.91
70.5	859,608	2,717	0.0032	0.9968	29.89
71.5	840,285		0.0000	1.0000	29.80
72.5	817,449		0.0000	1.0000	29.80
73.5	774,254	5,969	0.0077	0.9923	29.80
74.5	755,226	224	0.0003	0.9997	29.57
75.5	753,855		0.0000	1.0000	29.56
76.5	753,562	7,560	0.0100	0.9900	29.56
77.5	746,002	13,499	0.0181	0.9819	29.27
78.5	732,503	1,992	0.0027	0.9973	28.74
79.5	690,038	1,009	0.0015	0.9985	28.66
80.5	666,219		0.0000	1.0000	28.62
81.5	666,219	93,422	0.1402	0.8598	28.62
82.5	571,509	145,641	0.2548	0.7452	24.60
83.5	388,418	128,208	0.3301	0.6699	18.33
84.5	156,783		0.0000	1.0000	12.28
85.5					12.28

on the dollar value of plant exposed to retirement ("Exposures at Beginning of Age Interval") for each age interval and the actual retirements that occur in each age interval.[5] The chart below shows a graphical depiction of the data presented in Table R1 (this is also referred to as the "original survivor curve" or "stub curve") for the periods, 1904-2011 and 1981-2011. The plot shown in Figure R7 shows the Percent Surviving column of the original life table in the Y-axis and the Age at Begin of Interval as the X-axis.

Figure R7



Original life tables can be developed based on any range of years of historical data. The original life table in Table R1 was based on all historical data (1904-2011) available in the Company records. In the chart in Figure R7 above, a band with more recent data (1981-2011) has also been displayed. The use of different bands can be helpful in determining trends in the data. In this case, there appears to be a trend towards a slightly longer life. However, the shape of the curve in both bands is very similar.

[5] For a more detailed discussion of how exposures and retirements for the retirement rate method are calculated, please refer to pages II-10 through II-18 of the Depreciation Study.

Q. How are the original life tables used to estimate the average service lives and dispersion patterns for a group of property?

A. Iowa survivor curves can be either visually or mathematically fit through any set of the data points on the curve in order to forecast the survivor characteristics of the assets in the plant account.

Q. What is "visual curve matching"?

A. For visual curve matching, smooth survivor curves (normally Iowa survivor curves) are charted on the same graph as the original curve. By graphing the curves on the same graph, one can visually make a determination as to how close a match the smooth curve is to the original curve.

Q. What is "mathematical curve matching"?

A. When performing mathematical curve matching, the difference between the smooth survivor curve and the original survivor curve is compared mathematically. This matching is typically performed using computer software. Gannett Fleming's software uses a measure of fit called the "residual measure[6]." Mr. Majoros's study is based entirely on the results of mathematical curve matching from Gannett Fleming's software.

As I have explained in detail, Mr. Majoros's sole reliance on the results of mathematical matching is inappropriate for a depreciation study and often leads to unusual – even ridiculous - results. In the example I presented earlier, Mr. Majoros's estimate for meters projects that over forty percent of the account will be in service for over 50 years, and some will last longer than 200 years!

Q. For both methods of curve matching, can the selection of data points impact the results of the analysis?

A. Yes, it can. It is very important to determine which data points from the original survivor curve should be included in the analysis, and which should be emphasized more than

[6] The residual measure is the square root of the total sum of the squares of differences between points on the original and smooth divided by the number of points.

others. Depending on the data points included, the curve fitting process can yield different results.

Q. In the service life statistics included in the depreciation study, have you provided any indication as to which data points you considered for the life analysis?

A. In the charts included in the Service Life Statistics section of the Depreciation Study, I have only shown the points from the original life table that I considered to be relevant to the estimation of the appropriate survivor curve estimate.

Note, however, that while I excluded points that were deemed not to be representative of future life expectations, this does not mean that all data points shown in the depreciation study were given equal weight in the analysis.

Q. On page 16 of his testimony, Mr. Majoros accuses you of implementing "bias by failing to show the OLT in many instances." Is he correct that the decision to exclude certain data points from the charts included in the Depreciation Study introduces a bias to your study?

A. No, he is completely wrong. For most plant accounts, certain data points have little to no value in the life analysis. This is often because the levels of exposures are too small to have any statistical significance, but can also be for other reasons. It is standard practice in the industry to exclude certain points from the curve fitting process. In fact, despite Mr. Majoros's flawed approach to life analysis, he has still excluded certain points from the mathematical curve matching he employed (generally those points for which the exposures are less than 1% of the largest exposure).

Q. Can you provide an example to illustrate how the selection of data points impacts the curve fitting process?

A. Yes. Figure R8, Figure R9 and Figure R10 show different curves fit to the original life table plotted in Figure R7. The three curves represent the Iowa survivor curves that are mathematically and visually best fit curves for the original data. The difference is that in Figure R8 the survivor curve is fit through all data points, in Figure R9 the survivor curve is fit through the first 71 data points, and in Figure R10 the survivor curve is only fit through the first 59 data points. As this example shows, the selection of data points can be significant in estimating the most appropriate average service life.

Figure R8

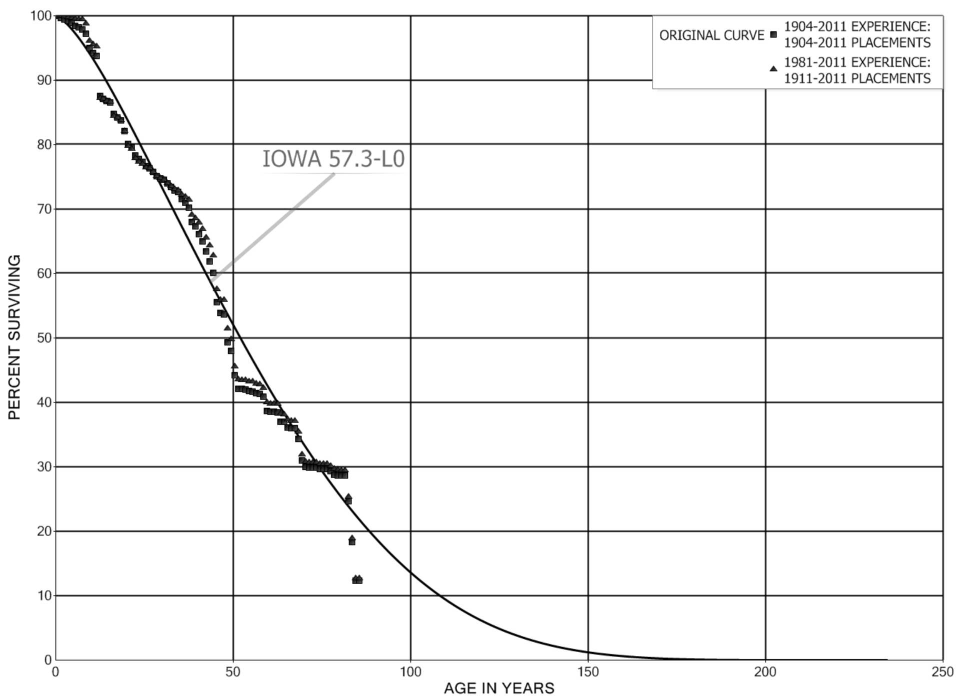


Figure R9

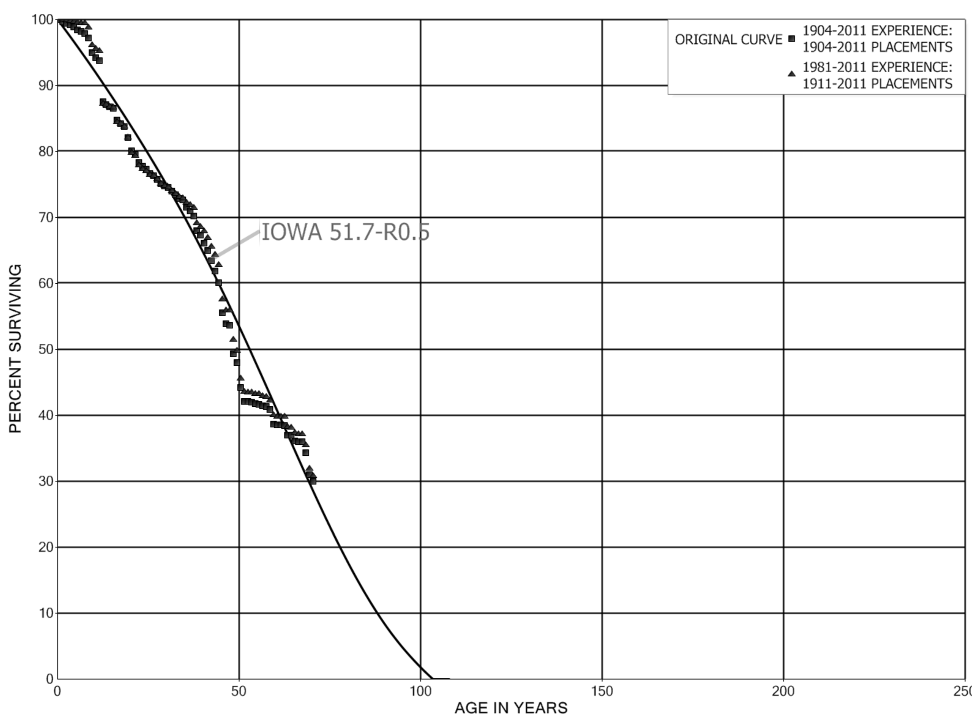
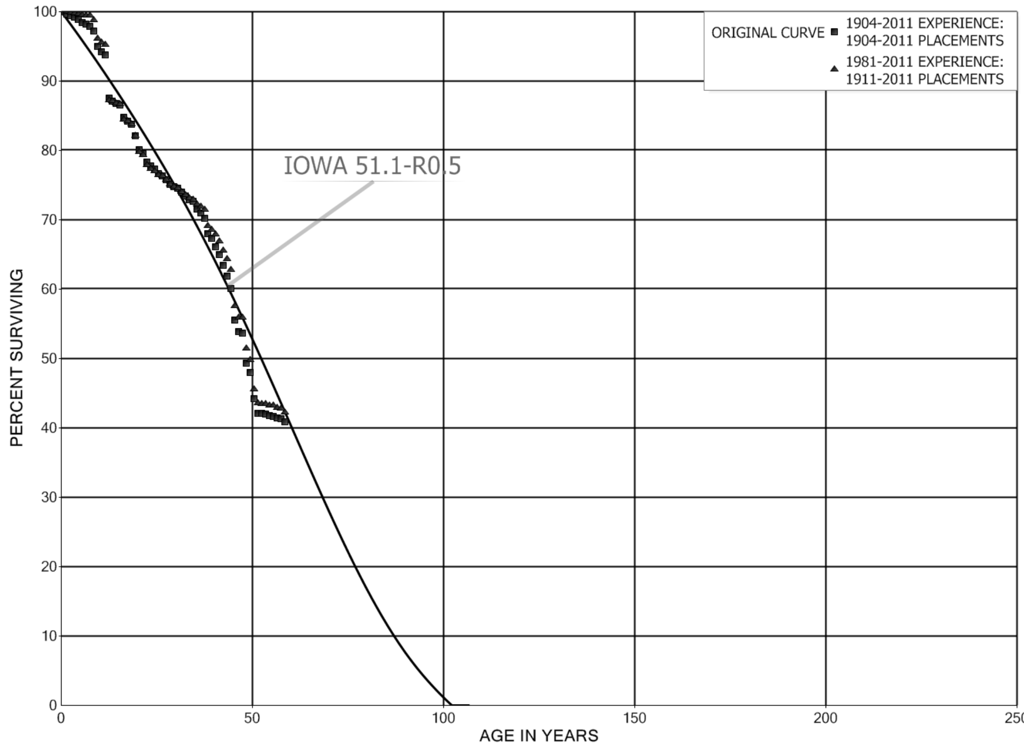


Figure R10



Q. How do you determine which data points are most appropriate to include in the curve fitting process?

A. First, I should emphasize that the goal of life analysis is to select the survivor curve that is the best estimate of the retirement dispersion that will be experienced by plant currently in service. As the above example shows, care must be taken to ensure that the appropriate data points are included in the analysis because different ranges of fit can yield different results. With this concept in mind, I consider whether the dollar level of exposures represented by each data point are significant, and also whether the data points represent activity that is likely to be indicative of future experience of this account.

To illustrate this concept, refer to the original life table in Table R1, on pages 16 and 17 of this testimony. The exposures column represents the dollar amount at each age. As can be seen in the table, these amounts decrease significantly as the age increases – for the first nine age intervals there are over $100 million in exposures, but from age 70.5 there are less than $900,000. Due to the magnitude of the differences in exposures for each age interval, not every data point carries the same weight. It should be clear in this example that $100 million in investment is far more significant than $900,000. Thus, the age intervals from age 70.5 and later offer little value in the analysis.

Generally, there are two main criteria that I consider when determining which points to emphasize in the analysis. First, I take into account the dollar level of exposures for later ages and the activity at ages in which the highest percentages of retirements occur (or the ages closest to the mode of the survivor curve). Later ages are normally given less weight in the analysis when there are far fewer exposures available than for earlier parts of the curve. For the ages closest to the mode of the curve, the ages where the percent surviving ranges from 85% to 15% are considered to provide the most significant retirement activity[7].

I should emphasize that neither of these criteria represent the only considerations one should take into account for the curve fitting process. Specific characteristics of each group of property also need to be taken into account, and may lead to a deviation from these criteria.

Q. Does Gannett Fleming's mathematical curve matching algorithm take these considerations into account?

A. To a certain degree, Gannett Fleming's depreciation software does take both of these considerations into account in its algorithms for mathematical curve matching. To minimize the impact of the tail of the curve, curves are fit from age zero through the age interval in which exposures are less than 1% of the largest exposure. To analyze the ages

[7] Robley Winfrey, upon whose research the Iowa Curves are based, provides a detailed explanation of the reasoning for placing emphasis for these age intervals in Bulletin 125, pages 86 through 93. Note that Winfrey's analysis examined 10% age intervals, and his recommendation is that the most significant data points are found between 80% and 20% surviving.

which exhibit the most significant retirement activity, curves are also fit for the ages in which the percent surviving is between 85% and 15%[8].

Q. Do you end your analysis here?

A. No, I do not. This is the most critical difference between my study and the estimates presented by Mr. Majoros. While I often find this mathematical matching routine can be useful, it is only a starting point for my analysis. I then look at the underlying data and the type of property being analyzed, and both visually and mathematically match curves through a variety of age ranges. As a result, I am able to determine which survivor curve best represents the historical survivor characteristics for the account. I will also factor in any information provided me in interviews with Company personnel, knowledge of the type of property being studied, and the results of prior depreciation studies for the Company. This information could be used to increase or decrease expected lives in the future or it could be used to confirm the estimate based on my historical life analysis.

Q. How has this information been factored into your estimate for this account?

A. The other information obtained while conducting the life analysis that factored into the most appropriate survivor curve for Account 362, Station Equipment, was the basis for truly understanding the life characteristics. First, the station equipment account is relatively stable so life characteristics do not change drastically from period to period. The currently approved estimate is a 55-R1.5 survivor curve. Based on discussions with Company personnel, the major forces of retirement over the past few years and into the near future for station equipment are load upgrades and reliability issues. Both forces affect all ages but do have a higher impact on older assets. Also, the expected average life should be around 45-55 years. With the additional information and expected primary future forces of retirement the 50-R1.5 survivor curve was selected as the best representation of life characteristics at this time. This curve considers a lower percentage of young retirements than the statistics set forth.

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[8] This range of fitting also excludes any points beyond the 1% of largest exposure threshold. In some cases, there are not enough data points in this age range for meaningful curve fitting to be performed.

Q. Has Mr. Majoros conducted a study of his own?

A. Mr. Majoros has made his own life and curve recommendations for each plant account. Based on the evidence provided in his testimony, he did not conduct a depreciation study, but instead selected best fit curves from statistical life analysis.

Q. Has Mr. Majoros taken any of the non-mathematical considerations listed above into account?

A. No, he simply used the results of the mathematical curve matching.

Q. Has Mr. Majoros made any recommendations for life characteristics for gas or common assets?

A. No, he has not. I can only assume that the mathematical best fit methodology that he employs for the electric accounts does not apply to gas and common assets. Thus, Mr. Majoros does not take exception with my methodology for life analyses and recommended survivor curves for all gas and common plant accounts.

Q. Is there any reason to believe that gas and common plant should be studied differently than electric plant?

A. No.

III. INTERIM SURVIVOR CURVES

Q. What is an interim survivor curve?

A. An interim survivor curve is used to estimate the interim retirements for life span property.

Q. How have you developed your interim survivor curve estimates?

A. I have made estimates for interim survivor curves in a similar manner to the estimates for all other accounts discussed in the Life Analysis section. There are a handful of additional factors I have considered that are specific to production plant, which I will discuss later in this section.

Q. Has Mr. Majoros made his own interim survivor curve estimates?

A. Yes, he has. Similar to other accounts, Mr. Majoros's estimates are based entirely on the results of mathematical curve matching.

Q. Mr. Majoros claims that based on your estimates, you are "assuming vastly more interim retirements in the future than the Companies will actually incur." Do you agree with this criticism?

A. No. Based on all of the information available – both statistical analysis and other important factors – the interim survivor curves represent the best estimates of future interim retirements for production plant accounts. As I will show, Mr. Majoros's sole reliance on statistics leads to estimates that result in too few interim retirements.

Q. Mr. Kollen provides an example (with which Mr. Majoros concurs) on pages 24 through 26 of his direct testimony that he says demonstrates the effect of your interim survivor curve estimates for production plant. Do you agree?

A. No. His example does not illustrate anything other than that an inaccurate life estimate will result in a suboptimal recovery pattern for depreciation expense. However, this is true if life estimates are too long or too short. As I showed in the Life Analysis section, and will discuss in more detail in this section, many of Mr. Majoros's life estimates are far too long. Thus, Mr. Kollen's example is more of an indictment of Mr. Majoros's life estimates than of mine.

Q. Please summarize Mr. Kollen's illustration.

A. Mr. Kollen uses an example of a car as a proxy for utility life span property. He supposes that a car owner ("Jessica") has owned a previous automobile and tracked the annual spending required to keep her first automobile running (tires, brakes, etc.). Once her first car has reached the end of its life span, Jessica plans on purchasing a new automobile.

Mr. Kollen's example then has Jessica performing two analyses when purchasing this new automobile in order to estimate the appropriate weighted average life and depreciation rate for her new car. In the first analysis, she forecasts that her new car will experience the replacement of components in exactly the same pattern as her previous car. In the second, she assumes that replacements will occur more frequently than was the case with the historical experience of her previous car.

Q. What does Mr. Kollen conclude from this example?

A. Mr. Kollen concludes that in her second analysis, Jessica must be wrong because she assumes the future will deviate from her past experience. Mr. Kollen apparently considers it axiomatic that the future will always occur the same as the past.

Q. Is it a reasonable assumption to assume that the future will behave the same as the past?

A. No, it is not. In some cases it will, but in others it will not. This is precisely why informed judgment is such a crucial component of life analysis.

In the example provided by Mr. Kollen, there are a number of reasons why Jessica's new car could experience a higher rate of replacements than her previous car. Perhaps she has purchased a car that is much less dependable, and will therefore require more trips to the mechanic to replace parts. Perhaps she has a new job or has moved, resulting in a much different commute than was the case when she owned her prior vehicle (say, more city driving than highway driving). Maybe her new car is a different technology than her prior one – like a hybrid compared to a traditional gasoline powered car – which will have very different operational and maintenance characteristics. Or, perhaps the EPA has issued new emissions regulations that require more components to be replaced at each annual state inspection than was the case under previous EPA guidelines.

Any of these factors, or any combination of them, could lead to the weighted average life of Jessica's new car to be shorter than that of her previous car. In such a case, her second analysis would be the correct one, whereas the first – which assumes that the future will be identical to the past – would estimate a life too long and a depreciation rate too low.

Q. What is the result of estimating too long of a life?

A. The effect would be to have depreciation rates that are too low, which would in turn defer recovery to future years (and in the case of rate regulated utilities, to future ratepayers). Mr. Majoros elaborates on Mr. Kollen's example on page 24 of his testimony, and puts forth the example of paying a mechanic a small amount each month expecting to replace brake pads every 40,000 miles, when past experience has shown brake pads to be replaced every 80,000 miles. Like Mr. Kollen, he seems to assume that 80,000 must be the correct number, only because it is what was experienced in the past. However, if for any of the reasons mentioned above the correct mileage for future replacements is 40,000 miles, then the estimate of 40,000 miles will result in the correct recovery (or payments to the mechanic, in Mr. Majoros's parlance). In this case, payments based on an estimate of 80,000 miles will underpay for the actual replacements, leaving an unexpected large bill at the time of replacement. At this point in time, only half of the required payment for the replacement of brake pads would have been made.

Q. Is the example presented by Mr. Kollen applicable to the life analysis for production plant?

A. No, it is not. Mr. Kollen's example has a number of flaws. It first assumes that I have ignored the historical data and assumed without justification that lives will be shorter in the future than in the past. Second, his example is based on a simplified analysis of the history of a single car, which is very different from the real-world analysis in the depreciation study, consisting of the study of many different assets. Further, it assumes that the historical database has experienced a full life cycle, which is not always the case in depreciation studies. Finally, it ignores any factors that may result in the future being different from the past.

Q. Please elaborate.

Unlike in Mr. Kollen's example, in which the historical analysis is based on a single car, for the life analysis for Louisville Gas and Electric the historical database consists of multiple power plants, each of different ages and sizes. For example, Table R2 shows the age of each of LG&E's power plants at the end of 2011.

Table R2

Unit	Installation Year	Age at 2011
Cane Run Unit 1	1954	57
Cane Run Unit 2	1956	55
Cane Run Unit 3	1958	53
Cane Run Unit 4	1962	49
Cane Run Unit 5	1966	45
Cane Run Unit 6	1969	42
Mill Creek Unit 1	1972	39
Mill Creek Unit 2	1974	37
Mill Creek Unit 3	1978	33
Mill Creek Unit 4	1982	29
Trimble County Unit 1	1990	21
Trimble County Unit 2	1990,2011	21,0

The only plants that have reached 40 years of age in the historical database are at Cane Run. All of these older plants either are retired or are planned to be retired within the next five years. In performing the actuarial studies for the Depreciation Study, much more weight was given to the data points in the original life table through age 42 than for subsequent ages.

Figure R11 below shows the life table for Account 312, Boiler Plant Equipment. The circled points are those for ages 42 and younger, which are the points most representative of future expectations due to the reasons discussed above.

Figure R11

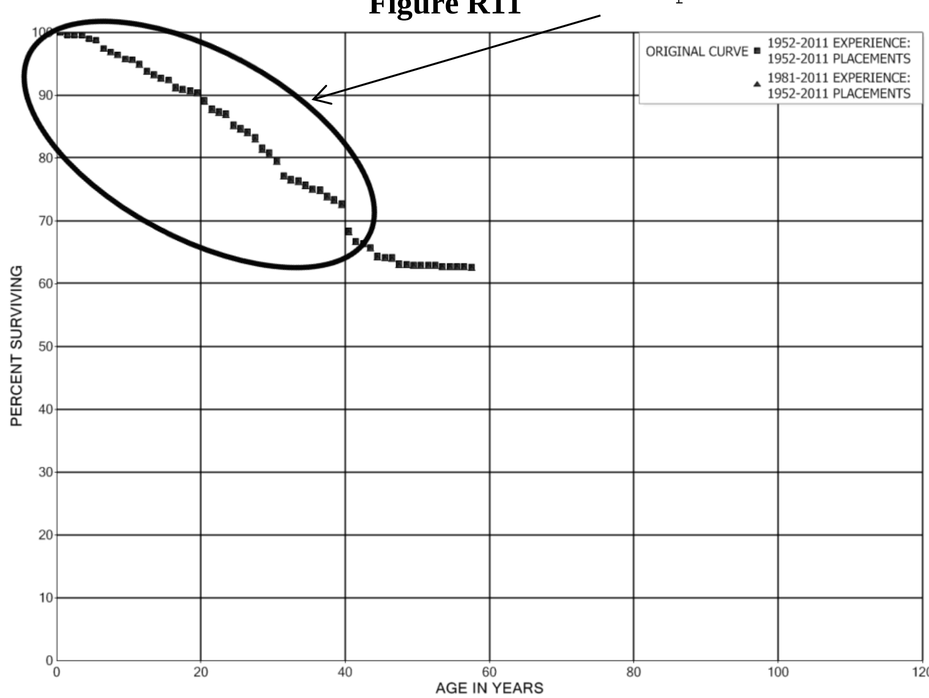
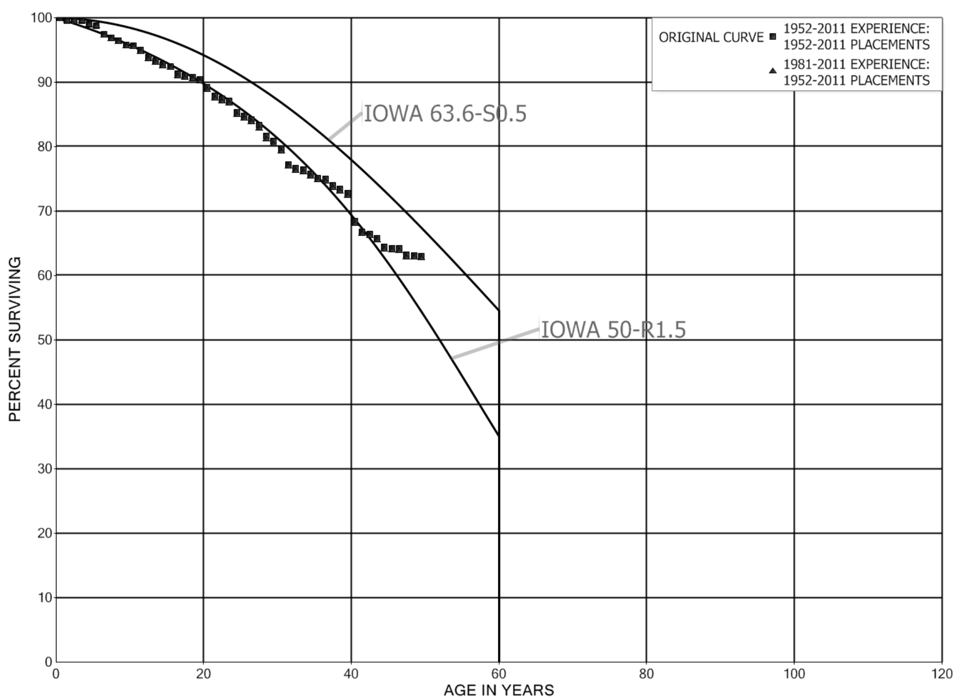


Figure R12 below shows a comparison of the life estimate from the Depreciation Study and the estimate proposed by Mr. Majoros with the original life table plotted through age 41.5. As the chart shows, Mr. Majoros's 63.6-S0.5 estimate is to the right of the original curve through all 42 ages. In contrast, the 50-R1.5 from the Depreciation Study is a very good fit of all the data points through age 42. Thus, my 50-R1.5 is actually a much better representation of the historical data than that of Mr. Majoros. Mr. Majoros's estimate, which projects more property to survive through 60 years, is actually understating the retirements that will occur in the future, when compared to the most representative historical data. It is possible that Mr. Majoros intended to recommend a 63.6-L0.5 estimate based on the mathematical curve fitting, but his lack of consistency in his recommendations makes it hard to understand his thoughts. Additionally, he has calculated depreciation expense using the 63.6-S0.5 curve which of course produces lower depreciation expense.

Figure R12



For this reason alone, Mr. Kollen's example fails. The estimates presented in the Depreciation Study do represent a good fit of the historical data – and, most importantly, the best fits of the most representative portions of the historical data.

Q. Are there other ways in which Mr. Kollen's example is not an accurate representation of the results of your Depreciation Study?

A. Yes. In fact, some of the hypothetical factors that I discussed above related to Jessica's automobile are also considerations for the life analysis for LG&E's production facilities. Perhaps the most important factor is EPA regulations of emissions. As a result of existing and potential regulations on mercury, SOx and NOx, both LG&E and KU have had to either install or replace a number of major components at their coal facilities, including scrubbers, SCRs and baghouses. Thus, in addition to contributing to the final retirements of a number of their plants (such as Cane Run for LG&E), EPA regulations have had significant effects on interim retirements as well.

There are two main ways these regulations have impacted interim retirements. First, the installation of major pollution control equipment has directly resulted in interim retirements for these facilities, both for the replacement of older pollution control equipment, and for the retirement of other assets in order to retrofit new pollution control equipment to existing plants. Second, the new equipment being installed is different technology from that at existing plants, and could thus have different life characteristics than assets previously in service. As an example, prior to recent installations, none of LG&E's plants had baghouses, and older generation scrubbers were designed to meet more lenient emissions targets than those in current and proposed regulations.

Q. Does the historical database incorporate all of the interim retirements required to meet EPA guidelines?

A. No, it does not. On the field visits I conducted for the Depreciation Study, I learned of future capital projects that will be required to meet these regulations. For example, FGDs and baghouses will be added to some of the Mill Creek units, and a baghouse for Trimble County Unit 1. This is in addition to other major capital projects, such as turbine overhauls and scrubber upgrades at Mill Creek. All of this work will lead to interim retirements, and some will lead to a different mix of assets going forward.

Q. How does this information affect your life analysis?

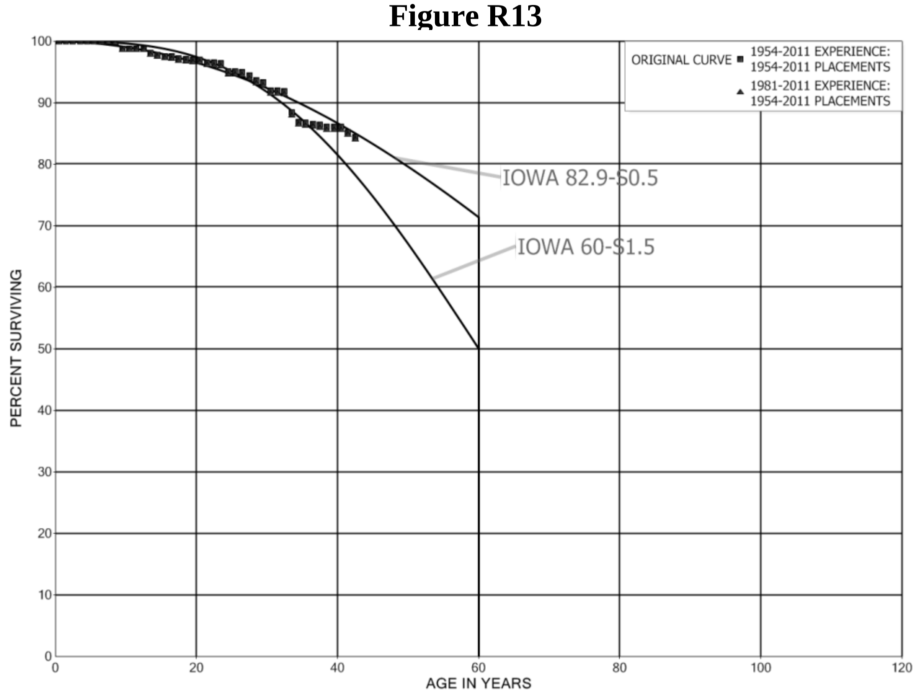
A. One way it impacts the life analysis is that it provides further justification for giving more weight to the newer coal units. Older units such as Cane Run Units 1 through 6 have less pollution control equipment than newer units – no scrubbers, baghouses or SCRs for example. As a result, this gives further support to placing much greater emphasis on the points from the original life through age 42 than those at later ages.

Another way in which this knowledge affects the original life tables is that it helps to determine the future life characteristics of property for the Mill Creek and Trimble County plants – that is, it helps to forecast the pattern of retirements past age 42.

Q. Can you provide an example of how this information can be used to forecast the pattern of retirements past age 42?

A. Yes. As an example, Figure R13 below shows both my estimate (60-S1.5) and that of Mr. Majoros (82.9-S0.5) plotted against the original life table through age 41.5. As the chart shows, both curves are similar fits of the data and are similar to each other through age 41.5. However, the two estimates start to deviate from one another after this age.

Figure R13



As discussed above, the capital investments I learned about during my site visits and discussions with management are likely to lead to an increase in interim retirements going forward. I have reflected this in my estimate in a couple of ways. First, as the chart shows, the estimate I have made indicates increasing retirements as the plants age. Second, the approved life estimate for this account from the 2006 Depreciation Study was the 50-S1.5. An increase in life to the 60-S1.5 interim survivor reflects the expectation that on average assets will remain in service longer but there will be more interim retirements as assets reach age 42 going forward.

Q. Does Mr. Majoros take any of this information into account?

A. No. Mr. Majoros's estimate takes none of this information into account. For this account, his estimate is actually a significant increase over the approved estimate, which runs counter to the expected increase in interim retirements as assets age.

All of his estimates are nothing more than mathematical best fits to historical data. I have discussed at length the importance of informed judgment and the consideration of many factors in making the most appropriate life estimates. I have further discussed a number of important considerations I have incorporated into the interim survivor curve estimates for production plant. Mr. Majoros's estimates represent the use of a poor methodology and result in unreasonable estimates that should be rejected by the Commission.

IV. NET SALVAGE – INTERIM AND FINAL

Q. Does Mr. Majoros criticize your net salvage estimates?

A. Yes, but his criticism is mistaken.

Q. Please describe the methods used to determine net salvage estimates for the Depreciation Study.

A. As stated on page II-30 of the Depreciation Study, net salvage estimates by account are based on (i) historical data compiled through 2011; (ii) judgment which incorporated expectations with respect to future removal requirements and markets for retired equipment and materials and (iii) previous studies for Louisville Gas and Electric and other electric utilities. The historical data by account for the period, 1972-2011, included annual retirements, cost of removal and gross salvage. The cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on an annual and three-year moving average basis. The expectations of future removal requirements and the future market for scrap value were discussed with Company personnel and compared to information obtained during the conduct of studies with other electric industry personnel. Finally, the past approved net salvage estimate for Louisville Gas and Electric as well as the industry ranges were reviewed in the process of determining the most appropriate net salvage percent for each account. In the case of production plant, the net salvage percent was segregated into two components: the interim net salvage and the final net salvage. Each component was based on the level of plant to be retired on an interim or final basis.

Q. What is "final" net salvage?

A. To understand final net salvage (also referred to as terminal net salvage), one must understand the life span concept. In depreciation, the life span method is used for a group of property for which the entire group is expected to be retired concurrently. A classic example of life span property is a power plant. While some assets will be replaced throughout the life of the plant, at some point the entire plant will be retired. At this time, all assets at the plant will be removed from service at the same time. Assets that are retired at this date are referred to as "final" or "terminal" retirements. Assets that are retired before this date are referred to as "interim" retirements, and any assets installed after the date of construction but before the final retirement date is an "interim" addition.

Any net salvage (removal costs or gross salvage) associated with interim retirements is referred to as "interim" net salvage, and any net salvage associated with the final retirement of the facility is referred to as "final" or "terminal" net salvage. Note that even if the facility is not completely torn down or demolished, there can still be final net salvage costs – final net salvage is any net salvage costs that occur at the final retirement of the plant.

Q. What have you recommended for final net salvage in the depreciation study?

A. In the depreciation study, I have recommended final net salvage of negative ten percent for steam production plant and negative five percent for hydraulic and other production plant. These percentages are applied only to the portion of plant expected to retire as final retirements.

Q. What is the basis for your recommendations?

A. There were a number of factors I considered in making these estimates. These factors included Company plans and outlook, past experience for LG&E and KU, and the experience of other utilities. Based on all of these factors and the information currently available, the estimates of negative ten percent for steam production and negative five percent for hydraulic and other production represent the most reasonable estimates of terminal (final) net salvage.

Q. What were the net salvage estimates approved in the previous Depreciation Study?

A. In the last Depreciation Study for Louisville Gas and Electric, I determined net salvage estimates based on an analysis of the historical net salvage data. At the time there was not enough information to make a separate determination for final net salvage and interim net salvage. As a result, I applied one net salvage estimate to the entire plant balance, as opposed to segregating between interim and final retirements.

Q. Why did you not segregate the net salvage estimates into interim and final net salvage?

A. During the conduct of the last study, there was no information available to me regarding final net salvage. Thus, I made the best estimates based on the information available at the time, which was generally our standard practice.

Q. Was this a common practice at the time of the last Depreciation Study?

A. Yes, it was. Please see the response to KIUC’s second set of data requests, (Question 29, part d) for my experiences for industry practice.

Q. Why have you improved the methodology for production plant net salvage for this Depreciation Study?

A. There are a number of reasons why I have improved my methodology. First, with the approaching retirements of a number of LG&E and KU's coal-fired power plants, as well as the potential for the full dismantlement of previously retired plants, there is more information now available on the fate of these plants upon final retirement. Second, there is more information available regarding retirement obligations for these plants, including pond remediation and asbestos disposal. Third, as more plants have been retired in the industry, more information has become available regarding the final net salvage of power plants. Finally, as more plants have been retired and dismantled across the country, there has been a need to determine the most accurate estimates of final net salvage possible.

Q. Is the methodology you have proposed an improvement over that used in the prior Depreciation Study?

A. Yes, it is. I consider it to be a more accurate reflection of future expectations for these plants.

Q. Mr. Majoros states on page 29 of his testimony that "the Companies have increased their proposed production plant depreciation rates to account for two types of future net salvage." Do you agree with this statement?

A. No. Mr. Majoros's statement is misleading. Net salvage has been included in depreciation rates for all accounts (both production and all other accounts) for all prior studies. Including final net salvage in the depreciation rates for this study is not "increasing" the depreciation rates, but merely reflecting the appropriate estimates of future net salvage.

Further, Mr. Majoros's statement is misleading because it appears to imply that the net salvage estimates I have proposed result in an increase in depreciation expense over the prior study. In fact, the opposite is true.

Q. How do the net salvage estimates you have proposed for this study compare to the approved estimates from the prior study?

A. Table R3 below provides a comparison of the net salvage estimates from the prior study to the blended net salvage estimates proposed for this study.

Table R3

Account	2006 Study	2011 Study
311.00	(10)	(10) to (15)
312.00	(30)	(10) to (15)
314.00	(10)	(10) to (15)
315.00	(5)	(10) to (15)
316.00	(5)	(10) to (15)
331.00	(5)	(6)
332.00	(5)	(6)
333.00	(10)	(6)
334.00	(5)	(6)
335.00	(10)	(6)
336.00	0	(6)
341.00	(5)	(5)
342.00	(5)	(5)
343.00	(5)	(5)
344.00	(5)	(5)
345.00	0	(5)
346.00	0	(5)

Due to the fact that net salvage estimates for production plant were developed by account in the 2006 Study and net salvage estimates for the 2011 Study were developed by site, some accounts had net salvage estimates that are more negative, while others are less negative. However, for the largest account, Account 312 in Steam Production, the 2011 net salvage estimate represents a decrease. As a result, in total, net salvage represents a significant decrease over the approved net salvage estimates. The overall net salvage estimates for Steam Production represent a decrease in forecast net salvage costs of approximately 53%. The estimates for all of production represent a decrease of approximately 52%.

Q. Has Mr. Majoros made his own net salvage estimates for production plant?

A. Yes. Mr. Majoros has used a similar methodology to mine. That is, he has developed a blended net salvage estimate based on separate estimates for interim and final net salvage. However, Mr. Majoros has recommended zero percent for final net salvage for all of production plant.

Q. What is the basis for his recommendation?

A. Mr. Majoros argues that LG&E and KU have no current plans to fully dismantle their power plants, and as a result zero net salvage should be used for production plant. In doing so, he ignores the actual costs that will be incurred whether or not the plants are dismantled. He further ignores the potential for dismantlement in the future, and the need to recover these costs over the lives of the plants.

Q. Mr. Majoros states that "terminal net salvage reflects the assumption that a Company has plans and obligations to dismantle its production plants upon final retirement from service."[9] Do you agree with this statement?

A. No, I do not. Even if LG&E and KU do not fully dismantle their power plants, there will still be costs recorded to accumulated depreciation at the final retirement of each plant. As the Company has already presented in its responses to Requests for Information, there are costs expected to be incurred for plants for which the Company has no current plans to dismantle.

Q. Does the Company have any current plans to dismantle any of its existing fleet?

A. At the current time, there are no plans to dismantle any of the Company's plants that are in service. However, most of the Company's fleet, with the exception of Cane Run, is not expected to retire until 2032 at the earliest, and Trimble County Unit 2 is expected to be in service until 2066. These dates extend beyond any current planning period. Thus, the determination of the eventual fate of these plants requires judgment in order to estimate future expectations for these plants. Essentially, the estimate of final net salvage

[9] Direct Testimony of Michael J. Majoros, Jr., p. 29.

for these plants is an estimate of what decisions the Company will make many years into the future.

Further, while the Company has not finalized any plans, there is consideration of dismantling the retired Paddy's Run and Canal power plants. The potential for the dismantlement for these plants, and the estimated costs, were discussed with me during the Depreciation Study which were one of the factors I considered for my estimate and have been included in responses to data requests.

Q. Does the Company have plans to retire any plants in the near future?

A. Yes. Louisville Gas and Electric plans to retire Units 4, 5 and 6 at the Cane Run coal plant by 2015. Kentucky Utilities plans to retire Tyrone and Green River by 2015.

Q. Does the Company have plans to dismantle these facilities?

A. At the current time, it does not.

Q. Does the fact that the Company does not have plans to dismantle these facilities mean that the final net salvage will be zero?

A. No, it does not. In fact, the Company's plans for the retirement of these facilities make clear that there will be removal costs. In the response to Staff's 2nd Request for Information, Question No. 95, the Company indicates that at the retirement of the Cane Run plant, there will be costs to stabilize the facilities estimated at $9 million.

These costs represent the minimum costs that will be expended, as additional costs could be incurred once their eventual fate is determined. Still, it should be clear from these costs that an estimate of zero percent is inappropriate and will fail to recover costs that the Company will occur upon the final retirement of these plants.

Q. Was Mr. Majoros aware of these costs?

A. Yes. These costs were identified in the data request response. However, Mr. Majoros chose to ignore this evidence and recommend a zero percent net salvage estimate that is clearly too low.

Q. Mr. Majoros claims on page 30 of his direct testimony that the Companies "have neither a legal nor a moral obligation" to incur final net salvage costs. Is this assertion correct?

A. No, it is not. Again Mr. Majoros has chosen to ignore evidence provided by the Company – evidence that Mr. Majoros even included in his direct testimony.

In the response to KIUC's 2nd Request for Information, Question No. 50, Louisville Gas and Electric identified approximately $29 million in asset retirement obligations related to its coal-fired power plants in service. These obligations are related to the remediation or retirement of facilities at these plants such as ash ponds, coal storage facilities, and assets containing asbestos.

Q. Was Mr. Majoros aware of these costs?

A. Yes. Mr. Majoros has been presented the response to the Data Request. Yet despite the $29 million in costs the Company has specifically identified for Louisville Gas and Electric, Mr. Majoros has chosen to ignore these costs in the development of his recommended depreciation rates.

Q. Given all of these considerations, is the zero percent net salvage estimate for final net salvage proposed by Mr. Majoros appropriate?

A. No, it is not. Given all of the information presented by the Company, it should be clear that at a minimum there will be final net salvage costs well in excess of zero for each of LG&E's power plants. Mr. Majoros's estimate of zero percent will therefore fail to recover these costs over the lives of these plants while they are in service. Instead, he will defer these costs to future customers to pay after the plants are retired – that is, to customers that will receive no benefit from the plants.

V. NET SALVAGE PERCENTS FOR TRANSMISSION, DISTRIBUTION AND GENERAL PLANT

Q. Are there any other issues or discrepancies in Mr. Majoros's testimony that you need to address?

A. Yes. Mr. Majoros has presented in his adjustments a reduction of $43,814,655 in depreciation expense for LG&E. The reduction of $43,814,655 which he sets forth on page 5 of his testimony includes $12,257,883 which he claims are relating to Transmission, Distribution and General Plant life estimate changes. However, that is not accurate. Upon additional review, I discovered that a large portion of the $12,257,883 reduction relates to changes in the net salvage percents for transmission, distribution and general plant.

Q. Was there any discussion in Mr. Majoros's testimony related to net salvage changes for these accounts?

A. No. I discovered this issue when attempting to understand Mr. Majoros's testimony.

Q. Has Mr. Majoros explained the differences between his testimony and his schedules?

A. Mr. Majoros has supplied the document designated as Attachment JJS-R4 as his explanation. Although he has quantified how much he considers as changes in depreciation expense related to net salvage for transmission, distribution and general plant which are assumed to support his position. In my review, there is absolutely no support for his estimates in his workpapers.

Q. Is there any rationale or standard practice that supports what Mr. Majoros said he has done to arrive at his net salvage percents?

A. Absolutely not. Mr. Majoros has taken the statistical analyses that I have accumulated and presented in the Depreciation Study and arbitrarily reduced the net salvage percents. There is no basis or standard practice which would support this methodology. This was a last ditch effort to lower depreciation expense because the other unsupported methods that Mr. Majoros has created will likely not be accepted.

Q. Can you discuss the flaws in his example that he sets forth in Attachment JJS-R4?

A. Yes. Mr. Majoros uses LG&E Account 369.2, Services – Overhead, to establish his random net salvage percent determinations. A more thorough understanding of the statistical analyses will show Mr. Majoros's explanation is just a weak attempt to lower depreciation expense. The net salvage statistical analyses for LG&E Account 369.2, is set forth on pages III-425 through III-427 of the Depreciation Study. This shows $2.1 million in retirements for the period, 1972-2011, and an associated net salvage (cost of removal and gross salvage) of $2.4 million. This represents negative net salvage of 112 percent ($2,386,521/$2,122,081). Other key facts about Account 369.2, which Mr. Majoros neglects to mention, include the average service life for this account of 50 years and the average age of historical retirements to date represented in the statistical analyses is approximately 30 years. Therefore, the $2.1 million in retirements for the 1972-2011 period does represent 10% of the current surviving balance, but is almost 50% of the assets that were in service for the initial 30 years. Therefore, these net retirements actually represent a more significant data analysis than what Mr. Majoros leads one to believe. Also, since the average age of retirements for the period 1972-2011 has been 30, and the average service life for the account is 50 years, then it should be noted that future retirements will exceed age 50 in order to actually reach the 50-year average. Thus, the net salvage percent in the future will most likely exceed the negative 100% that is currently recommended by me. This assumption is built on the concept that labor costs will increase over time, so if the time differential between original installation of the plant retired and the end of life cost of removal increases, then the net salvage percent will become more negative. Therefore, the randomly reduced 50% net salvage percent suggested by Mr. Majoros is unrealistic.

Q. Has Mr. Majoros made similar unsupported changes to your net salvage percentages for gas and common plant?

A. No, he has not. There are no discussions or depreciation expense adjustments for gas or common plant accounts, so I must assume that his random reductions of net salvage percents did not apply to gas and common plant. Therefore, Mr. Majoros either accepted my methodology for net salvage percents or he felt the effort to reduce depreciation expense for these accounts was not worth his time.

Q. Is there any reason to believe that gas and common plant should be studied differently than electric plant?

A. No.

VI. REPLACEMENT COSTS AND REGULATORY LIABILITY

Q. On pages 28 and 29 of his direct testimony, Mr. Majoros argues that all costs related to replacement of assets should be capitalized to the new asset, as opposed to recorded as cost of removal for the asset being replaced. Do you agree with his opinion?

A. No, I do not. The only evidence he provides in support of his opinion is FERC's definition of replacement. From the FERC Uniform System of Accounts (USofA), the definition of replacement is:

> "32. A. *Replacing* or *replacement*, when not otherwise indicated in the context, means the construction or installation of electric plant in place of property retired, together with the removal of the property retired."[10]

From this definition, Mr. Majoros somehow makes the leap that all costs associated with replacements should be assigned to the new asset, as opposed to being assigned to the actual activities that generated the costs (i.e. retirement or addition). This would be an unusual conclusion even if the FERC Uniform System of Accounts said nothing else on the matter.

Q. Does the USofA address the proper treatment of replacement costs?

A. Yes, it does so in multiple places. The following sections of the USofA clearly state that

[10] 18 CFR Ch. 1, Subchapter C, Part 101, Definition 32

cost of removal associated with a retirement should be charged to accumulated depreciation; the USofA does not distinguish between retirements for replacement and retirement without replacement.

1. Electric Plant Instruction 11(A) applies to the cost of removal that relates to the retirement, with or without replacement:

   > "…all items relating to the retirements shall be kept separate from those relating to construction…,"

2. The description of Account 108, Accumulated Provision for Depreciation of Electric Plant, states in paragraph B states that this treatment is for retirements with or without replacement:

   > "At the time of retirement of depreciable electric plant, this account shall be charged with the book cost of property retired and the cost of removal,"

3. Electric Plant Instruction 10(B)(2) specifies that there is no distinction between retirements with replacements and retirements without replacements:

   > "when a retirement unit is retired from electric plant with or without replacement the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in Paragraph D below. If the retirement unit is of depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to accumulated provision for depreciation applicable to such property. The cost of removal and salvage shall be charged or credited, as appropriate, to such depreciation account."

4. Electric Plant Instruction 10(F) states:

   > "The book cost less net salvage of depreciable electric plant shall be charged in its entirety to Account 108 Accumulated Provision for Depreciation of Electric Plant in Service…"

Q. Does the FERC USofA support Mr. Majoros's position on replacement costs?

A. In the passages above, the USofA is clear that Mr. Majoros is wrong. His unusual interpretation of the definition of "replacement," ignores clear instructions provided by FERC elsewhere in the USofA. The Company's accounting treatment of cost of removal is consistent with FERC's instructions. Further, any subsequent arguments made by Mr. Majoros regarding replacements are clearly incorrect and should be summarily rejected.

Q. Has Mr. Majoros made some unsubstantiated claims with regards to the topic of regulatory liabilities?

A. Yes. First, regulatory liabilities relate to financial reporting not regulatory ratemaking. Thus, it is not applicable to depreciation rates as depreciation for ratemaking purposes includes recovery of the full service value of an asset which by definition includes the cost of removal and gross salvage amounts.

Q. Why would utility companies have a regulatory liability on their financial statements?

A. Because, as common practice, a utility accrues for the end of life costs, cost of removal and gross salvage, while the asset is in service. The end of life costs for current assets are greater than the incurred costs of the assets being retired today. Thus, as expected, the net salvage accrual is greater than the net salvage expense. So for financial reporting purposes a regulatory liability is recorded.

Q. Is the approach used by LG&E accepted and consistent with depreciation practices?

A. Yes, the approach is accepted by the leading texts on depreciation such as NARUC's *Public Utility Depreciation Practices; Depreciation Systems* by Wolf and Fitch; and *Introduction to Depreciation and Net Salvage* by EEI/AGA.

The LG&E approach has been used and accepted at the state jurisdiction level as well as FERC for many years.

Q. Has NARUC recommended your approach of accounting for net salvage?

A. Yes. The NARUC Manual recommends the accounting for net salvage used by LG&E. NARUC states on page 18:

> Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. The goal of accounting for net salvage is to allocate the net cost of an asset to accounting periods, making due allowance for net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.

NARUC's entire discussion on page 18 related to the net salvage analyses are set in the context of the common methodology for recovery of net salvage. NARUC also recognizes that this treatment:

> … tends to remove from the income statement any fluctuation caused by erratic, although necessary, abandonment and removal operations. It also has the advantage that current customers pay or receive a fair share of costs associated with the property devoted to their service, even though the costs may be estimated.

NARUC Manual, 1996, page 18.

Further, on page 157, NARUC discusses historical practices of state commissions related to net salvage:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of its retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

Q. Is it true that the Company accrues more net salvage than it actually spends each year?

A. Net salvage costs will be incurred in the future. Collecting those costs over the service life of the asset is the basic principle of depreciation. Net salvage expenditures for each year are based on retirements of property that has been in service for many years. Future net salvage expenditures will be based on all plant that is currently in service today. Due to system growth and inflation, annual retirements in the future will exceed current levels of retirements. As a result, future levels of net salvage expenditures will be higher in dollar terms than what the Company currently spends each year. For this reason it is unsurprising that net salvage accruals exceed net salvage expenditures each year. Similarly, depreciation accruals exceed retirements each year, and additions exceed retirements in most years.

Q. Is it appropriate to ask current customers to pay for future costs of removal or net salvage?

A. Yes it is. The future cost of removal or net salvage on an item of plant is part of the service value that it renders to current customers and a ratable portion of such costs should be recovered from these customers. Again that is the definition of depreciation, the loss in service value during a specific period. As these future costs are recovered from current customers, they are deducted from rate base. This deduction in the amount on which the utility is entitled to earn a fair return, in effect, represents a return to customers. That is, as customers provide for the future cost of removal, they receive a return on such accounts, in the form of a reduction in the return they otherwise would have to pay the utility. This is fair compensation for making payment prior to the cost incurrence by the utility.

Q. **Are there regulatory requirements related to net salvage?**

A. Yes. The following excerpt from the 1996 NARUC Manual, page 18, addresses this concept:

> Under presently accepted concepts, the amount of depreciation to be accrued over the life of an asset is its original cost less net salvage. Net salvage is the difference between the gross salvage that will be realized when the asset is disposed of and the cost of removing it. Positive net salvage occurs when gross salvage exceeds cost of removal, and negative net salvage occurs when cost of retirement exceeds gross salvage. Net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired. The goal of accounting for net salvage is to allocate the net cost of an asset to annual accounting periods, making due allowance for the net salvage, positive or negative, that will be obtained when the asset is retired. This concept carries with it the premise that property ownership includes the responsibility for the property's ultimate abandonment or removal. Hence, if current users benefit from its use, they should pay their pro rata share of the costs involved in the abandonment or removal of the property and also receive their pro rata share of the benefits of the proceeds realized.
>
> This treatment of salvage is in harmony with generally accepted accounting practices and tends to remove from the income statement any fluctuations caused by erratic, although necessary, abandonment and uneconomical removal operations. It also has the advantage that current consumers pay or receive a fair share of costs associated with the property devoted to their service, even though the costs may be estimated.

Thus, under regulatory accounting, it is evident that depreciation is intended to include a component for net salvage. It is important to note no reference is made in this passage to present value or normalized net salvage amounts. In fact, the passage describes how to calculate a net salvage allowance.

Q. **Are the principles of the traditional net salvage approach outlined in the FERC USofA?**

A. Yes. The FERC USofA outlines the principles for determining net salvage accruals. The FERC USofA defines depreciation as "the loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of property in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance."

The operative words in this definition are service value. The FERC USofA goes on to define service value as "the difference between the original cost and the net salvage value of the utility plant", not as just the original cost. The service value rendered by an asset, i.e., depreciation, must reflect both its original cost and its net salvage.

Q. Does the FERC USofA also address the manner in which depreciation is to be recognized?

A. Yes, it does. The FERC USofA requires that depreciation be recognized through accrual accounting. That is, the service value of an asset must be accrued during the life of the asset. Because net salvage is a part of the service value, it must be accrued during the life of the related asset in order to comply with the FERC USofA.

Q. Why should ratemaking follow the procedure outlined in the FERC USofA?

A. The FERC USofA was developed for public utilities and adopted by regulatory commissions to provide useful information for regulatory reporting and ratemaking purposes.

Q. Is there a need for the Commission to specifically recognize a regulatory liability for regulatory and rate-making purposes?

A. No, there is not. There is no need to recognize a financial accounting entry for ratemaking purposes, particularly when it is contrary to the cardinal ratemaking tenet of intergenerational equity.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF PENNSYLVANIA)
) SS:
COUNTY OF CUMBERLAND)

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is Senior Vice President, Valuation and Rate Division for Gannett Fleming, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos
JOHN J. SPANOS

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of October 2012.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2015

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2015
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

ATTACHMENT JJS-R1

CHAPTER VIII

ACTUARIAL LIFE ANALYSES

Knowing what happened yesterday may help one to better understand what is happening today and what may happen tomorrow. This is also true with depreciation studies. Historical life analysis is the study of past occurrences that may be used to indicate the future survivor characteristics of property. Accumulation of suitable data is essential in an historical life analysis. As discussed in the previous chapter, the detail available in the data determines the kinds of analyses (actuarial v. simulation) that can be performed. Understanding the data is necessary in order to assess the limitations and application of the data in reflecting future events. Informed judgment plays a major role in determining how the data should be interpreted and used.

Actuarial analysis is the process of using statistics and probability to describe the retirement history of property. The process may be used as a basis for estimating the probable future life characteristics of a group of property.

Actuarial analysis requires information in greater detail than do other life analysis models (e.g., turnover, simulation) and, as a result, may be impractical to implement for certain accounts (see Chapter VII). However, for accounts for which application of actuarial analysis is practical, it is a powerful analytical tool and, therefore, is generally considered the preferred approach.

Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or capital budgets.

Mortality History

The purpose of actuarial analysis is to analyze the life characteristics of the utility's property using the historical data contained in the Continuing Property Records (CPR) (see Chapter III). In order to be used in actuarial analyses, the database must contain the property's year of installation (i.e., vintage) and year of retirement. Since the property records are maintained primarily for purposes other than depreciation studies (e.g., for capital budgeting or to accurately reflect a utility's plant), they may require adjustment before use in a depreciation study.

The Treatment of Adjustments and Transfers

The company's property records may contain adjusting entries and transfers (see Chapter III). In the treatment of these adjustments and transfers for preparing life tables, all plant exposed to the forces of retirement at any time during the age interval must be included as an exposure at the beginning of the age interval.

The retirement ratio can be used to depict history or to forecast future activity. These contexts require two differing approaches to the handling of transfers, accounting errors, and adjustments. These two concepts are discussed separately below.

Depiction of History

When determining whether a particular accounting entry is to be included in either exposures or retirements, the criterion is whether the data accurately represent history. The analyst should remember that accurately representing the history of the physical asset may be different from accurately representing the history of the investment. Unusual retirements, or retirements based on outdated accounting methods (i.e., changing of the capitalization threshold), should not be adjusted when the goal is to restate history, as long as those retirements accurately reflect the history.

Conversely, items such as accounting errors, which misstate the history of the investment under study, should be adjusted. For example, assume a retirement in an activity year (year 1) is made from the wrong vintage (vintage A, where the correct vintage is B) and is corrected in a subsequent activity year.

The correction includes the following steps:

1. Excluding the retirement from vintage A in activity year 1 and restating the closing balance in activity year 1 and all subsequent activity years, for that vintage, and

2. Making the retirement in vintage B in activity year 1 and restating the closing balance in activity year 1 and all subsequent activity years, for that vintage.

Forecast of Future Activity

In general, historical data used to forecast future retirements should not contain events that are either anomalous or unlikely to recur. Therefore, in making adjustments to the data, the analyst must consider the purpose of the analysis. Often the same data and the same analysis will be used both as a statement of history and as a basis for forecasting.

A sizable benefit may be obtained for a relatively minor incremental cost if the general principles are adhered to in the initial data collection phase. This is particularly true because the time required to appropriately adjust the data benefits both the current study and all future studies.

Despite the benefits of collecting good data, often the decision is made to proceed with the data "as is." In these instances, the analyst must keep in mind the nature of any transfers, anomalies, or adjustments present in the data; how they may affect the result; and how the result of the analysis is going to be used.

Retirements Subject to Reimbursement

Retirements may be subject to reimbursement from various sources. For example, wood poles in either the telephone or electric industries may be retired subject to reimbursement from an insurance company (e.g., a pole damaged by an automobile) or the government (e.g., a line of poles that must be retired due to street or highway work). Depending on the accounting treatment for reimbursements related to retired property, the analyst may need to remove such plant from the database. If the reimbursement is recorded as salvage, no adjustment of retirement data would be necessary, assuming that such salvage is also considered in establishing future depreciation rates. Consistent treatment is the rule.

Banding

Banding is the compositing of a number of years of data in order to merge them into a single data set for further analysis. Often, several bands are analyzed. By making determinations of the life and retirement dispersion indicated in successive bands, the analyst can get a clear indication of whether there is a trend in either the life of the plant or in the dispersion of the retirements.

In general, there are three reasons to use bands:

1. *Increase the sample size.* In statistical analyses, the larger the sample size in relation to the universe (the body of all data), the greater the reliability of the result (i.e., the greater the probability that the results will be applicable to the universe as a whole).

2. *Smooth the observed data.* Generally, the data obtained from a single activity or vintage year will not produce an observed life table that can be easily fit.

3. *Identify trends.* By looking at successive bands, the analyst may identify broad trends in the data that may be useful in projecting the future life characteristics of the property.

The following sections discuss placement bands and experience bands, as well as different types of bands—rolling, shrinking, and fixed.

Placement Bands

Placement bands show, for a group of vintages, the composite retirement history from the property's placement in service to the present. Placement bands allow the analyst to isolate the effects of changes in technology and materials that occur in successive generations of plant. For example, consider a telephone company that installed air-core buried cable before a given year and jelly-filled cable thereafter. In order to identify the differences in service life and retirement dispersion between the two types of cable, one might want to look at a placement band consisting of all vintages prior to the changeover and a second band of all vintages after the changeover.

An advantage of placement bands is that they generally yield smooth curves when based on fairly narrow bands. Unfortunately, placement bands yield fairly complete curves only for the oldest vintages. The newest vintages, presumably of greater interest in forecasting, yield the shortest stub curves.

Experience Bands

Experience bands show the composite retirement history for all vintages during a select set of activity years. These bands allow the analyst to isolate the effects of the operating environment over time.

Experience bands yield the most complete curves for the recent bands because they have the greatest number of vintages (ages) included. However, they may require significant smoothing because the data for each age is independent of the data for other ages. This independence can result in an erratic retirement dispersion.

Experience bands require that during the experience band, in order to construct an observed life table, at least one vintage in the band must be at age zero.

Types of Bands

There are several ways to select placement and experience bands. Rolling bands and shrinking bands may be useful in identifying trends in the data. These bands, along with fixed bands, are discussed below.

Rolling. To set up rolling bands, the analyst selects beginning and ending years for the initial band. The second band has beginning and ending points x years (usually one year) later than those of the first band; the third band has beginning and ending points each x years (usually one year) later than those of the second band; and so on. The result is a series of "rolling" bands of identical width as shown in the sample three-year rolling bands below:

Band 1:	1990	1991	1992		
Band 2:		1991	1992	1993	
Band 3:			1992	1993	1994

Rolling bands are useful in isolating and identifying the effects of specific events or changes that affect the life and retirement dispersion of the plant. However, rolling placement bands have the disadvantage of producing short observed life tables for recent placement bands.

Shrinking. To set up shrinking bands, the analyst selects a wide band (often the band is much wider than would be used for any other type of banding). Generally, the last year in the band is the most recent year of data. Successive bands are derived by dropping one or more years from the beginning of the band.

The advantage of shrinking bands anchored at the most recent year is that all of the resulting bands contain the most recent data. Each successive band more strongly reflects the effect of the more recent data. This is especially useful with placement bands, for which the more recent bands result in shorter survivor curves.

Fixed. Fixed bands are generally of a selected width and are nonoverlapping. They are often selected in order to investigate the impact of certain events on the company's property. They are less useful than rolling and shrinking bands in revealing trends. However, fixed bands generate a more manageable number of bands to review.

Selection of Bands and Band Width

The analyst must select a band width (number of activity years to include in the band) which meets two, often conflicting, constraints: (1) The band must include enough data to provide some confidence in the reliability of the resulting curve fit; and (2) the band must be narrow enough that an emerging trend can be observed. Bands of three to five years are often chosen for rolling or fixed bands. However, for longer life plant (e.g., conduit), widths of ten or more years may be necessary.

The Observed Life Table Exhibit

The observed life table exhibit (Table 8-1) presents the exposures, retirements, retirement ratio, survival ratio, and life table values (percent surviving) for each age interval. To illustrate

TABLE 8-1

OBSERVED LIFE TABLE EXHIBIT

Band 1992 - 1994

Age	Exposures	Retirements	Retirement Ratio	Survival Ratio	Observed Life Table
(A)	(B)	(C)	(D)=(C)/(B)	(E)=1 - (D)	$(F)_{(x)}=F_{(x-1)} * E_{(x-1)}$
0	4,843,776	9,705	0.00200	0.99800	100,000
0.5	4,761,957	23,810	0.00500	0.99500	99,800
1.5	5,298,919	52,989	0.01000	0.99000	99,301
2.5	5,825,563	87,383	0.01500	0.98500	98,308
3.5	6,462,684	129,254	0.02000	0.98000	96,833
4.5	4,343,837	108,596	0.02500	0.97500	94,896
5.5	3,145,870	94,376	0.03000	0.97000	92,524
6.5	2,309,272	80,825	0.03500	0.96500	89,748
7.5	2,864,124	114,565	0.04000	0.96000	86,607
8.5	2,294,969	103,274	0.04500	0.95500	83,143
9.5	1,695,740	84,787	0.05000	0.95000	79,401
10.5	725,080	39,879	0.05500	0.94500	75,431
11.5	585,138	35,108	0.06000	0.94000	71,283
12.5	449,968	29,248	0.06500	0.93500	67,006
13.5	369,726	25,881	0.07000	0.93000	62,650
14.5	309,333	23,200	0.07500	0.92500	58,265
15.5	340,553	27,244	0.08000	0.92000	53,895
16.5	289,195	24,582	0.08500	0.91500	49,583
17.5	188,651	16,979	0.09000	0.91000	45,369
18.5	49,802	4,731	0.09500	0.90500	41,285
19.5					37,363
Total All	47,154,157	1,116,416			1,482,691

the development of the observed life table values, a sample chart "Summary of Historical Mortality Data" (Table 8-2) containing both exposures and retirements for each vintage from 1975 to 1994 is used. For each vintage, the investment exposed to retirement at the beginning of each age interval is shown on the same line as the year placed. On the following line, the vintage's retirements during each age interval are shown.

The half-year convention is used in Table 8-2. Retirements that occurred between age 0.0 and 0.5 years are shown under the heading N=0. Retirements that occurred between age 0.5 and 1.5 years, and the exposures that are 1.5 years old at the end of the age interval, are shown under the heading N=1, and so on. Using the half-year convention, the first age interval (N=0) has a width of 0.5 years from age 0.0 (a new installation) to age 0.5 (the end of the calendar year in which the plant entered service). Later age intervals have a width of one year.

Consider a three-year experience band for the years 1992 through 1994. The plant exposures and retirements for this band form a diagonal strip with a width of three years through Table 8-2 ascending from the lower left to the upper right (see the data between the two double lines).

The exposures and retirements for the 1992-1994 band are summed by age interval and depicted at the bottom of Table 8-2. The data at each age relates to the activity years 1992, 1993, and 1994, as explained below:

Age 0: The exposures ($4,843,776) represent plant added in 1992 through 1994, and the retirements ($9,705) represent the amount of these additions retired between 1992 and 1994 (i.e., in the same year in which they were placed).

Age 1: The exposures ($4,761,957) represent plant added in 1991 through 1993 that is surviving one year after placement. The retirements ($23,810) represent the amount of these additions retired between 1992 and 1994 (i.e., one year after placement).

Age 2: The exposures ($5,298,919) represent plant added in 1990 through 1992 that is surviving two years after placement. The retirements ($52,989) represent the amount of these additions retired between 1992 and 1994 (i.e., two years after placement), and so on.

Once the exposures and retirements by age interval have been developed for a band, the retirement ratios, survival ratios, and life table values (percents surviving) are calculated. The retirement ratio for an age interval is calculated by dividing the retirements during the age interval by the exposures at the beginning of the age interval. The survival ratio is one minus the retirement ratio. The percent surviving at the end of an age interval is calculated by multiplying the percent surviving for the previous age interval by the survival ratio for the current age interval. The observed life table begins with a value of 100% (or 1.0) at age zero.

TABLE 8-2
SUMMARY OF HISTORICAL MORTALITY DATA

Year Placed	Total Amount of Plant Placed	Total Amount of Plant Retired	Total Amount of Plant Still in Service	Nth Year After Year of Placing — UPPER FIGURES: Plant Remaining in Service At Beginning of Nth Calendar Year After Year of Placing; LOWER FIGURES: Plant Retired During Nth Year After Year of Placing							
				N = 0	1	2	3	4	5	6	7
1975	120,672	75,601	45,071	-	120,387	119,785	118,587	116,808	114,472	111,610	108,262
				285	602	1,198	1,779	2,336	2,862	3,348	3,789
1976	295,287	173,417	121,870	-	294,597	293,124	290,193	285,840	280,123	273,120	264,926
				690	1,473	2,931	4,353	5,717	7,003	8,194	9,272
1977	167,490	91,528	75,962	-	167,098	166,263	164,600	162,131	158,888	154,916	150,269
				392	835	1,663	2,469	3,243	3,972	4,647	5,259
1978	169,323	85,397	83,926	-	168,923	168,078	166,398	163,902	160,624	156,608	151,910
				400	845	1,681	2,496	3,278	4,016	4,698	5,317
1979	194,280	89,609	104,671	-	193,825	192,856	190,927	188,063	184,302	179,695	174,304
				455	969	1,929	2,864	3,761	4,608	5,391	6,101
1980	226,742	94,676	132,066	-	226,212	225,081	222,830	219,488	215,098	209,720	203,429
				530	1,131	2,251	3,342	4,390	5,377	6,292	7,120
1981	250,743	93,705	157,038	-	250,156	248,905	246,416	242,720	237,866	231,919	224,961
				587	1,251	2,489	3,696	4,854	5,947	6,958	7,874
1982	343,663	113,468	230,195	-	342,858	341,144	337,732	332,666	326,013	317,863	308,327
				805	1,714	3,411	5,066	6,653	8,150	9,536	10,791
1983	367,167	105,531	261,636	-	366,306	364,474	360,830	355,417	348,309	339,601	329,413
				860	1,832	3,645	5,412	7,108	8,708	10,188	11,529
1984	1,423,589	348,641	1,074,948	-	1,422,214	1,415,103	1,400,952	1,379,938	1,352,339	1,318,530	1,278,974
				1,375	7,111	14,151	21,014	27,599	33,808	39,556	44,764
1985	968,495	199,759	768,736	-	966,225	961,394	951,780	937,503	918,753	895,784	868,911
				2,270	4,831	9,614	14,277	18,750	22,969	26,874	30,412
1986	914,111	154,353	759,758	-	911,969	907,409	898,335	884,860	867,163	845,484	820,119
				2,142	4,560	9,074	13,475	17,697	21,679	25,365	28,704
1987	691,326	92,793	598,533	-	689,706	686,257	679,395	669,204	655,820	639,424	620,242
				1,620	3,449	6,863	10,191	13,384	16,395	19,183	21,708
1988	1,794,969	183,836	1,611,133	-	1,791,573	1,782,615	1,764,789	1,738,317	1,703,551	1,660,962	1,611,133
				3,396	8,958	17,826	26,472	34,766	42,589	49,829	
1989	2,091,388	156,534	1,934,854	-	2,087,003	2,076,568	2,055,802	2,024,965	1,984,466	1,934,854	
				4,385	10,435	20,766	30,837	40,499	49,612		
1990	2,786,937	141,523	2,645,414	-	2,782,102	2,768,191	2,740,510	2,699,402	2,645,414		
				4,835	13,911	27,682	41,108	53,988			
1991	1,047,328	33,516	1,013,812	-	1,044,872	1,039,648	1,029,251	1,013,812			
				2,456	5,224	10,396	15,439				
1992	1,501,303	25,134	1,476,169	-	1,498,573	1,491,080	1,476,169				
				2,730	7,493	14,911					
1993	2,222,862	15,443	2,207,419	-	2,218,512	2,207,419					
				4,350	11,093						
1994	1,119,611	2,625	1,116,986	-	1,116,986						
				2,625							
TOTAL	18,697,286	2,277,085	16,420,201								

Three-Year Bands		Age of Plant Remaining January 1 of any year							
		0.0	0.5	1.5	2.5	3.5	4.5	5.5	6.5
1992-1994	Exposures	4,843,776	4,761,957	5,298,919	5,825,563	6,462,684	4,343,837	3,145,870	2,309,272
Between = = Lines	Retirements	9,705	23,810	52,989	87,383	129,254	108,596	94,376	80,825

TABLE 8-2 (continued)
SUMMARY OF HISTORICAL MORTALITY DATA

Year Placed	Nth Year After Year of Placing — UPPER FIGURES: Plant Remaining in Service At Beginning of Nth Calendar Year After Year of Placing; LOWER FIGURES: Plant Retired During Nth Year After Year of Placing												
	8	9	10	11	12	13	14	15	16	17	18	19	20
1975	104,473	100,294	95,781	90,992	85,987	80,828	75,574	70,284	65,013	59,812	54,728	49,802	45,071
	4,179	4,513	4,789	5,005	5,159	5,254	5,290	5,271	5,201	5,084	4,925	4,731	
1976	255,654	245,428	234,384	222,664	210,418	197,793	184,936	171,991	159,091	146,364	133,923	121,870	
	10,226	11,044	11,719	12,247	12,625	12,857	12,946	12,899	12,727	12,441	12,053		
1977	145,009	139,209	132,944	126,297	119,351	112,190	104,897	97,555	90,238	83,019	75,962		
	5,800	6,264	6,647	6,946	7,161	7,292	7,343	7,317	7,219	7,057			
1978	146,593	140,729	134,396	127,677	120,654	113,415	106,043	98,620	91,224	83,926			
	5,864	6,333	6,720	7,022	7,239	7,372	7,423	7,397	7,298				
1979	168,203	161,475	154,209	146,498	138,441	130,134	121,676	113,158	104,671				
	6,728	7,266	7,710	8,057	8,306	8,459	8,517	8,487					
1980	196,309	188,456	179,976	170,977	161,573	151,879	142,007	132,066					
	7,852	8,481	8,999	9,404	9,694	9,872	9,940						
1981	217,088	208,404	199,026	189,075	178,676	167,955	157,038						
	8,684	9,378	9,951	10,399	10,721	10,917							
1982	297,535	285,634	272,780	259,141	244,889	230,195							
	11,901	12,854	13,639	14,253	14,693								
1983	317,884	305,168	291,436	276,864	261,636								
	12,715	13,733	14,572	15,228									
1984	1,234,210	1,184,842	1,131,524	1,074,948									
	49,368	53,318	56,576										
1985	838,499	804,959	768,736										
	33,540	36,233											
1986	791,415	759,758											
	31,657												
1987	598,533												
1988													
1989													
1990													
1991													
1992													
1993													
1994													
TOTAL													
3-year bands	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	
1992-1994	2,864,124	2,294,969	1,695,740	725,080	585,138	449,968	369,726	309,333	340,553	289,195	188,651	49,802	
between = =	114,565	103,274	84,787	39,879	35,108	29,248	25,881	23,200	27,244	24,582	16,979	4,731	

The calculations discussed above are summarized below:

1. Retirement Ratio for age interval (n):
   $\text{Retirement Ratio}_n = \text{Retirements}_n / \text{Exposures}_n$

2. Survival Ratio for age interval (n):
   $\text{Survival Ratio}_n = 1 - \text{Retirement Ratio}_n$

3. Percent Surviving at end of age interval (n):
   $\text{Percent Surviving}_n = \text{Percent Surviving}_{n-1} \times \text{Survival Ratio}_{n-1}$

Curve Fitting Techniques

Plotting the Survivor Curve

Although the analyst may find it helpful to plot the retirement ratios and survival ratios from the observed life table, generally, the percents surviving are plotted. These points may be connected to form an observed survivor curve as shown in Figure 8-1. The most common difficulties in using this curve are discussed in the following sections.

Stub Curve

An observed survivor curve that does not reach 0% surviving is a stub. Because the average life associated with a survivor curve is represented by the area under the *complete* curve, the observed survivor curve must be smoothed and extended to 0% surviving, as discussed later in this chapter. The longer the stub, the more reliable the resulting curve fit and extension. As a result, the analyst may be forced to choose between a more reliable longer stub, which by necessity reflects older data, and a less reliable shorter stub, which reflects more recent vintages and, therefore, is more likely to reflect the future.

It is generally considered desirable to have the stub curve drop below 50% surviving. It is understood, however, that this is not always possible since some accounts have so few retirements that none of the placement or experience bands produces survivor curves that meet this test.

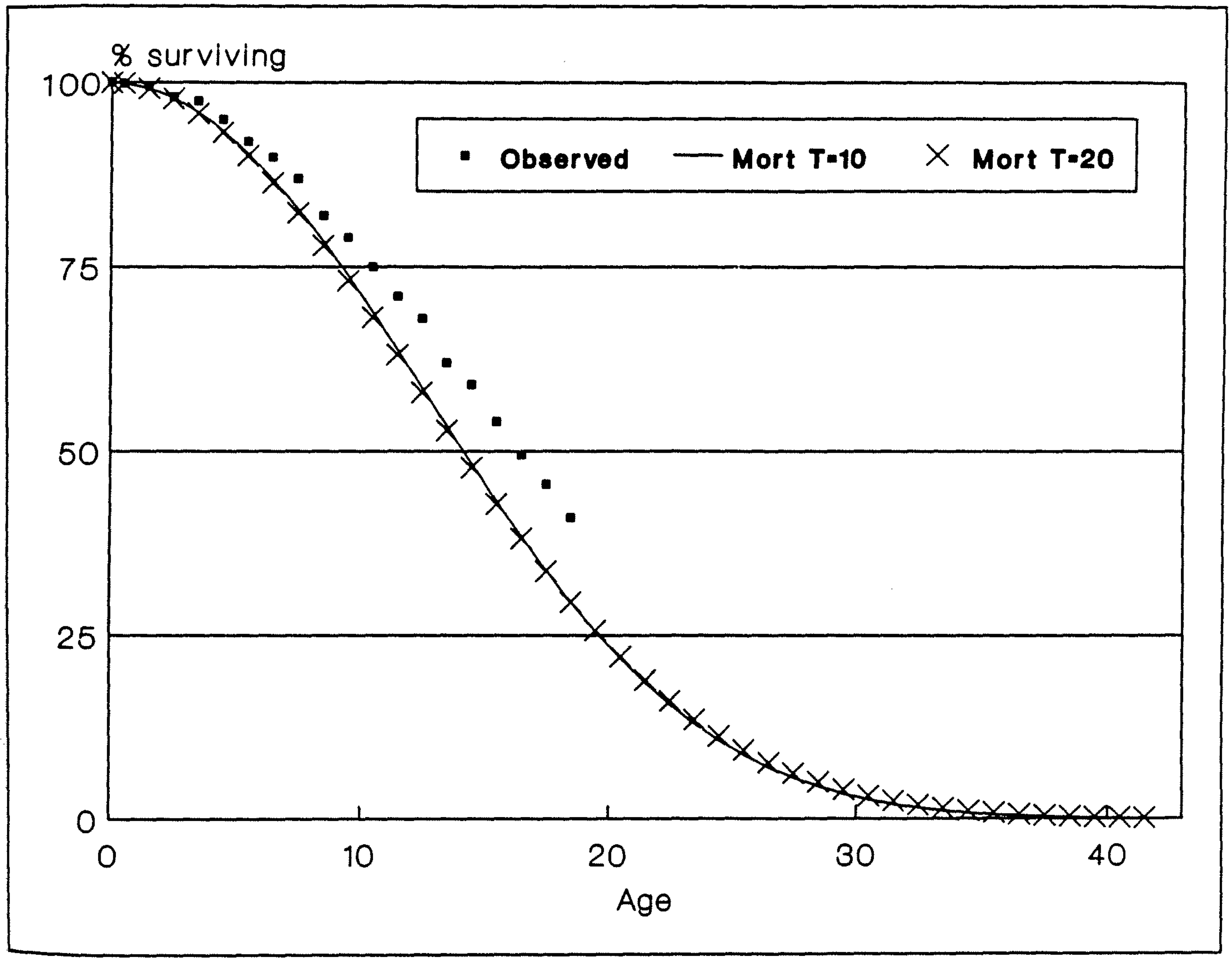


Fig. 8-1 Comparison of Observed Data and Graduated Survivor Curves.

Data Irregularities

Property that exhibits homogenous life characteristics produces smooth survivor curves. Many of a utility's property accounts, however, have experienced change in the forces of retirement due to, for example, changes in a utility's services or capital budgets. These accounts may exhibit a number of irregularities. For example, the survivor curves may look like stair steps as the different changes take effect. Extended leveling-off periods may result from reasons such as delayed booking of retirements during an accounting system conversion. Irregularities at the older ages of the survivor curve often result from inadequate exposures.

Bimodality. Bimodality, the presence of two peaks on the retirement frequency curve, was once considered to be a new curve shape. Later study, however, revealed that bimodality results from superimposing two distinct retirement frequency curves, each with its own mode. This results from a lack of homogeneity in the property, such as occurs when low-volume and high-volume gas meters with different retirement dispersions are included in one account.

Bimodality should be investigated by attempting to separate the two groups by either selecting different placement or experience bands (assuming the lack of homogeneity is due to differences in technologies or environments over time) or segregating the raw data (as would be required in the above gas meters example). Minor stair steps or flat areas of curves may be ignored. Where appropriate, significant occurrences should be removed from consideration either through the selection of different bands or through the use of a Truncation-cut (T-cut).

T-cuts. A T-cut is a truncation of the observed life table values and is generally used in a mathematical fitting of a curve to the observed values. A T-cut is used to mathematically perform a function that is automatic in visual fitting (i.e., setting a point beyond which the observed data are considered irrelevant or unreliable and are, therefore, ignored).

Careful selection of a T-cut can greatly enhance the reliability of the resulting analysis. Conversely, since the use of a T-cut involves truncating the observed data, careless selection can impair the reliability of subsequent work.

In Figure 8-1, two different "best fits" of Gompertz-Makeham curves based on the least sum of squared deviations are shown. The difference between the two best fits is that one is based on the entire observed survivor curve and the other has a T-cut established at 13 years. The location of the T-cut can affect the resulting best fit curve. By excluding only a few ages by a T-cut, the shape and remaining life of the best fit curve may change.

The use of a T-cut can also have an adverse effect on reliability by creating a stub curve. The observed survivor curve at the early ages fits a large number of curves. This is particularly true where the mode of the retirement frequency curve is greater than the average life (i.e., the majority of retirements occur at later ages).

Both of the problems mentioned above are exacerbated when the T-cut occurs near the mode of the retirement frequency curve, i.e., the steepest portion of the survivor curve. Therefore, T-cuts near or at the mode of the retirement frequency curve should be avoided.

The following methods are generally used to smooth irregularities in the observed data or to extend a curve where data are lacking: (1) smoothing and extending the observed life table values, (2) smoothing and extending the retirement frequency curve, (3) smoothing and extending the retirement ratio curve, and (4) matching generalized survivor curves to the observed life table values. Each of these methods is discussed briefly below.

1. Smoothing and Extending the Observed Life Table Values

The Gompertz-Makeham formula, originally developed in connection with studies of human mortality, may be used to smooth and extend the observed life table values. The Gompertz-Makeham formula is:

$$l_x = k * s^x * g^{c^x} \tag{1}$$

where l_x is the number surviving at age x

The parameters k, s, g, and c are derived from the data in the observed life table. For further discussion of the derivation and application of the Gompertz-Makeham formula, see Appendix A, part 1.

2. Smoothing and Extending the Retirement Frequency Curve

This method is seldom used today. It is discussed to a limited degree in both the *1943 NARUC Report* and the *1968 NARUC Manual.*

3. Smoothing and Extending the Retirement Ratios

The Exposure-Weighted Gompertz-Makeham method graduates the observed mortality ratios, rather than the percents surviving, to determine the best fit. This application of the Gompertz-Makeham formula is mathematically superior to the original unweighted formula because retirement ratios are independent of observations at prior ages. The method is explained in detail in Appendix A, part 2.

There is another method of smoothing and extending the retirement ratios that predates the Exposure-Weighted Gompertz-Makeham method and has been in use for many years. This method is referred to simply as "smoothing the retirement ratios." It involves fitting a smooth curve to the observed retirement ratios and then extending the curve. The extended fitted curve is used to develop the smoothed survivor curve. Originally, an unweighted fit to the retirement ratios was used but a weighted fit process was later developed. This method is also further discussed in Appendix A, part 4.

4. Matching Generalized Curves to the Observed Life Table Values

In lieu of using mathematical models to smooth and extend the observed percents surviving, one may match generalized curve shapes to the observed life table values.

Iowa Curves. Probably the most widely used of the standard curve sets, the Iowa curves were originally conceived by Edwin Kurtz and developed by Robley Winfrey. They may be found in *Bulletin 125* published by the Iowa Engineering Station (now the Engineering Research Institute) of Iowa State University. Based on empirical analyses of the retirement histories of various forms of utility, railroad, industrial, and agricultural equipment, Winfrey derived three general classes of curves—L, S, and R. Frank Couch, Industrial Engineering Department, Iowa State University, expanded the family of Iowa curves by adding the O curves.

Bell Curves. The Bell curves, developed by the Bell telephone companies, are standardized Gompertz-Makeham curves and are largely used only in the telephone industry. Each Bell curve (from 0.0 through 5.5) has a set of c, G, and S values.

h Curves. The h curves, published in 1947, were developed by Bradford Kimball of the New York Public Service Commission staff. They are based on a normal statistical distribution of retirements (bell-shaped curve), with the tail truncated at various standard deviations.

For a more detailed discussion of generalized curves, see Appendix A, parts 3 and 5.

Visual Matching

Graphs of the various standard curves are available. While visual matching is still used, it is more time consuming than mathematical matching and so is generally used only in educational settings or as an adjunct to mathematical matching.

First, the observed life table is plotted to the same scale as one of the available published overlays. Successive overlays are then applied to the plotted survivor curve until a good correlation between the observed data points and the published curve is noted. An experienced eye can often cut this process short by eliminating certain classes of standard curves. Elimination is based on the appearance of the observed data once plotted. High resolution computer graphics have automated the visual matching process.

Mathematical Matching

Without the use of computers, mathematical matching would be impractical due to the number of calculations involved in determining the goodness of fit of a single curve. Since the Bell curves are essentially Gompertz-Makeham curves, the mathematical matching proceeds similarly for both types of curves. For the Iowa and h curves, mathematical matching consists of comparing the observed data to standard tables of the percent surviving at each age and calculating the goodness of fit between the observed data and the standardized curves.

Generally, the goodness of fit criterion is the least sum of squared deviations. The difference between the observed and projected data is calculated for each data point in the observed data. This difference is squared, and the resulting amounts are summed to provide a single statistic that represents the quality of the fit between the observed and projected curves.

The difference between the observed and projected data points is squared for two reasons:

(1) the importance of large differences is increased, and (2) the result is a positive number, hence the squared differences can be summed to generate a measure of the total absolute difference between the two curves. The curves with the least sum of squared deviations are considered the best fits. The intent is not to select the one *best* curve but to consider the indicated patterns.

Interpreting the Results

Once data assembly and property grouping have been completed, the next step is to determine how to use this information. Several techniques are available to detect changes in the property. For example, placement bands may be used to show the effects of technological and material changes, whereas experience bands are used to show the effects of business and operational changes. Such banding is necessary because the analyst does not have access to a database wherein each factor (e.g., change in materials/technology or operational environment) is held constant.

In order to help identify the effect of trends in the historical data, analysts in the telecommunications field often use "worm charts," so called for their resemblance to the shape of a worm. Figure 8-2, a worm chart, shows the indicated life obtained from each band.

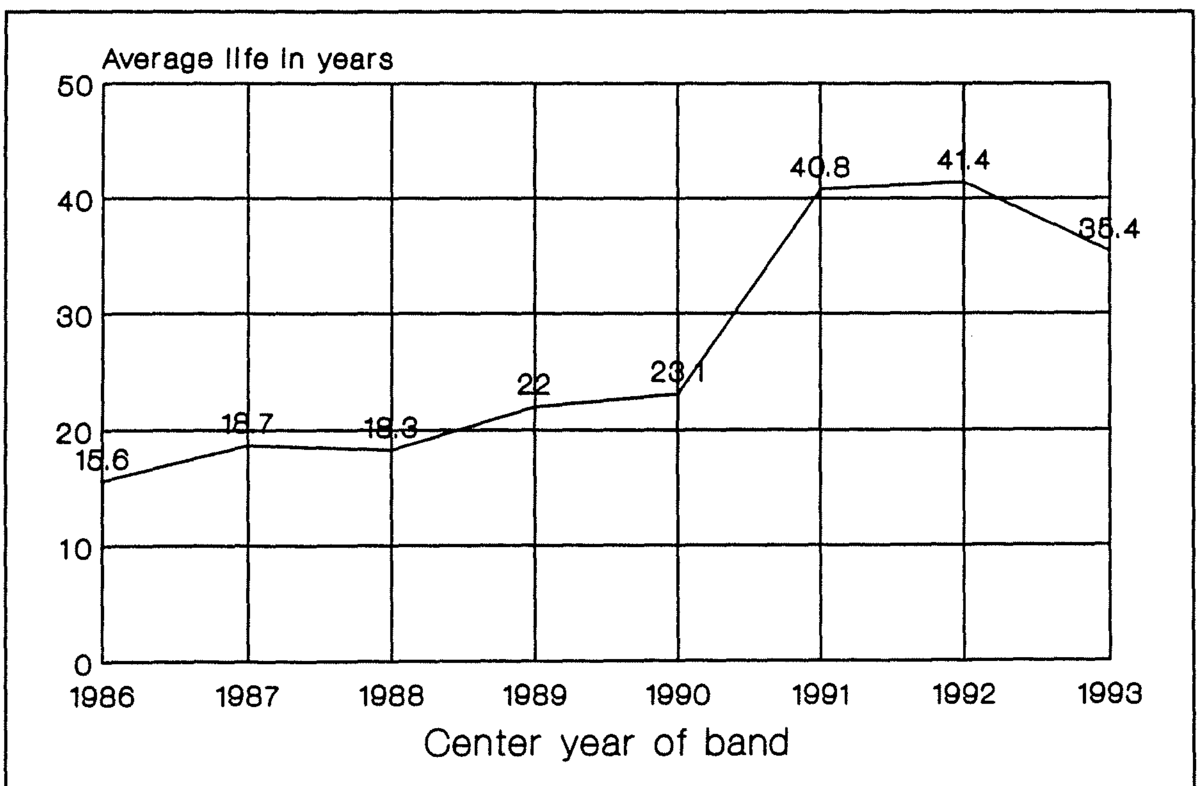


Figure 8-2. Worm Chart—Three-Year Band.

Selecting the Projection Life Curve

The projection life is a projection, or forecast, of the future of the property. Historical indications may be useful in estimating a projection life curve. Certainly the observations based on the property's history are a starting point. Trends in life or retirement dispersion can often be expected to continue. Likewise, unless there is some reason to expect otherwise, stability in life or retirement dispersion can be expected to continue, at least in the near term.

Depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions. The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future. The importance of being aware of circumstances having direct bearing on the reason for making an historical life analysis cannot be understated. These circumstances, when factored into the analysis, determine the application and limitations of an historical life analysis.

Past Indications as a Measure of Future Activity

How well does an historical life analysis reflect what may happen in the future? Will history repeat itself? These questions must be answered in order to use the results of an historical life analysis. The analyst should become familiar with the physical plant under study and its operating environment, including talking with the field people who use the equipment being studied. For example, such discussions could reveal unique circumstances that brought about premature retirement of certain property. If these circumstances are not likely to happen again, the analyst should modify the study to reflect what would likely happen based on present operating conditions. For example, if the analyst discovers that corrosive material used in equipment was used in a certain past period and noncorrosive improved material which lasts much longer is predominantly used now, the analyst should discount the period in which corrosive material was used as not being representative of future activity. For further discussion, see Chapter II.

Other Factors to be Considered

Company Plans

In addition to talking with field people, the analyst should talk with management. Understanding past and present company policies concerning maintenance practices and retirements will determine how well historical retirement patterns will be repeated in the future. A company might retire automobiles every three years and trucks every five years. This pattern would be present in the historical data; however, if management changes its policy, this retirement pattern would also change. Management might also reveal planned future retirements that follow no historical pattern. In such a case, the analyst could modify the historical retirement pattern to reflect management's plans for retirement of certain facilities. If management has chosen a specific date for the retirement of certain facilities, then these facilities would comprise a life span group.

Technical and Economic Obsolescence

Technical and economic obsolescence are ongoing and an historical life analysis will reflect these factors to the extent that they were present in the past. Knowing the types of property susceptible to obsolescence will help determine the applicability of the historical retirement patterns to depict future plant life. For example, computer equipment is susceptible to technical obsolescence. Its historical, present, and future usage should be considered. When a utility has a continuing discernable pattern of updating its computer equipment, the historical life analysis will reflect technical obsolescence. However, when this pattern is broken, historical retirement patterns should be altered to reflect future use.

An example of economic obsolescence in the gas industry is products extraction equipment. This type of equipment is used to extract marketable byproducts sometimes present in natural gas production. The life of this equipment will partly depend on the market for the byproducts. With no available market this equipment will not follow the historical retirement pattern.

Regulatory and Customer Requirements

The effects of regulation and customer requirements, the costs of which may be hard to quantify, should also be considered. Regulatory requirements can cause both inadequacy and obsolescence, e.g., specifying that gas mains must be made from specific material or that telecommunications cables and electric distribution lines must be placed underground.

The two requirements can sometimes combine to cause change. An example of this may be a zoning conversion from an industrial to a residential area, which would result in changes in customer service requirements. The old electric power distribution system, e.g., lines, poles, and transformers, might be subject to premature retirement as the system is replaced with perhaps an underground residential distribution system. Public authorities can require plant to be relocated because of its interference with planned public uses, such as highway or other public transportation projects. Plant may also be replaced because its design fails to meet public standards of safety or appearance (aesthetics).

Most utilities use public rights-of-way. Consequently, municipalities or other owners of these rights-of-way may require the utility to move its facilities. Again, this usually results in premature retirement of utility plant. Therefore, if a utility is conducting a depreciation study, and there are known or anticipated public improvements involving loss of rights-of-way (for which the utility will not be reimbursed), consideration of this fact should be given by the analyst in developing service lives.

Obsolescence may cause retirements of plant items by rendering them uneconomical, inefficient, or otherwise unfit for service because of improvement in the art and technology, or because of changes in function. Retirements of this sort are especially relevant in the telecommunications industry, as competition forces change to more efficient and technologically superior equipment. For example, the replacement of copper cable with fiber optic cable not only enhances the operational efficiency but also provides the potential for future applications mandated by the changing requirements of customers and market forces.

Growth

Growth in demand for utility service may cause present facilities to become inadequate. The service life of longer life property may be shortened because of the need for capacity to carry a greater load. Growth in demand should be examined for the impact on past retirements and the analyst should consider whether future growth will alter the historical trend of retirements. If growth was present in the past and is expected to be slow in the future, then the analyst might expect service lives in the future to be greater than in the past. The historical period might be filled with replacements that were improvements over the property being retired. On the other hand, if future growth is expected to be greater than past growth, service lives may decrease because present property might not be adequate to handle future demand.

Informed Judgment

A depreciation study is commonly described as having three periods of analysis: the past, present, and future. The past and present can usually be analyzed with great accuracy using many currently available analytical tools. The future still must be predicted and must largely include some subjective analysis. *Informed judgment* is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.

The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance. For example, the following forces of retirement need to be considered: Do the past and current service life dispersions represent the future? Will scrap prices rise or fall? What will be the impact of future technological obsolescence? Will the company be in existence in the future? The analyst must rank the factors and decide the relative weight to apply to each. The final estimate might not resemble any one of the specific factors; however, the result would be a decision based upon a combination of the components.

Judgment is not necessarily limited to forecasting and is used in situations where little current data are available. The analyst gathers what is known about a particular situation and modifies and refines the data to reflect the actual circumstances. The analyst's role in performing the study is to review the results and determine if they represent the mortality characteristics of the property. Using judgment, the analyst considers such things as personal experience, maintenance policies, past company studies, and other company owned equipment to determine if the stub curve represents this class of property.

The use of informed judgment sometimes becomes a point of controversy in the regulatory setting because some of the analyst's opinions cannot be quantified or easily supported. It is sometimes impossible to pinpoint the reasons for making a decision that diverges from a company's historical data or standard reference material. For instance, limited retirement data show that a new transformer design appears to have a significantly shorter service life; this would result in a significantly higher depreciation rate. Since this is a new design, there is no field experience to apply to the estimate, other than the scant data. Should the rate be based solely on the data? In the other extreme, should this preliminary data be given little weight and should the rate be based upon other types of transformers as reasonable indicators of the life of this new design? It is the analyst's responsibility to apply any additional known factors that would produce the best estimate of the service life. The analyst's judgment, comprised of a combination of experience and knowledge, will determine the most reasonable estimate.

In summary, several factors should be considered in estimating property life. Some of these factors are:

1. Observable trends reflected in historical data,
2. Potential changes in the type of property installed,
3. Changes in the physical environment,
4. Changes in management requirements,
5. Changes in government requirements, and
6. Obsolescence due to the introduction of new technologies.

ATTACHMENT JJS-R2

LOUISVILLE GAS AND ELECTRIC
ELECTRIC PLANT

COMPARISON OF CURRENT AND LOUISVILLE GAS AND ELECTRIC PROPOSED AND MAJOROS PROPOSED SURVIVOR CURVES

	ACCOUNT	CURRENT SURVIVOR CURVE	PROPOSED SURVIVOR CURVE	MAJOROS SURVIVOR CURVE	
	(1)	(2)	(3)	(4)	
	DEPRECIABLE PLANT				
	STEAM PRODUCTION PLANT				
311.00	STRUCTURES AND IMPROVEMENTS	100-S1.5	100-S1	225-S0.5	
312.00	BOILER PLANT EQUIPMENT	45-R1.5	50-R1.5	63.6-S0.5	*
312.01	BOILER PLANT EQUIPMENT - LOCOMOTIVE	25-R2	25-R2.5	25-R2.5	
312.02	BOILER PLANT EQUIPMENT - RAIL CARS	25-R2	25-R2.5	25-R2.5	
314.00	TURBOGENERATOR UNITS	50-S1.5	60-S1.5	27.30	*
315.00	ACCESSORY ELECTRIC EQUIPMENT	50-S2	55-S2	185.3-L0	
316.00	MISCELLANEOUS PLANT EQUIPMENT	40-S2	45-R2.5	45-R2.5	
	HYDROELECTRIC PRODUCTION PLANT				
331.00	STRUCTURES AND IMPROVEMENTS	100-S2.5	100-S2	100-S2	
332.00	RESERVOIRS, DAMS & WATERWAY	100-S2.5	100-S2.5	100-S2	
333.00	WATER WHEELS, TURBINES & GENERATORS	100-S2.5	100-S2.5	100-S2	
334.00	ACCESSORY ELECTRIC EQUIPMENT	80-S4	80-S4	83.9-S0.5	
335.00	MISCELLANEOUS PLANT EQUIPMENT	80-S3	80-S1.5	80-S1.5	
336.00	ROADS, RAILROADS & BRIDGES	80-S4	80-S4	91-L5	
	OTHER PRODUCTION PLANT				
341.00	STRUCTURES AND IMPROVEMENTS	55-R3	55-R3	112-S1	
342.00	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	50-R3	45-R2.5	66.8-L0	
343.00	PRIME MOVERS	30-R2	30-R2	171.7-O3	
344.00	GENERATORS	60-S3	60-S3	259-S0	
345.00	ACCESSORY ELECTRIC EQUIPMENT	35-S1.5	45-R3	148-R4	
346.00	MISCELLANEOUS PLANT EQUIPMENT	50-S3	50-S3	71-L4	
	TRANSMISSION PLANT				
350.10	LAND AND LAND RIGHTS	50-R3	60-R3	294-R2.5	
352.10	STRUCTURES AND IMPROVEMENTS	60-R2.5	55-R1.5	59.3-R0.5	
353.10	STATION EQUIPMENT	55-R2.5	55-R2.5	80-S0	
354.00	TOWERS AND FIXTURES	65-R3	70-R3	129.2-R2	
355.00	POLES AND FIXTURES	50-R2	53-R2	68.9-S0	
356.00	OVERHEAD CONDUCTORS AND DEVICES	50-R2	50-R2	154.9-O1	
357.00	UNDERGROUND CONDUIT	50-R3	55-R3	227-R2	
358.00	UNDERGROUND CONDUCTORS AND DEVICES	30-R3	35-R3	42.9-R4	
	DISTRIBUTION PLANT				
361.00	STRUCTURES AND IMPROVEMENTS	60-R3	50-L1.5	74.8-O3	
362.00	STATION EQUIPMENT	55-R1.5	50-R1.5	55-L0	
364.00	POLES, TOWERS, AND FIXTURES	50-R2.5	50-R2.5	59.8-R1	
365.00	OVERHEAD CONDUCTORS AND DEVICES	45-R1.5	50-R1.5	50.1-L1	
366.00	UNDERGROUND CONDUIT	70-R4	70-R4	77.4-L5	
367.00	UNDERGROUND CONDUCTORS AND DEVICES	50-R2	55-R3	82.2-L2	
368.00	LINE TRANSFORMERS	45-R1.5	45-R3	46-S3	
369.10	SERVICES - UNDERGROUND	45-R1.5	45-R2.5	50.4-L1.5	
369.20	SERVICES - OVERHEAD	45-S1.5	50-R2	69.9-L1	
370.00	METERS	30-R2	30-R2.5	53.5-O3	
373.10	STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD	30-L1	28-L0.5	28-L0.5	
373.20	STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND	35-R1.5	35-R2	40-R1	
	GENERAL PLANT				
392.10	TRANSPORTATION EQUIPMENT - CARS AND TRUCKS	5-SQ	7-L2.5	18.5-L1	
392.20	TRANSPORTATION EQUIPMENT - TRAILERS	30-S4	20-S1	32.4-L5	
392.30	TRANSPORTATION EQUIPMENT - HEAVY TRUCKS AND OTHER	5-SQ	14-S1.5	14-S1.5	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	25-SQ	25-SQ	
396.10	POWER OPERATED EQUIPMENT - SMALL MACHINERY	5-SQ	8-L2	43.8-O2	
396.20	POWER OPERATED EQUIPMENT - OTHER	30-R1.5	17-L3	26.8-R1	
396.30	POWER OPERATED EQUIPMENT - LARGE MACHINERY	30-R1.5	12-L1.5	12-L1	

* CURVE NOT CONSISTENT BETWEEN MAJOROS SCHEDULES

ATTACHMENT JJS-R3

Louisville G&E 2012-00222

Depreciation Life Analysis Study Through 2004

Account: **361.00 -**

Balance: **4,257,660**

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Comments: Balance matches Spanos' Balance on Depreciation Study III-9

Company:

LOUISVILLE GAS AND ELECTRIC COMPANY
ELECTRIC PLANT

ACCOUNT 361 STRUCTURES AND IMPROVEMENTS

SUMMARY OF CURVE FITTING RESULTS - PCT SURV BALANCED AREAS

PLACEMENT BAND 1904-2011 001 EXPERIENCE BAND 1904-2011

SURVIVOR CURVE	RESID MEAS	RANGE OF FIT	SURVIVOR CURVE	RESID MEAS	RANGE OF FIT*
54.0-S0	11.64	0 - 87	54.1-S0	13.29	21 - 87
53.7-S0.5	13.62	0 - 87	54.1-S0.5	15.42	21 - 87
53.4-S1	15.71	0 - 87	54.1-S1	17.64	21 - 87
54.6-R0.5	10.38	0 - 87	53.7-R0.5	11.96	21 - 87
53.6-R1	12.99	0 - 87	53.4-R1	14.93	21 - 87
53.4-R1.5	15.38	0 - 87	53.5-R1.5	17.56	21 - 87
53.1-R2	17.92	0 - 87	53.6-R2	20.30	21 - 87
59.1-L0	8.02	0 - 87	58.2-L0	9.12	21 - 87
57.3-L0.5	9.10	0 - 87	57.2-L0.5	10.41	21 - 87
55.9-L1	10.48	0 - 87	56.3-L1	11.88	21 - 87
55.1-L1.5	12.45	0 - 87	55.8-L1.5	14.04	21 - 87
55.8-O1	8.36	0 - 87	54.2-O1	9.30	21 - 87
62.2-O2	8.09	0 - 87	60.2-O2	8.85	21 - 87
79.0-O3	7.06	0 - 87	74.8-O3	6.88	21 - 87
99.3-O4	7.14	0 - 87	NOT FITTED		

* SEGMENT BETWEEN 85.0 AND 15.0 PERCENT SURVIVING

Best Fit Curve Results
Louisville G&E 2012-00222
Account: 361.00 -

Curve	Life	Sum of Squared Differences
BAND	**1904 - 2011**	
O1	53.0	8,187.389
L0	55.0	9,316.959
S-0.5	54.0	9,392.241
L0.5	55.0	9,780.080
R0.5	55.0	10,352.499
O2	57.0	10,464.367
L1	55.0	11,133.115
S0	55.0	11,974.686
R1	56.0	14,133.040
L1.5	55.0	14,359.419
O3	66.0	14,751.147
S0.5	56.0	15,646.464
O4	83.0	18,325.154
L2	55.0	18,673.118
R1.5	57.0	19,218.346
S1	57.0	20,291.601
R2	58.0	25,607.641
S1.5	57.0	26,079.316
L3	55.0	31,727.007
S2	58.0	32,797.087
R2.5	59.0	33,354.064
R3	59.0	42,381.313
S3	57.0	47,403.019
L4	55.0	51,450.841
R4	55.0	59,622.196
S4	53.0	65,372.852
L5	51.0	68,636.110
R5	49.0	75,533.902
S5	49.0	78,830.919
S6	47.0	89,067.776
SQ	44.0	108,039.730

Analytical Parameters

OLT Placement Band:	1904 - 2011
OLT Experience Band:	1904 - 2011
Minimum Life Paramet	1
Maximum Life Parame	300
Life Increment Parame	1
Max Age (T-Cut):	108.0

ATTACHMENT JJS-R4

LOUISVILLE GAS AND ELECTRIC COMPANY
CASE NO. 2012-00222

KENTUCKY UTILITIES COMPANY
CASE NO. 2012-00221

Re: Transmission, Distribution and General Net Salvage ratios.

Q. On page 5 of his testimony, Mr. Majoros makes adjustments to the depreciation study which includes 18,626,542 for KU and 12,257,883 for LG&E for Transmission, Distribution and General Lives. However, in reviewing his work papers, these amounts reflect changes in net salvage percents that are not discussed in testimony. Can you explain Mr. Majoros's opinion?

A. This is correct; I did adjust several of Mr. Spanos's net salvage ratios for the Transmission, Distribution and General accounts. My workpapers for those adjustments are the two attached spreadsheets and Spanos's Net Salvage Studies for LGE (Exhibit JJS-LGE pgs. III-353 to III-520) and KU (Exhibit JJS-KU, pgs. III-209 to III-273).

Originally, I intended to propose net salvage allowances reduced to their present value. This would have reduced Mr. Spanos's requested amounts almost to zero, but as I stated on page 26 of my testimony, "In past cases, I have proposed an approach that is closer to expensing current removal costs in lieu of the approach Kentucky utilities have taken. However, the Commission has made it perfectly clear it prefers the approach the Companies have sponsored in these cases." As a matter of policy, my client discouraged a present value approach, given the Commission's history.

Hence, I adjusted Mr. Spanos's net salvage proposals based solely on data included in his net salvage analyses. I added the "Percentages of plant balances retired to date from Mr. Spanos's study as shown in Column (4), and I added my judgment to recommend my proposed net salvage values shown in Column (6).

Where I thought, based on his summaries, and the percentage of retirements to plant balance, that a less negative net salvage ration could be justified, I replaced his proposed net salvage ratio with the lowest amount that could still be justified based on the known facts revealed by Mr. Spanos's studies. Remember, the ratios in Mr. Spanos's studies are distorted on their face, given that the net salvage amount s are in current dollars, but the retirements are in old historic dollars. Hence, his summaries present an apples and oranges comparison.

Nevertheless, I used his summaries. Next, I considered the percentage of cost of the retirements in his studies to the original cost plant balance to which he applied his proposals. A very low ratio of retirements to balance warrants scrutiny. For example, Mr. Spanos proposes a negative 100 percent net salvage ratio for LGE account 369.2 Services-Overhead. He based his estimate on $2.1 million of retirements from an account whose balance is $21.1 million.

Mr. Spanos's 100 percent proposal increases the net service value of this account from LGE's recorded $1,379,780 service value to a hypothetical $22,495,176 service value. This in turn, increases the annual depreciation expense accrual from $46,457 to $758,402. But, for this account, LGE only spent only $39,438 on average for net salvage over the last 5 years. Remember, Mr. Spanos's proposals increase current charges to current ratepayers cost of removal expenses. Nevertheless, the mismatch for this account and others is not justified on its face.

I propose 50 percent as a much more reasonable estimate given the relatively low percentage of actual retirements that have occurred. My recommendation is a judgment call, but so is Mr. Spanos's and mine is much easier to support than Mr. Spanos's negative 100 percent. Similar results are obtained for all the accounts where I have provided an alternative net salvage estimate. As I explained in my testimony, the need for these types of estimates would go away if the Companies merely capitalized the full cost of replacements rather than allocating a piece to cost of removal.

In the rush to file my testimony, I forgot that I had made these adjustments and used the adjusted numbers in my calculations. I assumed that the only numerical dollar difference between the Companies' and my recommendations for the Transmission, Distribution and General depreciation rates came from the life differences. Those differences as summarized on page 5 of my testimony overstated the effects of the life differences since they also included the net salvage difference. The total difference for each Company, however, does not change. I have further disaggregated the amounts as follows:

	KU	LGE
No terminal net salvage	(14,496,777)	(11,443,432)
Correct interim retirements	(1,609,340)	(2,592,983)
Production Plant remaining lives	(6,815,983)	(17,520,356)
Trans, Dist and General lives	(11,340,819)	(8,001,995)
Trans, Dist and General N/S	(7,285,723)	(4,255,888)
	(41,548,642)	(43,814,654)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	)))	**CASE NO. 2012-00221**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	))))))))	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF
SHANNON L. CHARNAS
DIRECTOR OF ACCOUNTING AND REGULATORY REPORTING
KENTUCKY UTILITIES COMPANY AND LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

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

A. My name is Shannon L. Charnas. I am the Director of Accounting and Regulatory Reporting for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies") and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points made by intervenors in this proceeding. Specifically, I address (1) Mr. Kollen's invitation to the Commission to prejudge the depreciation study to achieve a desired end result; (2) Mr. Majoros's incorrect assertions about the Companies' past depreciation proposals; and (3) why Mr. Majoros's contention about the Companies' net salvage expense is contrary to established Commission orders.

<u>KIUC Witness Kollen's Results-Oriented Depreciation Proposal</u>

Q. Did Mr. Kollen propose adjustments to the Companies' revenue requirement deficiencies based upon Mr. Majoros's arguments about the Companies' proposed depreciation rates?

A. Yes. In 2008, the Commission approved the Companies' current depreciation rates.[1] In the cases before the Commission now, and based upon Mr. Spanos's depreciation study and recommendations, LG&E is proposing to increase its approved

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[1] *In the Matter of: Application of Kentucky Utilities Company for an Adjustment of Electric Base Rates*, Case No. 2008-00251; *In the Matter of: Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates*, Case No. 2008-00252. Note that the two depreciation cases originally filed in 2007 were consolidated with the 2008 rate cases. *In the Matter of: Application of Louisville Gas and Electric Company to File Depreciation Study*, Case No. 2007-00564; *In the Matter of: Application of Kentucky Utilities Company to File Depreciation Study*, Case No. 2007-00565.

depreciation expense by $124,147 and KU is proposing to decrease its depreciation expense by $5,764,976.[2] As shown in my direct testimony, these proposed changes are included in the calculation of the overall revenue requirement deficiencies.

Mr. Kollen, based on Mr. Majoros's assertions, proposes to reduce LG&E's electric revenue requirement deficiency by $44.459 million for changes in depreciation expense and reduce KU's revenue requirement deficiency by $36.180 million for the same reason.[3] The significant difference between the adjustments recommended by the Companies, which are based on a complete depreciation study, and those noted above demonstrate the extreme nature of Mr. Kollen's and Mr. Majoros's positions. As Mr. Spanos describes, Mr. Kollen's and Mr. Majoros's proposals do not employ the "informed judgment" required to prescribe depreciation rates, but rather propose "an arbitrary figure selected for convenience."[4] As the National Association of Regulatory Utility Commissioners ("NARUC") has written, "[t]he depreciation rate is a calculated figure, and there is a zone of reasonableness within which the underlying parameters may be expected to lie."[5] Mr. Kollen's proposals are well outside any zone of reasonableness.

Q. In making these recommendations, does Mr. Kollen recommend the Commission prejudge the Companies' depreciation study?

A. Yes. Mr. Kollen attempts to bolster his recommendation by asking the Commission to overlook the essential question—are the depreciation rates reasonable—and instead

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2 Attachment to LG&E KIUC 2-88; Attachment to KU KIUC 2-89.

3 Direct Testimony of Lane Kollen at 28. Neither Mr. Kollen nor Mr. Majoros proposed any changes to LG&E common or LG&E gas depreciation expense.

4 *See* NARUC, *Public Utility Depreciation Practices* 23 (Aug. 1996) (discussing the importance of setting depreciation rates).

5 *Id.*

employ an end-results test. Specifically, Mr. Kollen asserts that because changes in depreciation rates do not affect earnings, the Commission should adopt a proposal simply because it leads to lower depreciation rates and expenses, thus lowering the Companies' revenue requirement deficiencies.[6] Although his assertion that changes in depreciation do not affect earnings is technically correct, his contention is irrelevant to the Commission's responsibility to objectively evaluate whether the proposed changes in depreciation rates are reasonable.

Mr. Kollen asserts that "[t]here is no question that the Companies will recover the entire amount of their plant costs; the only question is over what period of time they will recover these costs, i.e., what is the best estimate of the average service lives."[7] The estimates proposed by the Companies, as determined by Mr. Spanos, are the Companies' best estimates of average service lives. Inappropriately lengthening service lives to reduce current depreciation expense will inequitably increase depreciation expense later in the assets' lives—in other words, future ratepayers will be required to pay more to fully recover the costs of the assets used to provide service to customers today. This intergenerational inequity is contradictory to using a systematic and rational method of allocating the costs of assets ratably over the assets' lives. Additionally, it is inequitable to current and future customers whose rates would be based upon a short-sighted, results-oriented view, not upon their use of assets.

[6] *Id.* at 26–27.
[7] *Id.* at 27.

Q. Should the Commission accept Mr. Kollen's position?

A. No. The Commission should reject Mr. Kollen's appeal for a biased and results-oriented approach because it is contrary to sound regulatory and accounting principles. NARUC has provided guidance on this point: "It is essential to remember that depreciation is intended only for the purpose of recording the periodic allocation of cost in a manner properly related to the useful life of the plant. It is not intended, for example, to achieve a desired financial objective or to fund modernization programs."[8] Mr. Kollen's proposal does nothing but attempt to achieve "a desired financial objective," a practice that NARUC and this Commission do not follow.

Q. What is your recommendation to the Commission?

A. The Commission should approve the changes in depreciation rates shown in Mr. Spanos's depreciation study and recommended by him. Mr. Spanos's study uses the Average Service Life ("ASL") methodology and represents a reasonable approach.

<u>The Companies' Past Depreciation Cases</u>

Q. Did Mr. Spanos participate in the Companies' 2003 rate cases in which new depreciation studies were submitted?

A. No. Mr. Majoros incorrectly asserts that Mr. Spanos participated in Case Nos. 2003-00433 and 2003-00434.[9] Mr. Spanos did not submit a depreciation study on behalf of the Companies until 2007.[10] In the 2003 cases, Mr. Earl Robinson submitted depreciation studies on behalf of the Companies.

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[8] NARUC, *Public Utility Depreciation Practices* 23.

[9] *In the Matter of: An Adjustment of the Gas and Electric Rates, Terms, and Conditions of Louisville Gas and Electric Company*, Case No. 2003-00433; *In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434.

[10] Case No. 2007-00564; Case No. 2007-00565.

Q. Does Mr. Spanos depart from the depreciation methodologies traditionally used by the Companies?

A. No. For at least the preceding three depreciation cases, the Companies have utilized the ASL methodology for their established depreciation rates.[11] Mr. Robinson used this procedure in both the settled 2001 depreciation case and the litigated 2003 rate case when proposing depreciation rates, and though Mr. Spanos originally proposed the Equal Life Group methodology in the last depreciation case, he also submitted ASL-based rates which were eventually adopted in a settlement approved by the Commission. Mr. Spanos continues using the ASL methodology in this case.

<u>Net Salvage Expense</u>

Q. Does Mr. Majoros contend that the Companies' depreciation expenses for net salvage should be adjusted?

A. Consistent with his testimony in previous cases, but in contravention of Commission precedent and the Companies' historical practice, Mr. Majoros asserts that the net salvage values recommended by Mr. Spanos should be reduced. In doing so, Mr. Majoros demands the Commission disallow recovery of net salvage, but fails to demonstrate any imprudence by the Companies. Mr. Majoros would also have the Companies distribute some $651 million to customers from net salvage expense "over and above the actual net salvage expense [the Companies] have incurred."[12] Such a demand would require future customers to pay for the costs of units currently in service.

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[11] *See In the Matter of: Application of Kentucky Utilities Company for an Order Approving Revised Depreciation Rates*, Case No. 2001-140; *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving Revised Depreciation Rates*, Case No. 2001-141; Case Nos. 2003-00433 and 2003-00434; Case Nos. 2008-00251 and 2008-00252

[12] Direct Testimony of Michael J. Majoros, Jr. at 27.

Mr. Majoros also ignores the fact that the Companies periodically file new depreciation studies which the Commission reviews and evaluates.

Q. Has Mr. Majoros made this claim in prior proceedings?

A. Yes, and unfortunately Mr. Majoros again makes unfounded arguments against the Companies.[8] Mr. Majoros's originally filed direct testimony asserted that the Companies were unlikely to ever spend the net salvage reserves. Additionally, Mr. Majoros made the outlandish claim that the Companies just could "keep the money" if they wanted.[13] Mr. Majoros later withdrew this testimony through an errata filing.[14]

Q. Has the Commission previously rejected Mr. Majoros's proposal?

A. Yes. The Commission previously rejected Mr. Majoros' argument when it determined that the "[t]he AG's claim that KU likely would never incur, or had no legal obligation to incur, the included retirement costs is irrelevant. The real question is whether it is reasonable to capitalize the cost of removal in order to recover those costs over the life of the investment." In doing so, the Commission observed that the Companies' proposal was "common practice" that had "been accepted by this Commission for a number of years."[15] While Mr. Majoros acknowledges that "the Commission has made it clear it prefers the approach the Companies have sponsored in [past] cases,"[16] once again, he recommends an unreasonable approach that has never been adopted or approved by the Commission.

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[13] *Id.* at 28. Mr. Majoros made similar claims in the 2003 rate cases. On the stand, however, Mr. Majoros admitted that "[n]obody has specifically told me that your company doesn't plan on spending that money." Case Nos. 2003-00433 and 2003-00434, Transcript of Evidence, Volume III, Testimony of Michael J. Majoros, Jr. at 164:6–7 (May 6, 2004).
[14] Majoros Errata Direct Testimony at 28.
[15] Case No. 2003-00433, Order at 32; Case No. 2003-00434, Order at 28.
[16] Majoros Direct at 26.

Q. Do independent authorities support the Companies' net salvage expense practices?

A. Yes. In addition to the Commission's prior orders, NARUC has published guidance on this topic. NARUC's *Public Utility Depreciation Practices* states that "[h]istorically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates."[17] The Companies and the Commission have followed this practice for some time. NARUC also observed that revenues should be matched with costs and recognized "the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life."[18]

Costs of removal are costs that will be incurred in the future and collecting these costs over the service lives of the assets to which they relate is the basic principle of depreciation. Costs of removal have been appropriately collected through rates and the Companies fully intend to spend the money collected on its intended purpose. If in the future the Companies do not plan to use these amounts to cover costs of removal, or if the costs of removal amounts should be different, the Companies will propose adjustments in future depreciation studies.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission approve as reasonable the changes in the depreciation rates proposed by Mr. Spanos. The Commission has historically approved the Companies' approach. The Companies' depreciation practice is to

[17] NARUC, *Public Utility Depreciation Practices* 157.
[18] *Id.*

include a cost of removal component in their depreciation rates to ensure that customers benefitting from the use of assets are paying a portion of the ultimate replacement or removal costs for those assets. Mr. Majoros's proposal is unsupported by precedent or practice.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director, Accounting and Regulatory Reporting for LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2ND day of November 2012.

Joan A. Henry (SEAL)
Notary Public

My Commission Expires:

July 21, 2015

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF
J. CLAY MURPHY
DIRECTOR – GAS MANAGEMENT, PLANNING, AND SUPPLY
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

REBUTTAL TESTIMONY OF J. CLAY MURPHY

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is J. Clay Murphy, and my business address is 820 West Broadway, Louisville, Kentucky.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I filed direct testimony in this proceeding on June 29, 2012, on behalf of Louisville Gas and Electric Company ("LG&E").

Q. What is the purpose of your testimony?

A. My testimony rebuts the direct testimony filed in this proceeding by Mark Ward on behalf of the Stand Energy Corporation ("Stand") and by John Mehling on behalf of Hess Corporation ("Hess"). LG&E also addresses certain notions put forth by ProLiance Energy, LLC ("ProLiance") in its Comments filed in this case.

Q. Why has LG&E proposed modifications to its transportation services in this case?

A. In the Appendix to the Commission's Order dated December 28, 2010, in Case No. 2010-00146, *In the Matter of: An Investigation of Natural Gas Retail Competition Programs* (the "Order"), the Commission states as follows:

> Therefore, the Commission will review the reasonableness of the existing transportation tariffs of each of the above-named LDCs and any proposed changes in rate design and product and service availability in their next individual general rate proceeding. While the Commission does not advocate mandating or legislating volumetric thresholds for gas transportation service, as we believe the LDCs are best equipped to propose and implement their own systems' products and programs, we are committed to ensuring the

> reasonableness of transportation tariffs by reviewing them in the LDCs' next rate cases.[1]

The Order concludes by stating:

> The Commission believes that existing transportation thresholds bear further examination, and the Commission will evaluate each LDC's tariffs and rate design in each LDC's next general rate proceeding.[2]

LG&E has carefully reviewed not only the Commission's Order in that case, but also its own system operations and costs, and believes that its proposals in this case fully comply with the Commission's directives in Case No. 2010-00146.

II. THE MARKETER AS COMPETITOR

Q. Please describe the two entities that are intervenors.

A. Both entities are marketing companies. Stand currently serves three of LG&E's customers under Rate FT. Hess does not serve any of LG&E's customers. Neither entity is a pool manager under either Rider PS-TS or Rider PS-FT. Neither entity has any responsibility for the gas operations of a local distribution company ("LDC").

Q. Do these companies compete with LG&E?

A. Yes they do -- despite the fact that both claim otherwise.[3] Their positions in this proceeding, including lower transportation service thresholds, are those that might typically be expected of a marketer trying to advocate its commercial and competitive interests. Mr. Mehling puts it very clearly when he states "there needs to be a sufficient level of qualifying customers to warrant our investment to

[1] Order at p. 16.
[2] Order at p. 23.
[3] Stand states that it "does not compete with any utility in any state" Ward at p. 10. While describing itself as "one of the largest competitive natural gas transportation suppliers in the country" on p. 1 of its Motion to Intervene, at p. 2 of that same Motion, Hess states that it "is not a 'competitor' to an LDC."

market and operate in a LDC service territory"[4] and to "maximize customer enrollments."[5] Because marketers sell natural gas at a profit, lower LDC thresholds improve opportunities for marketer profitability. Additionally, both companies compare their price offerings to LG&E's regulated gas cost rates. Hess, as a competitor of LG&E, sees its role as offering transportation customers "the potential to realize cost savings compared to LDC supply offerings."[6] Stand actually compares its rates to those that a sales customer "would have paid LG&E."[7] Competition based on price is a recognized marketplace identifier. ProLiance claims that LG&E's proposals will "reduce competition," therefore, they must be a competitor of LG&E.[8] In short, then, these are entities seeking to compete with LG&E and tilt the playing field in their favor in order to enable them to do so more profitably – commercial interests being their sole motive in this proceeding.

Q. But aren't these marketers a unique kind of competitor?

A. Yes. They are competitors that seek to disadvantage the LDC's merchant function and to eliminate it where possible.[9] In fact, the Commission in its Order in Case No. 2010-00146 clearly states "we find it important that the LDCs remain in the merchant function and that customers retain the ability to receive service from their LDC."[10] Marketers advocate for lower thresholds and weakened balancing regimes. They seek to disadvantage the LDC's role as a gas supplier

[4] Mehling at p. 6.
[5] Mehling at p. 6.
[6] Mehling at p. 3.
[7] Ward at p. 9.
[8] ProLiance Comments at p. 1.
[9] Ward at p. 10 apparently supports an elimination of the LDC's merchant function when he claims that "many utilities in the United States are actually getting out of the 'merchant function'…."
[10] Order at p. 23.

(its merchant function) by disregarding the costs to preserve system reliability and operate transportation programs.

Q. Have either Hess or Stand provided anything new that was not already raised in Case No. 2010-00146?

A. No. Despite their characterizations to the contrary, these marketers have put forth the same flawed propositions regarding reliability, costs, and transportation program design that were presented in Case No. 2010-00146.

Q. What is the marketers' flawed *reliability proposition?*

A. The marketers' flawed *reliability proposition* is that gas supply reliability will be unaffected by the expansion of transportation programs. Stand refers to concerns about maintaining system reliability in the wake of expanding transportation services as "old school thought."[11] Hess denies any link between system reliability issues and gas transportation programs.[12] ProLiance states that "[r]eliability of supply has not been an issue for quite some time."[13]

Q. What is LG&E's position on system reliability?

A. LG&E is concerned that reliability could be jeopardized by implementing the programs put forth by marketers which would result in a significant increase in the number of space-heating customers that are eligible for transportation service. LG&E is concerned that actions will be required to prevent such reliability impairment and that those actions will be paid for by sales customers if the

[11] Ward at p. 3.
[12] Mehling at p. 8.
[13] ProLiance Comments at p. 3. Interestingly, ProLiance also claims that LG&E's proposals "are inconsistent with the operational requirements of *other* (emphasis added) Kentucky LDCs"[13] – as if all LDC systems are the same.

marketer's model is adopted. Transportation programs should be designed to preserve system reliability for all customers without shifting costs to sales customers.

Q. What is the marketers' flawed *cost proposition*?

A. The marketers' flawed *cost proposition* is that any costs related to participation in transportation programs are a "barrier to competition" and should be socialized in a way that will not inhibit the marketer's pursuit of expanded market share. These so-called barriers include appropriate balancing tools and charges as well as administrative charges to recover costs incurred by the LDC to facilitate the customer's choice of an alternate supplier.

Q. What is LG&E's position on costs associated with expanded transportation programs?

A. Transportation programs should be designed to minimize costs, assign costs to the cost causer and prevent costs from being shifted to other customers.

Q. What is the marketer's flawed *program design proposition*?

The marketers' flawed *program design proposition* is a "one-size-fits-all" proposition. They advocate that transportation programs should be identical across all LDCs in terms of thresholds, charges, balancing tools and other provisions. Additionally, they advocate that such thresholds, charges, balancing tools and other provisions should be designed to provide marketers with the ability to maximize their profits without regard for the LDC's operational concerns or the administrative costs that sales or transportation customers must bear to put such programs in place.

Q. What is LG&E's position on transportation program design?

A. LDCs are in the best position to design their transportation programs based on their knowledge of the operational parameters, load profiles, and costs associated with their gas distribution systems.[14] This position is in line with the Commission's Order in Case No. 2010-00046.

III. RELIABILITY AND TRANSPORTATION SERVICES

Q. Do you believe that expanded transportation will degrade gas system reliability?

A. Yes. The uncertainty created by expanded gas transportation will impact LG&E's gas system operations and reliability. This position is based not on a hypothetical, but on LG&E's experience since 1985 when it first started transporting natural gas for customers. LG&E became particularly focused on the negative impact transportation customers could have on its ability to balance its system during the winter of 1993/1994.[15] On January 19, 1994, Louisville experienced a record <u>average</u> temperature of -12° F. Because Rate T customers did not have telemetry, LG&E did not know how much gas these customers were using. The pipeline was interrupting deliveries of gas being made to LG&E on behalf of these customers, and there was no way to make sure that the gas deliveries to Rate T customers would match their gas consumption. It became readily apparent that Rate T was wholly inadequate to enable LG&E to manage its system given the

[14] Ward, a former employee of Columbia Gas Distribution Companies, acknowledges at p. 3 that "Columbia's five different distribution companies are each unique so each transportation program had to be designed separately."

[15] Beginning November 1, 1993, interstate pipeline sales service was terminated when the Federal Energy Regulatory Commission issued Order 636. LDCs were no longer able to rely on the "safety-net" that had hitherto been provided by pipeline sales service.

growing level of customer transportation. In 1995, LG&E withdrew Rate T and introduced Rate FT in Case No. 95-037. Rate FT provided LG&E with a transportation program that incorporated tools to incent customers to more accurately forecast their loads and fulfill their delivery obligations – and charge them if they failed to do so. These tools included telemetry, daily tolerance bands, cash-out provisions, and Operational Flow Orders ("OFOs"). Rate FT has been updated periodically to account for changes in the market that impact its associated balancing provisions. To the extent that LG&E's proposals with regard to Rider TS-2 are not adopted (including the use of telemetry), the stage could be set for a similar scenario as that experienced in 1994. Adopting the marketers' suggestions to eliminate or loosen balancing requirements, and therefore limiting LG&E's ability to manage the deliveries of its gas transportation customers, would be a significant step backwards. Without the proper tools to manage its system and to collect the associated costs from those who cause them, sales customers will pay for expanded transportation programs in terms of decreased reliability and increased costs.

Q. Why are balancing tools and transportation thresholds an integral part of any transportation program?

A. Thresholds and balancing tools help to mitigate the reliability risks associated with transportation programs. When a customer opts for transportation service that customer's supplier becomes a *de facto* supplier to LG&E – but not a supplier which LG&E can manage like other suppliers. Just as LG&E manages the gas supplies and pipeline capacity it has under contract, it must also be able to manage the supplies delivered to it for transportation customers. Without thresholds and balancing tools, deliveries on behalf of transportation customers can amount to a wild card in LG&E's supply planning and system management processes. Even with thresholds and balancing tools in place, LG&E continues to see dramatic over- and under-deliveries on any given day and often in months that would appear to have no exogenous weather variable to account for unpredictability.

Q. But marketers do not agree that transportation programs degrade reliability?

A. No, they do not agree. Hess disputes LG&E's concern that allowing smaller, primarily space-heating customers to transport poses reliability issues because "LG&E has reported no instance"[16] and Mr. Mehling is "not aware of any instances"[17] of such reliability issues. The fact that an LDC has not reported a system failure attributable to transportation customer imbalances does not mean that those imbalances do not have to be managed to prevent them from jeopardizing system reliability. Neither Hess nor Stand has LDC system operation responsibilities from which to provide a perspective and neither has offered any evidence from which to make such a determination.

Q. When you use the terms "degrade" or "jeopardize" reliability with respect to expanded transportation services, to what are you referring?

A. Importantly, customers do not have to lose gas service for a system reliability concern to be identified and addressed. In the case of gas system management,

[16] Mehling at p. 8.
[17] Mehling at p. 8.

reliability can be jeopardized when gas supplies do not match gas demand on an hourly and daily basis. If a marketer supplying a transportation customer fails to deliver an adequate amount of gas to meet the customer's hourly and daily demand, that customer can jeopardize not only its own gas service but the gas service of other customers as well. A related reliability concern posed by transportation customers relates to the kind of interstate pipeline capacity the marketer has in place to serve the customer's gas loads.[18] Additionally, operational integrity is jeopardized when over- and under- deliveries by gas transportation customers infringe upon the operational integrity of LG&E's on-system underground gas storage. Indeed, any action or inaction by transportation customers that results in deliveries to LG&E that do not match the customers' use can jeopardize the reliability and safety of gas service to customers.

Q. Please describe LG&E's gas distribution business, especially in the context of LG&E's concerns about its system reliability.

A. LG&E's gas distribution business serves approximately 319,000 mostly residential gas customers in Jefferson County and 16 surrounding counties. LG&E's gas distribution assets include approximately 4,200 miles of gas distribution pipe, over 380 miles of transmission pipe, and five underground gas storage fields. For the 12 months ended March 31, 2012, LG&E's annual

[18] LG&E remains concerned that customers may be relying on pipeline delivery services which are not firm and may be recalled by the primary capacity holder or curtailed by the pipeline. Rate FT customers (or their Pool Managers under Rider PS-FT) manage their own upstream pipeline resources, and LG&E is not privy to the capacity being utilized or the firmness of this capacity. ProLiance attempts to reduce the reliability argument to one regarding the firmness of interstate pipeline capacity by asserting that capacity used at a secondary in-path delivery point has the same level of firmness as firm capacity with primary delivery point rights. ProLiance Comments at pp. 2-3. LG&E disagrees with ProLiance. Another delivery method that marketers may also use to deliver gas to LG&E on behalf of a customer is recallable (interruptible) capacity.

throughput volume was about 39 Bcf. About 30 percent of LG&E's throughput was gas transported for large volume commercial and industrial customers; about 45 percent was gas sold to residential customers; and about 25 percent was gas sold to small commercial and industrial customers. Therefore, the bulk of LG&E's annual throughput is to high-priority, space-heating customers. LG&E is somewhat unusual among LDCs in that it owns and operates on-system underground gas storage, which provides about half of LG&E's winter sales volumes.

Q. What resources are available to LG&E to manage its gas system?

A. LG&E has two main resources to supply gas to and balance its gas system. They are the capacity it holds on interstate gas pipelines and the capacity available from its on-system underground storage. These resources are dedicated to serving sales customers.

Q. How are these resources managed by LG&E?

A. These gas supply resources are managed in unison to ensure the optimal dispatch of adequate gas supplies to and through LG&E's gas distribution system in an efficient and cost effective manner. Resource management activities performed by LG&E include dispatching deliveries of gas to and from LG&E's on-system storage facilities and managing the interstate pipeline capacity used to deliver gas supplies in order to ensure that LG&E can meet customer requirements. These two resources must be managed by LG&E within defined operational or contractual parameters. Constraints related to maintenance assessments and work, whether on LG&E's system or on the interstate pipeline, also factor into LG&E's daily management of its gas supply resources.

Q. Please describe the role that LG&E's on-system underground storage plays in its overall supply plan.

A. LG&E has considerable on-system storage – unlike many other LDCs. About half of LG&E's winter season deliveries come from its five on-system underground storage fields. Storage can create significant operational and cost risks if not properly managed. This factor distinguishes LG&E from LDCs whose deliveries are only made via the interstate pipeline system -- such as Duke Kentucky.

LG&E's on-system storage provides its retail sales customers with considerable benefits, but that storage must be operated within defined parameters to ensure those benefits. Storage enables LG&E to avoid purchasing additional pipeline capacity during winter months. Storage also allows LG&E to mitigate the customer's exposure to price volatility during the winter months. To the extent that imbalances created by transportation customers interfere with LG&E's ability to effectively manage its storage, sales customers are exposed to cost risks and all customers are exposed to reliability risks.

Q. Please describe some of the operational parameters supporting LG&E's on-system storage operations.

A. The operation of LG&E's underground gas storage is a tug-of-war between two diametrically opposed goals. The first goal is to ensure that enough gas is in storage to provide adequate deliveries throughout the winter when pipeline deliveries alone are inadequate. Absent the required storage inventory levels, storage field pressures will be inadequate to allow storage withdrawals to meet peak loads. The second goal is to ensure that enough gas has been withdrawn from storage by the end of the winter season in order to mitigate storage field losses and maintain long-term storage field deliverability. Conversely, during the summer season, injections must occur within defined limits so that target field pressures are not exceeded while, at the same time, achieving required inventory levels prior to the beginning of the next winter heating season. Storage field deliveries and pressures are subject to continual monitoring by engineers combined with geological assessments.

Q. How does LG&E manage its storage capabilities?

A. In order to achieve maximum benefits for customers, LG&E has established a set of storage field inventory levels applicable to each of its five on-system storage fields. Storage field activity is continuously monitored to ensure adequate inventories are available to meet system requirements. Each gas storage field has its own set of unique delivery capabilities, inventory targets, and overall operating parameters. Each gas storage field fits into the overall scheme of LG&E's gas system operations. Some fields provide base load service while others provide peaking capabilities. It is imperative that the inventory levels for each storage field be maintained at specified levels continuously through the withdrawal season to ensure that pressures are adequate so that target deliverability can be achieved. During the injection season, LG&E must ensure that specified pressures are not exceeded and that storage is refilled by the start of the winter season. Observance of these specified pressures and target inventory levels ensures that the overall integrity of the storage field is maintained and that long-term storage field deliverability is not impaired.

Q. Are there other parameters that must also be managed in conjunction with field pressures and storage deliverability?

A. Storage deliveries are subject to more than daily limitations driven by inventory levels. They are also subject to hourly limitations based on compression, purification, transmission, and other restrictions. Hourly storage withdrawals must be managed in combination with the hourly deliveries of pipeline supplies, including supplies delivered on behalf of transportation customers.

Q. How does LG&E manage its pipeline services?

A. LG&E contracts for multiple interstate pipeline delivery services from two interstate pipelines. These interstate pipeline services each contain multiple receipt and delivery point restrictions, maximum seasonal, daily, and hourly restrictions, as well as pricing provisions that LG&E must manage. LG&E's contractual arrangements vary from transportation services that only permit deliveries at uniform hourly rates of flow (1/24th of the daily volume delivered) to more flexible services allowing hourly variations needed to address the load requirements of variable space-heating customers.[19] Pipeline supplies must be managed in order to ensure month ending targets for on-system storage field inventories are met and in order to meet system demand not otherwise met

[19] The hourly gas loads of transportation customers do not match the hourly flexibility of the pipeline services used by transportation customers to make deliveries to LG&E. Those pipeline services require LG&E as the operator of the interconnection with the pipeline to take gas at uniform daily rates of flow, that is, at 1/24th of the daily amount being delivered. This hourly mismatch is but one aspect of the reliability concerns expressed by LG&E.

through gas storage withdrawals. To the extent that imbalances caused by transportation customers interfere with LG&E's ability to effectively manage its interstate pipeline transportation services, sales customers are exposed to increased costs and reliability risks.

Q. Does LG&E develop operating plans that enable it to manage its storage and pipeline capacity to support system reliability?

A. Yes. Annually, LG&E develops a long-term supply plan. The long-term supply plan enables LG&E to take a fresh look at its anticipated needs over the next few years and make adjustments for known changes.[20] This annual planning process ensures that LG&E does not have pipeline or on-system storage capacity in excess of its specified requirements to serve its firm sales customers. Excess capacity increases costs to sales customers.[21] As a part of the process, LG&E not only re-forecasts its long-term supply requirements, and renegotiates pipeline capacity, it also establishes a portfolio of gas supplies that will enable it to meet its sales requirements. Hess implies that LG&E is not "routinely evaluating its upstream capacity and on-system storage assets to determine whether it is cost-effective to shed some of these assets."[22] In fact, LG&E does routinely perform these evaluations and reflects in its gas supply plans any changes in sales loads and transportation service elections. This is superior to Hess's suggestion that LG&E

[20] LG&E's storage and pipeline capacities are not more than enough to ensure that it can meet the unfettered requirements of transportation customers.

[21] Other LDCs may be less concerned about balancing the loads of transportation customers, because unlike LG&E, these other LDCs may have excess pipeline or storage capacity with which to manage their gas loads. Excess capacity may allow them to offer balancing provisions to transportation customers that differ from LG&E's.

[22] Mehling at p. 9. ProLiance suggests that the March 31 notice period for customers electing service under Rider TS-2 (and also presumably Rate FT) is unnecessary. ProLiance Comments at p. 2. This notice period is necessary in order to give LG&E the opportunity to re-evaluate its loads, adjust pipeline capacity, and modify its gas supply portfolio.

should employ a capacity release program in order to shift costs away from sales customers.[23]

Q. Does forecasting, planning, and load management to ensure system reliability also happen in real time?

A. Yes. LG&E's long-term demand, capacity, and supply plan analyses support its short-term daily supply plans. LG&E monitors its gas system and dispatches the necessary gas supplies in real time, but its daily dispatch plan is established early in the immediately preceding business day. Because natural gas markets are generally day-ahead markets,[24] LG&E must plan its supply activities a day in advance (or longer over weekend or holiday periods).[25] LG&E monitors daily the natural gas market and the requirements of LG&E's system to determine how its supply plan should be modified. In addition to modifying its supply plan to reflect operational requirements, LG&E may also modify its supply plan to take advantage of more economically priced supply options that may be available to meet system requirements.

Q. How are transportation requirements reflected in LG&E's processes?

A. The gas supply and balancing requirements of transportation customers served under Rate FT are specifically excluded from LG&E's long-term supply plan

[23] Hess indicates that "LG&E could employ a capacity release program in order to shift costs away from sales customers." Mehling at p. 9. Capacity release may be a short-run solution if there is unused capacity as the result of warmer-than-normal weather. However, capacity release is not a preferred alternative to long-term capacity planning. Any revenues from capacity release activity provides releasing shippers, such as LG&E, with only minimal revenue credits for sales customers when compared to the cost of firm capacity purchased from the interstate pipeline. Shedding excess capacity in this way would actually tend to shift costs to remaining sales customers.

[24] The "gas day" begins on one calendar day at 10:00 AM Eastern Clock Time and ends the next calendar day at 10:00 AM Eastern Clock Time.

[25] This is an important factor supporting LG&E's proposal to have transportation customers provide their delivery volumes ("nominations") to LG&E by 8:00 AM on the day preceding the gas delivery. This earlier notice will allow LG&E time to make optimal supply purchasing and storage dispatch decisions on behalf of sales customers.

process. LG&E does not contract for firm gas supplies or pipeline capacity, nor does it hold on-system storage for these customers. However, in the short-term, LG&E must ensure that the impact of Rate FT and Rider TS-2 delivery imbalances are eliminated; on-system storage and pipeline capacity enable LG&E to do that. When imbalances occur, LG&E must take whatever actions are necessary in order to balance the system – even if those actions are uneconomic or are paid for by customers other than the transportation customer(s) causing the imbalance (over- or under-delivery of gas). If the system is not continually balanced, if receipts of pipeline and storage supplies do not match deliveries to customers, then service to firm sales customers will be impaired.

Q. What happens if the gas distribution system is not balanced?

A. The gas distribution system can be out of balance if there is too much gas or too little gas. If there is too little gas, pressures may become inadequate, such that deliveries cannot be effectuated and customers lose service. If gas service is lost, the service restoration process can be lengthy and detrimental to human health and safety. If there is too much gas, storage inventories can become too high and storage field performance impaired, resulting in increased gas losses and long-term storage field impairment.

Q. Why will lowering the threshold for transportation service increase the potential for transportation customer imbalances to affect system reliability and the costs paid by sales customers?

A. Reliability and cost shifting problems are exacerbated when threshold volumes are lowered and numerous small customers with highly temperature-sensitive daily gas loads transport their own gas supplies. Large volume gas customers who use gas in high load factor processes should be expected to deliver gas supplies close to the hourly and daily volumes they use, but as illustrated in Section VI herein even these customers can cause significant hourly and daily imbalances to occur. If these kinds of imbalances occur with large volume process gas users with little or no temperature sensitive load, how can smaller and less sophisticated customers with highly variable, temperature-sensitive gas loads be expected to accurately match their gas supplies and gas loads?

As the threshold levels applicable to transportation customers are lowered, LG&E's ability to properly manage underground storage may be affected. If target storage inventory levels cannot be achieved, winter storage deliverability could be adversely affected and storage losses increased, with an overall impairment of gas storage performance.

While LG&E is proposing to decrease the threshold for Rider TS-2, LG&E has been careful to include the necessary balancing tools in Rider TS-2, Rate FT, and the associated pooling services to preserve system reliability. Weakening these balancing tools would increase marketer profitability at the expense of sales customers whose reliability would be degraded.

IV. COST SHIFTING AND TRANSPORTATION SERVICES

Q. Are marketers concerned with cost shifting as a result of reduced thresholds and expanded transportation programs?

A. No, marketers are not concerned with cost shifting that can occur as the result of transportation programs. For example, Hess is "not aware" of "cost shifting to sales customers."[26] Stand is particularly opposed to the appropriate assignment of transportation program costs to participating customers and considers them as "financial thresholds" – an obstacle rather than a responsibility.[27] It is easy for marketers to be "unaware" of cost shifting because they are not held accountable for appropriate cost assignment. Additionally, they do not care if sales customers bear the costs associated with transportation programs because they are focused on supporting tariff provisions that make it easier for them to do business and capture market share.

Q. Please explain how cost shifting can occur as thresholds are reduced.

A. There are several types of cost shifting that can occur when transportation thresholds are reduced.[28] Costs are shifted to sales customers when the balancing resources dedicated to sales customers are used – but not paid for – by transportation customers. To the extent that LG&E uses its pipeline capacity and gas supplies to balance transportation customers (and appropriate balancing mechanisms are not in place), then costs will be shifted to sales customers through the operation of LG&E's gas cost recovery mechanism, the Gas Supply Clause ("GSC"). Costs are also shifted to sales customers when customers that transfer to Rate FT make a lower contribution to fixed costs.[29] Costs are shifted to sales or other customers when the resources necessary to administer transportation programs or balance transportation loads (through on-system gas storage) are not

[26] Mehling at p. 9.
[27] Ward at p. 4.
[28] In its response to AG 2-21, LG&E discusses how many of the proposed changes in Rider TS-2 and Rider PS-TS-2 are intended to address cost shifting and other concerns with respect to expanded transportation services.
[29] Mehling at p. 9.

paid for by the transportation customers causing those costs. Costs are shifted to sales customers when transportation customers do not pay their share of lost and unaccounted for gas ("LAUFG"). Additionally, costs may be shifted to sales customers if transportation customers do not pay their share of GSC under-collections (if any) that occurred prior to the customer switching to transportation service. As discussed below, LG&E has included several provisions in its transportation services to prevent cost shifting to sales customers. However, contrary to assertions by Hess, it is impossible to create a transportation program that does not contain some element of cost shifting.[30] LG&E rejects the model that it should be responsible for bearing the operational and financial risk of operating a transportation program and that sales customers should bear the costs imposed by these programs. In essence, this is the model proposed by marketers.

Q. You have discussed at length the cost shifting that can occur when the LDC balances the loads of transportation customers, but can you discuss how the transfer of a sales customer to Rate FT affects revenues net of gas costs and how those net revenues are shifted to sales customers?

A. Yes. When customers transfer from sales service to service under Rate FT, the customer assumes a lower distribution charge, and, contrary to Hess's assertion, the customer's contribution to fixed costs decreases.[31] For example, under Rate CGS a customer pays a distribution charge of $1.8722 per Mcf during the five winter months and $1.8722 per Mcf less $0.50 per Mcf for all use over 100 Mcf

[30] Mr. Mehling at pp. 9-10 states that "LG&E's argument that allowing more customers to switch to FT service will result in higher rates to sales customers is premised on improper inaction by LG&E and should be disregarded."
[31] Mehling at p. 9.

per month during the seven summer months. A customer served under Rate FT will pay a distribution charge of $0.43/Mcf. In the case of a Rate FT customer using 18,250 Mcf/year (50 Mcf/day x 365 days), there is a loss in annual net revenue of $21,319 ($29,167 under Rate CGS compared to $7,848 under Rate FT). When the transferring customer meets the eligibility requirements of Rate FT (process gas customer using large volumes of gas with deliveries being made from LG&E's high pressure gas system), the customer qualifies for the lower rate. However, if small, temperature-sensitive customers not generally served from the high-pressure gas system are allowed to qualify for service under Rate FT, then the $0.43/Mcf paid by those space-heating customers will not cover the costs to serve those customers. As customers elect services with lower distribution charges, the reduction in revenue responsibility is permanently shifted to all other customers at the time of the next rate case.

Q. How might the costs of administering transportation programs get shifted to sales customers or other transportation customers?

A. Lower thresholds result in higher administrative costs; not lower administrative costs as insinuated by marketers.[32] The costs that can be attributed to a transportation program should be paid by participating customers so as to prevent cost shifting to sales or other transportation customers. For this reason, LG&E

[32] Ward p. 11. As LG&E explained in its response to Stand 1-14, because administrative costs do not vary by volume of usage by the customer, the administrative costs would increase as the number of transportation customers increases. Smaller customers are likely to require even higher levels of administration than larger customers. Therefore, customers made eligible for transportation as the result of lower threshold levels can be expected to have higher administrative costs. Smaller, less experienced customers cannot be expected to understand the intricacies of gas supply contracting and management. Thus, more resources will be required to administer the program and assist the customer in understanding the provision of transportation service and related processes.

has proposed an Administrative Charge for Rate FT and Rider TS-2 that fully allocates the per customer cost of the transportation program to each customer.

Q. How has LG&E addressed cost shifting related to LAUFG and GSC under-collections (if any) that should be attributed to transportation customers?

A. LG&E has proposed a provision in Rider TS-2 that requires participating customers to pay their share of LAUFG.[33] LG&E has also proposed that customers served under Rate FT and Rider TS-2 be subject to a "Gas Cost True-Up Charge" to pay their share of GSC under-collections or receive their share of GSC over-collections.

Q. Do all LDCs have the same cost shifting concerns or address similar cost shifting concerns in the same way?

A. No. LDCs may be operating under different regulatory regimes or have other reasons for being less concerned about cost shifting. Some LDCs may have an affiliated marketer doing business in the LDC's service territory and have an incentive to design less restrictive balancing provisions or to assign transportation program costs differently than proposed by LG&E. LDCs that have exited the merchant function have no sales customers to protect; balancing and other program costs are allocated amongst transportation customers.[34]

[33] Customers served under Rate FT are not assessed LAUFG because they are served from high-pressure mains and, as such, are not generally responsible for gas system losses as are customers served from low- and medium –pressure gas systems.

[34] According to Stand, "many utilities in the United States are actually getting out of the 'merchant function'…. Ward at p. 10. While LG&E does not necessarily agree with this assessment, LDCs that are exiting the merchant function do not need to be as concerned about protecting sales customers from potential cost shifting caused by implementing transportation services. All customers are allocated these balancing costs because all customers are transportation customers.

V. "ONE-SIZE-FITS-ALL" TRANSPORTATION SERVICES

Q. What does the Commission's Order in Case No. 2010-00146 say about thresholds?

A. The Commission's Order is clear when it stated that "transportation thresholds bear further examination." The Order does not require that all thresholds have to be the same for all LDCs;[35] it does not require that all LDC programs be the same; it does not require that the costs for those programs should be the same; in fact the Order does not require any change whatsoever to any LDC transportation program. It requires only "further examination."

Comparing LDC thresholds in a vacuum is precisely what the Commission indicated that it would not do when it stated that it would "evaluate each LDC's tariffs and rate design."[36] In the case of LG&E, this would include the rates and services contemplated under Rate FT and Rider TS-2 as well as the applicable pooling services. The Commission's Order directly conflicts with the "one-size-fits-all" approach suggested by marketers where it states that the Commission "does not advocate mandating or legislating volumetric thresholds for gas transportation service, as we believe the LDCs are best equipped to propose and implement their own systems' products and programs."[37] In this statement, the Commission recognized that each LDC's gas system, load profile, risk tolerance and operating costs are unique.

Q. What do the marketers say about thresholds and other program provisions?

[35] In point of fact, the Order in Case No. 2010-00146 expressly stated that it would not mandate thresholds. Order at p. 16.
[36] Order at p. 23.
[37] Order at p. 16.

A. Marketers want a one-size-fits-all program designed by them for their benefit. Marketers propose transportation programs with the lowest of thresholds and a minimum of balancing responsibilities. In fact, marketers have presented the transportation programs of other LDCs as a smorgasbord from which to pick various elements in order to assemble a program that best suits their tastes. The most popular threshold on the transportation program smorgasbord appears to be the threshold of 2,000 Mcf/year offered by Duke Kentucky in its Rate FT-L.[38] Hess prefers low thresholds in order to "maximize customer enrollments,"[39] and claims that "Duke Kentucky's gas transportation program thresholds are much more reasonable…."[40] Stand rejects LG&E's proposed thresholds because they do not represent a "significant concession."[41]

Q. What about the other elements of a transportation program?

A. Marketers support Duke Kentucky's Rate FT-L threshold of 2,000 Mcf/year -- but not all charges and provisions associated with Rate FT-L. Instead marketers select their preferred charges and provisions from the transportation program smorgasbord. For example, their preference is for programs with no or low administrative charges,[42] or programs with monthly (not daily) balancing

[38] At p. 3 of its Comments, ProLiance supports a threshold of 5,000 Mcf/year presumably because its affiliated LDC operations (Vectren North and Vectren South) have the same threshold set forth in their transportation tariffs.
[39] Mehling at p. 6.
[40] Mehling at p. 6.
[41] Ward at p. 6.
[42] Notwithstanding the fact that transportation customers, not sales customers, cause LG&E to incur these added administrative costs, both Stand and ProLiance object to having the transportation customers pay for them. Stand refers to administrative charges as "financial thresholds." After reciting the administrative charges, but not the corresponding distribution charges, of the transportation services offered by other Kentucky LDCs, Stand reports that Delta's transportation service has no administrative charge. Ward at p. 7. Stand, however, objects to Duke Kentucky's Administrative Charge of $430.00/month as "excessive." Ward at p. 8. ProLiance objects to both the Telemetry Charge and the Administrative Charge as an attempt to "penalize customers." ProLiance Comments at p. 2.

tolerances,[43] or programs without appropriate operational requirements.[44] In each and every case, marketers have selected the charge or provision from the transportation program smorgasbord that provides them with the maximum flexibility, the lowest cost to do business, and the ability to shift the responsibility for system reliability and program costs from marketers to LG&E and its sales customers.

Q. Are transportation programs generally uniform from one LDC to another?

A. No. Even Stand acknowledges in its response to a Commission data request that there is considerable variability in the thresholds of various transportation programs – in Kentucky and across the U.S.[45] However, the favored marketer threshold is that of Duke Kentucky because it is the lowest.

Q. Why wouldn't Duke Kentucky's threshold be appropriate for Rider TS-2 and Rate FT?

A. There are two main reasons that a 2,000 Mcf/year threshold would not be appropriate for LG&E's Rider TS-2 or Rate FT. The first relates to LG&E's system configuration and operational requirements, and the second relates to program and rate design. While Duke Kentucky, with its multiple interstate

[43] Notwithstanding the fact that transportation customers are causing imbalances which LG&E must accommodate, both Stand and ProLiance object to having the transportation customers pay for these balancing costs. Stand contrasts LG&E's daily balancing provisions to those of other Kentucky LDCs that do not have "excessive daily balancing provisions during non-critical periods." Ward at p. 8. ProLiance objects to the proposed 2% daily tolerance under Rate FT; LG&E agrees with ProLiance that the existing 5% daily tolerance band is "difficult enough to manage" for an LDC and for this reason has requested a reduction. Not surprisingly, ProLiance prefers the larger monthly tolerance bands of Duke Kentucky and Atmos as these will shift the need to balance from ProLiance to the LDC. ProLiance Comments at p. 3.

[44] Notwithstanding the fact that LG&E must maintain gas system reliability, ProLiance states that LG&E should not be allowed to impose "strict operational requirements" or "substantial cost increases." ProLiance at p. 3. As might be expected, ProLiance objects to LG&E's ability to manage customer deliveries under Rider TS-2 through the Action Alert as an "additional penalty." ProLiance Comments at p. 2.

[45] See Stand's response of October 18, 2012, to PSC 1- 2 dated October 15, 2012.

pipeline interconnects, operates no on-system storage, LG&E operates significant underground on-system storage and is largely dependent on a single interstate pipeline. Consequently, transportation programs and balancing services offered by Duke Kentucky and LG&E are different because the resources to balance their systems are subject to different operational parameters. There are also differences in system configuration and operational parameters when comparing LG&E to Delta, Atmos or Columbia.

Q. What is the second reason?

A. The second reason that a 2,000 Mcf/year threshold is not appropriate relates to the rate design and costs of the LDC. Because the transportation programs of each LDC operate differently, they have different rate structures reflecting the costs incurred by the LDC, whether those costs are telemetry costs, administrative costs, balancing costs, or distribution costs. For example:

- Duke Kentucky is cited as having a transportation service with a threshold of 2,000 Mcf/year; Rate FT-L provides firm transportation service to customers with an applicable distribution charge of $1.7369/Mcf. Additionally, Duke Kentucky's Rate IT provides interruptible transportation service for customers using over 1,000 Mcf/month for the seven summer months. The applicable distribution charge is $0.9493/Mcf. Both services have a monthly administrative charge of $430.00. Both transportation services require telemetry and an interruptible balancing service in addition to the above charges.

- Delta is cited as having no administrative charge for its transportation service and its threshold is 25 Mcf/day. The distribution charges applicable to firm transportation volumes commence at $4.3185/Mcf, and decline to $1.2735/Mcf for volumes over 10,000 Mcf/month. The distribution charges applicable to interruptible transportation volumes commence at $1.6000/Mcf, and decline to $0.6000/Mcf for volumes over 10,000 Mcf/month. These distribution charges are in addition to a monthly customer charge.
- Columbia offers transportation service under Rate DS for customers with an annual volume over 25,000 Mcf/year. The applicable distribution charge is $0.5467/Mcf, and over 30,000 Mcf/month declines to $0.2905/Mcf. This charge is in addition to a monthly customer charge of $583.39 and a monthly administrative charge of $55.90.
- Atmos offers transportation service to customers with an annual threshold of 9,000 Mcf/year. Rate T-3 is an interruptible transportation service with an applicable distribution charge of $0.6300/Mcf, and over 15,000 Mcf/month declines to $0.4100/Mcf. Rate T-4 is a firm transportation service with an applicable distribution charge of $1.1000/Mcf for the first 300 Mcf/month; $0.7700/Mcf for the next 14,700 Mcf/month, and $0.5000/Mcf over 15,000 Mcf/month. These charges are in addition to a monthly customer charge of $300.00 and a monthly administrative charge of $50.00. Both transportation services require telemetry and a balancing service in addition to the above charges.

Each of these transportation programs stands in sharp contrast to LG&E's Rate FT which is a firm transportation service with "as-available" (interruptible) balancing service. Rate FT has a distribution charge of $0.43/Mcf applicable to all Mcf. LG&E's Rider TS-2 provides a firm transportation service and firm balancing service. Natural gas supply to commercial customers is firm regardless of any action or inaction by its gas supplier. The distribution charge applicable to commercial customers is $1.8722/Mcf (less $0.50/Mcf for every Mcf over 100 Mcf/month during the seven summer months). The Rider TS-2 distribution charge includes costs to balance these customers on a firm basis.

From these examples, it is easy to see that each LDC has its own level of costs, its own methods of cost recovery, and different transportation services with different distribution charge levels, administrative fees, and balancing regimes. The threshold of a transportation service must be considered in coordination with the character of service and all the costs and provisions of that service.

Q. Since you indicate that Duke Kentucky's transportation services appear to be those preferred by marketers, please compare LG&E's transportation services to those of Duke Kentucky.

A. The transportation services offered by Duke Kentucky differ in material ways from both LG&E's Rider TS-2 and Rate FT.

Duke Kentucky's Rate FT-L is a firm transportation service with a 2,000 Mcf/year threshold. Under Rate FT-L, Duke Kentucky offers a firm transportation service to small commercial customers, and the marketer is responsible for providing the customer's full requirements. Customers must be in a pool that meets a 30,000 Mcf annual threshold. Customers are provided with interruptible balancing service. The monthly administrative charge associated with this service is $430.00 and the distribution charge is $1.7369/Mcf.

Comparing Duke Kentucky's Rate FT-L to LG&E's Rate FT and Rider TS-2 for the purpose of determining an appropriate threshold is misleading and like comparing apples and oranges.

LG&E's Rate FT service is a firm transportation service with an "as-available" balancing service to a particular type of high load factor customer. Under Rate FT, LG&E offers a firm re-delivery service to large gas process customers with an "as-available" balancing service. The character of service and high load factor of these customers allows LG&E to provide Rate FT customers with a $0.43/Mcf distribution charge. On the other hand, LG&E's Rider TS-2 provides customers with a firm transportation service with firm balancing service. The character of the transportation service is the same as the underlying sales rate schedule.

Duke Kentucky also offers Rate IT to larger customers in recognition of that fact they may be able to withstand a gas transportation service interruption.[46] The 1,000 Mcf/per summer month threshold offered by Duke Kentucky under Rate IT is associated with an interruptible transportation service and interruptible balancing services.

Unlike Duke Kentucky's Rate IT, LG&E's Rider TS-2 and Rate FT do not allow LG&E to interrupt the re-delivery of customer-owned gas for the purpose of

[46] Duke Kentucky's tariff for service under Rate IT states: "Customers who satisfy the definition of human needs and public welfare customers must purchase standby service from a Company supplier, or have alternative fuel capability, or have a combination thereof sufficient to maintain minimal operations." LG&E's tariff contains no such requirement for alternate fuel.

balancing its system. Both LG&E's Rider TS-2 and Rate FT offer a higher priority of service than Duke Kentucky's Rate IT. LG&E believes that firm transportation services are more attractive to LG&E's customers than interruptible transportation services, and imperative for space-heating customers such as those served under Rider TS-2.

Therefore, comparing Duke Kentucky's Rate IT to LG&E's Rider TS-2 and Rate FT for the purpose of determining an appropriate threshold is misleading.

Q. Is it meaningful to look at the thresholds of a transportation service while disregarding the other characteristics of a transportation service?

A. No, it is not meaningful. Thresholds do not tell the whole picture about a transportation service; the underlying rates and character of service must also be examined. When marketers compare thresholds (invariably selecting the lowest one) they ignore (1) the underlying character of service, (2) the mechanics and functionality of the transportation program, and (3) the operational requirements of the LDC offering the transportation program.

Q. Are the thresholds proposed by LG&E an integral part of the transportation programs?

A. Yes, they are not separable. If the Commission mandates that LG&E adopt lower thresholds than those proposed herein, then LG&E should have the opportunity to rework the underlying charges and service provisions supporting that threshold. Just as the need for marketer certification and consumer protections are tied to threshold levels, so is the design of the transportation tariffs and the rates for those services. While LG&E does not support lowering the thresholds for either

Rate FT or Rider TS-2, LG&E strongly urges the Commission not to look at the threshold in isolation.

VI. EXAMPLES OF TRANSPORTATION CUSTOMER IMBALANCES

Q. What evidence does LG&E offer to support its concern that expanded transportation services will negatively impact its ability to maintain reliability and shift costs to sales customers?

A. Unlike its own on-system storage or the interstate pipeline capacity and gas supplies it has under contract, LG&E has considerably less control over the delivery of customer-owned gas to its system. Expanding transportation service is concerning given that about 30% of LG&E's annual throughput is on behalf of transportation customers that produce hourly and daily supply imbalances for LG&E to manage. Data provided by LG&E clearly demonstrate that customers served under Rate FT have often exceeded the applicable daily balancing tolerance levels.[47] That data and the additional examples included herein support LG&E's assertion that FT customers or their pool managers are often unable to nominate their gas supplies with any degree of accuracy. If large gas process customers have difficulty forecasting their requirements, then LG&E has reason to be concerned that extending gas transportation programs to the less predictable and more volatile loads of space-heating customers will produce additional hourly and daily imbalances for LG&E to manage.

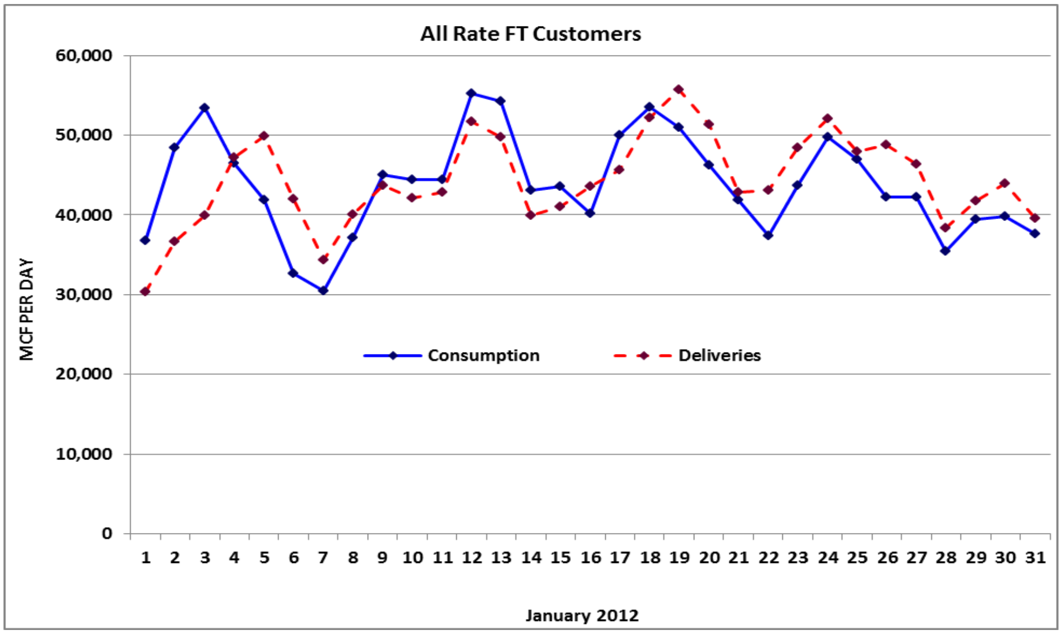
Q. Can you provide an example of the daily imbalances caused by Rate FT customers as a class?

[47] See LG&E's response to PSC 2-22(d).

A. Yes. Below is a graph showing total daily gas consumption for customers served pursuant to Rate FT as compared to the volumes of gas delivered to LG&E by their suppliers for January 2012. As you can see, the consumption by Rate FT customers almost never matches the volume delivered resulting in daily imbalances for LG&E to manage. Rate FT customers were either over- or under-delivered by more than 5% on 23 of the 31 days in January 2012. The following daily imbalances are particularly noteworthy.

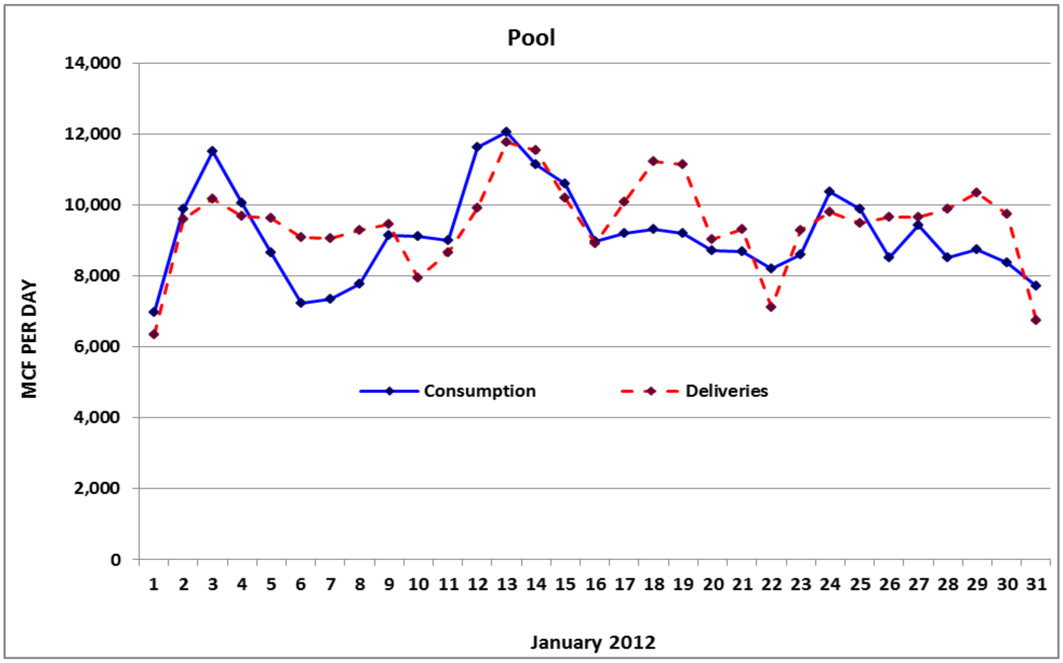
- On January 3, Rate FT customers used 53,351 Mcf, but only delivered 39,912 Mcf – consuming 13,439 Mcf, or about 34%, more than the volume they delivered to LG&E.
- On January 6, Rate FT customers used 32,624 Mcf, but delivered 42,002 Mcf – consuming 9,378 Mcf, or about 22%, less than the volume they delivered do LG&E.
- On January 12, Rate FT customers used 55,230 Mcf, but only delivered 51,753 Mcf – consuming 3,477 Mcf, or about 7%, more than the volume they delivered.
- From January 19 through January 31, Rate FT customers consistently over-delivered to LG&E.

On any day when Rate FT consumption does not match Rate FT deliveries, sales customers are supporting transportation activities – either through LG&E's pipeline services, on-system storage or both.



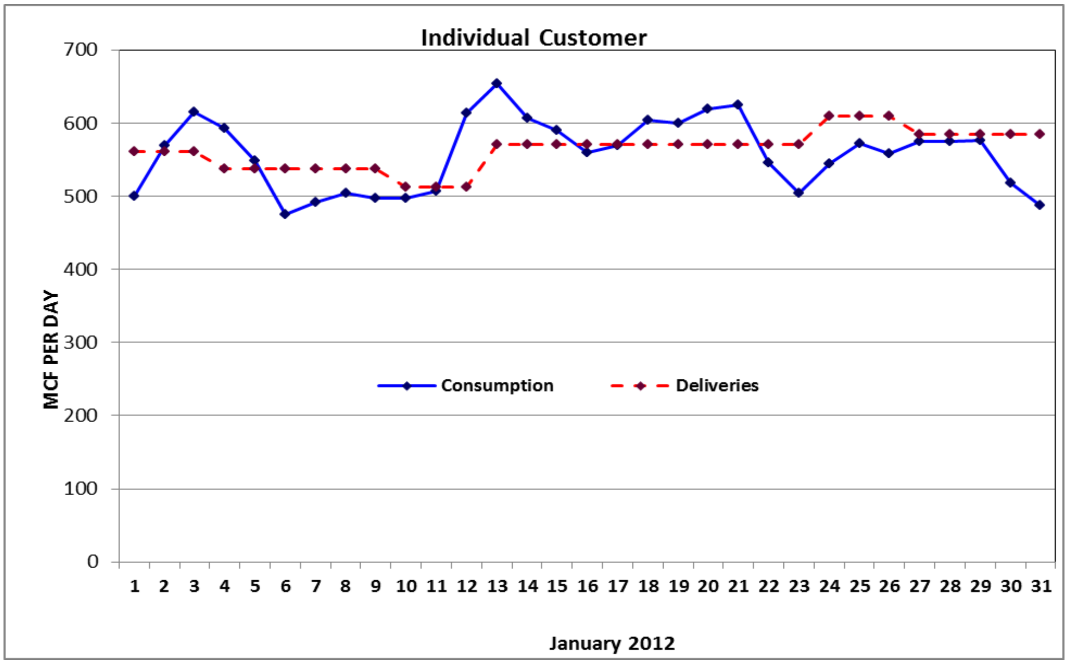
Q. Can these same kinds of imbalances be seen when looking at an individual pool?

A. Yes. Below is a graph showing total daily gas consumption for customers served by a Rate FT pool manager as compared to the volumes of gas delivered to LG&E by that pool manager for January 2012. As you can see, the consumption by these pool customers almost never matches the volume delivered by the pool manager resulting in imbalances for LG&E to manage. In the case of this pool manager, its deliveries were below or lagged actual customer use during the first half of the month, after which the pool manager generally over-delivered gas for the customers in its pool. On one day, the customers used as much as 17% more than the volumes being delivered by the pool manager, while on another day, the customers' use was 17% less than the volumes delivered by the pool manager.



Q. Can these same kinds of imbalances be seen when looking at an individual customer?

A. Yes. Below is a graph showing total daily gas consumption for an individual Rate FT customer as compared to the volumes of gas delivered to LG&E by that customer for January 2012. As you can see, the consumption by this customer (which is not in a pool) almost never matches the volume delivered by the customer resulting in daily imbalances for LG&E to manage. In the case of this customer, the deliveries to LG&E remained the same for several days regardless of the changes in the customers use. When the customer adjusted its deliveries to LG&E it appeared to be taking an “after-the-fact” corrective action. On one day, the customer used as much as 20% more than the volumes being delivered, while on another day, it used 17% less than the volume delivered.



Q. Is LG&E also balancing the hourly loads of these customers?

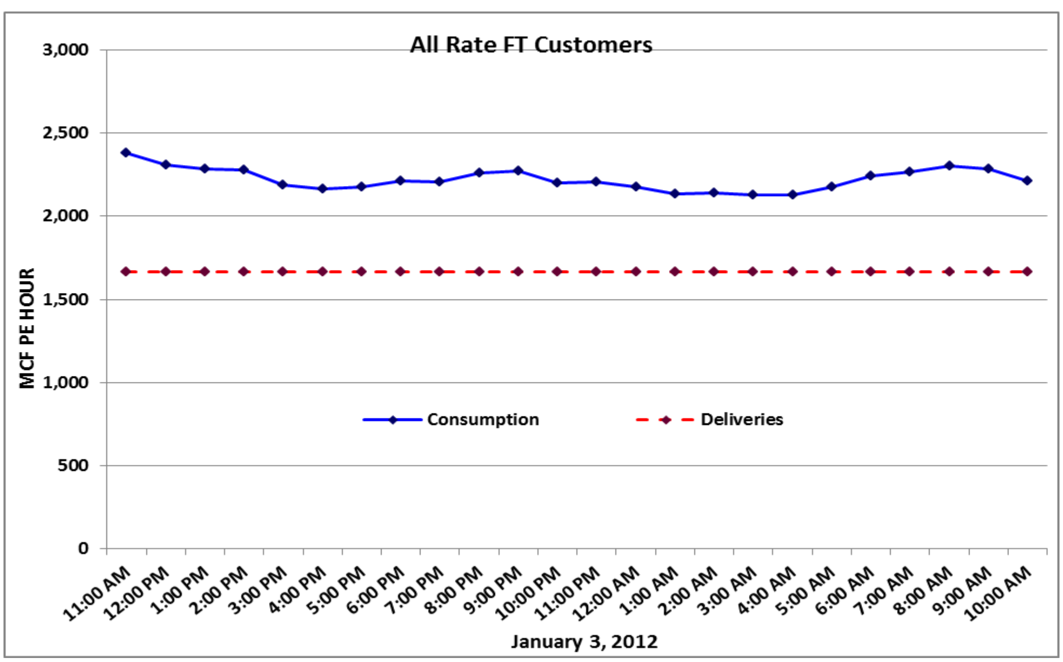
A. Yes. Not only is LG&E providing daily balancing services each day of the month, LG&E is providing balancing service each hour throughout the day. That is the case for customers transporting under Rate FT as well as Rider TS-2.

Q. Why is LG&E providing hourly balancing service?

A. LG&E provides hourly balancing service to transportation customers because the pipeline capacity that marketers use to deliver gas to LG&E is not adequate to meet the varying hourly requirements of transportation customers. The capacity that marketers use to deliver gas to LG&E requires that the gas be taken "in as nearly as possible uniform hourly quantities during any day." This means that LG&E must take the gas in hourly increments of $1/24^{th}$ of the quantity being delivered. For example, if LG&E is receiving 24,000 Mcf on behalf of Rate FT customers for a given day, LG&E is required to take the gas as nearly as practicable at 1,000 Mcf/hour. Large process gas customers do not use gas in hourly increments of 1/24th. As a result, LG&E manages the hourly imbalances of transportation customers using the interstate pipeline capacity and on-system storage dedicated to sales customers. If large gas process customers do not match hourly deliveries with hourly requirements, then LG&E has reason to be concerned that extending gas transportation programs to the less predictable and more volatile loads of space-heating customers will produce additional hourly imbalances for LG&E to manage.

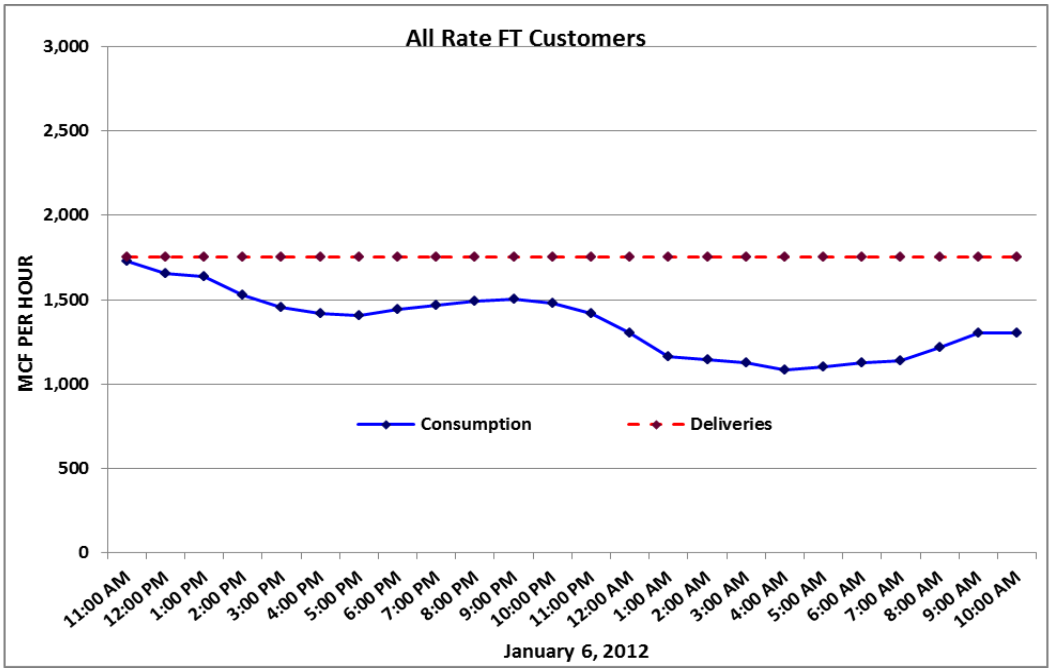
Q. Can you provide some examples of the mismatch between hourly deliveries and hourly consumption?

A. Yes. Below is a graph showing the gas consumption by customers served pursuant to Rate FT on Janaury 3, 2012, compared to the gas supplies being delivered to LG&E for these customers. On this day, gas consumption by Rate FT customers was well in excess of the gas being delivered to LG&E for these customers, both for the day and for each of the hours across the day.



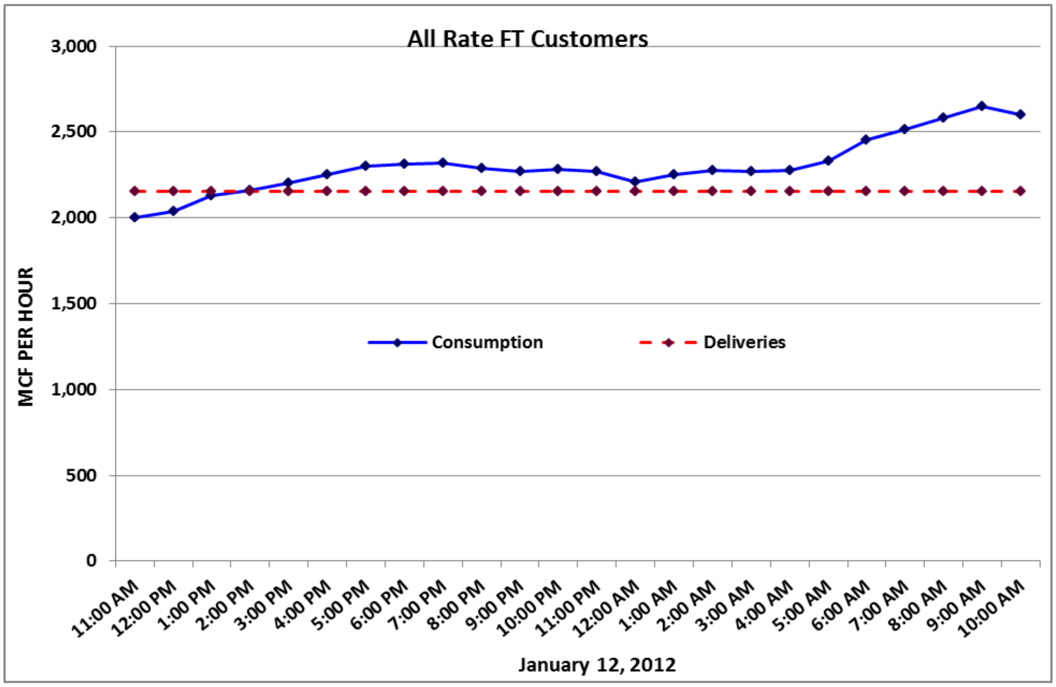
Q. Do you have another example of hourly mismatches by Rate FT customers?

A. Yes. The graph below illustrates that just three days later on January 6, 2012, customers over-delivered, both for the day and for each of the hours across the day.



Q. Are there occasions when customers over- and under-deliver on an hourly basis during the same day?

A. Yes. The graph below illustrates that on January 12, 2012, customers were over-delivering at the beginning of the day, but by the end of the day, were consuming gas in excess of the amount being delivered to LG&E on an hourly basis.



Q. Are these daily and hourly imbalance examples typical of the daily and hourly imbalances that LG&E routinely sees?

A. Yes.

Q. Do hourly and daily transportation customer imbalances ever help LG&E?

A. No. Contrary to the assertion of Stand, these over- and under-deliveries do not "help" the LDC to manage its system.[48] There is no situation in which over- or under-deliveries by a transportation customer is beneficial to either LG&E or its customers. Over- or under-deliveries are random and can upend and invert the LDC's gas supply plans and promote suboptimal gas management that results in higher gas costs and inefficiencies. These higher gas costs and inefficiencies will be borne by sales customers – unless the appropriate mechanisms are included in the transportation services to mitigate harm to sales customers.[49]

[48] Ward at p. 8.
[49] Even though hourly imbalances may be of concern, LG&E has not proposed a remedy for the resultant cost shifting in this proceeding.

Q. Can you provide an example of how the imbalances caused by Rate FT customers can directly harm sales customers?

A. For example, if the price of gas rises during the month due to colder weather, marketers acting as pool managers (or transportation customers) speculating that the price will fall later in the month may under-deliver gas to LG&E in order to avoid purchasing higher priced gas in the market. In order to balance the system, LG&E must either purchase the higher priced gas or withdraw more gas from storage than planned. Excess storage withdrawals can impair storage deliverability later in the season. Higher priced gas supplies will be also borne by sales customers. Later in the month, marketers (or transportation customers) may then over-deliver gas to LG&E in order to make-up previous under-deliveries. Over-deliveries injected into storage can reduce LG&E's ability to reach target storage inventory levels, potentially increasing gas storage losses (which will be paid for by sales customers) and also impairing storage deliverability. Over-deliveries may also prevent LG&E from purchasing lower priced gas on behalf of sales customers thereby raising the price they will pay.

Q. What happens if imbalances cannot be managed and adequate supplies cannot be made available to meet demand?

A. In less extreme situations, LG&E may issue OFOs to customers served under Rate FT and interrupt gas sales service to customers served under Rate AAGS. In extreme situations, curtailment plans are an example of the contingencies that LG&E has in place if gas supplies are inadequate to meet demand. The curtailment process provides for the elimination of lower priority customer demands from LG&E's gas system in order to provide service to higher priority customers, such as residential sales customers, which make up about 50% of LG&E's annual gas throughput.

Q. How has LG&E designed its transportation services to minimize the imbalances caused by transportation customers?

A. The balancing provisions and charges included in LG&E's transportation tariffs are intended to encourage forecasting accuracy, discourage "gaming" by customers and marketers alike, and to mitigate the impact of transportation customer over- and under-deliveries on sales customers. However, it is nearly impossible to create a transportation program that ensures that sales customers do not bear some cost-shifting and reliability risks related to these programs.

Q. How has LG&E addressed reliability risk and cost shifting so that transportation customers do not leave LG&E "holding the bag" in terms of reliability and sales customers "holding the bag" in terms of covering program costs?

A. While it is impossible to eliminate all reliability risks and cost shifting, LG&E has sought to minimize the risks of these impacts on customers by:

- following cost causation principles in the structure of the rates and services included in the Company's gas transportation tariffs;
- including balancing tools and mechanisms in the Company's various gas transportation rate schedules that are designed to minimize the reliability and cost shifting concerns created by transportation programs; and

- using gas transportation service thresholds to limit the type of customers eligible to be served under each rate schedule.

In the next two sections, I describe how LG&E's proposals are intended to mitigate reliability risks and cost shifting to the greatest extent possible.

VII. RATE FT

Q. Do marketers object to LG&E's proposals with respect to Rate FT?

A. Yes.

Q. Please describe Rate FT.

A. Under Rate FT transportation service, LG&E provides customers with a firm redelivery service but LG&E has no obligation to provide any gas supplies or any firm balancing services. For each Mcf delivered to the customer's facility the customer is charged $0.43 per Mcf. Contrary to the statements of Mr. Mehling,[50] it is not an interruptible service as is Duke Kentucky's Rate IT. As long as gas is being delivered to LG&E on behalf of the customer, LG&E is obligated to re-deliver a like amount of gas to that customer. From a delivery point of view Rate FT is a firm service. Outside of force majeure or similar emergencies, any interruption of deliveries to customers would be the result of the marketer's failure to deliver gas to LG&E for the customer's account. Only the balancing service provided to Rate FT customers is interruptible because LG&E does not contract for pipeline capacity or gas supplies or hold storage available to serve these customers.

Q. What costs are reflected in the Rate FT distribution charge of $0.43/Mcf?

[50] Mehling at p. 5.

A. The costs to serve customers under Rate FT are very different from the costs to serve other customers. The $0.43/Mcf rate charged is consistent with the character of service Rate FT customers receive as described above.[51] Customers served under Rate FT can generally be described as large volume, process gas customers served from LG&E's high pressure mains that do not use LG&E's on-system storage to facilitate the delivery of gas.[52] If customers not meeting these qualifications were provided service under this rate, the overall distribution rate for this customer class would have to increase in order to cover the costs to serve them. For example, lowering the threshold for service under this rate schedule would result in a distribution charge higher than $0.43 as a portion of LG&E's non-high pressure system would need to be allocated to this rate class.[53] Also, additional storage costs would have to be allocated to this rate class if it included firm service to space-heating customers. If the Rate FT distribution charge were not adjusted upward to cover these costs, then sales customers would subsidize the small, space-heating customers allowed onto Rate FT.

Q. What do marketers claim about the proposed Rate FT Administrative Charge?

A. Stand is concerned about the increase in the Administrative Charge. Mr. Ward compares LG&E's Administrative Charge to those of other LDCs in Kentucky as if all LDCs incur identical costs to administer transportation programs regardless

[51] Mr. Conroy discusses the cost allocation associated with Rate FT in his testimony commencing at p. 51.

[52] Although the rate was specifically designed around the consumption patterns of this kind of customer, ProLiance recommends that the 50 Mcf/day threshold applicable to Rate FT be supplanted by an annual usage requirement because it is "inconsistent with other Kentucky LDCs who have much lower annual usage requirements." ProLiance Comments at p. 2.

[53] Compare, for example, the distribution charges and thresholds of Duke Kentucky's transportation programs. Its Rate FT-L has a threshold of 2,000 Mcf/year and a distribution charge of $1.7369/Mcf, and its Rate IT has a threshold of 1,000 Mcf/summer month and a distribution charge of $0.9493/Mcf.

of the program design.[54] Hess on the other hand recognizes that "[t]ransportation programs routinely have higher administrative costs."[55] ProLiance claims that "LG&E has not supported why the substantial increase is necessary."[56]

Q. Why is LG&E proposing an increase in the Rate FT Administrative Charge?

A. LG&E has proposed to increase the monthly Administrative Charge under Rate FT from $230 to $600 so that it more fully reflects all of the costs associated with the administration of LG&E's gas transportation programs. LG&E considers it important for customers to know and bear the fully allocated costs associated with the services they may be eligible to receive in order to make an informed decision about the value of that service to their individual circumstance. The costs for administering LG&E's transportation programs include the costs related to rendering monthly customer bills, answering customer and pool manager inquiries, contract administration, processing daily nominations from customers or pool managers, facilitating daily confirmations of gas flows with the interstate pipeline, verifying transportation customer gas flow records from the interstate pipeline, preparing gas transportation reports, gas control and measurement, and generally providing the day-to-day service this group of customers and their pool managers require. The administrative costs for customers are generally the same whether the customer is served under Rate FT, Rider TS, or Rider TS-2.[57]

Q. Why is the proposed Administrative Charge appropriate?

[54] Ward at pp. 7-8.
[55] Mehling, note 6 at p. 6. "A customer must undertake its own cost-benefit analysis as to whether it has sufficient demand that the supply cost savings realized through selecting a third-party supplier outweighs the increase in administrative costs assessed under a transportation program."
[56] ProLiance Comments at p. 3.
[57] See Mr. Conroy's testimony commencing at p. 54, p. 63, and p. 64 for Rate FT, Rider TS, and Rider TS-2, respectively.

A. LG&E's proposed Administrative Charges for Rate FT, Rider TS, and Rider TS-2 are based on the cost it has incurred to support these programs. Absent a full allocation of administrative costs to the Administrative Charge, subsidies can occur. If the higher Administrative Charges are not approved, then the full costs to administer the program will not be paid for by those causing the costs to be incurred.

Q. Please describe how the balancing provisions of Rate FT work in order to promote reliability and prevent cost shifting.

A. The chief challenge in facilitating transportation service is to balance the receipts from the marketer with the deliveries to the customer. As explained earlier in this testimony, LG&E uses resources dedicated to, and paid for by, sales customers to effectuate this balancing – LG&E's interstate pipeline capacity and on-system storage. Customers who cannot match the volume of gas they deliver to LG&E with the volume they require at their facility may use these balancing resources on an "as-available" basis. Under LG&E's proposed tariff revision, customers under Rate FT are allowed +/- 5% daily balancing tolerance at no charge. Outside that tolerance they are charged a Utilization Charge for Daily Imbalances ("UCDI"). The UCDI essentially provides a mechanism for Rate FT customers to pay firm sales customers for using the balancing resources (interstate pipeline capacity and on-system storage) that would otherwise be paid for by firm sales customers. If LG&E did not assess the UCDI, sales customers would be paying the costs required to balance deliveries to transportation customers outside the prescribed limits. Not only does the UCDI mitigate any cost shifting to sales customers, it also provides an incentive for transportation customers to match receipts and deliveries and promotes system reliability. The UCDI is entirely avoidable if the customer maintains receipts and deliveries within the required tolerance band.

Q. Can you give an example of how the charges are applied?

A. Yes. Assume that 100 Mcf is delivered to LG&E for a given day. The customer may use as little as 95 Mcf or as much as 105 Mcf for that day without incurring a charge -- even though receipts do not match deliveries and LG&E has used some combination of pipeline service or storage to balance the customer. However, if the customer uses 94 Mcf, then the customer is assessed the UCDI on the 1 Mcf outside the tolerance. Similarly, if the customer uses 106 Mcf on that day, the customer is assessed the UCDI on the 1 Mcf outside the tolerance.

Q. Can this daily balancing service be suspended by LG&E?

A. Yes. LG&E can suspend the "as-available" daily balancing service by issuing an OFO. LG&E may issue an OFO that directs the customer not to deliver less than its actual consumption or not to deliver more than its actual consumption. The OFO does not suspend or otherwise interrupt any other aspect of the firm transportation service under Rate FT. Those customers that do not follow the specific OFO directive are assessed an OFO charge on each Mcf that is more or less than the customer's consumption – depending on the type of OFO issued. The OFO charge is equal to $15.00 per Mcf plus the price of gas on that day as indicated by *Platt's Gas Daily* mid-point price posting for "Dominion—South Point."[58] Any amounts collected are refunded to sales customers through the GSC

[58] Contrary to the statements of Mr. Ward at p. 8 that LG&E "penalizes customers for helping the system during critical periods," LG&E does not assess an OFO charge to customers that adhere to the OFO

in recognition of the fact that the customers not adhering to the OFO were using either pipeline or storage service dedicated to sales customers.

Q. Does LG&E agree with the marketers' assertions that LG&E has enough operational assets and administrative mechanisms in place to ensure that transportation customers and pool managers accurately forecast customer loads if transportation services are expanded?

A. No. Hess claims that LG&E's on-system storage and pipeline transportation capacity provide LG&E "with sufficient operational flexibility to deal with customer demand during the operating day and throughout the year."[59] However, Hess ignores the fact that these storage and pipeline capacities are used to support the service to sales customers (and are paid for by them). Again, LG&E does not hold pipeline capacity or on-system storage for the purpose of balancing Rate FT customers. Although LG&E may have the ability to issue an OFO, customers do not always observe these OFO directives. Balancing guidelines and directives can be more often honored in the breach than the observance.

Q. Why do marketers object to a daily balancing requirement?

A. Marketers object to a daily balancing requirement because it shifts more of the burden (and costs) for matching gas deliveries with gas consumption from the LDC to the marketer. Daily balancing requires higher levels of accuracy and effort on their part. Marketers prefer monthly balancing because it is easier for them to manage deliveries at a lower cost.

directive. Additionally, over-deliveries by Rate FT customers during cold weather are not helpful to LG&E in managing its gas system. Over-deliveries during cold weather are just another uncertainty added to LG&E's gas system planning and management process.

[59] Mehling at p. 8.

Q. What happens to the accumulated over- and under-deliveries that occur throughout the month?

A. The daily over- and under-deliveries that occur throughout the month are accumulated so that they are netted at the end of the month and any net over-delivered amounts are purchased and any net under-delivered amounts are sold to the customer. The process is called "cash-out" and is fairly standard through the industry. LG&E has proposed no change with respect to its cash-out mechanism.

Q. Are there other important features of Rate FT that you want to mention?

A. Yes. One of the most important features is that customers served under Rate FT are required to have installed telemetry. Telemetry provides LG&E and the customer a way in which to monitor the customer's gas use.[60]

Q. Please explain the changes that LG&E has proposed to Rate FT.

A. In addition to the proposed change in the daily balancing tolerance from 10% to 5%, LG&E has proposed to incorporate some additional features to prevent further cost shifting. These changes include the incorporation of a Contract Year (November 1 through October 31). The Contract Year creates certainty and definition around LG&E's obligations and longer-term gas supply contracting practices by enabling LG&E to know what loads it will be (and will not be) responsible for serving over the coming year. As a practical matter, this requirement would not be expected to affect any customer as customers typically

[60] Both Stand and ProLiance have questions about how the telemetry works. (LG&E's response to Stand 1-9.) ProLiance in its comments complains that LG&E's telemetry "system does not allow an auto-pull [sic] feature." ProLiance Comments at p. 3. This software allows the customer to dial into its own meter account. It is provided to the customer's gas supplier at no charge as a conduit to get the same readings that the customer is receiving. The software is capable of downloading both daily and hourly history that can be exported into an Excel format. An upgrade that has an auto-poll feature can be purchased by the supplier through the software vendor. If additional training is required, LG&E offers to provide such training.

do not switch between sales and transportation service on a monthly basis. The Contract Year eliminates the uncertainty around this possibility and is a logical extension of the notice period customers must provide in order to transfer from sales service to transportation service.

LG&E's other proposed changes include the memorialization of LG&E's methodology for evaluating eligibility and brings transparency to the determination process. LG&E has also proposed a "Minimum Daily Threshold Requirement and Charge" in order to provide a mechanism that allows customers to know and understand the repercussions of not meeting the required minimum threshold for service under the tariff, an incentive for the customer to remove itself from transportation service if it no longer qualifies, and a tool for LG&E to remove the non-qualifying customer if the customer does not act to remove itself. LG&E has also proposed a "Gas Cost True-Up Charge" to ensure that customers transferring from sales service to transportation service do not leave behind for sales customers any un-refunded or uncollected gas costs that may have been either over- or under-collected. This mechanism is keyed to the November 1 Contract Year. Other provisions include: shifting the time by which customers are to provide their nominated volumes for the following day from 10:00 AM to 8:00 AM, helping LG&E to better manage its system; limiting the delivering pipeline to Texas Gas Transmission, LLC; limiting service under Rate FT to customers with Maximum Daily Quantities less than 20,000 Mcf/day; and stipulating that service under Rate FT is not available to customers generating electricity. All of these proposals help LG&E to manage customers served under Rate FT and its system as a whole.

Q. Are pooling services available to customers served under Rate FT?

A. Yes. Pooling service enables a marketer to act as a pool manager and aggregate qualifying loads. As Hess explains, by "participating in … an aggregation pool comprised of a group of the supplier's customers, a customer whose usage deviates from its typical usage profile can mitigate any associated penalties by having its deviations offset by other pool customers."[61] In recognition of this load diversity within a pool, the proposed daily balancing tolerance is 2%, which is similar to that allowed by interstate pipelines.[62] LG&E operates five pools, and most of LG&E's customers served under Rate FT are in a pool. Even though Stand recognizes the value in netting imbalances, Stand is not a pool manager for the customers it serves, and therefore does not take advantage of the netting available to pool managers.[63] Most of the third-party suppliers providing gas to LG&E's customers recognize the value of balancing customers within a pool. It is for these reasons that LG&E has proposed to continue a lower daily balancing tolerance for a pool than for a customer operating outside of a pool. No charge is assessed on imbalances within the daily balancing tolerance.

Q. What is your conclusion?

A. The threshold for this service is appropriate given the Rate FT program design and should not be changed. The program design and associated costs support the threshold and mitigate shifting costs and reliability risks to sales customers.

[61] Mehling at p. 4.
[62] Please see LG&E's response to PSC 2-28(c).
[63] Ward at p. 8.

VIII. RIDER TS-2

Q. Do marketers object to LG&E's proposals with respect to Rider TS-2?

A. Yes.

Q. Please explain Rider TS-2?

A. The service provided under Rider TS-2 is very different than that provided under Rate FT. At its most basic, the service under Rider TS-2 is the same as that of the under-lying sales service provided to the customer. In recognition of that, Rider TS-2 is a rider to the sales rate under which the customer takes service.[64] It is very different from the transportation-only service for large volume process gas customers under Rate FT. Rider TS-2 is proposed to become effective November 1, 2013, with the customer required to provide notice to LG&E by the preceding March 31.[65]

Q. What kinds of customers are eligible for service under Rider TS-2?

A. Large volume space-heating customers using more than 25,000 Mcf/year are eligible for service under Rider TS-2.

Q. How is Rider TS-2 designed to work?

A. In recognition that the requirements of gas space-heating customers are different from those of large process gas users, LG&E has an on-going obligation to serve customers under Rider TS-2 on a firm basis. While the customer has the ability to select an alternate supplier, LG&E stands ready to serve these customers with firm balancing services including gas supplies.

[64] Rider TS-2 is a rider to Rates CGS, IGS, and AAGS. Rates CGS and IGS provide firm gas sales service to commercial and industrial customers. Rate AAGS provides the customer with "as-available" or interruptible gas sales service.

[65] ProLiance objects to March 31 notice proposal. ProLiance Comments at p. 2.

Q. What are the charges associated with Rider TS-2?

A. Because the character of service is the same as the underlying sales rate, the customer and distribution charges are the same. In addition to these charges, and because of the incremental administrative costs to facilitate this transportation service, customers under Rider TS-2 pay an Administrative Charge similar to the one paid by customers served under Rate FT.

Q. Are there other important features of Rider TS-2 that you want to mention?

A. Yes. One of the most important features is that customers served under Rider TS-2 are required to have installed telemetry. Telemetry provides LG&E and the customer a way in which to monitor the customer's gas use.[66]

LG&E's other proposed changes include the memorialization of LG&E's methodology for evaluation eligibility which brings transparency to the determination process. LG&E has also proposed a "Minimum Annual Threshold Requirement and Charge" in order to provide a mechanism that allows customers to know and understand the repercussions of not meeting the required minimum threshold for service under the tariff, an incentive for the customer to remove itself from transportation service if it no longer qualifies, and a tool for LG&E to remove the non-qualifying customer if the customer does not act to remove itself. LG&E has also proposed a "Gas Cost True-Up Charge" to ensure that customers transferring from sales service to transportation service do not leave behind for sales customers any un-refunded or uncollected gas costs that have been either

[66] LG&E proposes telemetry for customers served under Rider TS-2 because it does not want to recreate the situation discussed earlier with respect to Rate T (now Rate FT) customers. Specifically, prior to 1995 LG&E was unable to determine the volumes these customers were using as compared with the supplies being delivered. See Section III.

over- or under-collected. This mechanism is keyed to the November 1 Contract Year. Provisions designed to also help LG&E to more efficiently manage its system loads include limiting the delivering pipeline to Texas Gas Transmission, LLC; and limiting service under Rider TS-2 to customers with Maximum Daily Quantities less than 5,000 Mcf/day.

Q. Why are customers served under Rider TS-2 required to join a pool?

A. Most customers served under Rate FT are in pools, and pooling service can foster transportation program administrative efficiencies. The pooling service, Rider PS-TS-2, includes all of the provisions for balancing as well as a provision for charging customers LAUFG. The LAUFG calculation is dependent on the use of telemetry which is pressure and temperature corrected, thus eliminating losses from those sources. Absent telemetry, LG&E's LAUFG calculation would have been different than LG&E's proposal which requires telemetry.

Other provisions include: a monthly cash-out mechanism; the time by which customers are to provide their nominated volumes for the following day from 10:00 AM to 8:00 AM, helping LG&E to better manage its system. All of these proposals help LG&E to more efficiently manage its system loads. Rider PS-TS-2 also provides for Action Alerts.

Q. How will Action Alerts be used under Rider TS-2?

A. Action Alerts are used to manage the volume of gas being delivered on behalf of Rider TS-2 customers. While LG&E retains the obligation to balance these loads, the delivery of gas to LG&E must follow parameters to ensure, for example, that there are not large gas over-deliveries on warm weather days and large gas under-deliveries on cold weather days. In particular, LG&E's required storage inventory levels must be maintained. The Action Alert specifies an amount to be delivered and is tied to the Maximum Daily Quantity of the customer.

Q. What is your conclusion?

A. The proposed threshold for this service is appropriate given the Rider TS-2 program design and should not be changed. The program design and associated costs support the threshold and mitigate shifting costs and reliability risks to sales customers.

IX. CONSUMER PROTECTIONS

Q. Does LG&E have a marketer certification program?

A. No. LG&E does not certify marketers and has not proposed to certify marketers as the result of its proposed transportation expansion.[67]

Q. Has LG&E proposed any consumer protections as it relates to its expanded transportation program?

A. No. LG&E has no consumer protections in place now for its large volume transportation program and did not believe it was necessary to propose any given that only large customers would be eligible for service under the expanded transportation service proposed by LG&E.

Such consumer protections might typically be expected to accompany transportation service offerings designed for smaller commercial and industrial

[67] Hess states that it "has taken steps to become certified and approved to participate in the gas transportation programs of several Kentucky local natural gas distribution companies ('LDCs'), including … LG&E." Mehling at p. 1. Hess first inquired in April 2012 about becoming a pool manager under Rider PS-FT, but Hess had no customers to pool. When a customer appoints Hess as its agent for the purpose of Hess becoming its pool manager, LG&E will enter into a Rate FT Pool Management Agreement with Hess. At that point, Hess, like all other pool managers, will be required to provide surety as specified in Rider PS-FT. This is a guaranty against its obligations owing to LG&E, not a "certification" or "approval" of Hess as a pool manager by LG&E.

gas customers. Smaller, less energy-intensive customers should generally not be expected to understand the intricacies of gas supply contracting and management. Gas transportation programs designed for smaller customers are more likely to provide a forum for abuse, and should also provide an adequate forum for dispute resolution.

Q. Why does LG&E believe that is the case?

Columbia's 2012 Annual Report on its Customer Choice Program ("Annual Report") filed on June 19, 2012, in Case No. 2010-00233 continues to show losses by customers participating in its gas transportation program. Since its inception in 2000 the program shows that customers have lost $27,713,334 when compared to the Columbia's alternative tariffed gas cost recovery rate.[68] These losses include the losses incurred by commercial customers participating in the program.

Q. How significant is participation by commercial customers in Columbia's program?

A. The commercial customers that participate in this program use less than 25,000 Mcf/year. By number, commercial customers make up 13% of the customers participating in the program. By volume, these commercial customers make up 48% of the total purchased from marketers under the program.

Q. Why are these losses significant in light of LG&E's proposed expansion of its transportation program?

[68] Ward at p. 2 states that he was "involved in the development of Columbia's customer CHOICE programs for five Columbia distribution companies." At p. 4, he states that as Columbia of Kentucky developed the Small Volume Gas Transportation Program, he "co-authored the writing of the tariff and the program description for CKY. That program became effective in July 2000 and is still functioning today."

A. These losses are particularly relevant when considered in the light of the Customer Choice Survey ("Survey") filed on July 13, 2012, in Case No. 2012-00132. Columbia's Survey indicates that saving money is the primary driver for commercial customers to participate in Columbia's choice program, and yet many commercial customers were apparently unsure whether or not they saved money. According to the Survey, 71% of commercial customers originally decided to participate in order to save money.[69] Less than half of commercial customers indicated that they saved money by participation in Columbia's Choice Program. Of those customers indicating that they had saved money, 75% did not know how much they had saved.[70] The customers' desire to save money, their inability to determine whether or not they had saved money, and the losses that they actually incurred, are together illustrative of customer confusion with respect to the program.

Q. What is LG&E's recommendation with respect to consumer protections if the Commission mandates lower thresholds than those proposed by LG&E?

A. While LG&E does not support lowering transportation service thresholds below those proposed by LG&E in this case, if the Commission nevertheless mandates a reduction in LG&E's thresholds, LG&E believes that such a mandate must be accompanied by some protections for consumers. Not only should these protections include a marketer certification program, but should also include recourse to the Commission to resolve disputes between customers and marketers, and provide appropriate decision-making tools (including a price-to-compare tool

[69] Survey at p. 10.
[70] Survey at p. 12.

and an education program) to assist customers in evaluating whether or not to choose an alternate supplier. A funding mechanism paid for by all certified marketers should be established to pay for these incremental consumer protections.

Q. What other evidence do you have that small commercial customers might be confused in an unregulated marketplace?

A. Several customers have submitted form letters to the Commission advocating lower transportation thresholds. These submissions appear to be the result of a handbill circulated by Stand attached as Appendix A.

Q. What do these form letters say?

A. Attached as Appendix B is a single example of the 53 letters submitted to the Commission through the close of business on October 31, 2012. They all appear to be identical. In short, these letters composed by Stand advocate for a reduction in the gas transportation threshold to 2,000 Mcf/year. Some of the letters have the facsimile address of Stand across the top.

Q. What can you tell me about the Stand form letters?

A. The 53 letters cover 69 different customer accounts. Attached as Appendix C is a summary showing the gas consumption for the 69 accounts. Twelve of the letters that were sent covered the same 5 customer accounts. Eight of the form letters were from customer accounts that have no gas service. One of the letters is from a customer that is already a transportation customer. The average annual gas consumption of the various customer accounts (excluding the volumes of the customer already transporting) is 919.8 Mcf. Only 6 of the customer accounts would qualify for transportation under the 2,000 Mcf/year threshold proposed in the letter submitted by the customer to the Commission. Of customers with gas service, most are served under LG&E's Rate CGS applicable to firm commercial gas customers.

Q. What prompted these letters?

A. While the letters themselves address very specifically the thresholds for natural gas transportation services, they were prompted by a handbill encouraging customers to "PROTEST THE LG&E RATES INCREASE!" The handbill, with its two unfurled American flags across the top, appears more focused on the rate increase in general than on specific gas transportation issues. Indeed, the lettering in the largest font on the handbill proclaims "THIS RATE INCREASE COULD COST THE AVERAGE BUSINESS $1,590."[71] This amount would certainly come as a shock to the average customer submitting letters to the Commission whose estimated annual bill is about $5,725 per year. This would lead the customer to think LG&E's is proposing an increase of about 28%. In fact, LG&E has proposed an increase of about 6% in its commercial gas rates.

Q. What else do you find instructive about the handbill?

A. In return for helping Stand "'Put the chill' on rate increases," Stand promised that each customer sending in a form letter would "receive a 12-can convertible duffel cooler." This is indicative of the kind of marketing practices to which customers will be subject in the wake of lower transportation service thresholds.

[71] Mr. Ward at p. 10 acknowledges that "[t]his entire rate case filed by LG&E is to increase their charges for delivering gas to the customer and has nothing to do with their cost for the gas commodity."

Q. Is it LG&E's position that consumer protections will be endangered as the result of lower transportation thresholds?

A. Yes. Not only will customers be exposed to a variety of marketing schemes, they will be contracting for supply from unregulated marketers that are seeking to maximize profit. This is a vastly different environment compared to purchasing natural gas from a regulated utility whose price is reviewed and approved by the Commission based on least cost and reliability and does not include a profit.

X. CONCLUSION

Q. What is LG&E's recommendation in this proceeding?

A. LG&E transportation services and associated rates are appropriate as proposed. These services recognize LG&E's unique system, load profile, and operating costs. They are designed to maintain system reliability and prevent cost shifting to sales customers. LG&E recommends that the Commission approve those transportation programs as proposed rather than follow the models supported by marketers that would expose sales customers to reliability and costs shifting risks.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, J. Clay Murphy, being duly sworn, deposes and says he is the Director – Gas Management, Planning, and Supply for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

J. Clay Murphy

J. CLAY MURPHY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 5th day of November, 2012.

Rashelle W. Gaines (SEAL)
Notary Public

My Commission Expires:
Feb 28, 2014

MURPHY REBUTTAL - APPENDIX A

ENOUGH IS ENOUGH
PROTEST THE LG&E RATES INCREASE!

Louisville Gas and Electric is proposing a rate increase for its captive customers. This could result in substantial costs to you, and these changes could significantly affect your bottom line.

Stand Up and Help Us Reduce Your Costs

THIS RATE INCREASE COULD COST THE AVERAGE BUSINESS $1,590

Rate increase package includes:

- Continued supplier choices for only **select** customers
- Rate increase without any added benefits
- An inability to lock in natural gas prices, currently at 10-year lows
- Negative impacts to the bottom line for your business

How you can get on record

- **Copy the enclosed letter to your letterhead**
- **Date, sign, print your name and title**
- **Mail, email, or fax to the Kentucky PSC**
  - **Email: pscfiling@ky.gov**
  - **Fax: (502) 564-3460**

"Put the chill" on rate increases!
Send a copy of your letter to Terri and receive a 12-can convertible duffel cooler

- **Email: tleach@standenergy.com**
- **Fax: (513) 621-3773**

SEC
STAND ENERGY CORPORATION

John S. Phillips * Senior Vice President * Stand Energy Corporation * 1077 Celestial Street, Cincinnati, Ohio 45202 *
Office (513) 621-1113 * Fax (513) 621-3773

Stand Energy Corporation is a registered Kentucky Corporation, supplying Kentucky businesses since 1984!

MURPHY REBUTTAL - APPENDIX B

Murphy Rebuttal - Appendix B

RECEIVED

SEP 06 2012

PUBLIC SERVICE
COMMISSION

Date: 9.4.12

Chairman David Armstrong
Vice-Chairman James W. Gardner
Commissioner Linda K. Breathitt
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

Re: Louisville Gas & Electric Rate Increase; Case No. 2012-00222.

I understand the Louisville Gas and Electric (LG&E) tariffs are presently under review by the Kentucky Public Service Commission as part of LG&E's request for an increase in natural gas distribution rates. LG&E allows its "select" customers to buy their own natural gas from outside vendors.

I am a captive customer with no choices. My competitors, located in other states, are currently able to manage their natural gas costs, but I am not. My company would benefit from having the capability to control its energy costs.

The Public Utilities Commission should not be picking energy winners. LG&E rules should not only allow "select" customers exclusive rights, but all business should have this right. Natural gas prices are near 10-year lows – why can't I take advantage of this market?

The threshold for usage to be eligible to transport should be lowered to around 2,000 Mcf/year so that commercial customers can participate in fixing their energy costs.

Sincerely,

Watson Courtney
Name
A+H Advertising & Marketing
Company
Principal / President
Title/Position

Fax 1: (502) 564-3460
Fax 2: (513) 621-3773
Email: pscfiling@ky.gov

MURPHY REBUTTAL - APPENDIX C

SUMMARY OF USAGE ANALYSIS, STAND LETTER

Number of Letters	Number of Accounts	SERVICE RATE	12-MONTH (Mcf) USAGE ENDING AUGUST 2012
1		No gas service in this name and address	N/A
2	1	851 (CGS)	274.8
3	2	855 (IGS)	14,418.5
4	3	851 (CGS)	15.8
5	4	851 (CGS)	12.7
	5	851 (CGS)	45.7
6	6	851 (CGS)	62.4
7	7	851 (CGS)	2,519.4
	8	851 (CGS)	403.8
	9	851 (CGS)	336.0
	10	851 (CGS)	94.2
	11	851 (CGS)	1,999.9
	12	851 (CGS)	568.1
	13	851 (CGS)	371.5
8	14	851 (CGS)	188.5
9	15	851 (CGS)	284.2
	16	851 (CGS)	694.3
	17	851 (CGS)	422.8
	18	851 (CGS)	634.4
	19	851 (CGS)	427.3
	20	851 (CGS)	395.0
	21	851 (CGS)	324.8
	22	851 (CGS)	292.9
	23	851 (CGS)	4,963.9
	24	851 (CGS)	377.0
10	25	855 (IGS)	10,414.2
11	26	851 (CGS)	240.0
12	27	851 (CGS)	115.1
13	28	851 (CGS)	113.1
14	29	851 (CGS)	3.3
15		No gas service, electric only	N/A
16		No service in this name	N/A
17		No service in this name	N/A
18	30	851 (CGS)	0.4
19		851 (CGS)	N/A
20		851 (CGS)	N/A
21		851 (CGS)	N/A
22		851 (CGS)	N/A
23	31	851 (CGS)	1,093.7
	32	851 (CGS)	121.2
24	33	851 (CGS)	113.3
	34	851 (CGS)	108.3
25	35	851 (CGS)	1,680.8
	36	851 (CGS)	204.7
	37	851 (CGS)	250.6
	38	851 (CGS)	139.7
	39	855 (IGS)	1,291.4
26	40	851 (CGS)	4.9
27		851 (CGS)	N/A
28	41	851 (CGS)	39.7
29	42	851 (CGS)	613.2
		851 (CGS)	N/A
30	43	851 (CGS)	302.1
		851 (CGS)	N/A
31		No service in this name and address	N/A
32	44	851 (CGS)	81.7
33	45	851 (CGS)	4.0
34	46	851 (CGS)	415.4
35		No gas service, electric only	N/A
36	47	851 (CGS)	35.5
37	48	851 (CGS)	518.4
38	49	851 (CGS)	1,252.1
39	50	851 (CGS)	1,463.8
	51	851 (CGS)	315.8
40	52	855 (IGS)	390.6
41	53	851 (CGS)	240.7
42	54	851 (CGS)	91.5
	55	851 (CGS)	43.5
	56	851 (CGS)	382.8
43	57	851 (CGS)	90.1
44		No gas service in this name and address	N/A
45	58	851 (CGS)	676.9
	59	851 (CGS)	5,136.3
46	60	851 (CGS)	135.1
	61	851 (CGS)	166.8
	62	851 (CGS)	129.5
47	63	851 (CGS)	393.3
48	64	851 (CGS)	638.9
	65	851 (CGS)	2,360.3
49	66	851 (CGS)	544.1
50		No gas service in this name and address	N/A
51	67	851 (CGS)	2.8
52	68	851 (CGS)	56.7
53	69	already transporting	N/A
		Average annual usage	919.8
		Rate per Mcf	$ 5.83
			$ 5,366.75
		Annual customer charges	$ 360.00
		Estimated annual bill	$ 5,726.75

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC RATES	**)))**	**CASE NO. 2012-00221**

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS RATES, A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, APPROVAL OF OWNERSHIP OF GAS SERVICE LINES AND RISERS, AND A GAS LINE SURCHARGE	**))))))))**	**CASE NO. 2012-00222**

REBUTTAL TESTIMONY OF
ROBERT M. CONROY
DIRECTOR, RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: November 5, 2012

Table of Contents

Exhibits

I. INTRODUCTION

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

A. My name is Robert M. Conroy. I am Director, Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively, the "Companies"), and an employee of LG&E and KU Services Company, which provides services to the Companies. My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut Attorney General ("AG") witness Glenn A. Watkins concerning his proposed electric and gas cost-of-service studies, revenue allocation, and rate design; Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Stephen J. Baron concerning electric cost of service and rate design; The Kroger Co. ("Kroger") witness Kevin C. Higgins concerning his recommendations on revenue allocation and rate design; and Kentucky School Board Association ("KSBA") witness Ron Willhite concerning electric rate design.

II. ELECTRIC CLASS COST OF SERVICE

A. OVERVIEW OF INTERVENOR POSITIONS

Q. Please provide an overview of the intervenors' positions regarding their cost-of-service studies.

A. In these proceedings, only the AG and the KIUC presented recommendations related to the Companies' cost-of-service studies. While Kroger and KSBA presented testimony related to revenue allocation and electric rate design, neither presented any evidence on cost of service. The objective in performing the electric cost-of-service study is to determine the rate of return on rate base that each Company is earning from each jurisdictional customer class, which provides an indication as to whether the Companies' electric service rates reflect the cost of providing service to each customer class. The tables below summarize the current rate of return as presented by the AG and KIUC along with the Companies' filings.

Table 1 – KU Rates of Return

<table>
<tr><th colspan="6">Comparison of KU Class Rates of Return at Current Rates
Company and Intervernor Positions</th></tr>
<tr><th rowspan="2"></th><th rowspan="2">Company</th><th rowspan="2">Attorney General</th><th colspan="3">KIUC</th></tr>
<tr><th>"Corrected" BIP</th><th>PJM 5 CP</th><th>12 CP</th></tr>
<tr><td>Residential</td><td>3.97%</td><td>5.55%</td><td>3.86%</td><td>3.94%</td><td>3.42%</td></tr>
<tr><td>General Service</td><td>8.72%</td><td>9.68%</td><td>8.61%</td><td>8.28%</td><td>9.44%</td></tr>
<tr><td>All Electric Schools</td><td>7.25%</td><td>5.47%</td><td>7.13%</td><td>9.10%</td><td>4.46%</td></tr>
<tr><td>PS-Secondary</td><td>10.51%</td><td>8.03%</td><td>10.39%</td><td>9.43%</td><td>11.19%</td></tr>
<tr><td>PS-Primary</td><td>8.52%</td><td>7.39%</td><td>8.43%</td><td>7.39%</td><td>8.95%</td></tr>
<tr><td>TOD-Secondary</td><td>5.83%</td><td>2.67%</td><td>5.70%</td><td>5.42%</td><td>6.75%</td></tr>
<tr><td>TOD-Primary</td><td>5.89%</td><td>3.73%</td><td>5.79%</td><td>5.63%</td><td>6.08%</td></tr>
<tr><td>Retail Transmission</td><td>6.06%</td><td>5.21%</td><td>5.91%</td><td>6.55%</td><td>6.64%</td></tr>
<tr><td>Fluctuating Load</td><td>-1.59%</td><td>-2.18%</td><td>5.24%</td><td>16.07%</td><td>5.28%</td></tr>
<tr><td>Street Lighting</td><td>7.13%</td><td>8.33%</td><td rowspan="3">7.13% combined lighting</td><td rowspan="3">8.03% combined lighting</td><td rowspan="3">7.40% combined lighting</td></tr>
<tr><td>Lighting Energy</td><td>3.38%</td><td>0.01%</td></tr>
<tr><td>Traffic Energy</td><td>8.24%</td><td>7.32%</td></tr>
<tr><td>Total Company</td><td>6.02%</td><td>6.02%</td><td>6.02%</td><td>6.02%</td><td>6.02%</td></tr>
</table>

Table 2 – LG&E Rates of Return

Comparison of LG&E Class Rates of Return at Current Rates Company and Intervernor Positions					
	Company	Attorney General	KIUC		
			"Corrected" BIP	PJM 5 CP	12 CP
Residential	3.59%	5.19%	3.57%	2.61%	2.85%
General Service	10.33%	11.49%	10.30%	10.41%	10.50%
PS-Secondary	12.41%	8.12%	12.39%	15.08%	14.56%
PS-Primary	10.60%	9.25%	10.57%	11.56%	11.55%
TOD-Secondary	7.17%	2.65%	7.14%	9.72%	8.93%
TOD-Primary	5.56%	4.64%	5.56%	7.70%	6.78%
Retail Transmission	4.65%	4.09%	5.37%	10.82%	8.15%
Special Contract 1	0.59%	-0.48%	0.68% combined	3.05% combined	2.06% combined
Special Contract 2	1.24%	-0.99%			
Street Lighting	8.72%	8.31%	8.73% combined lighting	10.24% combined lighting	9.18% combined lighting
Lighting Energy	12.41%	1.58%			
Traffic Energy	8.44%	8.22%			
Total Company	6.14%	6.14%	6.14%	6.14%	6.14%

Q. Are there different methodologies for developing a cost-of-service study?

A. Yes. There are a number of methodologies used throughout the utility industry for allocation of costs in a cost-of-service study. In these proceedings, Mr. Watkins and Mr. Baron present studies that are different than the Companies' studies; furthermore, Mr. Watkins and Mr. Baron each presented results that tend to favor their clients' interests. For example, Mr. Baron proposes a "corrected" BIP along with two CP methods, all of which tend to favor higher-load-factor industrial customers and disfavor residential customers. Mr. Watkins, on the other hand, presents a study that tends to favor the residential class. The Companies have presented cost-of-service studies developed with a methodology consistent with the past three rate cases and which balance the interests of all rate classes. The class rates of return from the

Companies' studies should be used as a guide in allocating the revenue increase to the various classes of customers.

B. ALLOCATION OF FIXED PRODUCTION COSTS

Q. Is there agreement among the intervenor witnesses on the methodology that should be used to allocate costs in the class cost-of-service study?

A. No. In this proceeding, LG&E and KU submitted class cost-of-service studies using a methodology they have used consistently for at least the three previous cases (and in the case of LG&E, dating back to the early 1980s), and that the Commission has determined is reasonable and should be used as a guide for setting rates. A critical facet of the cost-of-service study is the methodology used to allocate fixed production costs, i.e., production capacity costs. As in prior rate case filings, the Companies have proposed to allocate fixed production costs using the modified Base-Intermediate-Peak ("BIP") methodology. Under the modified BIP methodology, a portion of fixed production costs are classified as "summer peak" costs and allocated on the basis of each customer class's loss-adjusted contribution to the system peak demand during the summer ("summer coincident peak allocator"); another portion of fixed production costs are classified as "winter peak" costs and allocated on the basis of each customer class's loss-adjusted contribution to the system peak demand during the winter ("winter coincident peak allocator"); and the remaining portion of fixed production costs are classified as "base" costs and allocated on the basis of each customer class's average demand ("average demand allocator").

A critical difference among the intervenor witnesses is the amount of fixed production costs allocated on the basis of an average demand allocator. In LG&E's and KU's cost-of-service studies, 34.35% of fixed production costs are allocated on the basis of an average demand allocator. Mr. Baron, testifying on behalf of KIUC, maintains that the modified BIP methodology allocates too much of the Companies' fixed production costs on the basis of an average demand allocator; whereas, Mr. Watkins, who is testifying on behalf of the AG, maintains that the modified BIP methodology allocates too little of the Companies' fixed production costs on the basis of an average demand allocator.

Because for LG&E and KU, fixed production costs represent approximately 65% and 68%, respectively, of the total cost of service, modifying the allocation factor used to assign these costs can have a significant impact on the results of the cost-of-service study. Allocating a larger percentage of fixed production costs on the basis of a demand allocator tends to shift costs to customer classes that use capacity less efficiently. Conversely, allocating a larger percentage of fixed production costs on the basis of an average demand allocator tends to shift costs to customer classes that use capacity more efficiently. In this context, "efficiency" relates to the extent to which the capacity is fully utilized and is generally measured by the load factor of a customer class. Greater utilization of the fixed assets corresponds to greater efficiency and a higher load factor and conversely, lower utilization of the fixed assets corresponds to lesser efficiency and a lower load factor. The efficient utilization of capacity is not something that is considered only in the utility industry. Rather, it is a concept that is extremely important in any capital-intensive industry, such as the airline industry or shipping industry. For example, it is more efficient, and extremely important, for an airline to fill all of the seats on its planes, for a railway company to fill all of the cars on its trains, and for an overseas shipping company to fill all of the holds in its ships. A standard objective of companies operating in capital-intensive industries is to maximize the utilization of their capacity. Companies operating in capital intensive industries are continuously looking for ways to increase the load factor and utilization of their capital investments.

Q. How do the witnesses propose to allocate fixed production costs?

A. Mr. Baron maintains that the modified BIP methodology allocates too much cost on the basis of an average demand allocator and offers two alternative methodologies that he recommends the Commission consider.[1] Additionally, Mr. Baron takes exception to the Companies' treatment of Curtailable Service Rider ("CSR") credits and offers a "corrected" BIP study that he purports to more accurately reflect the Companies' true costs and class rates of return. Mr. Baron's objection to the CSR credits in the modified BIP studies is addressed in detail later in my testimony; however, in brief, Mr. Baron suggests that CSR credits, which reduce the Companies' revenues, should be offset in their entirety because the cost of service should treat curtailable customers as firm load. The Companies' cost-of-service studies present the conclusion that the benefits received from the ability to curtail are not in alignment with the credits paid by the Companies during the test year, and as a result, customers receiving the CSR credits contributed less to the Companies' overall rates

[1] Direct Testimony and Exhibits of Stephen J. Baron on behalf of the Kentucky Industrial Utility Customers, Inc. in Case No. 2012-00221 and 2012-00222, filed October 3, 2012 ("Baron Direct"), p. 4-5.

of return than would have been the case with a better match between the credits paid and the associated benefits.

In addition to his "corrected" BIP, Mr. Baron offers two alternative cost-of-service studies for each Company. The first alternative, which Mr. Baron calls the "PJM 5 CP" method, allocates fixed production and transmission costs on the basis of the five highest system peaks, regardless of when such peaks occur. Mr. Baron offers the PJM 5 CP alternative because this is the method used by the PJM Regional Transmission Organization ("RTO") to assign capacity obligations to load-serving entities.[2] However, the Companies are not members of the PJM RTO, and as load-serving entities, the Companies are obligated to serve all load within their respective service territories, regardless of the similarity or variance in the load characteristics. It is important to note that the five highest hourly peak demands during the test year all occurred in the same month (July 2011), and of the five hours in July, four of the hourly peaks occurred in two days. Table 3 below shows the distribution of the hourly peaks Mr. Baron recommends the Commission "consider" in choosing a cost-of-service model to use as the basis for setting new rates.

Table 3 – 5 peak hours

Year	Month	Day	Hour	KU	LGE	Combined
2011	7	11	15	4,102	2,654	6,756
2011	7	28	14	4,062	2,671	6,733
2011	7	20	14	4,128	2,591	6,719
2011	7	11	16	4,060	2,655	6,715
2011	7	28	15	4,060	2,655	6,715

[2] Baron Direct, p. 17-18.

Mr. Baron fails to explain how such a distribution of demands accurately captures the actual annual usage of LG&E's and KU's production facilities. The PJM 5 CP is clearly of benefit to certain customers or customer classes represented by Mr. Baron, because the use of five peak hours, not five monthly peaks, incorporates hourly fluctuations in demand that result in lower total and average demands, and therefore lower demand cost allocations. The application of a cost-allocation methodology adopted by an RTO to which the Companies do not belong to end use customers whose electricity usage is widely diverse appears results-oriented.

Mr. Baron's second alternative, the 12 CP method, is similarly results-driven, allocating fixed production and transmission costs on the basis of the 12 highest monthly peak demands throughout the test year. The 12 CP method is an improvement over the PJM 5 CP method since the 12 CP method captures seasonal differences in class contributions to the monthly peaks. However, it shares the same shortcoming in that it can result in class contributions to monthly peaks that potentially understate the actual loads placed on the system. Both methods proposed by Mr. Baron are designed to shift costs from an energy allocator to a demand allocator, resulting in a cost assignment that benefits "high load factor" customers by lowering cost allocation based on energy.

Mr. Watkins, on the other hand, maintains that the Companies' cost-of-service studies do not allocate enough costs on the basis of average demand. Specifically, Mr. Watkins proposes to allocate 74.51% of the Companies' fixed production costs on the basis of an average demand allocator. He argues that because a large percentage of the Companies' production capacity is made up of coal-fired steam units, the original BIP methodology would have allocated most of the Companies' production fixed costs on the basis of an average demand allocator. Mr. Watkins's methodology, which he has explained numerous times in the past, has been previously rebutted by W. Steven Seelye, the Companies' witness on such matters in recent base rate cases.[3] Nonetheless, we restate here that assigning production fixed costs to demand periods on the basis of the kind of fuel consumed by a unit rather than on the usage characteristics of the unit yields unreasonable results.

Table 4 below illustrates the positions of the parties regarding the percentage of fixed production costs that should be allocated on the basis of demand and energy:

Table 4 – Comparison of Production Cost Study Results

	AG Mr. Watkins	LG&E and KU	KIUC Mr. Baron
Energy	74.51%	34.35%	0.00%
Demand	25.49%	65.65%	100.00%
Total	100.00%	100.00%	100.00%

Stated briefly, the energy-demand allocation proposed by Mr. Watkins results in a cost allocation that benefits the residential class at the expense of large industrial users. Conversely, the energy-demand allocation proposed by Mr. Baron results in a cost allocation that benefits large industrial users at the expense of the residential class. As can be seen from this table, the percentage of production fixed costs allocated on the basis of demand or energy in the Companies' cost-of-service study falls almost exactly in the middle of the range created by the positions of the AG and KIUC. Because the Companies seek to balance the interests of all customer classes,

[3] *See, e.g.*, Case Nos. 2009-00548 and 2009-00549, Rebuttal Testimony of William Steven Seelye (May 27, 2010).

LG&E's and KU's recommendations should be given greater weight. Unlike the intervenors, the Companies' motivation is not to advance the interest of a particular customer class, but rather to fairly recover their costs to serve each class. The selective benefits of Mr. Baron's and Mr. Watkins's preferred cost-of-service methods are illustrated in Charts 1-4 below, which compare class demands and the corresponding allocation of Production Fixed Costs using different cost-of-service methodologies presented in this case.

Louisville Gas and Electric Company

Chart 1

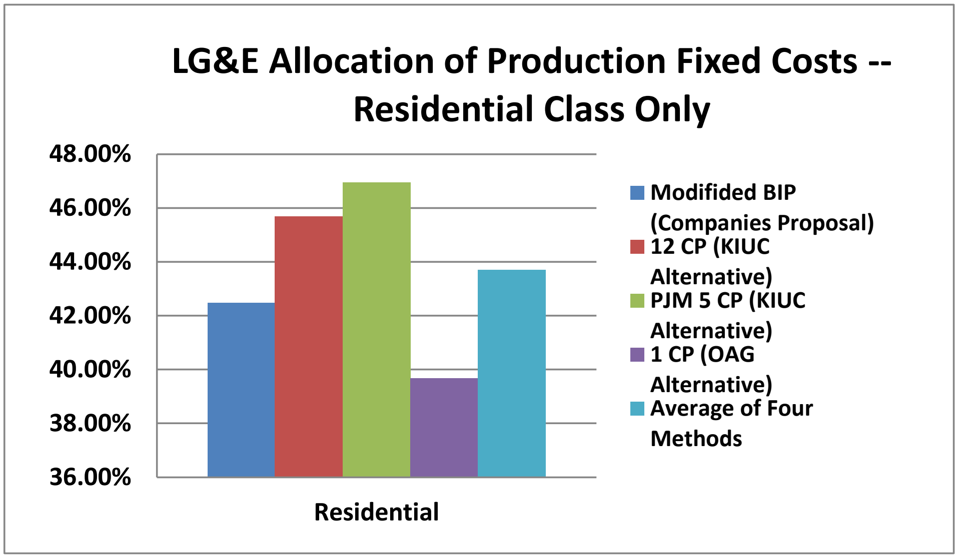
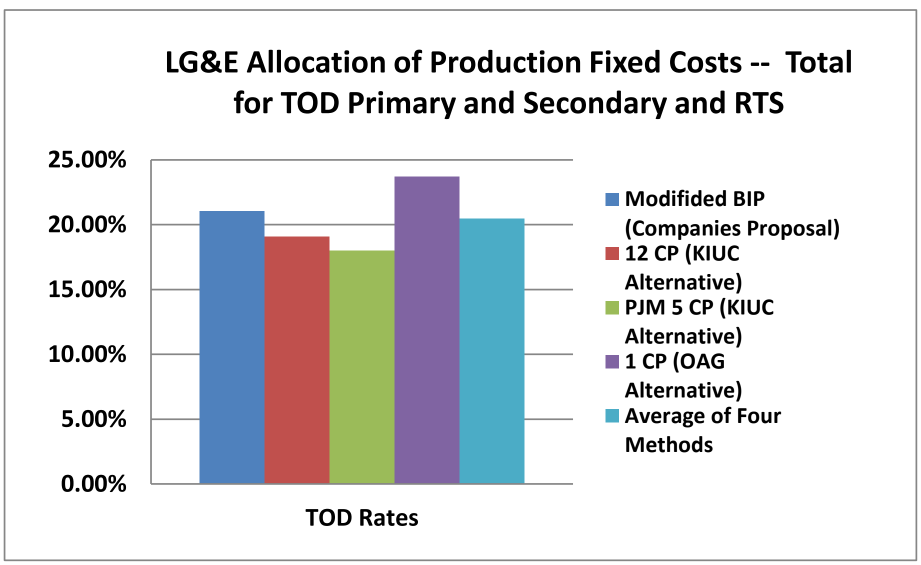


Chart 2



Kentucky Utilities Company

Chart 3

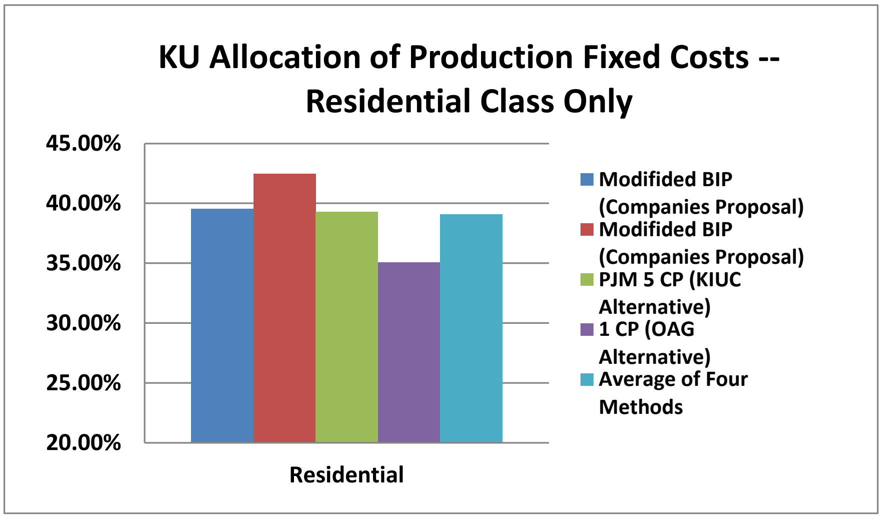
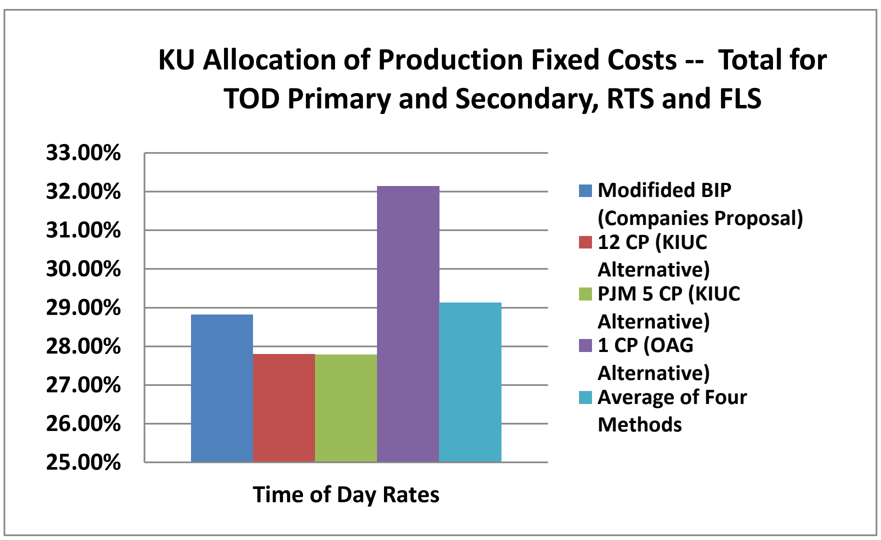


Chart 4



As Charts 1-4 clearly illustrate, the Companies' cost-of-service study results are a reasonable basis for allocating costs, have been used consistently in several preceding rate case filings, and have been accepted as reasonable by the Commission. The intervenors have not presented compelling evidence in support of a change in methods.

Q. Do you agree with Mr. Baron's argument that the modified BIP methodology allocates too much cost on the basis of an average demand allocator?

A. I agree that care must be taken in any cost-of-service study to avoid allocating too large of a percentage of fixed production costs on the basis of average demand. From a purely academic perspective, changes in a customer class's average demand do not have any impact on the Companies' capacity costs. For example, the Companies' fixed production costs will not increase if any given customer class were to increase its average demand without altering its contribution to the system peak demand. The converse, however, is not true. Except in situations where prolonged periods of excess capacity exist, if a customer class increases its demand at the time of the peak without altering its average demand, then the utility's fixed production costs will certainly increase over time. Particularly, the utility will need additional generation capacity to meet the increase in peak demand. The same result applies to any capital-intensive industry. Recalling the earlier example from the airline industry, increasing the average number of passengers on a flight (or flights) will not have any impact on an airline's fixed costs. Increasing the maximum number of passengers on flights can have a dramatic impact on fixed costs, including creating the necessity to buy additional planes, which, like power plants, are not inexpensive.

From an economics and production-planning perspective, Mr. Baron makes cogent points, but relying entirely on a coincident-peak allocator has its own problems since using a coincident-peak allocator will often result in free riders. For example, if a particular rate class, such as outdoor lighting or a set of industrial loads with unusual operating characteristics, is completely off-line at the time of the system peak, then the rate class will not be allocated any fixed production costs. Consequently, the customer would not make any contribution toward the utility's fixed production costs. From a purely economic and production-planning perspective, allocating no fixed production costs to outdoor lighting may make perfect sense, but from a regulatory-policy perspective such a result is unreasonable. A utility's generation capacity is used to provide service to customer classes that may not contribute much to peak, and customers in these classes derive some benefit from the utility's generation. This is the regulatory policy basis for assigning some fixed production costs to all classes on the basis of average demand. The issue is how much fixed production cost to assign in an effort to balance the system planning and regulatory policy perspectives.

Q. Do you agree with Mr. Watkins that the majority of fixed production costs should be allocated on the basis of average demand?

A. No. In Mr. Watkins's cost-of-service study, approximately 74.51% of the Companies' fixed production and transmission costs are allocated on the basis of an energy allocator. The Companies have traditionally allocated approximately 30% of these capacity costs on the basis of an energy allocator. Allocating 74.51% of the Companies' production and transmission capacity costs on the basis of energy is a direct consequence of his misapplication of the BIP methodology. Mr. Watkins designated nearly all of LG&E's and KU's coal-fired steam units as "base" units without considering how the units are used to provide service to native load customers and, more significantly, without considering why the units were originally installed by the Companies. For more than thirty years, increases in peak demand have been driving the need for new generation capacity on the LG&E and KU systems. The Companies must have sufficient capacity to meet the maximum demand placed on the two systems; therefore, allocating 74.51% of production capacity costs on the basis of energy cannot be supported by cost-of-service principles.

Q. How does Mr. Watkins misapply the BIP methodology?

A. Mr. Watkins attempts to use the original BIP methodology developed on an experimental basis to assign fixed production costs to costing periods in accordance with studies that were being conducted in the late 1970s related to requirements set forth in the Public Utilities Regulatory Policy Act. To my knowledge, the original BIP methodology was never adopted by any regulatory commission. The original BIP methodology was abandoned because it produced somewhat absurd results when applied to a generation mix that relied heavily on coal-fired generation. When the original BIP methodology was developed by EBASCO (an engineering consulting firm) in the late 1970s, the methodology was originally applied to a couple of utilities that had generation resource mixes that consisted of generating units that could be readily identified as "Base", "Intermediate", and "Peak" units. LG&E's resource mix consisted of a much larger percentage of base-load generation than the utilities originally used to test the BIP methodology. When LG&E hired EBASCO, the original developers of the BIP Methodology, in 1980 to assist in developing a time-differentiated cost-of-service study it quickly became apparent that the “traditional” BIP Methodology would not produce reasonable results. Specifically, when the traditional BIP Methodology was applied to LG&E's generation resources it produced peak-period costs that were lower than off-peak costs, which was obviously a counterintuitive result. LG&E worked closely with EBASCO to design a Modified BIP Methodology that would produce more reasonable results.

Q. Does an unmodified application of the BIP Methodology still produce counterintuitive results?

A. Yes. In his cost-of-service study, Mr. Watkins applied the traditional BIP Methodology to LG&E's fixed production costs. It still produces fixed production costs that are higher during the off-peak period than the winter on-peak period. As shown in Conroy Rebuttal Exhibit 1 (developed using Schedule GAW-2), Mr. Watkins’s assignment of units to Base, Intermediate, or Peak on the basis of Net Capacity Factor produces off-peak fixed production costs of $0.0921 per kWh and winter on-peak fixed production costs of $0.03968. This demonstrates that there is a serious flaw in Mr. Watkins’s assumptions and methods.

Further, although Mr. Watkins expresses reservations about the validity of a 1-CP approach to cost of service, an examination of his results shows that he uses the individual-class contribution to the summer peak as a basis for allocating his functional costs to each rate class. In effect, Mr. Watkins allocates costs on the basis of the 1-CP approach he dismisses as inappropriate in his testimony.

Q. Do you believe that each Company's cost-of-service study strikes a reasonable balance in the amount of fixed production costs allocated on the basis of average demand?

A. Yes. I believe that each does strike a reasonable balance. In Mr. Watkins's study, far too much fixed production cost is allocated on the basis of average demand. An argument can certainly be made that some small portion of each Company's fixed production costs should be allocated on the basis of average demand to account for the fact that there is some value associated with the utilization of capacity, even though, from a purely economic and production planning perspective, average demand does not have any impact on the fixed cost of providing service. In prior rate case orders, the Commission has found it reasonable to allocate at least some portion of fixed production costs on the basis of utilization. If the Commission continues to adhere to this policy, then a percentage determined by dividing the system minimum demand by the system maximum demand – the approach used in the modified BIP methodology – continues to be reasonable. The rationale for continuing to use the relationship of the minimum system demand to the maximum system demand for purposes of determining the percentage of fixed production costs to be allocated on the basis of utilization is that the Companies' production facilities will always supply an amount of production capacity at least equal to the minimum demand. Consequently, this minimum percentage of production capacity will be utilized each and every hour of the year. Thus, each rate class, regardless of when it needs the capacity, will be making at least some contribution to this minimum percentage of capacity.

C. TREATMENT OF CURTAILABLE CREDITS IN THE COST-OF-SERVICE STUDY

Q. Mr. Baron makes an adjustment to the pro-forma rates of return in the cost-of-service study to reflect actual as opposed to proposed interruptible credits under the Curtailable Service Rider.[4] Do you agree with Mr. Baron's approach?

A. No. Mr. Baron states that the curtailable service credit is "separately determined using an avoided cost based methodology…,"[5] which is accurate but does not take into account the need to reflect CSR credits in the Companies' cost-of-service studies on a going forward basis to develop rate proposals. In order to accurately determine the individual class contributions to the overall rates of return, the cost-of-service study must reflect the actual credits paid in the revenues and the actual avoided cost in the expenses. As explained in Mr. Bellar's rebuttal, the current power market, fuel costs, and the cost of installed peaking capacity indicate that the actual value to the Companies of the right to curtail its customers is less than the amount reflected in the current actual credit payments. Reflecting the actual credits paid as avoided cost in the cost-of-service studies, instead of using the actual avoided cost (as represented by the proposed credits), does not provide an accurate picture of the true profitability of the classes received the CSR credits. Therefore, the Companies used the proposed CSR credits in developing the class rates of return in the cost-of-service studies presented in these cases.

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[4] Baron Direct, p. 11-16.
[5] *Id.* at 11-12.

The Companies' cost-of-service treatment of actual test year CSR credits and proposed going forward CSR credits is correct because the cost-of-service studies serve as the starting points to determine rates required for each class to contribute appropriately to the overall rates of return. Since rates are developed on a going-forward basis, the CSR credit must also be developed on a going-forward basis; the corresponding expense adjustment referred to in Mr. Baron's testimony represents the additional contribution required from all customers to recover the proposed credits offered to curtailable service customers. This cost-of-service approach appropriately reflects both the actual revenue collected and the operating expense adjustment reflective of the proposed CSR riders, and therefore also appropriately represents each rate class's contribution to the overall rate of return.

Q. Have the Companies treated the CSR credits consistently in the cost-of-service studies in the past base rate case proceedings?

A. Yes. The Companies have consistently treated the CSR credits in the same manner, regardless of whether the credits were proposed to be decreased or increased, in the previous cost-of-service studies. Mr. Baron indicates that he has "identified an error in the Companies BIP studies related to the treatment of curtailable revenues (CSR)"[6] yet in prior rate case proceeding he did not indicate any error was made in the treatment of the CSR credits. The difference in these proceedings is that the Companies are reducing the level of the CSR credits, and as indicated by Mr. Baron, this reduction -- because of the claimed mismatch in the cost-of-service study -- "makes it appear that the curtailable customers are dramatically under-paying."[7] In

[6] Baron Direct, p. 5.
[7] Baron Direct, p. 12.

the prior rate case proceedings, the CSR credits were proposed to be <u>increased</u>. In those cases, however, Mr. Baron did not assert there was any "mismatch error" in the Companies' cost-of-service studies. In the present cases, he now argues:

> I should note that if the Companies were proposing to increase the curtailable credit, then the mismatch would make it appear that the curtailable customers were dramatically over-paying. The correct approach is to add-back the CSR credits that were actually in effect during the test year.[8]

This inconsistent position on the treatment of the CSR credit in the cost-of-service study demonstrates the results-oriented nature of Mr. Baron's testimony. The Commission should reject Mr. Baron's claim there was an error in the Companies' cost-of-service studies and continue to rely upon the Companies' studies as a guide in allocating the revenue increase to the various classes of customers.

D. ZERO-INTERCEPT METHODOLOGY

Q. Does Mr. Watkins propose an alternative to the Companies' zero-intercept method of allocating distribution-related costs in the cost-of-service study?

A. Yes. Mr. Watkins recommends that 100% of the distribution–related costs in the Companies' cost-of-service study should be allocated on the basis of demand due to a determination that the dispersal of customers across the Companies' service territory appears to be proportional. Mr. Watkins makes the argument that there is no distinct difference in the mix of customers being served by the Companies' and that each customer class is represented in a reasonably proportional manner in both rural and urban areas.

[8] Baron Direct, p. 13.

Q. Is the fact that the Companies' customers are uniformly dispersed across their service territories a valid reason to allocate all distribution-related costs on the basis of demand?

A. No. The uniformity of density across a service territory has little to do with the concept of classifying costs as demand or customer. The only known and measured attributes that can be used to fairly allocate costs to each class is kWh, demands, and number of customers. The costs on a utility's system will vary based on changes to one, or more, of these attributes. Allocating each cost according to the attribute that drives cost ensures the fairest treatment of each customer class in the cost-of-service study. To the extent that those costs are also properly reflected in the appropriate rate components, it also produces the most equitable rate for each customer in a given class of service. The concept of classifying costs as demand or customer relates to trying to identify the cost driver that best reflects what is causing those costs to be incurred by the utility. In other words, costs that vary with demand should be allocated to each class based on the appropriate demand allocator. Additionally, those costs should be billed to the customer on the basis of demand to achieve the most equitable distribution of those costs among each customer in the class. Costs that do not vary with demand or energy are fixed. Those costs are better allocated to each customer class on the basis of the number of customers. Since they are fixed in nature, and do not vary with changes in demand or energy usage, those costs are more fairly distributed to each customer in the class through a fixed monthly charge (the Basic Service Charge as proposed by the Companies).

The zero-intercept regression analysis utilized by the Companies' for line transformers, and overhead and underground conductor costs is a mathematical analysis that determines how much of the change in the cost is explained by the change in the capacity of the asset (demand related). The portion of cost that cannot be explained by the change in capacity of the asset is considered fixed (customer related). This would suggest that in the price a utility pays for a line transformer, for example, that a certain portion of that cost is fixed and does not vary with the capacity of the transformer. The fixed portion of the cost should not be allocated to each class on the basis of demand because demand does not explain the existence of that cost. The fixed portion of cost is better allocated to each class on the basis of the number of customers and is more fairly distributed to each customer in a class through a fixed monthly charge. Allocating the fixed portion on demand and distributing the costs to each customer in a class on the basis of a demand charge, or energy charge, in the case of residential, creates a situation where high use customers will over pay those costs and low use customers will under pay those costs. Density has no bearing on this issue and should not be considered in the classification of these costs.

Q. Does Mr. Watkins accept the Companies' application of the zero-intercept methodology for classification of distribution plant?

A. No. The Companies' cost-of-service studies classify certain distribution costs as customer-related or demand-related using a methodology that is referred to as a zero-intercept methodology. The central idea behind the zero-intercept methodology is to determine, using a regression analysis, the portion of costs that are invariant with respect to the load-carrying capability of certain distribution facilities. The zero-intercept methodology is typically applied to overhead conductor, underground conductor, and transformers. In applying the zero-intercept methodology, LG&E and KU have traditionally used a weighted regression analysis. Mr. Watkins disagrees with the Companies' zero-intercept methodology using weighted regression and claims it deviates from the industry-accepted zero-intercept methodology using an unweighted regression approach. In support of this assertion, Mr. Watkins refers to the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual:

> To ensure that costs are properly allocated, the analyst must first classify each account as demand-related, customer-related, or a combination of both. The classification depends upon the analyst's evaluation of how the costs in these accounts were incurred. In making this determination, supporting data may be more important than theoretical considerations.
>
> Allocating costs to the appropriate groups in a cost study requires a special analysis of the nature of distribution plant and expenses.[9]

Mr. Watkins appears to be selective in his reliance on the NARUC Cost Allocation Manual, however. For example, the Cost Allocation Manual goes on to state:

> Distribution plant Accounts 364 through 370 involve demand and customer costs. The customer component of distribution facilities is that portion of costs which varies with the number of customers….Two methods are used to determine the demand and customer components of distribution facilities. They are, the minimum-size-of-facilities method, and the minimum-intercept cost (zero-intercept or positive-intercept cost, as applicable) of facilities.[10]

[9] NARUC Electric Utility Cost Allocation Manual at 89 (Jan. 1992).
[10] *Id* at 90.

Further, the manual specifically instructs the analyst to weight conductor by feet or investment, and to weight transformers by number.[11]

In contrast with a comprehensive reading of the NARUC Cost Allocation Manual, Mr. Watkins goes to great lengths to support his argument that an *unweighted* regression approach is theoretically correct, and then inexplicably dismisses zero-intercept analysis completely. Instead, Mr. Watkins proposes that 100% of distribution related costs should be allocated on a demand basis based on customer density in the Companies' service territory.

Q. Why is it necessary to use weighted regression in performing a zero-intercept analysis?

A. Weighted least-squares is necessary in a zero-intercept analysis because the summary data used in the analysis includes average cost information reflecting vastly different quantities of the various types of plant identified in the analysis. For example, in the cost data used to perform the zero-intercept analysis for LG&E's transformers, there were 3,213 transformers with a size rating of 25 kVA but only seven transformers with a size rating of 3000 kVA. On a very basic level, the 3000 kVA transformers – totaling only seven transformers – should not be given the same weight in the analysis as the 3,213 25 kVA transformers when there are many times more of them included in the analysis. Using weighted least squares regression more accurately replicates the results that would be obtained if a regression were performed using cost data for each transformer rather than summary data (average) for each type of transformer. For instance, if cost data were available for each transformer (rather than each type of transformer), then there would be 3,213 data points for the 25 kVA transformers and

[11] *Id* at 93.

only seven data points for the 3000 KVA transformers. In fact, there would be 3,208 more 25 kVA transformers in the regression analysis than 3000 kVA transformers, and the 25 kVA transformers would have a correspondingly larger impact on the results of the regression analysis. Obviously, if cost data were available for each and every transformer on the system, then the 3000 kVA transformers would have very little impact on the results of a regression analysis performed using cost data for each transformer. In fact, it is likely that the seven 3000 kVA transformers could be removed from the analysis without indicating any noticeable effect on the regression coefficients.

The purpose of a zero-intercept analysis is to properly represent the actual composition of a utility's distribution facilities. If the analysis is weighted then it accomplishes this task. But if the analysis is not weighted, then the zero-intercept analysis will not accurately represent the distribution of the various types of overhead conductor, underground conductor, and line transformers actually installed by the utility, and will thus produce inaccurate results.

Q. Mr. Watkins claims that unweighted least-squares regression is the standard approach used to perform the zero-intercept analysis. Is he correct?

A. No. The NARUC Electric Utility Cost Allocation Manual clearly indicates that the zero-intercept analysis should be weighted. NARUC's Electric Utility Cost Allocation Manual provides the following instructions for overhead conductor, underground conductor and transformers:

Account 365 – Overhead Conductors and Devices

> Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor **weighted** by feet or investment in each category, and developing a cost for the utility's minimum size conductor.

Account 366 and 367 – Overhead Conductors and Devices

> Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable **weighted** by feet of investment in each category.

Account 368 – Line Transformers

> Determine zero intercept of transformer cost using cost per transformer by type, **weighted** by number for each category.[12]

Mr. Watkins's claim that unweighted least-squares regression represents the industry-standard approach cannot be reconciled with these instructions from NARUC's Electric Utility Cost Allocation Manual, which clearly indicates that the analysis should be weighted.

In addition, a recent text book on electric ratemaking written by Lawrence J. Vogt, P.E. titled Electric Pricing: Engineering Principles and Methodologies (CRC Press, Taylor & Francis Group, 2009) also explains that a weighted regression analysis must be used in the application of the zero-intercept methodology. Mr. Vogt states as follows:

> The minimum intercept or zero-intercept methodology provides a rational basis for separating the cost of a device between its customer and demand components. The zero-intercept methodology is a weighted linear regression of the unit costs of standard ratings or sizes of a specific device, such as a single-phase overhead line transformer, plotted as a function of its capacity characteristic, which would be kVA for a line transformer. The objective of the regression analysis is to determine the y-intercept. The y-intercept

[12] *Id* at 93-94. (emphasis added)

> represents that portion of a device's total cost that is associated with zero capacity and thus the customer-related component. The unit costs must be weighted by the numbers of devices because of the uneven distribution of the various ratings or sizes of the devices in service.[13]

Contrary to being simply a "clever arithmetic exercise," as claimed by Mr. Watkins, weighted least-squares regression is the standard approach used in the industry to perform zero-intercept analysis.[14]

Q. Were cost-of-service studies utilizing weighted regression to perform the zero-intercept analysis found to be reasonable by this Commission in earlier Commission Orders?

A. Yes, on many occasions. For example, weighted least-squares regression was accepted by the Commission in its Order dated November 10, 2004, in Case No. 2004-00067 approving rates for Delta Natural Gas Company. The AG's own witness in that proceeding also utilized weighted least-squares regression to perform a zero-intercept analysis.

Q. In making his recommendation, has Mr. Watkins demonstrated that weighted least-squares regression produces incorrect results?

A. No. Calling weighted least-squares regression a "clever arithmetic exercise" does not demonstrate that it produces incorrect results. He claims that it "violates theoretical statistical principles of linear regression and skews his results" but he fails to indicate what "theoretical principles of linear regression" are violated or to demonstrate how the results are "skewed" by application of the methodology. Offering rhetoric

[13] Lawrence J. Vogt, P.E., Electricity Pricing: Engineering Principles and Methodologies, p. 500.

[14] Prepared Direct Testimony and Schedules of Glenn A. Watkins on behalf of the Kentucky Office of the Attorney General in Case No. 2012-00221 ("Watkins KU Direct") and Case No. 2012-00222 ("Watkins LG&E Direct") filed October 3, 2012, p. 30.

without support is not sufficient grounds for arguing against weighted least-squares regression. It is incumbent on Mr. Watkins to demonstrate that weighted regression is mathematically flawed, statistically inaccurate, or otherwise produces incorrect results. He has not demonstrated that the methodology is flawed in any respect. Instead, he introduces an alternative analysis that he claims justifies his conclusion that 100% of distribution overhead and underground conductor and transformers should be classified as demand. What Mr. Watkins has done when discussing the zero-intercept analysis is fail to recognize that a different type of regression methodology is required when analyzing summary data than when analyzing individual unit cost data.

Q. What is the difference between "summary data" and "individual unit cost data"?

A. In the context of a zero-intercept analysis, "individual unit cost data" refers to the cost of each piece (unit) of property recorded on the utility's books. In the case of line transformers, "individual unit cost data" would refer to the cost of each individual transformer purchased by the utility. Utilities generally do not retain information on the cost of each individual transformer that it has purchased, or at least not in any readily accessible database. Consequently, the data used to perform a zero-intercept analysis is almost always provided in summary form. With "summary data," the information retained for each type of transformer (or other types of property) includes the total cost of each transformer type and the total number of transformers (or units) by type. From this type of summary data, the average unit cost by transformer type can be calculated by dividing (i) the total cost for each type of transformer by (ii) the total number of transformers for that particular transformer type. This is the kind of summary data that is normally used to perform a zero-intercept analysis.

Q. Is it appropriate to use unweighted least squares when analyzing summary data?

A. No. Although it would be appropriate to use unweighted regression if individual unit cost data were analyzed, using unweighted least-squares regression to analyze summary data will almost certainly produce incorrect results. As unambiguously stated in NARUC's Electric Utility Cost Allocation Manual, the summary cost data for each type of property must be weighted by the number of units shown for each property type.

Q. Could you provide an example demonstrating that the failure to use weighted least squares will produce incorrect parameter estimates?

A. Yes. Perhaps the clearest way to demonstrate that unweighted regression yields incorrect results is to perform a least-squares regression analysis using individual unit cost data and compare the results of that analysis to the results of an unweighted regression analysis performed using summary data for the same dataset. Comparing the regression coefficients from the two procedures will demonstrate that performing unweighted regression using summary data will produce incorrect parameter estimates, i.e., results that differ significantly from the "true" results determined from the underlying individual unit cost data. But we will be able to see that the parameter estimates determined by applying weighted least squares to the summary data will produce the exact same coefficients determined from the application of unweighted least squares to the underlying data. These comparisons will thus invalidate the zero-intercept methodology recommended by Mr. Watkins but will confirm the methodology used by the Company.

Q. Please describe the underlying unit cost data used in your example.

A. In order to demonstrate the fundamental problem with using unweighted regression to analyze summary data, I will perform unweighted regression on a sample dataset containing individual unit cost data for six different transformer types. Specifically, the dataset includes twenty 25 kVA transformers, three 50 kVA transformers, twenty 100 kVA transformers, three 200 kVA transformers, and twenty 500 kVA transformers. The purpose of this sample is to illustrate the effect on a regression analysis of including transformer types for which there are relatively few units. In this case, there are only three 50 kVA transformers and three 200 kVA transformers. These two transformer types will not have a major impact on a regression analysis performed using the underlying data, but will have a major impact when Mr. Watkins's recommended methodology is applied to the summary data. I have limited the number of transformer types and the quantity of transformers to a minimum to make it easier to analyze the individual unit cost data. The unit cost data is shown in the following table:

Table 5 – Transformer Unit Cost Data

Transformer Type	25 KVA	50 KVA	100 KVA	200 KVA	500 KVA
Individual Unit Cost of Transformer	$ 400	$ 400	$ 1,800	$ 11,000	$ 7,800
	500	500	1,800	12,000	7,800
	600	600	1,900	13,000	7,900
	700		1,900		7,900
	800		2,000		8,000
	850		2,000		8,000
	900		2,000		8,000
	950		2,100		8,100
	950		2,100		8,100
	1,000		2,100		8,100
	1,000		2,100		8,100
	1,050		2,100		8,100
	1,050		2,100		8,100
	1,100		2,200		8,200
	1,150		2,200		8,200
	1,200		2,200		8,200
	1,300		2,300		8,300
	1,400		2,300		8,300
	1,500		2,400		8,400
	1,600		2,400		8,400
Average Unit Cost	$ 1,000	$ 500	$ 2,100	$ 12,000	$ 8,100

Q. Please describe the results of performing a least-squares regression analysis using this dataset.

A. Because the dataset contains individual unit cost data, it is appropriate in this instance to use unweighted least-squares regression to calculate the intercept and slope coefficients. The least squares analysis is performed using the cost of each transformer as the dependent variable (y) and the transformer size (kVA) as the independent variable (x). Performing an unweighted regression analysis using this underlying data produces the following regression estimates:

$$y = a + bx$$

$$y = 929.97 + 15.10x$$

Stated another way, the intercept (a coefficient) of the model is $929.97 and the slope (b coefficient) is $15.10. The results of this regression analysis are shown in Conroy Rebuttal Exhibit 2.

Q. Do these parameter estimates represent accurate estimates of the linear model that best fit the data?

A. Yes. Because individual unit cost data is analyzed, unweighted least squares provides the parameter estimates for a linear model (i.e., a straight line) that most accurately fits the data. Therefore, these parameter estimates can be used to evaluate the accuracy of model estimates determined from applying unweighted and weighted least squares to summary data developed from the underlying dataset.

Q. How would unweighted least-squares regression (Mr. Watkins's approach) be performed using summary data?

A. The summary data for this dataset consists of the average cost of each type of transformer, as follows:

Type	Average Cost
25 kVA	$ 1,000
50 kVA	$ 500
100 kVA	$ 2,100
200 kVA	$12,000
500 kVA	$ 8,100

Using Mr. Watkins's approach, unweighted regression would be applied to these five data points without giving any consideration to the number of transformers installed for each transformer type. Applying unweighted least-squares regression to these five data points produces the following regression estimates:

$$y = a + bx$$

$$y = 1{,}750.42 + 17.08x$$

The intercept (a coefficient) of the model using Mr. Watkins's approach is \$1,750.42 and the slope (b coefficient) is \$17.08. These regression estimates are clearly not the same as those determined by performing least-squares regression using the individual unit cost data. The results of this regression analysis are shown in Conroy Rebuttal Exhibit 3.

Q. What conclusion can be drawn from this analysis?

A. It demonstrates that Mr. Watkins's methodology is fundamentally flawed. If his methodology were correct, then it would produce results that were somewhere close to the coefficients obtained from the underlying individual unit cost data. In this example, his methodology produces coefficients nowhere close to the original estimates.

Q. How would weighted least-squares regression (the standard approach used by the Companies) be performed using summary data?

A. Using the methodology prescribed by NARUC's Electric Utility Cost Allocation Manual and utilized by the Companies, the average cost of each type of transformer would be weighted by the number of units for each transformer type. Mathematically, this is done by weighting the squared differences by the number of units (n_i), and calculating the regression coefficients that minimize the sum of squared differences. Applying weighted least-squares regression to the five data points produces the following regression estimates:

$$y = a + bx$$

$$y = 929.97 + 15.10x$$

The intercept (a coefficient) of the model using the Companies' approach is $929.97 and the slope (b coefficient) is $15.10.These regression estimates are exactly the same as those determined by performing least-squares regression using the individual unit cost data. The results of this regression analysis are shown in Conroy Rebuttal Exhibit 4.

Q. What conclusion can be drawn from this regression analysis?

A. It demonstrates that the methodology used by the Company is fundamentally sound and produces zero-intercept estimates that accurately represent the underlying data.

Q. Was the underlying data used in this zero-intercept analysis based on actual data from the Companies' records?

A. Yes. In the Companies' prior case a group of proxy data was used to determine the percentage of distribution related costs that should be classified as demand or customer related. This was due to the actual data from the Companies' CPR records yielding statistically erroneous results. This result was due to a change in software that the Companies' used to maintain their equipment cost information. This system did not import the detailed historical description of the equipment and grouped imported equipment into categories such as "overhead conductor" and "transformers" based on its year of installation. Thus, there was no information on which to base the zero-intercept size calculation, so a group of proxy data was utilized.

Since then the Companies have kept detailed information of new equipment installed on the system and have installed enough equipment to yield statistically relevant results. This explains the concern Mr. Watkins expresses in his testimony about the differences in sample sizes between this case and cases filed by the Companies' in 2009.

Q. Do you have any comments concerning Mr. Watkins's proposal to classify 100% of distribution costs as demand-related based on the argument that density across the Companies' service territories is relatively proportional?

A. Yes. Mr. Watkins states, at page 33 of his LG&E testimony "Based on my customer density/mix analysis of KU's distribution system, it is ***entirely likely*** that all of KU's and LG&E's distribution system should be classified as 100% demand-related." (emphasis added) Earlier, Mr. Watkins states, on page 24, "Mr. Conroy has made an *a priori* assumption that it is appropriate to allocate a portion of its distribution plant based on customer counts and a portion based on demand levels."

Contrary to Mr. Watkins's assertion, the Companies' classification of distribution conductor and transformers as demand- and customer-related was the result of rigorous analysis that used specific data taken from records of actual equipment installed for serving their customers, rather than the result of an *a priori* assumption. The weighted linear-regression analysis used in the zero-intercept analysis yielded statistically significant results with R-Squares for each equipment type above 0.90. This illustrates that there is a strong correlation between the dependent variable (cost) and the independent variable (conductor or transformer size) in determining the zero-intercept and that the regression line is a good fit for the underlying data. Using this standard methodology which is widely accepted in the industry, the Companies determined that a certain percentage of distribution-related costs were associated with a "zero-size" conductor or transformer and thus reflect the minimum amount of equipment needed to be in place to serve the customer. Therefore, a corresponding portion of total conductor and transformer costs are classified as customer related.

Q. Has Mr. Watkins proposed alternative methodologies for classifying distribution costs in the Companies' prior rate proceedings?

A. Yes. In the Companies' 2008 rate proceedings, Mr. Watkins filed testimony in support of a minimum system methodology for allocating distribution plant and stated:

> Although I prefer to use the zero-intercept method when possible, the data is such that his method is not reliable in this instance. This is because the regression equations produce negative intercept values (illogical) and have low R^2 (poor fits). As a result, I conducted a minimum size analysis, which by its very nature tends to overstate the customer percentage of distribution plant. [15]

In the Companies' 2009 rate proceedings, Mr. Watkins filed testimony in support of a zero-intercept methodology using the current carrying capacity of overhead and underground conductor and transformer kVA size and stated:

> The purpose of the zero-intercept analysis is to calculate the average cost of a zero load conductor in order to evaluate the customer portion as I have discussed previously. In my zero-intercept analysis, therefore, I have incorporated the ampacity (capacity or load capability) of LG&E's overhead conductors, rather than merely the physical size of these conductors.[16]

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[15] In the matter of: *Application of Louisville Gas and Electric Company for an Adjustment of Base Rates*, Case No. 2008-00252. Watkins Testimony at 31.

[16] In the matter of: *Application of Louisville Gas and Electric Company for an Adjustment of Base Rates*, Case No. 2009-00549. Watkins Testimony at 37.

In this proceeding, Mr. Watkins filed testimony in support of 100% demand classification of distribution plant based on uniform density of the Companies' service territories.[17] Thus, over the last three rate cases, Mr. Watkins has changed his method each time.

Q. Have the methodologies proposed by Mr. Watkins in the prior cases discussed above resulted in lowering the amount of distribution plant that is classified as customer-related when compared to the Companies' proposals?

A. Yes, with one exception in 2009, when Mr. Watkins and the Companies' agreed on the split of transformer costs. Below is a table for the three most recent rate case filings comparing Mr. Watkins' and the Companies' proposed methodologies for allocation of distribution plant:

Table 6
Comparison of Distribution Cost Allocations

Distribution Cost Category	2008		2009		2012	
	Watkins	Companies	Watkins	Companies	Watkins	Companies
Overhead Conductors						
Customer	39.30%	60.56%	26.00%	54.00%	0.00%	54.57%
Demand	60.70%	39.44%	74.00%	46.00%	100.00%	45.43%
Underground Conductors						
Customer	20.10%	62.65%	19.00%	31.00%	0.00%	75.21%
Demand	79.90%	37.35%	81.00%	69.00%	100.00%	24.79%
Transformers						
Customer	26.50%	48.75%	46.00%	46.00%	0.00%	44.30%
Demand	73.50%	51.25%	54.00%	54.00%	100.00%	55.70%

Since 2008, Mr. Watkins has used three different approaches for classifying distribution plant, each yielding results that have almost exclusively reduced the percentage of distribution plant classified as customer-related. Thus it is clear that Mr.

[17] Watkins KU Direct, p. 24-26; Watkins LG&E Direct, p. 24-26.

Watkins files methodologies that are results-oriented. During this same time the Companies' have filed the same zero-intercept methodology in every proceeding and have been consistent in using a standard approach that is widely accepted throughout the industry. Therefore, the Companies' proposed classification of distribution plant should be adopted in this proceeding because of its consistency. Further, the Companies' approach of using the zero-intercept methodology to classify distribution plant related costs has been accepted by the Commission on numerous occasions.

III. ALLOCATION OF THE ELECTRIC REVENUE INCREASE

Q. Earlier, you mentioned that there was no agreement among the intervenor witnesses regarding the electric cost-of-service methodology. Is there agreement among them on how the increase should be allocated to the rate classes?

A. No. Mr. Watkins found the Companies' proposed class revenue distribution to be reasonable. However, for LG&E he recommended increasing Rate PS-Primary by 50% of the system average while for KU he recommended increasing Rate FLS by 125%. Under both recommended changes, the Residential Class increase would be reduced by an equivalent amount. Mr. Baron, on the other hand, agrees with the Companies' recommended increase to the Residential Class but maintains that too much of the revenue increase is being allocated to the commercial and industrial rate classes. His recommendation is to apply a uniform increase to all of the other classes (besides Residential and LG&E Special Contracts), in spite of the fact that his own analysis indicates that, depending on the cost-of-service method chosen, a minimum of five of the rate classes he includes with a uniform increase are, at current rates, earning above the overall rate of return. Curiously, the FLS rate class, a class of particular interest to Mr. Baron, is earning at less than the overall KU rate of return in all but one of the cost-of-service methods he evaluates, yet he recommends that the FLS class be included as receiving his recommended uniform increase. Mr. Baron's proposed distribution of the revenue increase appears to harm smaller power service customers (a group of customers he does not represent) that are consistently earning above the overall rates of return for both Companies by applying a uniform percentage increase when a smaller, more targeted rate change would be appropriate and justified by two of Mr. Baron's own cost-of-service studies.

Q. Did any other intervenor propose a different revenue allocation without performing a cost-of-service study?

A. Yes. The Kroger witness, Mr. Higgins, proposes a much higher subsidy reduction than the 15% target the Companies proposed. While no specific allocation among rate classes is discussed, Mr. Higgins indicates that a more robust reduction in inter-class subsidization of 25% to 33% would be reasonable and demonstrate a more genuine commitment to moving toward cost-based rates.

Q. Do you agree with Kroger witness Higgins that a greater subsidy reduction should be achieved?

A. It is the Companies' long-standing goal to reduce subsidies over time. But doing so at the rate Mr. Higgins proposes—greater than 15% in this case—does not comport with the ratemaking principle of gradualism.

Q. What do you recommend the Commission consider in allocating the revenue increase across the rate classes?

A. The Commission should be guided by the results of the Companies cost-of-service studies instead of the results-oriented recommendations of Mr. Watkins and Mr. Baron. As stated in my direct testimony, it is the Companies' intent to continue the principles followed in the previous two rate cases of gradually eliminating cross-subsidization. This approach balances the interests of the various customer classes and is fully in line with the ratemaking principle of gradualism.

IV. ELECTRIC RATE DESIGN

A. BASIC SERVICE CHARGE

Q. Are the Companies proposing to move the basic service charges closer to the actual cost of service?

A. Yes. It has been a longstanding goal of the Companies to move basic service charges (formerly called "customer charges") more in line with the actual cost of service. Because of the infrequency of rate case filings by the Companies and because a number of base rate changes over the last 20 years have resulted in decreases, it has been difficult for the Companies to make much progress in this area. In the settlement submitted in Case No. 2003-00433, the parties agreed to basically double the basic service charge. In the settlement in Case Nos. 2008-00251 and 2008-00252, the parties agreed to maintain the basic service charge at the same level even though the case resulted in a revenue decrease. In the settlement in the previous rate cases (Case Nos. 2009-00548 and 2009-00549), the parties agreed to raise the residential basic service charge from $5.00 to the current level of $8.50. Therefore, in the previous proceedings some progress was made to move the basic service charge more in line with cost of service. However, not nearly enough movement has been made in this direction. The basic customer cost of serving a residential customer is $18.82 per month for KU customers and $18.11 for the LG&E system, whereas the Companies' basic service charge for residential service is currently $8.50 per month. Thus, over $9 per customer per month in customer-related fixed distribution costs are being recovered through a volumetric kWh charge rather than through the basic service charge where these costs should be collected. This violates the basic ratemaking principle of collecting fixed costs through fixed charges and variable costs through variable charges. When this principle is violated, it results in intra-class subsidies, as is the case here where customers with above average usage are paying more than their fair share of customer-related fixed distribution costs and customers with below average usage are paying less than their fair share of customer-related fixed distribution costs and are being subsidized. When the cost of service is not followed, customers are provided inaccurate price signals which encourage them to make incorrect decisions about energy efficiency. The residential basic service charge is currently less than 46 percent of the actual cost of providing service. I am unaware of any other charge billed by LG&E that is this far out of line with the actual cost of providing service.

Q. What does Mr. Watkins's own cost-of-service study indicate that the basic service charge should be?

A. Based on the allocations contained in Mr. Watkins's own cost-of-service study and using the same calculations in his Schedule GAW-8 (LG&E) and GAW-7 (KU), the residential basic service charge for LG&E and KU should be $9.23 per month and $11.65 per month, respectively. Even though Mr. Watkins claims that the monthly residential customer cost for LG&E and KU is only $3.23 per month and $4.29 per month, respectively, he gets there by ignoring the results of his own cost-of-service study. In his cost-of-service study, he classifies a portion of transformers as customer related, but he ignores these same costs when he calculates his proposed basic service charge. Specifically, he only includes costs associated with services, meters, meter reading, and records and collections in the calculation of his proposed basic service charge, ignoring costs associated with transformers and certain administrative and general expenses that were classified as customer-related in his own cost-of-service study. Furthermore, Mr. Watkins provides no sound rationale or basis for this omission. The following table compares the costs identified as customer-related in Mr. Watkins's cost-of-service study with the costs that he considered customer-related for purposes of developing the basic service charge:

Table 7 – Distribution Customer Costs

COST ITEM	IDENTIFIED AS CUSTOMER-RELATED IN WATKINS' COST OF SERVICE STUDY	IDENTIFIED AS CUSTOMER-RELATED IN CALCULATING HIS BASIC SERVICE CHARGE
Transformers	Yes	***No***
Services	Yes	Yes
Meters	Yes	Yes
Meter Reading	Yes	Yes
Records and Collection	Yes	Yes
Customer Accounts Supervision Expenses (Account 901)	Yes	***No***
Uncollectible Accounts (Account 904)	Yes	***No***
Miscellaneous Customer Accounts Expenses (Account 905)	Yes	***No***
Customer Service Supervision (Account 907)	Yes	***No***
Customer Assistance Expense (Account 908)	Yes	***No***
Customer Information and Instruction (Account 909)	Yes	***No***
Miscellaneous Customer Service	Yes	***No***
A&G Expenses	Yes	***No***

In calculating his proposed basic service charge, Mr. Watkins specifically excludes a large number of costs identified as customer-related in his own cost-of-service study, including transformer costs which he classifies as 100% demand related based on his density analysis, but has classified partially as customer costs in his cost-of-service study.

By leaving costs out of his calculation of customer-related costs in his Schedules GAW-8 (LG&E) and GAW-7 (KU), Mr. Watkins calculates residential basic service charges of only $3.23 and $4.29 per month, respectively. Conroy Rebuttal Exhibit 5 is a recalculation of Mr. Watkins's residential customer cost for LG&E, adding back in costs that were classified as customer-related in his own cost-of-service study. Conroy Rebuttal Exhibit 6 presents the same calculations for KU. As can be seen from these exhibits, Mr. Watkins's own cost-of-service study indicates that the monthly customer cost for the residential class for LG&E and KU should be $9.23 per month and $11.65 per month, respectively. The difference between Mr. Watkins's Basic Service Charge and the Companies' is directly attributable to Mr. Watkins's steadfast refusal to correctly classify significant portions of distribution plant as customer-related.

Q. Has the Commission rejected this type of selective interpretation of the cost-of-service study in prior rate orders?

A. Yes. In its Order dated September 27, 2000, in Case No. 2000-080, an LG&E rate case, the Commission specifically rejected this same type of selective and attenuated approach for determining basic service charges. Just as Mr. Watkins has done in the current proceeding, the AG's cost of service witness proposed a basic service charge in Case No. 2000-080 that ignored costs identified as customer-related in the zero-intercept analysis. The Commission rejected the AG's calculation in that proceeding and should do the same in this proceeding.

Q. In reinforcing his argument for a low monthly customer charge, does Mr. Watkins make reference to other jurisdictions subject to a regulatory environment different than what is experienced in Kentucky?

A. Yes. Mr. Watkins objects to the Companies' recovery of fixed customer-related costs through an appropriate monthly basic service fee based on his evaluation of competitive pricing models in use in Texas. However, this proceeding deals with rates and pricing issues in Kentucky, and Mr. Watkins fails to adequately demonstrate how the Texas experience is relevant to the Kentucky situation. Further, Mr. Watkins bases some of his recommendations concerning the monthly basic service charge on an evaluation of *competitive pricing* in Texas. As participation in this proceeding makes abundantly clear, Kentucky's regulated utilities are not subject to competitive pricing considerations. Again, Mr. Watkins does not demonstrate the relevance of the Texas competitive experience to the Kentucky regulated situation.

Q. Do you have any other comments regarding the basic service charge recommended by Mr. Watkins?

A. Yes. Even though he claims that his study can support a reduction to the monthly service charge, he recommends a basic service charge be maintained at its current level of $8.50. This is the exact same argument Mr. Watkins made in the prior rate case when the basic service charge was $5.00. He claimed the costs were lower, yet recommended the basic service charge be maintained at its then current level.

Mr. Watkins's proposal would recover more of the Company's fixed customer-related costs through a "volumetric" charge (i.e., energy charge) and send incorrect price signals to customers. The Basic Service Charge is designed to cover the minimum amount of equipment necessary to provide a customer with grid access, and an artificially low basic service charge sends the incorrect price signal that this minimum amount of equipment is relatively inexpensive. Mr. Watkins's proposal would increase the volatility in customer bills by collecting too much customer-related fixed distribution cost during peak months and during periods of extreme weather while collecting too little during periods of mild weather. This has the undesirable effect of unnecessarily increasing the volatility of customer energy bills, with the high bills higher than necessary and the low bills lower than necessary. Likewise, his proposal would increase the Companies' revenue volatility.

Additionally, Mr. Watkins's proposal would provide a disincentive for the Companies to promote energy efficiency, thus creating a poor regulatory environment for encouraging the Companies to take additional measures for customers to reduce their energy usage. An inappropriately low Basic Service Charge will not send a proper price signal to the customer and, as a result, a customer may be tempted to add a new meter point to accommodate increased load, rather than utilizing an existing meter point with an upgraded service. All other customers then pay for the under recovery of the additional delivery point. If customer-related fixed costs are inappropriately recovered through the energy charge assessed on a kWh basis rather than a fixed monthly basic service charge, then the utility will see a relative reduction in margins whenever customers reduce their consumption of electric energy. Many regulators have recognized the need to make rate design changes that align the interests of utilities and customers so as not to penalize the utility when customers reduce their energy consumption as a result of improved efficiency. Mr. Watkins's regressive recommendation would take us back to the failed approaches of the 1970s, when the accepted view was to try to induce utility customers to reduce energy usage by increasing volumetric charges. The Companies' approach is forward-looking and more consistent with progressive rate design philosophies that create a win-win for both the customer and the utility when customers use energy more efficiently.

Q. But can't a properly designed demand-side management (DSM) recovery mechanism protect utilities against the adverse financial consequences of improved energy efficiency?

A. Not necessarily. Unless the mechanism includes some type of broad-based decoupling mechanism, which completely severs the relationship between energy sales and revenues, then a DSM mechanism will not shield the utility against customer-initiated improvements in energy efficiency. While the Companies' DSM cost recovery mechanism includes a lost revenue component designed to provide limited recovery of lost net revenues from company-initiated programs, the mechanism does not include a decoupling mechanism and therefore will not recover lost revenues from customer-initiated energy efficiency efforts, such as replacing incandescent bulbs with more efficient compact fluorescent lamps (CFLs) or light emitting diodes (LEDs) and implementing smart energy technologies with low-power sensor networks using IEEE 802.15.4 MAC protocols or Zigbee architectures.

B. ITOD AND CTOD CONSOLIDATION

Q. Why is LG&E proposing to combine ITOD and CTOD into a single TOD rate?

A. LG&E proposed combining these rates in this proceeding because there is no cost justification for maintaining them separately. It doesn't matter what service is used for but it does matter how it is used. In Case No. 2009-00549, LG&E proposed a common rate structure for Rate CTODP and Rate ITODP, moving from kW billing with two demand tiers to kVA billing with three time periods, without consolidating the two rates. The proposed structure for Rate CTODP was agreed to by the parties; however, a settlement was reached delaying the change for Rate ITODP until the next rate proceeding to allow those customers impacted by kVA demand billing the necessary time to power factor correct their loads. Making this change now provides the TODP customers a more accurate price signal and greater flexibility in managing their billing.

Q. What are the Intervenor's positions on LG&E's proposal to combine its current Rate CTOD and Rate ITOD into one Rate TOD?

A. Each intervenor's position reflects the impact of the proposed change on the groups of customers the intervenor represents. For example, Mr. Baron, who is testifying on behalf of KIUC, and therefore on behalf of several customers currently on Rate ITODP, opposes the proposal in this proceeding because of a negative impact the proposal might have on some customers currently on Rate ITODP. However, he does not indicate an opposition to consolidate the secondary service, Rates CTODS and ITODS, into a single Rate TODS. Conversely, Mr. Higgins, testifying on behalf of

Kroger, supports the proposal stating that the "current practice of differentiating certain customers rates based solely on whether the customer is classified as industrial or commercial is an archaic and unduly discriminatory basis for differentiating rates."[18]

There is no cost of service justification for different rates based on the classification of a customer as engaging in commercial activities as opposed to industrial activities. In other words, rate schedule differentiation should be based on the characteristics of a customer's use of electricity, not whether the customer is classified as commercial or industrial.

Q. Does Mr. Baron oppose the concept of consolidating Rate CTOD and Rate ITOD?

A. No. He opposes the consolidation in this case only because of the large increase on Rate ITOD customers. In fact, Mr. Baron does not oppose the consolidation of the secondary service, Rates CTODS and ITODS, into a single Rate TODS. In the prior rate case, the KIUC opposed moving Rate ITODP to kVA billing because of the large impact on customers on Rate ITODP and agreed not to oppose the change in the Companies' next base rate proceedings. If the two rate schedules remain separate, and, under Mr. Baron's proposal, increase by equal percentages in this proceeding, any future consolidation would necessarily have a "disparate" impact on Rate ITOD.[19]

[18] Prepared Direct Testimony of Kevin C. Higgins on behalf of The Kroger Co. in Case No. 2012-00222 ("Higgins LG&E Direct") filed October 3, 2012, p. 7.
[19] Baron Direct, p. 27.

C. ALL-ELECTRIC SERVICE FOR SCHOOLS

Q. What is the Companies' position on Mr. Willhite's recommendation to add an All-Electric Schools Rate ("Rate AES") to LG&E's rate offerings that would be similar to KU's Rate AES, and to unfreeze KU's existing Rate AES?[20]

A. KU implemented its existing Rate AES decades ago to promote the building of all-electric schools. KU is now working to have the rate more closely reflect the cost of service for customers on the rate. But KU has consistently sought to freeze the rate, too, recognizing that the rate does not comport with cost-of-service principles. Applying AES to a rate class that is not reasonably homogeneous results in a failure to send a proper price signal while supporting cross-subsidization.

There is no cost-of-service justification for a special rate for schools. Different schools have different service characteristics, as Mr. Willhite implicitly acknowledges in his listing of the different rates under which schools now take service under LG&E's tariff. But more importantly, schools with particular service characteristics do not differ significantly from other customers taking service under the same rates. Further complicating the aligning of the cost of service and the recovery of those costs is the difference in the load patterns to which the simple structure of AES is applied. Despite referring to the customers on AES as schools, these are not just schools as one normally thinks of schools, comprising class rooms, offices, cafeterias, and gymnasiums; rather, current AES customers include garages, pumps, ball field lighting, storage sheds, pumps, and traffic lights. For small customer groups with significant variation in delivery voltages, loads, and load

[20] Prepared Direct Testimony of Ronald L. Willhite on behalf of the Kentucky School Board Association in Case No. 2012-00221 ("Willhite KU Direct") and Case No. 2012-00222 ("Willhite LG&E Direct") filed October 3, 2012,p. 6-7.

patterns, as single structure is not appropriate. Therefore, creating a new Rate AES for LG&E would likely, if not certainly, violate cost-of-service principles.

In sum, the Companies do not support adding a Rate AES to LG&E's tariff, and believe it is appropriate to gradually bring KU's existing Rate AES, as a class, more closely in line with the cost of service for Rate AES customers.

D. DEMAND MINIMUMS AND SERVICE THRESHOLDS

Q. Do you agree that the Companies should reduce the demand ratchets for Rate PS and proposed rates TODP and TODS as Mr. Willhite recommends?[21]

A. No, I do not agree with Mr. Willhite's recommendation. Although the Companies' rate structures have changed to improve their ability to recover various costs imposed on the electric system by customers, demand ratchets have long been employed in rate design. Mr. Willhite provides no justification for reducing the ratchets. For customers requiring the Companies to install facilities that do not provide minimal revenue streams to cover those facilities, the revenue deficit is recovered from or subsidized by other customers on the tariff. In his testimony concerning KU, Mr. Willhite agrees with the need to recover the fixed cost associated with a delivery point but then argues that recovery in off-peak months is an unjustified imposition.[22] But demand ratchets are necessary precisely because there are periods when a customer may not use much electricity, making the customer's revenue stream insufficient for fixed-cost recovery. Without the minimum demand ratchets the

[21] Willhite KU Direct, p. 7-8; Willhite LG&E Direct, p 8.
[22] *Id*.

proper price signals are not sent, energy efficiency is not promoted, and subsidization both within and between classes is promoted.

Q. Do you agree that KU should eliminate seasonal demand charges for Rate PS as Mr. Willhite recommends?[23]

A. No. That KU is dual-peaking does not mean the peaks are equivalent; indeed, they are significantly different. The difference in peaks justifies KU's seasonal demand charges in the same manner that LG&E has seasonal demand charges. Mr. Willhite has provided no justification or evidence that KU should alter the longstanding seasonal demand rate for PS.

Q. How do the Companies respond to Mr. Willhite's proposal to reduce the demand threshold for Rates TODP and TODS to 100kW?[24]

A. Mr. Willhite suggests that the only reason the Companies do not have a lower threshold for Rates TODP and TODS is metering cost.[25] But the Companies' proposed threshold of 250 kW addresses not only metering costs but also the added cost of processing the additional metering data and billing for more complicated rates. While these costs may seem manageable on a unit basis, the dollars become massive as the numbers of customers are considered in aggregate.

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[23] Willhite KU Direct, p. 8.
[24] Willhite KU Direct and Willhite LG&E Direct, p. 9.
[25] *Id.*

E. SPORTS FIELD LIGHTING

Q. What is the Companies' view of a Sport Field Lighting Rate as Mr. Willhite proposes?[26]

A. In the past, the Companies offered several "specialty rates" to promote various business types and to promote the use of electricity. However, the use of specialty rates has gradually diminished as the Companies move toward rates that reflect the usage characteristics of the customer groups, rather than commonalities between members of groups that are independent of energy consumption patterns. The Companies offer flexible rate designs, with a Basic Service Charge, an Energy Charge to recover variable costs, and for larger customer loads, a Demand Charge with a minimum designed to insure costs are recovered from customers that do not use the system efficiently. In general, the Companies believe the proposed rate structures can fairly accommodate the needs of their existing customers.

While the LE rate suggested by Mr. Willhite as an alternative may be appropriate in some circumstances, it is important to realize that the LE rate is designed for small constant loads, and Sport Field Lighting can be neither. Additionally, revising the Availability of Service terms to include lighting installed on non-public streets or highways could potentially create an unintended group of customers desiring this service. That notwithstanding, the Companies are willing to assist their customers in finding cost-effective solutions to the problems of minimum demand bills on lighting serving school sports fields.

[26] Willhite KU Direct and Willhite LG&E Direct, p. 9-10.

F. SCHOOLS NOT ON RATE AES

Q. Do you agree with Mr. Willhite's assertion that KU erred by not having certain schools on Rate AES?[27]

A. Absolutely not. Mr. Willhite's assertion that a number of schools have been taking service "under a wrong rate" is simply incorrect. Taking service under a "wrong" rate means taking service under a rate for which a customer is ineligible; Rate AES is and has always been an elective promotional rate, and it is not "wrong" that a school may have taken service under a rate other than Rate AES. Moreover, KU's tariff has been clear for a number of years that it is a customer's responsibility to choose between rates if the customer is eligible for more than one rate.

> If two or more rates schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which Customer desires to receive service.[28]

Therefore, that some schools did not elect to take service under Rate AES is not KU's responsibility, and no refunds are due.

V. GAS COST OF SERVICE AND RATES

A. OVERVIEW OF INTERVENORS' POSITIONS

Q. Please provide an overview of the intervenors' positions regarding their cost-of-service studies.

A. Mr. Watkins, testifying on behalf of the Attorney General, was the only intervenor to present recommendations related to LG&E's gas cost-of-service study. While ACM, Hess and Stand presented testimony related to the base rate increase, the Gas Line

[27] Willhite KU Direct, p. 10.
[28] Kentucky Utilities Company, P.S.C. No. 15, Original Sheet No. 97 (effective August 1, 2010).

Tracker, and the thresholds for the proposed Rider TS-2 and Rate FT, none presented any evidence on cost of service. The objective in performing the gas cost-of-service study is to determine the rate of return that the Company is earning from each customer class, which provides an indication as to whether the Company's gas service rates reflect the cost of providing service to each customer class.

Q. Does the AG agree with the methodology that LG&E used to allocate costs in the class cost-of-service study?

A. No. The AG had several issues with the Company's use of the Peak Responsibility methodology for allocating costs for the gas distribution mains. Mr. Watkins, the AG's witness, recommends the Peak and Average method instead, believing it to be a superior method because it recognizes that mains are used every day and therefore assigns costs based on historical annual throughput rather than estimated customer loads under the Company's design day. [29] Mr. Watkins does not believe that it is appropriate for LG&E to use a design day rather than an historic peak day to determine the loads to use in its cost-of-service study. He argues that a design day is a moving target which changes with the mix of customers, usage per customer, and number of current customers.[30] Finally, Mr. Watkins claims that the Peak Responsibility allocation method erroneously assumes the system was optimally designed and installed to meet today's mix and level of customers.[31]

Another issue that Mr. Watkins has with the classification of distribution costs centers on the results generated by the zero-intercept analysis used by the Company. His objection is that the analysis classified the majority of main-related costs based

[29] Watkins LG&E Direct, p. 37.
[30] *Id*. at 37.
[31] *Id.* at 37.

on the number of customers as opposed to prior cases in which the COSS classified the majority of mains as demand-related. He argues that 100% of the distribution costs for gas mains should be allocated based on demand, as he did in his testimony on the Company's electric cost-of-service study.[32]

Q. To your knowledge, has Mr. Watkins ever classified distribution main costs as customer-related in his cost-of-service study?

A. Yes. In LG&E's previous two rate cases, Case Nos. 2009-00549 and 2008-00252, Mr. Watkins accepts LG&E's classification of both low and high pressure distribution mains as partially customer-related and incorporates those results in his own cost-of-service study.[33] His rationale for accepting LG&E's classification in both cases was that, although he disagrees with the methodology employed by LG&E's cost-of-service witness, the amount classified as customer-related was relatively small.[34] His main objection in the current case seems to be the dollar amount that has been classified as customer-related.

B. GAS COST-OF-SERVICE METHODOLOGY

Q. Mr. Watkins recommends a "Peak and Average" methodology for allocating distribution mains in the cost-of-service study. Do you agree with this approach?

A. No. In its gas cost-of-service study, LG&E classified distribution mains as either customer- or demand-related using the zero-intercept methodology. Costs classified

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[32] *Id.* at 38.

[33] In the matter of: *Application of Louisville Gas and Electric Company for an Adjustment of Base Rates*, Case No. 2008-00252 and Watkins Testimony at 31-32, *In the matter of: Application of Louisville Gas and Electric company for an Adjustment of Base Rates*, Case No. 2009-00549. Watkins Testimony at 38,

[34] *Id.* at 38 and *Id.* at 31-32.

as customer-related are then allocated to the customer classes based on the number of customers for each customer class, and costs classified as demand-related are then allocated on the basis of maximum class demands. This is the same methodology used to classify overhead and underground conductor in LG&E's electric cost-of-service study. For a gas utility, mains serve exactly the same function as overhead conductor and underground conductor for an electric utility – they both transport the product (electric energy or natural gas) to the customer. Mains and conductors are also similar in another key respect – the capacity to transport the product varies in direct proportion to the size (cross-sectional area) of the main or the conductor. It is for this reason that the zero-intercept methodology has been used for over 30 years to classify mains on the gas side of LG&E's business and to classify overhead and underground conductor on the electric side of the business. If it is appropriate to use a zero-intercept analysis for classifying electric distribution lines, then it must also be appropriate to use a zero-intercept analysis for classifying gas distribution mains, Mr. Watkins's claims to the contrary notwithstanding.

Q. Has the zero-intercept methodology traditionally been used by LG&E to classify distribution mains?

A. Yes. The zero-intercept methodology has been used by LG&E for at least 30 years.

Q. Has the Commission found the zero-intercept methodology to be reasonable in gas cost-of-service studies?

A. Yes. The Commission has found the zero-intercept methodology to be reasonable in numerous rate cases, including LG&E's last rate case for which a settlement agreement was not reached by the parties – Case No. 2000-080, Order dated

September 27, 2000. In addition, NARUC's Gas Distribution Rate Design Manual, June 1989, identifies the zero intercept approach as a standard methodology for classifying gas distribution costs.

Q. Besides being inconsistent with a methodology that the Commission has found to be reasonable in numerous rate case orders, what objection do you have to using the Peak and Average Method for allocating gas distribution mains?

A. The Peak and Average Method allocates a portion of mains on the basis of demand and a portion on the basis of Mcf sales, and none on the basis of customers. While customers' maximum demand and the number of customers a utility serves have a direct impact on a utility's distribution costs, including the cost of mains, the annual quantity of gas sold by a utility has no effect whatsoever on cost of mains. From a distribution-planning perspective, the installation of distribution mains is unaffected by amount of gas sold on an annual basis to its customers. A gas utility installs pipe to reach its customers and to meet the peak load conditions of those customers. As long as the maximum demand requirements do not change, increases or decreases in annual throughput volumes do not have any impact on a utility's distribution costs, particularly the cost of mains. Because annual Mcf sales (or throughput volumes) do not have any effect on LG&E's investment in distribution mains, annual Mcf sales should not be used to allocate the cost of distribution mains. In its Order in Case No. 2000-080, the Commission specifically rejected a cost-of-service study that allocated a portion of mains on the basis of Mcf sales. Even though it has been recommended on numerous occasions, the Commission has never approved a cost-of-service study for LG&E that allocated the cost of distribution mains on the basis of Mcf sales.

VI. ALLOCATION OF THE GAS REVENUE INCREASE

Q. Do you agree with Mr. Watkins's position on allocating the proposed increase to natural gas customers?

A. Yes. Mr. Watkins states in his testimony that the Company's proposed class revenue increases reasonably reflect both LG&E's and his own cost-of-service findings.[35]

VII. GAS RATE DESIGN

A. BASIC SERVICE CHARGE

Q. Do you agree with the proposal by Mr. Watkins to maintain LG&E's current basic service charge rather than implementing the Company's proposed basic service charge?

A. No. Mr. Watkins's calculation of his recommended basic service charge for natural gas customers suffers from the same shortcomings as discussed earlier for the electric basic service charge. Although the Company's cost-of-service study indicates that the basic service charge should be $19.43 per meter, in the interest of gradualism, the Company has proposed to increase the basic service charge for residential customers to $15.50 per month. Maintaining the current basic service charge would not be appropriate given the results of the cost-of-service study.

[35] Watkins LG&E Direct, p. 40.

Q. What does Mr. Watkins's own cost-of-service study indicate that the basic service charge should be?

A. Mr. Watkins's cost-of-service study indicates that the residential basic service charge should be $8.10 per month.[36] He derives this charge by excluding the majority of the customer costs that LG&E incurs in providing natural gas service to its customers. Because his cost-of-service study classifies distribution mains as demand only, he ignores over $27.9 million in main customer-related costs. He further excludes general and common costs, correctly designated as customer-related, based on the argument that LG&E's proposed recovery of the majority of its costs through a fixed charge does not comport with the economic theory of competitive markets or the actual practices of such competitive markets. He states that prices in these markets are generally structured based on usage and are established on the theory that all costs are variable in the long run and therefore prices should not be designed to recover short-run sunk or fixed costs.[37] He points to the use of volumetric pricing in the deregulated electric market in Texas as an example in the utility world of this form of pricing. His example shows, however, that 25% of the electric providers in Texas still rely on traditional fixed customer charges.[38] He does concede that a utility should have a minimum level of fixed customer charges and for LG&E this fixed charge would include investments in service lines, meters and regulators as well as the operating expenses associated with meter reading, customer service, accounting and customer records, and collections.[39]

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[36] *Id.* at 47.
[37] *Id.* at 41-43.
[38] *Id.* at 44.
[39] *Id.* at 46-47.

Q. Do you have any other comments regarding the basic service charge recommended by Mr. Watkins?

A. Yes. As with his proposed electric basic service charge, Mr. Watkins's charge would only cover the minimum amount of equipment necessary to provide a customer with gas service, send the wrong price signal to customers and dramatically increase the volatility of a customer's bill.

Q. Are there any benefits to increasing the basic service charge?

A. Yes there are. Unlike the electric side of the business which sells electricity throughout the year, natural gas sales are concentrated in the winter months. Extremes in weather can drastically affect the Company's revenue stream and customers' bills. Recovering most of the fixed costs through a fixed rate would create less volatility for both the Company and customers; the Company would experience better recovery of its fixed costs even in mild winters and customers would experience less volatility in bills between summer and winter months than they would with a lower basic service charge and a higher volumetric charge. Under Mr. Watkins's proposal, both the Company's revenues and customers' bills would be at the mercy of weather extremes.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 2ND day of November 2012.

(SEAL)
Notary Public

My Commission Expires:

July 21, 2015

Conroy Rebuttal Exhibit 1

Schedule GAW-2

Kentucky Utilities & LG&E
Test Year Generation Statistics

Generating Unit	Fuel	Generator Nameplate (MW)	Net MWH Produced	Generation Order	Total Gross Investment	Total Net Investment	Capacity Factor Net	Capacity Factor Gross		Net Investment Energy	Net Investment Demand
Ghent 2	Coal	556	3,341,264	3	$273,472,042	$83,388,818	68.60%	74.64%	Base	$83,388,818	$0
Ghent 1	Coal	557	3,282,901	7	$457,703,835	$271,488,089	67.28%	72.69%	Base	$271,488,089	$0
Trimble County 1	Coal	566	3,308,126	2	$515,981,742	$278,424,714	66.72%	72.77%	Base	$278,424,714	$0
Mill Creek 4	Coal	544	3,150,394	6	$510,585,061	$228,578,983	66.11%	72.35%	Base	$228,578,983	$0
Mill Creek 1	Coal	356	2,053,056	4	$171,459,453	$52,146,990	65.83%	73.35%	Base	$52,146,990	$0
Trimble County 2	Coal	838	4,740,434	1	$1,019,959,483	$906,947,029	64.58%	69.84%	Base	$906,947,029	$0
Ghent 3	Coal	557	2,940,071	8	$778,865,366	$477,834,135	60.26%	66.46%	Base	$477,834,135	$0
Ghent 4	Coal	556	2,801,767	11	$426,413,546	$238,401,985	57.52%	63.51%	Base	$238,401,985	$0
Cane Run 4	Coal	164	807,948	24	$82,888,694	$16,703,463	56.24%	61.59%	Base	$16,703,463	$0
Mill Creek 2	Coal	356	1,734,022	5	$132,002,570	$40,056,311	55.60%	62.98%	Base	$40,056,311	$0
Mill Creek 3	Coal	463	2,051,810	10	$284,377,385	$122,639,799	50.59%	55.30%	Intermediate	$62,041,669	$60,598,130
Green River 4	Coal	114	501,882	9	$46,859,950	$8,588,941	50.26%	54.36%	Intermediate	$4,316,505	$4,272,436
Cane Run 5	Coal	209	905,328	18	$97,221,510	$23,631,839	49.45%	53.91%	Intermediate	$11,685,656	$11,946,183
Green River 3	Coal	75	320,975	23	$27,716,488	$10,089,303	48.85%	53.38%	Intermediate	$4,929,093	$5,160,210
Cane Run 6	Coal	272	1,138,782	21	$153,644,905	$56,407,604	47.79%	52.62%	Intermediate	$26,959,090	$29,448,514
Brown 2	Coal	180	581,164	25	$59,125,163	$28,891,106	36.86%	41.34%	Intermediate	$10,648,447	$18,242,659
Brown 3	Coal	464	1,298,614	27	$617,105,989	$469,702,193	31.95%	36.04%	Intermediate	$150,065,404	$319,636,789
Brown 1	Coal	114	275,317	32	$76,780,399	$36,383,634	27.57%	33.21%	Intermediate	$10,030,675	$26,352,959
Trimble County 6	Gas	199	93,551	13	$62,918,755	$46,166,154	5.37%	5.44%	Peak	$0	$46,166,154
Trimble County 7	Gas	199	91,965	14	$54,236,860	$39,700,952	5.28%	5.35%	Peak	$0	$39,700,952
Trimble County 9	Gas	199	85,420	16	$54,028,301	$39,977,482	4.90%	4.99%	Peak	$0	$39,977,482
Trimble County 5	Gas	199	62,572	12	$66,804,468	$48,361,256	3.59%	3.68%	Peak	$0	$48,361,256
Trimble County 8	Gas	199	61,973	15	$53,873,686	$39,444,963	3.56%	3.62%	Peak	$0	$39,444,963
Trimble County 10	Gas	199	53,035	17	$60,462,097	$45,235,631	3.04%	3.09%	Peak	$0	$45,235,631
Brown 7	Gas,Oil	177	34,745	20	$60,225,468	$43,404,094	2.24%	2.38%	Peak	$0	$43,404,094
Paddys Run 13	Gas	178	31,743	22	$65,720,461	$45,252,606	2.04%	2.06%	Peak	$0	$45,252,606
Brown 6	Gas,Oil	177	30,756	19	$64,812,407	$50,236,200	1.98%	2.13%	Peak	$0	$50,236,200
Brown 9	Gas,Oil	126	3,807	28	$48,713,646	$23,411,374	0.34%	0.53%	Peak	$0	$23,411,374
Brown 5	Gas	123	3,196	26	$49,685,284	$33,734,583	0.30%	0.50%	Peak	$0	$33,734,583
Brown 11	Gas,Oil	126	2,890	31	$44,740,278	$24,255,858	0.26%	0.41%	Peak	$0	$24,255,858
Brown 8	Gas,Oil	126	2,436	30	$37,227,939	$21,396,169	0.22%	0.36%	Peak	$0	$21,396,169
Brown 10	Gas,Oil	126	1,568	29	$30,167,921	$15,175,125	0.14%	0.29%	Peak	$0	$15,175,125
Cane Run 11	Gas,Oil	16	198	34	$3,557,311	$1,294,371	0.14%	0.14%	Peak	$0	$1,294,371
Haefling 1-3	Gas,Oil	21	169	37	$6,346,312	$2,227,070	0.09%	0.16%	Peak	$0	$2,227,070
Paddys Run 11	Gas	16	100	33	$1,609,957	($136,355)	0.07%	0.11%	Peak	$0	($136,355)
Zorn 1	Gas	18	(49)	36	$1,951,456	($99,370)	-0.03%	0.02%	Peak	$0	($99,370)
Paddys Run 12	Gas	33	(273)	35	$3,990,011	$419,642	-0.09%	0.00%	Peak	$0	$419,642
Tyrone 3	Coal	75	(1,477)		$28,798,957	$6,704,422	-0.22%	0.00%	Peak	$0	$6,704,422
Dix Dam 1-3	Hydro	9	82,033		$28,850,449	$20,621,308	34.68%	34.74%	Hydro	$20,621,308	$0
Ohio Falls 1-8	Hydro	10	185,569		$42,551,883	$33,455,820	24.63%	25.19%	Hydro	$33,455,820	$0
			36,059,782			$3,930,544,291				$2,928,724,184	$1,001,820,107
							Total System			74.51%	25.49%

	Net Investment Classified as Energy	Net Generation	Unit Cost
Base	$2,648,047,645	28,427,585	$0.09315
Intermediate	$280,676,539	7,073,872	$0.03968

Conroy Rebuttal Exhibit 2

Least-Squares Regression Based on Underlying Individual Unit Cost Data

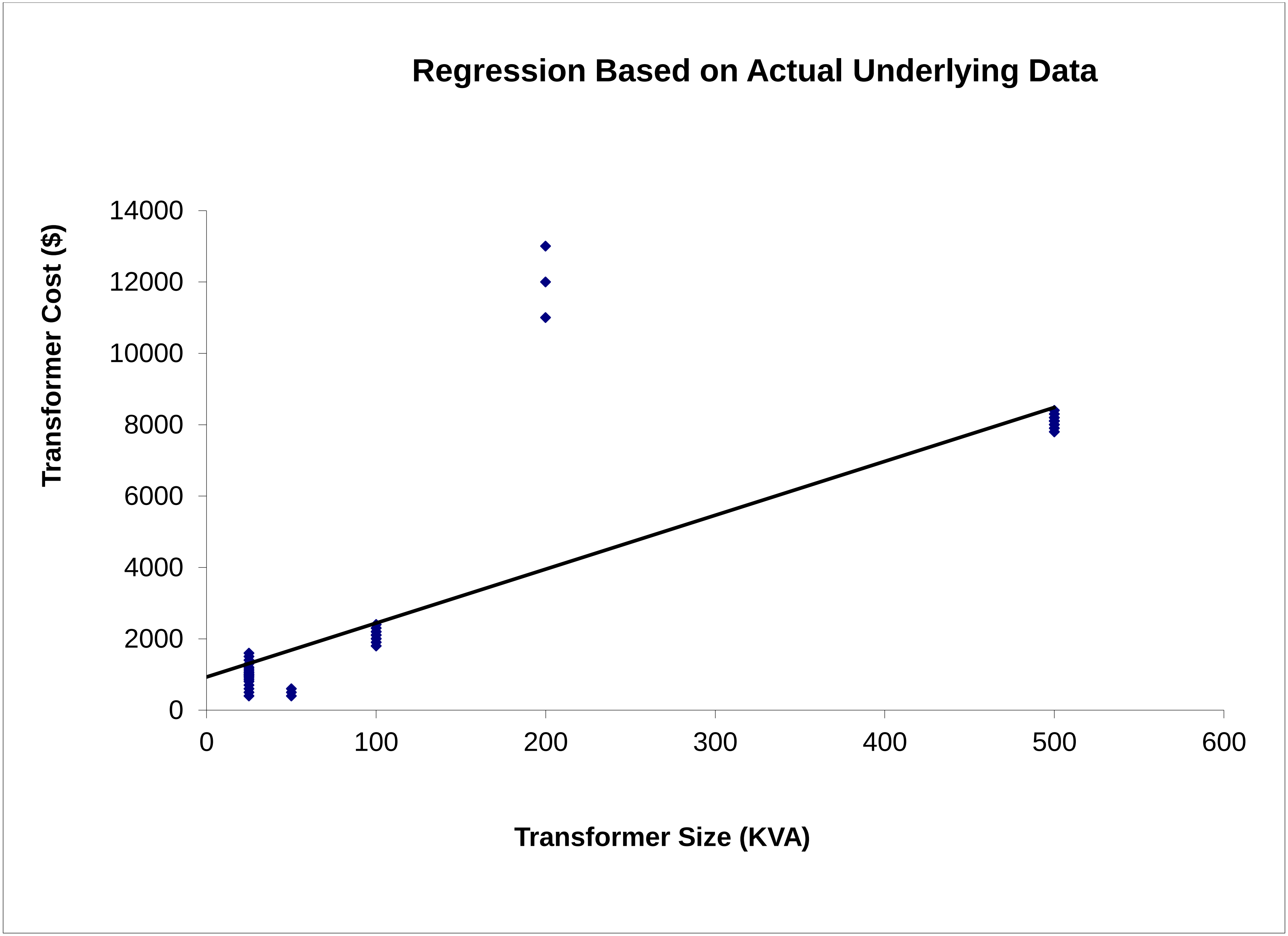
	Cost (y)	Size (x)
1	400	25
2	500	25
3	600	25
4	700	25
5	800	25
6	850	25
7	900	25
8	950	25
9	950	25
10	1000	25
11	1000	25
12	1050	25
13	1050	25
14	1100	25
15	1150	25
16	1200	25
17	1300	25
18	1400	25
19	1500	25
20	1600	25
21	400	50
22	500	50
23	600	50
24	1800	100
25	1800	100
26	1900	100
27	1900	100
28	2000	100
29	2000	100
30	2000	100
31	2100	100
32	2100	100
33	2100	100
34	2100	100
35	2100	100
36	2100	100
37	2200	100
38	2200	100
39	2200	100
40	2300	100

Least-Squares Regression Based on Underlying Individual Unit Cost Data

	Cost (y)	Size (x)
41	2300	100
42	2400	100
43	2400	100
44	11000	200
45	12000	200
46	13000	200
47	7800	500
48	7800	500
49	7900	500
50	7900	500
51	8000	500
52	8000	500
53	8000	500
54	8100	500
55	8100	500
56	8100	500
57	8100	500
58	8100	500
59	8100	500
60	8200	500
61	8200	500
62	8200	500
63	8300	500
64	8300	500
65	8400	500
66	8400	500

Least-Square Regression Results:

Intercept	929.97
Slope	15.10



Regression Based on Actual Underlying Data
Transformer Cost ($)
14000
12000
10000
8000
6000
4000
2000
0
0
100
200
300
400
500
600
Transformer Size (KVA)

Conroy Rebuttal Exhibit 3

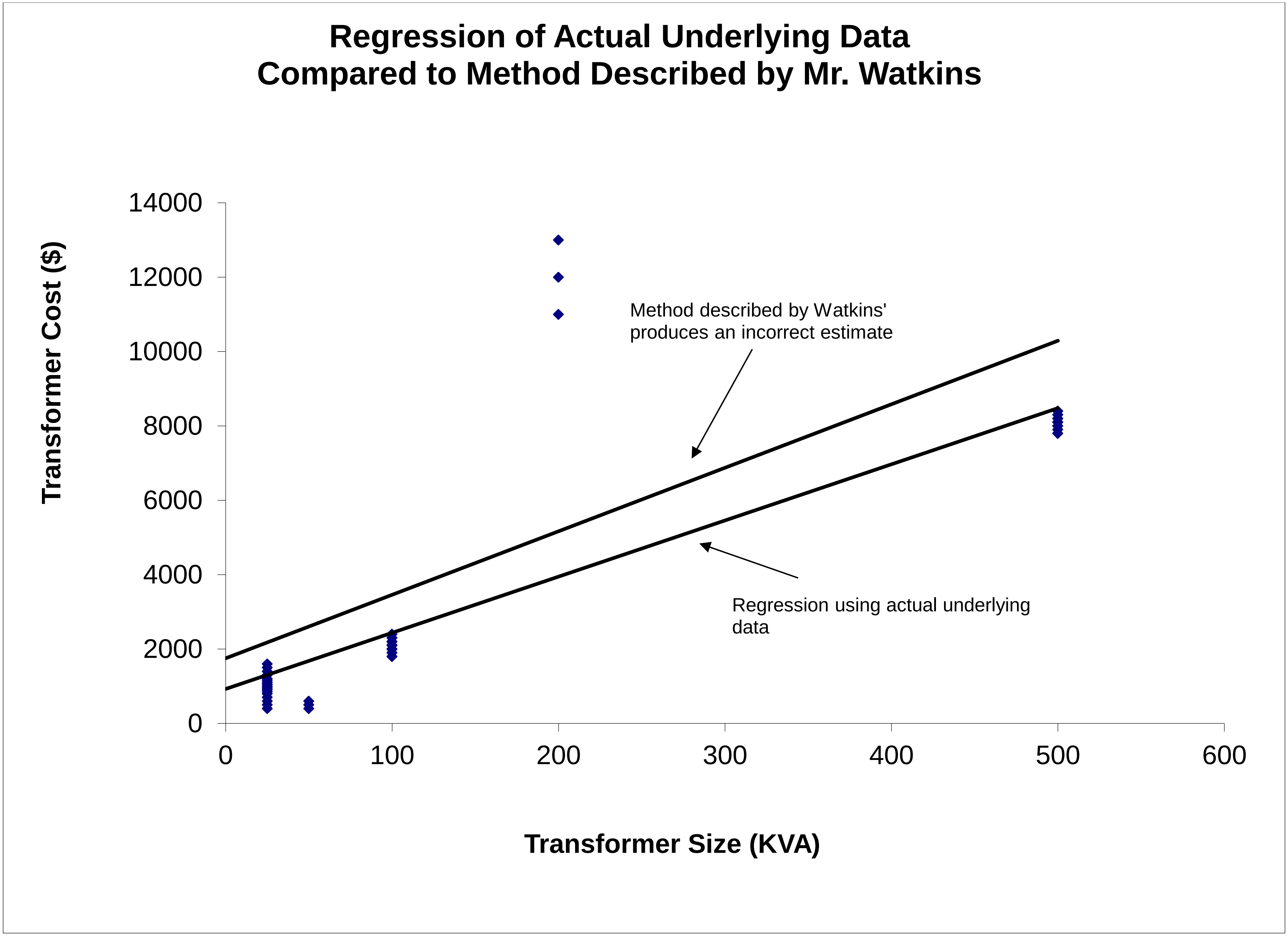
Method Described by Mr. Watkins
Unweighted Least-Squares Regression Applied to Summary Data

n	y	x	est y
20	1000	25	2177.5
3	500	50	2604.5833
20	2100	100	3458.75
3	12000	200	5167.0833
20	8100	500	10292.083

Unweighted Least-Squares Regression Results
Applied to Summary Data

Intercept	1,750.42
Slope	17.08

Method described by Watkins produces incorrect results


Regression of Actual Underlying Data
Compared to Method Described by Mr. Watkins
Transformer Cost ($)
14000
12000
10000
8000
6000
4000
2000
0
Method described by Watkins'
produces an incorrect estimate
Regression using actual underlying
data
0
100
200
300
400
500
600
Transformer Size (KVA)

Conroy Rebuttal Exhibit 4

LG&E's Methodology
Weighted Least-Squares Regression Applied to Summary Data

n	y	x	y*n^.5	n^.5	xn^.5
20	1000	25	4472.136	4.47	111.8033989
3	500	50	866.0254	1.73	86.60254038
20	2100	100	9391.4855	4.47	447.2135955
3	12000	200	20784.61	1.73	346.4101615
20	8100	500	36224.301	4.47	2236.067977

Unweighted Least-Squares Regression Results
Applied to Summary Data

Intercept	929.97
Slope	15.10

Weighted least-squares regression produces correct results

Conroy Rebuttal Exhibit 5

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Own Cost of Service Study
For Louisville Gas & Electric Company

		Residential	
Gross Plant			
368	Transformers - Power Pool (Customer Cost)	$53,297,175	**<<----Left Out By Watkins**
369	Services	$23,403,452	
370	Meters	$26,683,502	
	Total Gross Plant	$103,384,129	
Depreciation Reserve			
368	Transformers - Power Pool (Customer Cost)	$22,566,905	**<<----Left Out By Watkins**
369	Services	$17,266,223	
370	Meters	$14,184,447	
	Total Depreciation Reserve	$54,017,576	
Total Net Plant		$49,366,553	
Working Capital Assets			
Cash Working Capital - Operation and Maintenance Expenses		$3,751,879	
Materials and Supplies		$4,380,467	
Prepayments		$210,378	
Sub-total		$8,342,724	
Customer Advances			
Customer Advances		$107,412	
Sub-total		$107,412	
Other Items			
Total Accumulated Deferred Income Tax		$19,664,178	
Sub-total		$19,664,178	
TOTAL RATE BASE		$37,937,687	
Operation & Maintenance Expenses			
	Distribution Expense - Operating		
580	Operation Supervision & Engineering	$295,921	**<<----Left Out By Watkins**
586	Meter Expense	$4,348,074	
588	Misc Distribution Expense	$314,399	**<<----Left Out By Watkins**
589	Rents	$1,400	**<<----Left Out By Watkins**
590	Maintenance Supervision & Engineering	$37,444	**<<----Left Out By Watkins**
591	Structures	$74,673	**<<----Left Out By Watkins**
592	Maintenance Structures & Equipment	$85,833	**<<----Left Out By Watkins**
595	Maintenance of Line Transformers	$81,050	**<<----Left Out By Watkins**
598	Misc Distribution Expense	$42,121	**<<----Left Out By Watkins**
	Sub-total	$5,280,915	
	Customer Accounts Expense		
901	Supervision/Customer Accts	$760,219	**<<----Left Out By Watkins**
902	Meter Reading Expense	$1,614,704	
903	Records & Collections	$3,984,147	
904	Uncollectible Accounts	$2,472,449	**<<----Left Out By Watkins**
905	Misc Customer Accounts	$330,100	
	Sub-total	$9,161,619	

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Cost of Service Study
For Louisville Gas and Electric Company

		Residential	
	Customer Service & Information Expense		
907	Supervision	$128,164	**<<----Left Out By Watkins**
908	Customer Assistance Expense	$8,155,014	**<<----Left Out By Watkins**
909	Informational & Instruc.	$37,700	**<<----Left Out By Watkins**
910	Misc Customer Service	$237,496	**<<----Left Out By Watkins**
913	Advertising Expense	$14,291	**<<----Left Out By Watkins**
	Sub-total	$8,572,665	
	General Expenses		
920	Admin & General Salaries	$1,605,024	**<<----Left Out By Watkins**
921	Office Supplies & Expenses	$521,667	**<<----Left Out By Watkins**
922	Administrative Expenses Transferred	-$205,500	**<<----Left Out By Watkins**
923	Outside Services Employed	$513,717	**<<----Left Out By Watkins**
924	Property Insurance	$113,324	**<<----Left Out By Watkins**
925	Injuries & Damages - Insurance	$238,790	**<<----Left Out By Watkins**
926	Employee Benefits	$3,615,913	**<<----Left Out By Watkins**
927	Franchise Requirements	$779	**<<----Left Out By Watkins**
928	Regulatory Commission Fees	$29,735	**<<----Left Out By Watkins**
929	Duplicate Charges - Cr	-$14,991	**<<----Left Out By Watkins**
930	Miscellaneous General Expense	$281,306	**<<----Left Out By Watkins**
931	Rents & Leases	$45,269	**<<----Left Out By Watkins**
935	Maintenance of General Plant	$254,797	**<<----Left Out By Watkins**
	Sub-total	$6,999,832	
	Total O & M Expenses	$30,015,030	
Depreciation Expense			
368	Transformers	$1,262,516	**<<----Left Out By Watkins**
369	Services	$826,142	
370	Meters	$779,158	
	Total Depreciation Expense	$2,867,816	
Revenue Requirement			
	Interest	$827,782	
	Equity return	$3,021,431	
	Income Tax	$1,802,624	
	Revenue For Return	5,651,836	
	O & M Expenses	$30,015,030	
	Depreciation Expense	$2,867,816	
	Total Customer Revenue Requirement	$38,534,683	
	Number of Bills	4,173,228	
	Monthly Cost	$9.23	

	PCT	Cost	WGHT Cost
Debt	44.36%	3.78%	1.68%
Common	55.64%	11.00%	6.12%
Total	100.00%		7.80%
Tax Rate	37.37%		

Conroy Rebuttal Exhibit 6

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Own Cost of Service Study
For Kentucky Utilities Company

		Residential	
Gross Plant			
368	Transformers - Power Pool (Customer Cost)	$100,370,753	**<<----Left Out By Watkins**
369	Services	$40,175,956	
370	Meters	$42,024,614	
	Total Gross Plant	$182,571,323	
Depreciation Reserve			
368	Transformers - Power Pool (Customer Cost)	$39,126,796	**<<----Left Out By Watkins**
369	Services	$27,620,164	
370	Meters	$20,579,258	
	Total Depreciation Reserve	$87,326,218	
Total Net Plant		$95,245,105	
Working Capital Assets			
Cash Working Capital - Operation and Maintenance Expenses		$5,501,916	
Materials and Supplies		$6,815,893	
Prepayments		$388,913	
Sub-total		$12,706,722	
Customer Advances			
Customer Advances		$218,101	
Sub-total		$218,101	
Other Items			
Total Accumulated Deferred Income Tax		$25,955,839	
Sub-total		$25,955,839	
TOTAL RATE BASE		$81,777,886	
Operation & Maintenance Expenses			
	Distribution Expense - Operating		
580	Operation Supervision & Engineering	$273,660	**<<----Left Out By Watkins**
586	Meter Expense	$4,599,330	
588	Misc Distribution Expense	$630,390	**<<----Left Out By Watkins**
589	Rents	$1,434	**<<----Left Out By Watkins**
590	Maintenance Supervision & Engineering	$17,239	**<<----Left Out By Watkins**
592	Maintenance Structures & Equipment	$78,040	**<<----Left Out By Watkins**
595	Maintenance of Line Transformers	$68,669	**<<----Left Out By Watkins**
598	Misc Distribution Expense	$17,024	**<<----Left Out By Watkins**
	Sub-total	$5,685,786	
	Customer Accounts Expense		
901	Supervision/Customer Accts	$1,674,842	**<<----Left Out By Watkins**
902	Meter Reading Expense	$3,020,141	
903	Records & Collections	$8,789,944	
904	Uncollectible Accounts	$3,322,845	**<<----Left Out By Watkins**
905	Misc Customer Accounts	$460,594	
	Sub-total	$17,268,366	

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Cost of Service Study
For Kentucky Utilities Company

		Residential	
	Customer Service & Information Expense		
907	Supervision	$133,360	**<<----Left Out By Watkins**
908	Customer Assistance Expense	$8,865,553	**<<----Left Out By Watkins**
909	Informational & Instruc.	$96,416	**<<----Left Out By Watkins**
910	Misc Customer Service	$270,781	**<<----Left Out By Watkins**
913	Advertising Expense	$14,710	**<<----Left Out By Watkins**
	Sub-total	$9,380,820	
	General Expenses		
920	Admin & General Salaries	$2,850,592	**<<----Left Out By Watkins**
921	Office Supplies & Expenses	$972,565	**<<----Left Out By Watkins**
922	Administrative Expenses Transferred	-$378,632	**<<----Left Out By Watkins**
923	Outside Services Employed	$1,156,214	**<<----Left Out By Watkins**
924	Property Insurance	$114,182	**<<----Left Out By Watkins**
925	Injuries & Damages - Insurance	$464,750	**<<----Left Out By Watkins**
926	Employee Benefits	$5,261,956	**<<----Left Out By Watkins**
927	Franchise Requirements	$45,888	**<<----Left Out By Watkins**
929	Duplicate Charges - Cr	$525,075	**<<----Left Out By Watkins**
930	Miscellaneous General Expense	$275,780	**<<----Left Out By Watkins**
935	Maintenance of General Plant	$391,985	**<<----Left Out By Watkins**
	Sub-total	$11,680,357	
	Total O & M Expenses	$44,015,329	
Depreciation Expense			
368	Transformers	$2,437,738	**<<----Left Out By Watkins**
369	Services	$815,572	
370	Meters	$962,364	
	Total Depreciation Expense	$4,215,673	
Revenue Requirement			
	Interest	$1,627,234	
	Equity return	$5,626,128	
	Income Tax	$3,268,550	
	Revenue For Return	10,521,912	
	O & M Expenses	$44,015,329	
	Depreciation Expense	$4,215,673	
	Total Customer Revenue Requirement	$58,752,914	
	Number of Bills	5,044,176	
	Monthly Cost	$11.65	

	PCT	Cost	WGHT Cost
Debt	46.30%	3.69%	1.71%
Common	53.70%	11.00%	5.91%
Total	100.00%		7.62%
Tax Rate	36.75%		