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Edward Kahn, Steven Stoft and Timothy Belden
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March 1994

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1 Introduction

A substantial debate has emerged over the financial impacts of nonutility generation (NUG) contracts on investor-owned utilities. This debate is reflected in Section 712 of the 1992 Energy Policy Act (EPAct), which requires state regulatory commissions to consider whether long-term contracts for NUG power purchases would increase (or decrease) the utility's cost of capital.

The basis for the concern expressed in Section 712 of EPAct lies in the manner in which NUG power projects are financed. The vast majority of these facilities use a structure known as "project financing." This structure relies upon long-term purchase contracts with utilities that provide an assured market and price for electricity, subject to performance requirements.[1] The long-term contract, in particular the capacity payments that they typically entail, is perceived to be a contingent liability to the utility. In the language of the bond-rating agencies, these contracts are "debt equivalents." One observer has summarized this argument succinctly:

"...the power purchase contract which allows the non-utility to go in and get the financing is...an asset to the NUG, [therefore] it's a liability to the utility."[2]

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[1] The terms and conditions associated with power purchase contracts between NUGs and utilities are reviewed, see E. Kahn, "Risks in Independent Power Contracts: An Empirical Survey," *The Electricity Journal* 4:9:12-23, (1991). The nature of project finance as it is applied to NUG projects is summarized in Kahn *et al.* See E. Kahn, M. Meal, S. Doerrer, and S. Morse, *Analysis of Debt Leveraging in Private Power Contracts*, LBL-32487. (Berkeley, CA, 1992).

[2] L. Makovich, "Review Comments, Electric Operations Model." Proceedings of the National Energy Modeling System Conference, DOE/EIA-0566 (1993).

Representatives of NUG developers have not accepted the "debt-equivalence" argument. They argue that utilities which purchase power from NUGs reduce their risk by transferring certain of the burdens associated with power plant construction to private parties. It is argued that this should improve the credit of a utility that purchases power from NUGs.[3,4]

The bond-rating agencies have been active participants in the discussion of debt-equivalence. Each has a different approach to calculating the balance sheet liability associated with NUG commitments. Most argue that debt-equivalence is a relative phenomenon, determined jointly by the conditions of local regulation and by the precise nature of the power purchase contract.[5] The Standard and Poor's approach results in assigning a "risk factor" to each utility's position that discounts the nominal debt equivalence to account for important qualitative factors. Other agencies treat these issues qualitatively.

In this study, we approach these questions from the perspective of the equity markets, rather than from that of the debt markets. There are several reasons for this choice. First, the debt and equity markets are linked. If NUG contracts really are equivalent to debt, then they raise the risk of the firm, and this should be observable in the equity market. Studying utility stock price performance has the advantage of avoiding some of the circularity in the prior discussion of bonds. If the bond rating agencies declare that a certain risk exists, it is a self-fulfilling prophecy[6]. By observing the reaction of the equity markets we can see if the same assessment is made by shareholders. With regard to the basic question raised by Section 712 of EPAct, the cost of equity (and associated taxes) is the largest part of the overall cost of capital,[7] therefore any assessment should consider this market explicitly. Finally, there is a tradition of quantitative study of the cost of equity capital, which can inform the approach taken here.

Our goal is to study the debt-equivalence debate empirically. Financial markets absorb relevant information about the risks facing firms and adjust prices to reflect these judgments. This

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[3] R. Naill, and B. Sharp, "Risky Business? The Case for Independents," *The Electricity Journal* 4:.3:54-63, (1991).

[4] National Independent Energy Producers, "The Reliability of Independent Power: Operating, System, Planning, Fuel and Financial," (1991).

[5] Standard and Poor's, "Credit Issues for Investor-Owned Utility Purchasers," *Standard & Poor's CreditWeek*, (May 1992).

[6] The judgement of the rating agencies by itself will increase the cost of bonds, making the bond market appear to confirm their predictions, although this will not affect actual risk.

[7] The typical capital structure of electric utilities has a slightly larger fraction of debt and preferred stock than common equity. The cost of equity is typically several hundred basis points (100 basis points equals 1%) greater than debt and preferred. Furthermore, income taxes on equity returns raise its cost even more. For example, if a utility's capital structure was 55% debt at 8%, and 45% equity at 11%, and the total tax rate were 40%, then the weighted cost of debt is 4.4%, equity returns require 4.95%, and taxes on equity require 3.3%. Total cost of capital is 12.65%, but debt constitutes only about 35% of the total.

happens whether there are explicit reactions from industry spokesmen or not. For example, secondary market prices for bonds of electric utilities which had nuclear power assets reacted to the Three Mile Island accident reacted even if there was no direct risk to credit quality.[8] It is in this spirit therefore, that we want to study the arguments about NUG impacts on the utility cost of capital. We want to structure the arguments in a form which will potentially allow them to be confirmed or disproved.

This study is organized in the following fashion. Section 2 reviews the literature on the cost of equity capital for regulated utilities. Since there is no consensus definition of the intuitive "cost of capital" notion, we will have to work with several alternative formulations. Section 3 specifies our formulation of the debate on NUGs and the utility's cost of capital. Section 4 reviews variable definitions and data sources. Section 5 discusses statistical issues and results. Conclusions are given in Section 6.

2 Literature Review

There is no generally accepted definition of the cost of equity capital, but only a number of competing theories that are more or less capable of being applied numerically. In this section we survey a number of these theories, particularly as they apply to regulated public utilities. We describe their conceptual foundations and required assumptions.

Kolbe *et al.* (1984)[9] give a general survey of the literature on estimating the cost of capital for regulated firms. Their emphasis is on methods used for establishing the allowed rate of return for public utilities in rate hearings. They separate the approaches in use into five categories, and review each according to specific criteria on theoretical consistency and ease of use. Two of these approaches are so qualitative and judgmental in nature that they are not amenable to the kind of statistical methods that we wish to employ. The remaining three approaches are sufficiently quantitative that they can be used for empirical work. These are: (1) the discounted cash flow (DCF) method, (2) the capital asset pricing model (CAPM), and (3) the market to book value ratio (MBV). From these we distill three estimators for the cost of equity capital (r_e): (1) a DCF estimator, (2) the earnings price ratio (EPR), and (3) the CAPM equation. All of these methods rely primarily on stock market prices, but require additional data that must be estimated in particular cases as well. We review each of these methods below.

[8] W. Barrett, A. Henson, and R. Korb, "The Effect of Three Mile Island on Utility Bond Risk Premia: A Note," *Journal of Finance* 41:1:255-261, (1986).

[9] L. Kolbe, J. Read, and G. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, Appendix A (MIT Press, 1984).

2.1 Discounted Cash Flow

The discounted cash flow (DCF) method is an application of the standard present-value calculation to the market price of a utility stock, based on its expected dividends and their rate of growth. The formula for present-value calculations is given by the following expression

$$PV = \sum_{y=1}^{Y} \left[\frac{CF_y}{(1 + r)^y} \right]$$

where CF_y = cash flow in year y,
PV = present value, and
r = the discount rate.

The DCF model is based on the equivalence of the stock price, P, with the present-value of dividends, D_y, which are the cash flows in year y. The DCF model also requires two simplifying assumptions, namely: (1) that the discount rate r remains constant in the future, and (2) that dividends are expected to grow at a constant rate, g, into the indefinite future (i.e. Y in the present-value expression is infinite). Under these assumptions, the present-value definition of the stock price can be re-written as

$$P_0 = \sum_{1}^{\infty} \frac{D_0 \cdot (1+g)^y}{(1+r)^y} = \frac{D_0 \cdot (1+g)}{(r-g)} = \frac{D_1}{(r-g)}.$$

Solving this equation for r, and reinterpreting it as the cost of equity capital, r_e, gives the standard form of the DCF model

$$r_e = \frac{D_1}{P_0} + g, \tag{1}$$

which says that the cost of equity capital is the sum of the expected dividend yield (paid at the end of period 1) at the time of purchase (ex-dividend stock price at time 0) and the steady state expected growth rate of dividends in the future. Most of the difficulty associated with using the DCF model centers upon the estimation of the expected growth rate g.

The crucial step in the above argument is the reinterpretation of the stockholder's discount rate as the firm's cost of equity capital. To understand this, first note that the firm must maintain the value of existing stock when issuing new stock. If it does not, it will find its ability to raise funds in the equity market seriously impaired (and eventually eliminated if it persists in devaluing its stock), and its costs in the bond market will increase. In order to maintain the value of existing stock, total stock value must increase by the amount of the funds raised by a sale of new stock. For this to occur, the firm must increase its stream of dividends by an amount with a present value equal to the new stock price. Thus the cost of raising $P is a dividend stream with present value $P when evaluated at the stockholder's discount rate, r. This dividend stream is exactly equal to the interest payments that would be made on \$P borrowed at r%; this justifies equating r with the firms' cost of equity capital.

When using equation (1) to estimate the cost of equity capital, by far the greatest empirical difficulty arises from the estimate of the expected growth rate of dividends, g. Kolbe *et al.* give five methods for estimating g, to which we add a sixth.

1. Historical growth rate of dividends.
2. Historical growth rate of earnings.
3. Historical growth rate of book value per share.
4. Widely used forecasts of growth rates.
5. Retained earnings to book value ratio.
6. Retained earnings to market value ratio.

Because we are concerned with the future cost of equity capital and how it may be changed by the *future* impact of new contracts the first three estimates are inappropriate. We will implement the fourth method using various publicly available estimates of the growth in dividends per share as our estimate of g. The fifth method seems clearly inferior to the sixth because book value is simply market value distorted by various accounting conventions. As Kolbe *et al.* show, the sixth method simply reduces to the well know earnings-price ratio (EPR) method and we will also make use of this approach. We now demonstrate that DCF with the sixth estimation method for g reduces to the EPR method. First, replacing g in the DCF equation with the ratio of retained earnings to market value, *RE/P*.

$$r_e = \frac{D}{P} + \frac{RE}{P} = \frac{(D + RE)}{P}.$$

Then, since dividends plus retained earnings add to total earnings, E, we have arrived at the basic EPR formula,

$$r_e = E/P. \tag{2}$$

This estimator of r_e depends on the assumption that a firm can earn only its cost of equity capital, no more and no less. If the firm can earn more than the cost of equity capital, then the growth rate expected from a given level of earnings is greater, and thus $g > RE/P$. Carrying this inequality through the derivation yields $r_e > E/P$. The converse applies if the firm earns less than the cost of equity capital. This point will require further consideration since the change in the cost of equity capital that we are looking for would necessarily disturb any prior equality between ROE and r_e.

2.2 Capital Asset Pricing Model

The Capital Asset Pricing Model (CAPM) is the approach best grounded in economic and financial theory. Based on an equilibrium model of investor behavior and market valuation, standard business school textbooks on corporate finance favor this approach.[10]

The principal advantage of CAPM is that it provides a precise and measurable definition of risk as applied to stocks. The risk measure, called beta, is proportional to the correlation between the rate of return of a particular asset with the rate of return for the market as a whole[11]. This measure of risk is then related in a straight-forward fashion to the cost of equity capital through the basic CAPM equation as follows

$$r_e = E(r_j) = r_f + \beta_j \cdot [E(r_m) - r_f], \tag{3}$$

where $E(r_j)$ = the expected rate of return on asset j (i.e. the cost of equity capital),
r_f = the current risk-free rate of return,
β_j = the risk measure for asset j,
$E(r_m)$ = the expected rate of return for the market.

CAPM asserts that the expected rate of return is just the risk-free rate, r_f, plus a risk premium that is given by the risk measure, β, multiplied by "the market price of risk" (MPR). The MPR is the bracketed term in the CAPM expression, namely the difference between the expected rate of return for the market as a whole and the risk-free rate of return. The equivalence between the stockholders' expected rate of return and the cost of equity capital can be justified by the same argument that was used to equate the stockholders' discount rate with the cost of equity capital.

CAPM has a number of problems in the translation from theory into practice. Difficulties arise in the estimation of all its parameters. Empirical tests of CAPM have been ambiguous. A number of adjustments or re-formulations of CAPM have been proposed.

2.3 Market to Book Value Ratio

The market to book value ratio (MBV) provides a third approach to the cost of equity capital. MBV is usually expressed on a per share basis. The book value per share of a regulated firm is the rate base net of accumulated depreciation and debt divided by the number of shares. When MBV equals one, then the allowed rate of return equals the cost of equity capital. The argument for this proposition is a variation on the present-value logic underlying the DCF model. The

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[10] R. Brealey and S. Myers, *Principles of Corporate Finance*, 4th Edition (McGraw-Hill Inc., 1991)

[11] The proportionality constant is the ratio of the standard deviation of the asset's rate of return to the standard deviation of the rate of return for the market as a whole.

starting point for the argument is the same, the market value of any stock should approximately equal earnings, E, capitalized at the cost of equity capital, r; $MV = E/r$. Notice that this is exactly our basic EPR formula (with P renamed MV).

Next we observe that earnings, E, is given by the allowed rate of return, ROR, times the net book value of the firm, BV. This can be expressed as $E = ROR \times BV$. Putting these two facts together and solving for r we get

$$r = \frac{E}{MV} = \frac{(ROR \cdot BV)}{MV} = \frac{ROR}{MBV}$$

Notice that since MV is just a new name for P, this formula will be identical to equation (2) if the definition of E is the same. Equation (2) presumed that E was actual earnings, so if ROR is defined to be actual ROR earned on book value, this formula is identical to (2). On the other hand, if ROR is defined as the allowed rate of return, then E will be the allowed earnings which are typically different than actual earnings. This provides a new way of computing the cost of equity capital.

$$r_e = \frac{ROR_{allowed}}{MBV}$$

This definition would be advantageous if allowed earnings were a better proxy for expected earnings in future years than are this year's actual earnings. We will not employ this method because of a lack data for allowed rate of return.

2.4 Summary of Cost of Equity Capital Estimators to Be Used

We have now settled on three estimators of the cost of equity capital that will be used throughout the remainder of the paper, and in particular will form the dependent variables for our regressions. These are

$$r_e = \frac{D}{P} + \hat{g} \tag{1}$$

$$r_e = E/P. \tag{2}$$

$$r_e = r_f + \beta_j \cdot [E(r_m) - r_f], \tag{3}$$

It is import to spend some time clarifying the mechanisms by which these estimators could reflect the changes in the cost of equity capital caused by NUG contracts or commitment to capital expansion. The case of the second estimator is most straight forward; if stockholders believe that the utility's *future* earnings are made more risky by its commitments, then the price of stock will fall. This argument also holds for the first estimator, but in this case there is an additional effect which works through the estimate of g. Since this estimate is provided by market analysts, their judgment concerning the impact of the utility's commitments will play a role independent of stockholder's views.

The third estimator can only be effected through β, the covariance of the utility stock's rate of return with the market rate of return. Since any fluctuation in earnings must be absorbed by stockholders (i.e., the creditors having a prior claim), increasing the debt-equity ratio reduces the base over which these fluctuations are spread.[12] Since stock prices depend on earnings per share, and having a smaller base means greater *percentage* fluctuation in earnings per share, it also means greater fluctuations in the stock price. This in turn leads to a larger β. Thus anything that effectively increases a utility's debt-equity ratio should also increase its β.

3 Problem Formulation

Our goal is to study the debt equivalence debate empirically. This means establishing a general framework in which to examine those determinants of the utility cost of capital which are relevant to this debate. In this section, we first outline a qualitative approach to this problem. Second, we specify the basic form of an equation that will be estimated empirically. Third, we discuss how to specify the generic kinds of variables in the basic equation.

3.1 Qualitative Formulation

There are two sides to the debate over NUGs and the utility cost of capital. The debt equivalence argument suggests that there should be a positive correlation between the degree to which utilities are obligated to NUGs and their cost of capital. The alternative to contracting with NUGs is that the utilities construct their own facilities using their own credit. The utility construction alternative is not without financial risk either. Firms may have to sell securities that will reduce interest coverage for bonds and dilute earnings for shareholders. During the last major round of utility construction, these burdens proved substantial. Additionally, the risk of regulatory disallowances had a negative effect on utility finances. One study of the utility cost of capital which examined data from 1983 and 1984 found that forecasted construction expenses has a significantly negative effect on the market to book value ratio for a sample of 30 electric utility stocks (PHB, 1986). This finding is equivalent to a positive correlation between r_e and utility construction expenses.

[12] For a full discussion of this effect see L. Kolbe, J. Read, and G. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*. Appendix A. (MIT Press, 1984).

A reasonable representation of the buy versus build debate should incorporate the possibility of finding both effects. In the next section we outline a simple model which posits that the utility's cost of equity capital can be determined by either utility construction or NUG purchases.

3.2 Basic Equation

The effect of NUG contracts is hypothesized to be an effective change in the debt-equity ratio. Therefore, to model the impact of NUG contracts on the cost of equity capital we begin with a model of the effect of the debt-equity ratio on the cost of equity capital. Kolbe, Read, and Hall give two versions of this relationship, first developed by Modigliani and Miller (1958 and 1963). These are:

$$r_e = r_w + (r_w - r_d)\frac{D}{Eq} \quad \text{and}$$

$$r_e = r_{ae} + (1-t)(r_{ae} - r_d)\frac{D}{Eq},$$

where r_w is the weighted cost of capital, r_{ae} is the all-equity cost of capital r_d is the cost of debt, r_e is the cost of equity, and t is the tax rate. There has been a long debate over these two positions, but fortunately we do not need to resolve this controversy. In either case, the relationship between D/Eq and r_e has the following form:

$$r_e = \beta_0 + \beta_1\frac{D}{Eq}.$$

NUG contracts have capacity payments which are thought to be equivalent to debt payments and thus imply a value for the equivalent debt. Calling this NUG "equivalent debt" Dn, we find the utility's debt-equity ratio to be $(D + \alpha \cdot Dn)/Eq$, where α will be called the risk factor and indicates the extent to which Dn has a debt-like impact on the utility. This gives rise to the expanded cost of equity capital equation:

$$r_e = \beta_0 + \beta_1\frac{D}{Eq} + \beta_2\frac{\alpha \cdot Dn}{Eq}.$$

Because we are unsure of the accuracy of available estimates of α, in some cases we omit α.

Now in order to account for the effect of utility construction projects we must include one more variable. We start with CWIP, which is projected utility capital expenditures (on construction work in progress). This variable is usually available for only three future years and sometimes for five. This short time period does not allow us to compute accurately the present value of the work in progress (some of which might take 5 to 7 years). Thus, the best we can do is use the sum of the first three years, which we call C, as a proxy for the future growth in capital stock. Since we expect the impact of the CWIP variable to be proportional to its magnitude but inversely proportional to the equity base that its impact is spread over, we enter it in our stochastic equation as C/Eq. This brings us to our base stochastic model:

$$r_e = \beta_0 + \beta_1 \frac{D}{Eq} + \beta_2 \frac{Dn}{Eq} + \beta_3 \frac{C}{Eq} + \epsilon .$$

Note that equity, Eq, acts as a normalization divisor for all three variables, thus assuring a homoscadastic error term.

If $\beta_2 > \beta_3$ then the regression favors the hypothesis that buying NUG power raises the cost of capital relative to utility funded construction. To determine the statistical significance of our result we will test the hypothesis that $\beta_2 = \beta_3$; only if we can reject this hypothesis can we reliably conclude that one or the other side of the debate is probably correct.

If the bond rating agencies are correct, then we would expect a positive relationship between NUG and r_e, or $\beta_2 > 0$. Our expectations for CWIP are more complicated. We know of no theory indicating that CWIP should have an impact on r_e, but that does not rule out the possibility, On the other hand, the Putnam, Hayes and Bartlett, Inc. (1986) (PHB)[13] study previously cited would suggest that CWIP may raise r_e because of risks associated with potential disallowances.

The PHB study's result may have been a product of the nature of regulation during the period studied. Rothwell and Eastman (1987)[14] argue that both allowed and earned returns in the US electric utility industry were below the cost of equity capital at approximately the time studied. In such cases, it is profit maximizing for the utility to minimize investment.[15] Under more favorable circumstances, i.e. when returns exceed the cost of equity capital, then investment might be neutral or favorable. This effect does not directly bear on the cost of capital but it can affect one of our measures of it. As previously noted E/P measures the cost of capital only in the case of zero expected earnings growth. CWIP in the presence of a rate of return above the cost of capital will produce and increase in expected earnings. Thus in a favorable regulatory environment, CWIP may be negatively correlated with E/P. This would be indicated by $\beta_3 < 0$. In fact we get this result and discuss its meaning in more detail when it is presented.

[13] Putnam, Hayes and Bartlett, Inc,. "Are Regulatory Risks Excessive? A Test of the Modern Balance Between Risk and Reward for Electric Utility Shareholders," Prepared for the U.S.Department of Energy (1986).

[14] G. Rothwell, and K. Eastman, "A Note on Allowed and Realized Rates of Return of the US Electric Utility Industry," *Journal of Industrial Economics* 36:1:105-109, (1987).

[15] S. Peck, "Electric Utility Capacity Expansion: Its Implications for Customers and Stockholders," *Energy Journal -Special Electricity Issue* 4:1-12, (1983).

3.3 An Expanded Model

Our basic equation focuses on the policy debate in which we are interested, but may omit important variables that could explain variations in the cost of equity capital. There is a tradition of modeling the cost of equity capital for electric utilities which typically includes operational and regulatory variables as well as managerial and financial variables. There are potentially a number of such variables that might be added to our basic equation. Since sample size is constrained by data limits, we want to limit additional variables to the potentially most important ones. Previous studies have identified fuel mix and "regulatory climate" as among the more important sources of variation.

The representations of fuel mix vary in the previous work. In some cases, the specification emphasizes expensive fuels,[16] in other cases, the risks associated with nuclear power.[17] Since fuel costs are currently low, we will use nuclear power as a measure of operating risks. To measure the exposure to risk we use the ratio of nuclear assets to total electric utility plant.[18] We refer to this variable as *NUKE*. We would expect the sign of the coefficient on this variable to be positive; i.e. nuclear assets increase the cost of capital because they are risky.

"Regulatory climate" is a general term which describes the degree of stringency applied by state regulatory commissions to investor-owned utilities. It is a composite of many factors including the generosity of allowed rates of return, the effect of regulatory lags, and accounting procedures. Investment and research firms regularly publish rankings of state regulation. These have been found to be significant variables in previous studies of the cost of equity capital.[19,20] Regulatory factors have also been found to be significant source of variation in the cost of electric utility debt.[21] We use a regulatory climate variable that we refer to as *PUC*. The source of the data is Merrill Lynch (1993). This source gives numerical ratings to regulatory

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[16] J. Dubin, and P. Navarro, "Regulatory Climate and the Cost of Capital." *Regulatory Reform and Public Utilities*, ed. M. Crew (Lexington Books, 1982).

[17] R. Bowen, R. Castanias,and L. Daly, "Intra-Industry Effects of the Accident at Three Mile Island," *Journal of Financial and Quantitative Analysis* 18:1:87-107, (1983).

[18] Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities 1990*, DOE/EIA-0437/(90)/1. (Washington, DC, January 1992).

[19] R. Trout,. "The Regulatory Factor and Electric Utility Common Stock Investment Values," *Public Utilities Fortnightly* 104:11:28-31, (1979).

[20] J. Dubin, and P. Navarro, "Regulatory Climate and the Cost of Capital," *Regulatory Reform and Public Utilities*, ed. M. Crew (Lexington Books, 1982).

[21] R. Prager, "The Effects of Regulatory Policies on the Cost of Debt for Electric Utilities: An Empirical Investigation," *Journal of Business* 62:1:33-53, (1989).

commissions going from 1 (unfavorable to investors) to 5 (favorable to investors). We would expect the sign on the coefficient of this variable to be negative; i.e. a favorable regulatory climate would reduce risk and hence also reduce the cost of capital.

Adding these two additional variables results in an expanded model of the following form

$$r_e = \beta_0 + \beta_1 \frac{D}{Eq} + \beta_2 \frac{Dn}{Eq} + \beta_3 \frac{C}{Eq} + \beta_4 NUKE + \beta_5 PUC + \epsilon .$$

We will test whether the expanded model has more explanatory power than the basic equation.

4 Measurement Issues

4.1 Definitions of Regression Variables

Each of the regressions deriving from our basic equation makes use of four variables: cost of equity capital, r_e, the debt-equity ratio, the ratio of NUG "debt" to equity (i.e. *NUG)*, projected utility capital expenditures (i.e. *CWIP*). This sub-section defines those variables in terms of constituent variables that are available from sources that are discussed later in this section. The additional variables used in the expanded model are simple, and the source of the data was given above.

r_e The utility cost of equity capital can be measured through three different proxies: (1) the DCF approach, (2) its variant the EPR, or (3) the CAPM approach. We will test each as a dependent variable. The required constituent variables are:

1) D The stock dividend.
   P The stock price.
   $\hat{g}$ The expected growth rate of the dividend.

2) E Earnings.
   P The stock price.

3) β Beta, the covariance of the stocks return over the variance of market return.
   r_f The risk-free rate of return.
   $E(r_m)$ The expected market rate of return.

D/E The debt-equity ratio is self explanatory; it requires.
   x_1 The utility's debt ratio (debt divided by debt plus equity).

CWIP This variable is forecast by the utility, and includes construction expenses for T&D as well as for generation. It is typically not forecast very far into the future (3-5 years). This variable must be present valued and normalized to account for variations in firm size. Since its effect on the cost of equity capital will be inversely proportional to the value of the firm's equity, just as is true with debt, we normalize by dividing by the firm's equity. Thus CWIP is defined as:

$$CWIP = PCAP \; / \; Eq$$

PCAP Projected utility capital expenditures.
Eq Equity

NUG This is a pseudo "debt"-equity ratio due to capacity payments to non-utility generators, and must reflect the multi-year commitment to those generators. The present-value of this payment stream represents a first approximation to their debt equivalence. As a second approximation we will use the Standard and Poor's utility-specific "risk factors" as a means of weighting these payments to account for differences in terms and conditions of the contracts. NUG and its constituent variables are defined as follows:

$NUG_1 = Dn/Eq = (x_2 - x_1)/(1 - x_1)(1 - x_2)$
$NUG_2 = \alpha \cdot Dn/Eq$
Dn Equivalent "debt" due to NUG (derived from x_1 and x_2).
x_1 standard debt ratio.
x_2 debt ratio "adjusted" for NUGs
α Standard and Poor's "risk factor".

A detailed discussion of variables follows, though it should be noted that alternative approaches are possible, one of which would be to construct a NUG variable from EIA data on NUG capacity using proxy costs for different fuel types.

To explain the constituent variables we focus on Moody's data.[22] They present a table giving an unadjusted and an adjusted debt fraction for each of 51 investor owned utilities. It is useful to give explicit definitions of these concepts. First, the standard (or unadjusted) debt fraction is given by

$$x_1 = \frac{Db}{Db + Eq}$$

where x_1 is the debt fraction, Db is the total amount of debt and Eq is the total amount of equity (including preferred shares). The adjusted debt fraction is given by

$$x_2 = \frac{(Db + Dn)}{(Db + Dn) + Eq}$$

where Dn is the equivalent debt associated with power purchases. Since, for our regression we will need $NUG = Dn \; / \; Eq$ instead of x_2, we must solve for NUG in terms of x_1 and x_2.

[22] Moody's Investor Services, "Moody's Continues to Weigh the Credit Risks of Purchased Power on Electric Utility Credit Quality," (September 1992).

This is easily done by defining dn = Dn/(Db+Eq), and eq = Eq/(Db+Eq), and noting that Dn/Eq = dn/eq. We then find:

$$dn = \frac{x_2 - x_1}{1 - x_2}, \quad \text{and} \quad eq = 1 - x_1 .$$

This implies the first formula for NUG given above.

The equivalent debt, Dn, is a capitalization of capacity or demand-related payments. The bond rating agencies make calculations of this kind. Moody's uses certain simplifying assumptions to standardize their calculation of Dn. They assume that 60% of annual purchased power payments are capacity-related,[23] that contracts are 25 years in length, and that the present-value of the future capacity payment stream should be discounted at 10%.[24] They assert that this results in assuming that every $1 in annual capacity payments is equivalent to $6.5 in imputed debt.[25] Duff and Phelps (1992)[26] uses a capitalization method which results in a much smaller equivalent debt. They assume that only 20% of purchased power expense is capacity charges, but they capitalize this at 10 times, resulting in an equivalent debt that is 2 times annual purchase power costs. Although these methods are somewhat arbitrary, because they affect all NUG values by a constant factor they will bias the NUG coefficient, but they will not affect its t-statistic.

An important issue that should be examined is whether differences in the risk characteristics of NUG contracts are reflected in the NUG variable. If NUG values could be correctly adjusted for risk, that should improve the t-statistic, in other words it would make our statistical tests more sensitive. The Standard and Poor's approach to this issue allows for variation in risk by using a "risk factor." We illustrate how this works. If we designate the appropriate risk factor by α, then we can write down a "risk adjusted NUG "debt"-equity ratio," NUG_2 as follows

$$NUG_2 = \frac{\alpha \cdot Dn}{Eq} .$$

[23] The 60% figure is difficult to verify for a number of reasons, the foremost of which is dispatchability. Capacity payments are fixed, while total power purchase costs depend upon dispatch. A recent study of private power pricing found that capacity related payments were typically closer to 50% for high capacity factor operation. At low capacity factor, however, portions in excess of 70% can be expected. See E. Kahn, A. Milne, and S. Kito, *The Price of Electricity from Private Producers*, LBL-34578 (Berkeley, CA, 1993).

[24] Moody's Investor Services, "Moody's Continues to Weigh the Credit Risks of Purchased Power on Electric Utility Credit Quality," (September 1992).

[25] There is some ambiguity in the Moody's estimate. Taken literally, their method amounts to capitalizing capacity payments at a factor of 9, and total purchased power expense at a factor of 5.4 (=0.6*9). As explained in the note to Table 2 below, the actual capitalization factor used by Moody's seems to be 3.9 times total purchase power expense.

[26] Duff, and Phelps, "The Purchase Power Commitment." (1992).

We will give an illustration of the differences between the definitions of NUG_1 and NUG_2 in Table 1.

Table 1. NUG "Debt"-Equity Ratios

Company	Debt Ratio	Adjusted Debt Ratio	Risk Factor	"Debt"-Equity Ratio	"Debt"-Equity Ratio Risk Adjusted
	x_1	x_2	α	NUG_1	NUG_2
Consumers Power	.601	.738	.3	1.31	0.39
Southern California Edison	.552	.743	.1	1.66	0.17

This example takes two utilities that are highly dependent on purchased power and computes the quantities defined above. The estimates of the risk factor α are taken from Mockler (1993),[27] who attributes them to Standard and Poor's. These calculations show that the Moody's method estimates a substantially greater equivalent debt for Southern California Edison (SCE) than for Consumers Power (CP), although both are quite large compared to the strictly financial debt. As a result, NUG_1 is bigger for SCE than for CP, even though the unadjusted debt fraction for SCE is quite a bit lower. When risk is taken into account, however, the rank ordering reverses. The risk factor for CP is much greater than for SCE.

The actual construction of the NUG variables is complicated by the fact that the available data produces a ratio of Dn to book equity, while what is needed is the ratio of Dn to the market value of equity. Appendix A describes the conversion from one to the other, which requires the use of the book-to-market ratio (B:M).

4.2 Definitions and Sources of Constituent Variables

In the previous section we listed all of the variables needed to construct the four regression variables. In this section we define these constituent variables more precisely and indicate the source of values for each. Because we only have *PCAP* data for December 31, 1992, we attempt to find values for all other variables that are either valid at that date or a good proxy for the value at that date.

Dividend (D): Annual dividend yield reported by Value Line. Data for utilities in the west from the November 27, 1992 issue; data for utilities in the east from the December 18, 1992 issue; data for utilities in the midwest from January 15, 1993 issue.

[27] T. Mockler, "Testimony in California Public Utilities Commission," Appl. No. 93-05-08 et al. (1993).

Market Price of Common Stock (P): Market value of common stock on December 31, 1992 from annual reports. "Recent Price" per share from Value Line was used for thirteen companies that did not report year-end stock price in annual report.

Book Value of Common Stock - Book value of common stock as of December 31, 1992 from individual reports.

Book Value of Preferred Stock - Total value of all classes of preferred stock as of December 31, 1992 from annual reports.

Book-to-Market Ratio (B:M): From Merril Lynch

Estimated future growth rate of dividends ($\hat{g}$): Value Line's estimated growth in dividends using 1989 - 1991 as the starting period and 1995 to 1997 as the ending period.

Earnings Per Share (E): Average of 1992 and 1993 earnings per share was used in this analysis. 1992 values from individual annual reports. 1993 values based on Value Line estimates.

Beta (β): The stock's beta taken from Merrill Lynch (1993).[28]

Risk-Free Rate of Return (r_f): From Brealey and Myers.

Expected Market Rate of Return ($E(r_m)$): From Brealey and Myers.

Utility's Debt Ratio (x_1): From Duff and Phelp's estimate from 1992 data.

Projected utility capital expenditures (PCAP): From SEC 10k forms, 12/31/92. We used total electric construction expenditures.

"Adjusted" debt ratio (x_2): From Duff and Phelp's estimate from 1992 data.

Standard and Poor's "risk factor" (α): Standard and Poor's, as summarized in Mockler (1993).[29]

[28] Merrill Lynch, Global Research Review (February 1993).

[29] T. Mockler, "Testimony in California Public Utilities Commission," Appl. No. 93-05-08 et al. (1993).

4.3 Data Quality Issues

Holding Companies

A minor issue involves the question of utility holding companies. A holding company typically is the sole owner of the common stock of its operating subsidiaries. Therefore only the holding company's stock is publicly traded. The operating companies which are subsidiaries of a holding company may have substantially different commitments to construction and NUG contracts. For example, Jersey Central Power and Light (JCPL) and Metropolitan Edison Company (Met Ed), both subsidiaries of General Public Utilities (GPU), purchased more than 10% of their capacity from NUGs in 1991.[30] GPU's other subsidiary, Pennsylvania Electric (Penelec) has less dependence on NUGs. To represent the NUG variable for GPU, we simply weight the representation for each subsidiary by the capital structure of the holding company.

NUG Data

In principle, we want to use data on NUGs for year-end 1992. The only publicly available estimates for that time period are those from Duff and Phelps (1993).[31] As indicated above, this is our starting point. The choice is not unambiguous, however, because the Duff and Phelps estimation method is somewhat mechanical, and may include purchases, such as short-term economy energy, that are in no way equivalent to debt. The main competing source of data on NUG debt equivalence is Moody's 1991 estimate. This estimate may be more selective. There is a problem, however, with its being one year out of phase with our other variables. We illustrate the most extreme example of this time lag problem.

If the dependence of individual utilities upon NUG purchases were stable between 1991 and 1992, then using 1991 as a proxy for 1992 would be reasonable. Unfortunately, it is not. The best, if most extreme, example of this is the Niagara Mohawk Power Corporation (NMPC). Table 2 summarizes the problem.

Table 2. NMPC Debt Fractions for 1991 and 1992

Year	Debt (millions)	Equity (millions)	Unadjusted Debt Ratio	Purchased Power (millions)	Adjusted Debt Ratio
1991	3625	2627	0.580	394	0.664
1992	3776	2700	0.583	659	0.701

[30] Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities 1990*, DOE/EIA-0437/(90)/1 (Washington, DC, January 1992).

[31] Duff, and Phelps, "Electrics: By the Numbers," (July 1993).

The calculations in Table 2 are based on Moody's 1991 calculation of the adjusted debt ratio and NMPC's 1992 Annual Report. The term "Debt" includes Long term debt, Short term debt and Long term debt due within one year. "Equity" includes both common and preferred. The adjusted debt ratio is computed using Moody's capitalization method.[32]

The change in the Adjusted Debt Ratio in Table 2 reflects the substantial growth in NUG payments by NMPC between 1991 and 1992. Other utilities, such as Consumers Power or Southern California Edison, did not experience such large changes between 1991 and 1992.

As an alternative to the direct estimates of debt equivalence, a physical approach is also possible. EIA has data on NUG energy purchases and capacity commitments of utilities as of 1991. This data has the advantage of eliminating other purchases, such as short-term economy energy, from consideration. It is not available for 1992, which makes it insensitive to changes between 1991 and 1992. As an alternative to the financial NUG variables, based on Duff and Phelps data, we also test a physical NUG variable, which we call NUG_3, defined as the ratio of NUG energy purchases to total sources of energy for 1991.

Financially Distressed Utilities

A number of companies that might potentially be included in our sample are experiencing financial distress for one reason or another. This shows up in some of our cost of capital estimators in a number of anomalous ways. Value Line estimates the future dividend growth for Commonwealth Edison, for example, to be negative 7%. This would give a very low DCF r_e, which may not make sense since their beta is among the highest in the sample. The same arguments apply to Pinnacle West (i.e., Arizona Public Service).

There are two different approaches to deal with these situations. One option is to eliminate such companies from the database, and use regressions estimated on a smaller sample. Alternatively, we can use proxy costs of capital for these firms. The idea for a proxy is that intuitively we know that these are high risk firms. Therefore, they must have a high cost of capital. For some reason, the standard estimators do not result in a high risk r_e being assigned to them. As a proxy, we assign to such utilities a cost of capital that is arbitrarily higher than any observed in our sample, so that the anomalous data does not distort our analysis. For each cost of capital estimator, we assume that the financially distressed firms have a "true" value that is 10% more than the highest value observed. Thus for the DCF estimator, the highest observed value is 12.6%. By this procedure, we would use 13.86% for the financially distressed firms.

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[32] The 1991 value is Moody's estimate; see Moody's Investor Services, "Moody's Continues to Weigh the Credit Risks of Purchased Power on Electric Utility Credit Quality," (September 1992). If we capitalize the $394 million at a factor of 3.9, we get the stated adjusted debt ratio of 0.664. Using a greater capitalization factor (as potentially indicated in note 7 above) would result in a larger adjustment. The 1992 data is used with the factor of 3.9 to produce the estimate given in Table 2.

Although we prefer to exclude the financially distressed firms completely (to avoid the use of the proxy r_e), as discussed below, this is not possible in all cases due to other considerations.

4.4 Sample Selection

Sample selection is crucial to the outcome of any statistical analysis, and both size of sample and method of selection deserve careful attention. We will examine sample size first.

Sample Size

There is no question but that increasing the sample size is valuable, especially for a relatively small sample. However, additional data points often come with attendant statistical problems. Common among these is autocorrelation. When analyzing time series data there is always a threshold beyond which increasing autocorrelation will negate the benefit of a higher sample rate. (E.g. sampling GNP daily, even if it could be done, would yield essentially no new information about macroeconomic fluctuations when compared with a monthly sample, even though this would increase sample size by a factor of thirty.)

In the case of the present study even sampling at an annual rate would produce a very high degree of autocorrelation. This is because the key explanatory variables, NUG and CWIP, both involve long-term (typically twenty-year) contracts or investments. Thus adding an adjacent year of data would add almost no new information to our current sample. It would however require that a difficult[33] correction for autocorrelation be made. Added to the autocorrelation problem is the fact that the year chosen was the one for which data was most readily available, so extending to previous years would mean decreasing the average reliability of the sample.

The second method of increasing sample size is to include more utilities. This process has already been pursued vigorously and it is not evident that more data points can be added with out sacrificing reliability or incurring undue cost.

Selection Bias

There are many ways to bias statistical results by improper sample selection, but perhaps the best know is truncation bias. This occurs when sample points with either high or low values of the dependent variable are omitted. This is best understood by considering a one variable regression with a regression line sloping up to the right. If points with a high y-value are omitted they will tend to be at the right end of the data set. Thus their omission will lower the average value for points on the right and reduce the estimated slope of the regression line. This produces a biased (and inconsistent) estimate of the slope coefficient.

[33] Difficult because we would have a set of time series each of which was only two periods long and this is not the case normally covered in the literature.

Another type of sample selection chooses data points based on the value of an independent variable. This, by itself, does not bias coefficient estimates. In fact, the statistical model on which multiple linear regression is premised assumes that an experimenter chooses the values of the independent variables not by some statistically random technique, but entirely deliberately. In our case, if we could have afforded it, we would have conducted an experiment in which several utilities were instructed to implement a very high NUG value and an equal number of others were instructed to have a NUG value of zero. Barring that possibility, we simply chose to include in our sample as many firms as possible with high NUG values, since the low NUG-value end of the sample tended to be well enough represented. The point of including extreme values is to increase the accuracy of the estimates of the coefficients; points near the middle of the range tell us nothing about the slope of the relationship between the cost of capital and the value of NUG. Thus we were willing to incur much greater data-gathering costs for points near the extreme of the distribution.

This problem can be approached more rigorously as follows. Although the problem of truncation bias has been well know at least since Theil (1957),[34] Heckman (1979)[35] is perhaps the best known paper on the topic, and formulates the problem quite generally. In his formulation, there will be no selection bias "In the case of independence between U_{1i} and U_{2i}," where U_{1i} are the regression equation errors and U_{2i} are the selection equation errors. Now our selection criteria for utilities had a form that can be simply approximated as follows:

$$\text{Include the data point if } \quad NUG - \beta + U_{2i} > 0.$$

Clearly, for any selection parameter, higher values of NUG are more likely to be included. The error term is related only to the convenience of acquiring data, which should be unrelated to the error term in our regressions. It should also be noted that if we had simply selected all observations with NUG $> \beta$, the error term would have been zero. If the selection error term is zero it is certainly independent of the regression error term. Thus using Heckman's formal model confirms that our selection based on NUG values should not bias any coefficients.

Bias from Omitting Financially Distressed Utilities

There is one way in which the study does run the risk of truncation bias. Heckman warns: "in studies of panel data, it is common to use 'intact' observations. . . . Such procedures have the same effect on structural estimates as self selection: fitted regression functions confound the behavioral parameters of interest with parameters of the function determining the probability of entrance into the sample." In this study "intact" observations are those utilities that are not financially distressed, so Heckman is warning that the distressed utilities should not be omitted.

[34] H. Theil, "Specification Errors and the Estimation of Economic Relationships," *Revue de l'Institut International de Statistique* 25:41-51, (1957).

[35] J. Heckman, "Sample Selection Bias as a Specification Error," *Econometrica* 47: 1 (January 1979).

In defining our sample we came across seven financially distressed utilities as indicated by the fact that they were not paying dividends, or the fact that stock analysts were assigning negative growth rates to their dividends, or not even estimating dividend growth rate. Of these seven, five were omitted and two with the largest NUG values were retained. The omission of the five should be expected to bias our coefficients but not in a direction that would undermine our conclusions. Empirical implications of this selection bias will be discussed in section 5 below.

Special Cases

There are a number of cases where holding companies have substantial assets in non-utility businesses. Two particularly important examples of this kind are Southern California Edison and Consumers Power. In both instances the non-utility generation projects sell very substantial quantities of power to the affiliated utility. These cases have attracted much attention from state regulators, who have expressed concern about self-dealing, and have imposed financial penalties on the utilities in question.[36] Because both of these companies are among the largest NUG purchasers, we do not want to exclude them from the analysis. Yet the very special circumstances involving the self-dealing issue require that we run separate regressions with these companies in and out of the sample, so that we can isolate the effect of their special circumstances. The distressed financial condition of Consumers Power's parent company CMS Energy requires that we use the proxy method described above for its cost of capital.

4.5 Summary of Regressions Run

Here we list the total number of specifications of our basic equation that we test numerically. There are three versions of the cost of capital variable: (1) CAPM, (2) DCF and (3) EPR. For each of these dependent variables we will use our three NUG variables. NUG_1 is the 1992 Duff and Phelps estimate, suitably normalized. NUG_2 applies the Standard and Poors risk factor to NUG_1. NUG_3 is the 1991 physical NUG variable, taken from EIA data on non-utility purchases. Finally we run our basic sample of utilities without SCE and CMS (cases we designate as "N" for no self-dealing) and with SCE and CMS (cases we designate "S").

[36] For details involving Southern California Edison, see California Public Utilities Commission, Decision No. 90-09-088 (1990); also see California Public Utilities Commission, Decision No. 93-03-021 (1993). For Consumers Power, there is a good description in the financing documents associated with their affiliated NUG project known as Midland Cogeneration Venture; see Stone and Webster Management Consultants Inc., "Feasibility Report for the Midland Cogeneration Venture," in Midland Cogeneration Venture Limited Partnership, *Prospectus $999,905,607 Midland Funding Secured Lease Obligation Bonds* (1991).

4.6 Characteristics of Regression Variables

Each regression uses as dependent variables both the debt-equity ratio, D/E, and a measure of construction work in progress CWIP. Also included on the right is one of three measures of non-utility generation, NUG1, NUG2, or NUG3. The dependent variable is one of three measures of the cost of equity capital, CAPM, DCF, or EP. Appendix A contains a complete listing of each of these variables, while this section presents their standard summary statistics. Although there are three utilities that are sometimes included and sometimes not, for the purpose of calculating the summary statistics we have included all utilities that are used in any regression. Table 3 gives the mean and standard deviation of each variable.

Table 3. Descriptive Statistics

	CAPM	DCF	EP	NUG1	NUG2	NUG3	D/E	CWIP	NUKE	PUC
Average	0.104	0.094	0.078	0.189	0.024	0.058	0.884	0.291	0.257	2.971
Standard Deviation	0.011	0.012	0.018	0.214	0.031	0.079	0.306	0.104	0.156	0.784

Since both the NUG and cost-of-capital variables are estimated in three separate ways, it is interesting to see just how closely correlated they are. To that end we present a standard correlation matrix for each.

Table 4. Correlations Among Cost-of-Capital Variables

	CAPM	DCF	EP
CAPM	1		
DCF	0.39	1	
EP	0.59	0.56	1

Table 5. Correlations Among NUG Variables

	NUG1	NUG2	NUG3
NUG1	1		
NUG2	0.85	1	
NUG3	0.61	0.60	1

Note that the correlation of CAPM and DCF is quite low. We believe this is attributable to the poor quality of DCF as a measure of the cost of equity capital. Notice also that NUG3 the physical measure of NUG capacity does not correlate especially well with the two financial measure, NUG1 and NUG2. In this case we suspect measurement errors in all three variables.

5 Results

5.1 Omitted Variables

There are two reasons to include variables whose coefficients are not of interest. The first is to avoid the classic "omitted variable" problem which biases the coefficients of interest, and the second is to reduce the variance of the error term and thereby reduce the standard errors of the coefficients of interest.

The omitted variable problem occurs when a causal variable which is correlated with an included independent variable is omitted from the regression. In this case the included variable picks up some of the significance that should rightly be attributed to the omitted variable.

There is also a possible reason for not including an independent variable that is not causal. If such a variable is correlated with an independent variable of interest it will erroneously increase the standard error of the variable of interest.

In section 3.3 we outlined the case for expanding our basic model to include potentially important variables that were not included in the original formulation. When we include the two potential omitted variables, NUKE and PUC, we find the following changes in the CAPM regression statistics. Appendix B includes a complete listing of these regression results.

1. The adjusted R^2 decreases for all six regressions.
2. The D/E coefficient decreases slightly for all six regressions.
3. The NUG coefficient increases slightly in four of six regressions.
4. The CWIP coefficient increases in magnitude slightly for all six regressions.
5. The t-statistics get slightly worse on all 18 coefficients.

Two of these outcomes are particularly telling. First, the fact that adjusted R^2 decreased indicates that the two "omitted" variables together provided less new explanatory power than one would expect from two randomly generated X variables. In other words, they could not have performed worse. This rules out the possibility that these variables should be adopted for the second reason; to decrease standard errors.

Second, the fact that the CWIP coefficient *increases* in magnitude indicates that the standard omitted variables problem cannot be at work here. Therefore the increase in the standard error of the CWIP coefficients comes from a small colinearity problem contributed by the new variables. The NUG coefficient behaves less consistently. Four times out of six it increases, it remains unchanged once and decreases once. Measured in absolute terms or in standard error, the largest of these changes is the decrease. Thus if the addition of the new variables is correcting a bias, it is does this so poorly that it is not clear in which direction the correction is being made. Again there is virtually no evidence for a omitted variable problem. The Debt/Equity variable is the only one with a coefficient that behaves as if NUKE and PUC were correlated, causal omitted variables, although the effect is not particularly strong--the coefficient changes by about 1/2 a standard error or less. In the DCF regressions, five out of six times the coefficient increases. So once again there is little if any reason to believe we are witnessing anything of statistical significance, especially given the fact the D/E is the variable with the strongest theoretical backing.

5.2 Basic Specifications

Regression results are listed in Table 6 for CAPM, Table 7 for DCF and Table 8 for EPR.

For each variable, the estimated coefficient is given, with the t statistic listed in parenthesis below it. Recall that t statistics in excess of 2 are required for statistical significant at the 95% confidence level.

CAPM

The CAPM specification of our basic equation has the most explanatory power based on both its adjusted R^2 and on the number of significant coefficients. On theoretical grounds, we expect that the Debt/Equity variable should be positive and significant. It is only in the CAPM specification that this turns out to be the case. The DCF results (shown in Table 7) don't show a significant coefficient for Debt/Equity. The EPR results (in Table 8) show only marginal significance for this variable.

With respect to our central question, the CAPM specification gives unambiguous results. The CWIP variable has a positive and significant coefficient. There is no significance to the NUG coefficient. This result suggests that utility construction does increase risk and raise the utility cost of equity capital. This result is consistent with the PHB finding from 1983 and 1984 data before NUGs played much of a role in the electricity industry. The result is diametrically opposite from the finding of Sudarsanam (1992)[37] for unregulated industries. It is possible that the hypothesis offered in the PHB study explains these results, namely that the source of the risk lies with the behavior of the regulator. Our study sheds no light on such questions.

It is also worth noting that the S versions of the regression have much higher t statistics on the CWIP variable than the N versions. This is largely due to CMS, which has both the highest values of the CAPM r_e and the CWIP variable.

[37] P. Sudarsanam, "Market and Industry Structure and Corporate Cost of Capital," *Journal of Industrial Economics* 40:2:189-199, (1992).

Table 6. CAPM Results

	S1	N1	S2	N2	S3	N3
Intercept	0.0776 (15.18)	0.0812 (13.70)	0.0791 (14.51)	0.0816 (13.72)	0.0777 (15.27)	0.0817 (13.85)
Debt/Equity	0.0095 (2.08)	0.0099 (2.13)	0.0097 (2.13)	0.0099 (2.13)	0.0095 (2.07)	0.0099 (2.16)
NUG	-0.0034 (-0.47)	-0.0012 (-0.16)	0.0414 (0.67)	0.0223 (0.33)	-0.0108 (-0.59)	-0.0123 (-0.53)
CWIP	0.0636 (4.19)	0.0476 (2.34)	0.0522 (2.88)	0.0438 (2.18)	0.0631 (4.42)	0.0470 (2.52)
Adjusted R^2	0.45	0.26	0.46	0.27	0.45	0.27

The coefficients in Table 6 have a straightforward interpretation. The average r_e consists of three components: (1) the intercept term has a value of approximately 0.08, (2) the Debt/Equity coefficient of approximately 0.01 adds a return requirement of about 0.0088 for the average value of the Debt/Equity variable of about 0.88, and (3) the CWIP co-efficient of about 0.05 adds a return requirement of about 0.015 for an average value of the CWIP variable of 0.29. The result is an average cost of equity capital of about 0.1038, which is approximately the average value of r_e given in Table 3. For a utility with CWIP that is one standard deviation above the average, the cost of capital increases by 0.005.

Recalling our discussion of selection bias issues in 4.4, the omission of financially distressed firms raises the issue of selection bias effecting coefficient estimates. Financially distressed utilities will almost certainly have a high cost of capital, thus omitting them from our sample, effectively truncates the sample from above. The result is to reduce in magnitude the estimates of all regression coefficients. The fact that the two distressed utilities with the largest NUG values were retained will result in the NUG coefficient estimate being less biased than other coefficient estimates. Thus the CWIP coefficient is probably larger and more significant than we estimated it to be, and so is the NUG coefficient, but the effect is less for NUG. This means that our results indicating that the CWIP coefficient is larger than the NUG coefficients would probably be more certain if we had been able to include the omitted utilities.

The CAPM regressions can also be used to test whether our results contribute meaningfully to the build versus buy debate by conducting a statistical test of the hypothesis that the NUG coefficient differs from the CWIP coefficient. Four of the six regressions strongly reject this hypothesis while two contradict it only weakly. These tests were conducted by computing an F statistic based on the R^2 of the full regression and the R^2 of a regression in which the NUG and CWIP coefficients were restricted to be equal. This F statistic is useful for testing the hypothesis that the coefficients are in fact equal. Since in each case the CWIP coefficient is greater than the NUG coefficient, any hypothesis that the NUG coefficient is greater can be rejected with even more certainty. The Table 6A presents these results.

Table 6A. Test for Equality of the NUG and CWIP Coefficients

Regression	Degrees of Freedom	F Statistic	5% Critical Value	Reject Equality of Coefficients
CAPM S1	1, 31	11.72	4.16	Yes
CAPM N1	1, 29	6.19	4.23	Yes
CAPM S2	1, 31	0.03	4.16	No
CAPM N2	1, 29	0.07	4.23	No
CAPM S3	1, 31	10.12	4.16	Yes
CAPM N3	1, 29	5.90	4.23	Yes

DCF

The DCF specification (summarized in Table 7) performs poorly. Only two of the eighteen coefficients has a t statistic greater than 2, and these are both on CWIP. This is approximately what one would expect from chance, though there may be another weak indication that CWIP is positive and has a stronger impact than NUG.

One interesting coefficient in the DCF specification is on the NUG variable in case S2. This result may also be driven by the CMS data. As the discussion of Table 1 indicated, Consumers Power has a significant NUG equivalent debt even after adjusting for risk using the Standard and Poors risk factors. CMS, the parent of Consumers Power, is a financially distressed company, for which we use a high proxy value for r_e. SCE, on the other hand, has a high NUG value in the S1 case, but a much lower value in the S2 case. Its r_e is in the middle range. Therefore, the change in significance for the NUG variable between S1 and S2 seems largely due to CMS.

Table 7. DCF Results

	S1	N1	S2	N2	S3	N3
Intercept	0.0687	0.0782	0.0744	0.0793	0.0685	0.0757
	(8.22)	(8.36)	(8.78)	(8.61)	(8.59)	(8.51)
Debt/Equity	0.0104	0.0119	0.0104	0.0112	0.0112	0.0116
	(1.39)	(1.63)	(1.48)	(1.57)	(1.56)	(1.64)
NUG	0.0040	0.0073	0.1820	0.1324	0.0490	0.0641
	(0.33)	(0.61)	(1.91)	(1.26)	(1.71)	(1.83)
CWIP	0.0559	0.0131	0.0236	0.0062	0.0470	0.0171
	(2.25)	(0.41)	(0.84)	(0.02)	(2.10)	(0.61)
Adjusted R^2	0.21	0.04	0.29	0.08	0.27	0.13

EPR

The EPR specification (summarized in Table 8) resembles the DCF results. The coefficients for Debt/Equity are closer to significance than for DCF. Again, we have only two significant coefficients; it is the same as in Table 7; again case S2 produces the most positive value for NUG.

Table 8 also shows some interesting differences between the N and the S versions regarding the t statistics on the CWIP variable. Although none of the N case coefficients are significant, we get much better performance in these cases than the S versions. This is due again to CMS, which has very high values of r_e and CWIP. When these are removed a more clearly negative relationship begins to emerge between CWIP and EPR. In the next section, we explore this in more detail and perform an additional test which will help elucidate our basic question.

Table 8. EPR Results

	S1	N1	S2	N2	S3	N3
Intercept	0.0577	0.0725	0.0669	0.0737	0.0569	0.0690
	(5.23)	(6.05)	(6.12)	(6.23)	(5.23)	(5.70)
Debt/Equity	0.0171	0.0195	0.0168	0.0181	0.0175	0.0189
	(1.73)	(2.09)	(1.83)	(1.97)	(1.79)	(1.99)
NUG	0.0170	0.0217	0.3113	0.2354	0.0541	0.0529
	(1.08)	(1.41)	(2.54)	(1.74)	(1.39)	(1.11)
CWIP	0.0068	-0.0611	-0.0393	-0.0641	0.0083	-0.0412
	(0.19)	(-1.49)	(-1.08)	(-1.60)	(0.27)	(-1.07)
Adjusted R^2	0.07	0.09	0.20	0.12	0.09	0.07

5.3 Special Interpretation of the Earning-Price Ratio

Careful examination of Table 8 shows that CMS, a utility that is financially distressed, introduces a potentially spurious correlation between EPR and the CWIP variable. One reason why CMS has a high value for the CWIP variable is that we have normalized construction expenses to the market value of the firm's equity. Since the firm is financially distressed, the market value of the equity is relatively low. This is a property that all financially distressed utilities will tend to have. If we remove these extreme cases from our sample and re-estimate the equation without them, we may get results that have less noise in them.

Table 9 summarizes the results of such cases, which we designate by L. We have eliminated CMS and Niagara Mohawk from our sample, since these were the only two firms for which we used proxy values for r_e. We include SCE in the sample.

Table 9 shows a negative coefficient on CWIP in the E/P regression. As noted previously this probably does not indicate that CWIP reduces the cost of equity capital, because E/P ignores earnings growth, for which CWIP may be a reasonably good proxy. This does not make the result uninteresting, but does suggest a closer look at the mechanisms involved. We begin by reviewing E/P as measure of r_e.

As we noted in Section 2.1, when E/P was developed as a measure of r_e, it is the same as DCF but with the growth in dividends assumed to be exactly RE/P, retained earnings over price. This assumption is at best an approximation, but when CWIP is included it becomes a serious misspecification. This is because CWIP could be correlated with the difference between dividend growth and RE/P, thus E/P does not pick up one of the main ways in which CWIP affects r_e. To interpret the results of the E/P regression we will need some additional information; fortunately this is supplied by both the DCF regressions, and the CAPM regressions.

Table 9. EPR without Proxy Cost Firms

	L1	L2	L3
Intercept	0.0865 (7.3)	0.0869 (7.4)	0.0818 (6.7)
Debt/Equity	0.0111 (1.2)	0.0098 (1.1)	0.0113 (1.2)
NUG	0.0250 (1.9)	0.2446 (1.9)	0.0347 (1.0)
CWIP	-0.0913 (-2.4)	-0.0902 (−2.3)	-0.0648 (-1.8)
Adjusted R^2	0.12	0.14	0.05

The DCF regressions indicate that CWIP has essentially no effect on r_e, or more precisely essentially no effect on E/P + (g − RE/P). However the E/P regressions indicates that CWIP has a negative impact on E/P. Obviously the difference between these two results can be explained by the unobserved effect of CWIP on (g − RE/P). Clearly this must be a positive effect in order to cancel CWIP's negative effect on E/P and produce no net effect on E/P + g. The correct interpretation of the E/P CWIP result appears to be that an increase in CWIP causes both a decrease in E/P, and an increase in (g − RE/P). Or, more to the point, CWIP does not effect r_e, but it does lead to expectations of that dividend growth will be greater than RE/P, which occurs only if the return on capital is greater than the cost of capital.

There is a slight indication in two DCF regressions that the CWIP coefficient is positive, and the CAPM regressions give a strong positive correlation. Therefore, we should check whether or not this would change our interpretation. In fact it does not, it only reinforces it. If CWIP causes E/P + (g − RE/P) to go up but E/P to go down, then its impact on (g − RE/P) must be even more positive than we had thought.

The results are less conclusive regarding NUG, it appears to have a positive coefficient in the E/P regression and a slightly smaller, but still positive, coefficient in the DCF regression. These results are so weak as to be almost not worth the bother of interpretation, but if true they indicate that NUG has a positive effect on E/P and causes a very weak reduction in expected earnings growth. The combination of these two appears to result in a small increase in the cost of equity capital.

Before leaving the interpretation of the E/P results it is worth examining the underlying economic mechanism. The most straight forward explanation is based on CWIP being undertaken when a utility finds an opportunity to make a return that is above the cost of capital. In this case one can expect earnings-per-share to increase in the future when the project is brought on line. This increases the present value of the stream of expected future earnings without increasing current earnings. Since stock price, P, reflects the PV (expected earnings), it will increase and E/P will decrease. This explains the negative coefficient in the E/P regression. Since the decrease in E/P is exactly cancelled by the increase in the expected growth of earnings, these two effects explain the insignificant coefficient in the DCF equation.

6 Conclusions

Our principal finding is that we cannot detect any evidence to support the debt-equivalence hypothesis. At least as far as the cost of equity capital is concerned, we find more evidence to support the notion that utility construction raises the cost of capital than that NUG purchases do. This finding tends to support arguments made by NUGs on this issue.[38] This conclusion is supported by reasonably strong statistical results from the CAPM specification. There was no confirmation of this result from the DCF specification. The EPR results appear to suggest that utilities can earn more than the cost of capital from new construction, even if construction activity is risky and therefore somewhat more costly than purchasing from NUGs. Our results tell us nothing about the source of the risk associated with CWIP. It is entirely possible that it lies with the regulator, rather than with the firm.

If these results are correct, they imply that the buy versus build debate, insofar as cost of capital questions are involved, is not about the ratepayer impacts of NUG purchases. Rather, our results suggest that this debate is really about the long-run prospects for shareholder earnings; i.e. that it is a market share conflict.

These conclusions must be tempered by a frank assessment of the data quality upon which the statistical analysis rests. The NUG data in particular is quite weak. We have relied on the best publicly available compilations, but they are highly imperfect. We expect this situation to improve over time. It would be interesting to revisit these questions when the data quality is better.

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Appendix A

Methodology for Constructing Variables

A.1 Cost of Capital Variables

The following page contains the input and final regression variables used to represent the three dependent variables used in our analysis. These variables include a Capital-Asset Pricing Model (CAPM) estimate, a discounted cash flow (DCF) estimate, and an earnings-price (EP) estimate. For each measure we report an "Unadjusted" and an "Adjusted" value. Unadjusted values were calculated according to the methodology outlined below. We do not think that the "Unadjusted" values accurately reflect the cost of capital for financially distressed firms. As a proxy, we assign to such utilities a cost of capital that is arbitrarily higher than any observed in our sample, so that the anomalous data doesn't distort our analysis. For each cost of capital estimator, we assume that the financially distressed firms have a "true" value that is 10% more than the highest value observed. Using these "true" values produces the reported "Adjusted" values.

A.1.1 Capital Asset Pricing Model

CAPM is calculated for each company using the following equation:

$$CAPM = R_{RF} + (R_M - R_{RF}) \cdot Beta$$

where R_{RF} equals risk free rate of return, R_M equals market rate of return, and Beta equals the covariance of the stock's return over the market return. Values for risk free return and market return are from Brealey and Myers. These values are the same across companies. Values for Beta are company-specific and are from Value Line.

A.1.2 Discounted Cash Flow

DCF is calculated for each company using the following equation:

$$DCF = Dividend\ Yield + Dividend\ Growth$$

Dividend data is from Value Line.

A.1.3 Earnings / Price

E/P is simply the earnings per share for 1992 divided by the stock price at the end of 1992.

A.2 Construction Work in Progress Variables (CWIP)

The following page contains the input and final regression variables used for the independent variable CWIP. First, we obtained forecast annual construction expenditures for 1993 to 1995 from each company's SEC 10-k filing. We then calculated the net present value of these expenditures using a 10% discount rate. We normalized the net present value figure to equity. The following equation describes this procedure:

$$CWIP = \frac{NPV(CWIP93 + CWIP94 + CWIP95)}{Book\ Equity} \cdot \frac{Book\ Price}{Market\ Price}$$

A.3 Computing the D/E and NUG1, NUG2, NUG3 Variables

The following four pages contain the input, intermediate and final regression variables used to represent the debt-equity ratio and non-utility generation. The definition of the variables on the first of these pages can be found in section 4.2 of the report. We now present the equations for the subsequent three pages; the variable names used in these equations appear at the tops of the columns.

The first four intermediate variables are determined as follows.

$$UD{:}E = UD{:}C \ / \ UE{:}C$$

$$nug1 = \frac{AD{:}C - UD{:}C}{(1 - UD{:}C)(1 - AD{:}C)}$$

$$nug2 = \alpha \cdot nug1$$

$$Epc = EqP \, / \, EqC$$

UD:E is unadjusted debt/equity. UD:C is unadjusted debt/capital. UE::C is unadjusted equity/capital. AD:C is debt/capital adjusted for NUGS. "nug1" is NUG1 before equity is converted to market value (nug2 is similar). EqP is preferred equity, and EqC is common equity.

The second four intermediate variables are determined as follows.

$$D{:}Ec = UD{:}E + Epc + UD{:}E \cdot Epc$$

$$N1c = nug1 + nug1 \cdot Epc$$

$$N2c = nug2 + nug2 \cdot Epc$$

$$B{:}M = BV / MV$$

D:Ec is the ratio of debt to common equity. N1c and N2c are the NUG variables computed as a ratio to common book equity. B:M is the ratio of book to market value.

Finally, the four independent regression variables are determined as follows.

$$D{:}Em = D{:}Ec \cdot B{:}M$$

$$NUG1 = N1c \cdot B{:}M$$

$$NUG2 = N2c \cdot B{:}M$$

$$NUG3 = input$$

The first two NUG variable have now been expressed as a ratio of NUG debt to the market value of common equity.

Company	Beta	Risk Free Return	Market Return	CAPM Unadj.	CAPM Adj.	Div Yld	Div Grth	DCF Unadj.	DCF Adj.	92 EPS	93 EPS	12/92 MV	E/P Unadj.	E/P Adj.
Atlantic Energy Inc.	0.65	4.50%	12.90%	0.100	0.100	6.70%	1.50%	8.20%	8.20%	1.67	1.75	23.13	0.074	0.074
AEP	0.75	4.50%	12.90%	0.108	0.108	7.50%	1.00%	8.50%	8.50%	2.54	2.75	33.13	0.080	0.080
Baltimore Gas & Elec	0.71	4.50%	12.90%	0.105	0.105	6.30%	3.00%	9.30%	9.30%	1.63	1.80	23.00	0.075	0.075
Boston Edison Comp	0.65	4.50%	12.90%	0.100	0.100	6.30%	4.00%	10.30%	10.30%	2.10	2.20	27.50	0.078	0.078
Carolina Power & Lig	0.65	4.50%	12.90%	0.100	0.100	6.10%	4.00%	10.10%	10.10%	2.36	2.30	27.75	0.084	0.084
Centerior	0.69	4.50%	12.90%	0.103	0.103	8.00%	1.00%	9.00%	9.00%	1.50	1.85	19.88	0.084	0.084
Central Power & Lig	0.57	4.50%	12.90%	0.093	0.093	5.30%	5.00%	10.30%	10.30%	2.00	2.15	29.00	0.072	0.072
Cincinnati Gas & Ele	0.77	4.50%	12.90%	0.110	0.110	7.00%	2.00%	9.00%	9.00%	2.04	2.15	24.00	0.087	0.087
CMS Energy	0.73	4.50%	12.90%	0.106	0.137	2.50%	na	2.50%	13.86%	-3.72	1.25	18.38	-0.067	0.117
Con Edison	0.74	4.50%	12.90%	0.107	0.107	6.30%	3.00%	9.30%	9.30%	2.46	2.55	31.00	0.081	0.081
Detroit Edison	0.64	4.50%	12.90%	0.099	0.099	6.30%	4.00%	10.30%	10.30%	3.79	3.20	33.00	0.106	0.106
Dominion Resources,	0.55	4.50%	12.90%	0.091	0.091	6.40%	3.00%	9.40%	9.40%	2.76	3.05	39.50	0.074	0.074
DPL	0.55	4.50%	12.90%	0.091	0.091	5.90%	3.00%	8.90%	8.90%	1.34	1.50	19.75	0.072	0.072
Duke Power	0.66	4.50%	12.90%	0.100	0.100	5.10%	4.00%	9.10%	9.10%	2.21	2.50	36.13	0.065	0.065
Florida Progress Cor	0.67	4.50%	12.90%	0.101	0.101	6.10%	3.00%	9.10%	9.10%	2.06	2.35	32.63	0.068	0.068
FPL Group	0.77	4.50%	12.90%	0.110	0.110	6.90%	2.00%	8.90%	8.90%	2.65	2.75	36.25	0.074	0.074
General Public Utiliti	0.58	4.50%	12.90%	0.094	0.094	6.60%	6.00%	12.60%	12.60%	2.27	2.50	27.63	0.086	0.086
Houston Lighting & P	0.60	4.50%	12.90%	0.095	0.095	6.50%	2.00%	8.50%	8.50%	3.36	3.50	45.88	0.075	0.075
Kansas City Power &	0.67	4.50%	12.90%	0.101	0.101	6.40%	2.00%	8.40%	8.40%	1.35	1.70	22.75	0.067	0.067
New England Electric	0.74	4.50%	12.90%	0.107	0.107	6.00%	2.00%	8.00%	8.00%	2.85	2.90	38.50	0.075	0.075
Niagara Mohawk Po	0.65	4.50%	12.90%	0.100	0.137	4.80%	na	4.80%	13.86%	1.61	1.75	19.13	0.088	0.117
NYSEG	0.69	4.50%	12.90%	0.103	0.103	7.00%	1.00%	8.00%	8.00%	2.40	2.55	31.00	0.080	0.080
Northern States Pow	0.75	4.50%	12.90%	0.108	0.108	6.00%	4.00%	10.00%	10.00%	3.04	3.20	43.25	0.072	0.072
Ohio Edison	0.80	4.50%	12.90%	0.112	0.112	6.50%	2.00%	8.50%	8.50%	1.70	1.60	23.13	0.071	0.071
Pacific Gas & Electri	0.65	4.50%	12.90%	0.100	0.100	5.80%	5.00%	10.80%	10.80%	2.58	2.70	32.00	0.083	0.083
Pacificorp	0.59	4.50%	12.90%	0.095	0.095	8.10%	0.00%	8.10%	8.10%	-1.42	1.60	19.00	0.005	0.005
Pennsylvania Power	0.71	4.50%	12.90%	0.105	0.105	6.00%	3.00%	9.00%	9.00%	2.02	2.10	27.25	0.076	0.076
Portland General Cor	0.95	4.50%	12.90%	0.125	0.125	6.40%	4.00%	10.40%	10.40%	1.93	1.80	18.38	0.101	0.101
Potomac Electric Po	0.74	4.50%	12.90%	0.107	0.107	6.80%	2.00%	8.80%	8.80%	1.80	1.85	24.00	0.076	0.076
San Diego Gas & Ele	0.60	4.50%	12.90%	0.095	0.095	6.10%	2.50%	8.60%	8.60%	1.77	1.85	24.00	0.075	0.075
Southern	0.67	4.50%	12.90%	0.101	0.101	6.20%	3.00%	9.20%	9.20%	3.02	3.10	38.50	0.079	0.079
SCE Corp	0.66	4.50%	12.90%	0.100	0.100	6.50%	3.00%	9.50%	9.50%	3.32	3.65	44.00	0.079	0.079
Texas Utilities	0.67	4.50%	12.90%	0.101	0.101	7.10%	1.00%	8.10%	8.10%	3.26	3.55	43.00	0.079	0.079
Union Electric Comp	0.58	4.50%	12.90%	0.094	0.094	6.30%	2.00%	8.30%	8.30%	2.83	2.80	37.00	0.076	0.076
WI Energy Corp	0.66	4.50%	12.90%	0.100	0.100	5.20%	5.00%	10.20%	10.20%	1.67	1.90	26.50	0.067	0.067

Sources:

Beta - Merrill Lynch's U.S. Company and ADR Statistics; outlined data from Value Line.

Dividend Yield - Value Line

Dividend Growth - Merrill Lynch's U.S. Company and ADR Statistics; outlined data from Value Line.

EPS - 92 values from annual reports; 93 values from Value Line; outlined 1992 data from Value Line.

Market Value - As of 12/92 from annual reports; outlined data from Value Line.

Indicates where data has been changed.

Company	1993	1994	1995	1996	1997	PV 993-1995	Book Equity	B:M	CWIP	Notes
Atlantic Energy Inc.	143	146	120			341	792	0.66	0.282	
AEP	716	716	716			1,782	4,246	0.69	0.291	2
Baltimore Gas & Electric	431	430	408			1,054	2,535	0.77	0.319	
Boston Edison Company	250	195	200	205	210	539	840	0.68	0.436	
Carolina Power & Light	392	413	541			1,104	2,534	0.62	0.271	
Centerior	293	326	291			754	2,889	1.02	0.266	
Central Power & Light	176	129	101			342	1,438	0.61	0.145	
Cincinnati Gas & Electric Compa	233	233	233	233		579	1,655	0.78	0.274	1
CMS Energy	377	416	443			1,019	727	0.49	0.694	
Con Edison	658	670	646	621	630	1,637	4,887	0.70	0.236	
Detroit Edison	395	395	395	395	395	983	3,114	0.64	0.202	1
Dominion Resources, Inc.	777	702	702			1,814	4,131	0.64	0.280	1
DPL	80	90	105	105	107	228	1,000	0.49	0.112	
Duke Power	639	910	851			1,972	4,151	0.56	0.267	
Florida Progress Corporation	446	375	400	285	429	1,016	1,738	0.61	0.356	
FPL Group	960	960	840	830	880	*2,297*	3,836	0.58	0.347	
General Public Utilities	234	277	277			650	2,379	0.78	0.212	3
Houston Lighting & Power	417	417	417			1,036	3,285	0.55	0.174	1
Kansas City Power & Light	132	123	138	120	171	325	854	0.61	0.231	
New England Electric	375	465	320			966	1,486	0.59	0.386	
Niagara Mohawk Power	412	504	458	457	446	1,135	2,240	0.85	0.433	
NYSEG	261	296	248			668	1,586	0.74	0.310	
Northern States Power	381	438	438	438	438	1,037	1,622	0.60	0.383	1
Ohio Edison	320	320	320	320	320	796	2,408	0.68	0.225	1
Pacific Gas & Electric	1,555	1,687	1,818	1,884	1,901	4,174	10,091	0.61	0.253	
Pacificorp	735	685	687			1,750	2,908	0.63	0.377	
Pennsylvania Power & Light	438	544	358	0	0	1,117	2,367	0.57	0.270	
Portland General Corporation	100	100	100	100	100	249	724	0.86	0.297	1
Potomac Electric Power Compa	*285*	295	*295*	*280*	314	724	1,823	0.66	0.261	
San Diego Gas & Electric	252	313	416	432	437	800	1,449	0.52	0.289	
Southern	*1,066*	985	*1,088*	*1,122*	944	2,601	7,234	0.59	0.213	
SCE Corp	1,453	1,396	1,285			3,440	5,954	0.60	0.349	
Texas Utilities	640	650	880			1,780	6,591	0.71	0.191	
Union Electric Company	285	285	285	285	285	709	2,164	0.57	0.188	
WI Energy Corp	426	366	360	448	484	960	1,543	0.56	0.351	

Source: SEC 10K

Notes:

1 Values were given in the aggregate; annual #'s obtained by evenly prorating.

2 Only a value for 1993 provided; used 1993 value for 1994 and 1995.

3 Only a value for 1993 & 1994 provided; used 1994 value for 1995.

Input Variables Used to Construct D/E and NUG1,2,3

Company	Unadj Eq./Cap UE:C	Unadj Debt/Cap UD:C	NUG-Adj Debt/Cap AD:C	Common Equity EqC	Preferred Equity EqP	NUG-Risk Factor Alpha	Market Value MV	Book Value BV
Atlantic Energy Inc.	0.550	0.450	0.520	792	230	0.100	23.130	15.17
AEP	0.47	0.53	0.59	4,246	765	0.100	33.125	23.01
Baltimore Gas & Electric	0.570	0.430	0.470	2,535	565	0.100	23.000	17.63
Boston Edison Company	0.410	0.590	0.670	840	221	0.100	27.500	18.71
Carolina Power & Light	0.470	0.530	0.580	2,534	144	0.100	27.750	17.27
Centerior	0.430	0.570	0.587	2,889	718	0.100	19.875	20.22
Central Power & Light	0.540	0.460	0.470	1,438	279	0.100	29.000	17.65
Cincinnati Gas & Electric Compan	0.530	0.470	0.480	1,655	330	0.100	24.000	18.80
CMS Energy	0.390	0.610	0.700	727	163	0.300	18.375	9.09
Con Edison	0.600	0.400	0.470	4,887	641	0.100	31.000	21.85
Detroit Edison	0.410	0.590	0.600	3,114	334	0.100	33.000	21.10
Dominion Resources, Inc.	0.530	0.470	0.530	4,131	829	0.200	39.500	25.21
DPL	0.510	0.490	0.500	1,000	121	0.100	19.750	9.75
Duke Power	0.590	0.410	0.480	4,151	780	0.100	36.125	20.26
Florida Progress Corporation	0.540	0.460	0.490	1,738	216	0.100	32.625	19.85
FPL Group	0.510	0.490	0.580	3,836	551	0.100	36.250	20.99
General Public Utilities	0.531	0.469	0.592	2,379	465	0.125	27.625	21.46
Houston Lighting & Power	0.510	0.490	0.540	3,285	558	0.100	45.880	25.36
Kansas City Power & Light	0.510	0.490	0.500	854	91	0.100	22.750	13.79
New England Electric	0.567	0.433	0.699	1,486	223	0.100	38.500	22.88
Niagara Mohawk Power	0.420	0.580	0.620	2,240	460	0.150	19.125	16.33
NYSEG	0.510	0.490	0.510	1,586	267	0.100	31.000	22.85
Northern States Power	0.570	0.430	0.470	1,622	275	0.100	43.250	25.91
Ohio Edison	0.450	0.550	0.560	2,408	414	0.100	23.125	15.78
Pacific Gas & Electric	0.480	0.520	0.590	10,091	1,062	0.100	32.000	19.55
Pacificorp	0.440	0.560	0.570	2,908	636	0.150	19.000	11.90
Pennsylvania Power & Light	0.490	0.510	0.520	2,367	549	0.100	27.250	15.58
Portland General Corporation	0.490	0.510	0.570	724	152	0.200	18.375	15.87
Potomac Electric Power Company	0.530	0.470	0.500	1,823	274	0.100	24.000	15.75
San Diego Gas & Electric	0.490	0.510	0.580	1,449	131	0.100	24.000	12.55
Southern	0.502	0.498	0.543	7,234	1,359	0.100	38.500	22.86
SCE Corp	0.490	0.510	0.650	5,954	637	0.100	44.000	26.59
Texas Utilities	0.500	0.500	0.530	6,591	1,328	0.100	43.000	30.33
Union Electric Company	0.550	0.450	0.470	2,164	219	0.100	37.000	21.19
WI Energy Corp	0.580	0.420	0.460	1,543	98	0.100	26.500	14.97

Intermediate Variables (1): D/E and NUG1,2,3

Company	Unadj Debt/Eq UD:E	nug1	nug2	EqP/EqC Epc
Atlantic Energy Inc.	0.818	0.265	0.027	0.29
AEP	1.132	0.282	0.028	0.18
Baltimore Gas & Electric	0.754	0.132	0.013	0.22
Boston Edison Company	1.439	0.591	0.059	0.26
Carolina Power & Light	1.128	0.253	0.025	0.06
Centerior	1.326	0.094	0.009	0.25
Central Power & Light	0.852	0.035	0.003	0.19
Cincinnati Gas & Electric Compar	0.887	0.036	0.004	0.20
CMS Energy	1.564	0.769	0.231	0.22
Con Edison	0.667	0.220	0.022	0.13
Detroit Edison	1.439	0.061	0.006	0.11
Dominion Resources, Inc.	0.887	0.241	0.048	0.20
DPL	0.961	0.039	0.004	0.12
Duke Power	0.695	0.228	0.023	0.19
Florida Progress Corporation	0.852	0.109	0.011	0.12
FPL Group	0.961	0.420	0.042	0.14
General Public Utilities	0.885	0.568	0.071	0.20
Houston Lighting & Power	0.961	0.213	0.021	0.17
Kansas City Power & Light	0.961	0.039	0.004	0.11
New England Electric	0.763	1.558	0.156	0.15
Niagara Mohawk Power	1.381	0.251	0.038	0.21
NYSEG	0.961	0.080	0.008	0.17
Northern States Power	0.754	0.132	0.013	0.17
Ohio Edison	1.222	0.051	0.005	0.17
Pacific Gas & Electric	1.083	0.356	0.036	0.11
Pacificorp	1.273	0.053	0.008	0.22
Pennsylvania Power & Light	1.041	0.043	0.004	0.23
Portland General Corporation	1.041	0.285	0.057	0.21
Potomac Electric Power Compan'	0.887	0.113	0.011	0.15
San Diego Gas & Electric	1.041	0.340	0.034	0.09
Southern	0.990	0.197	0.020	0.19
SCE Corp	1.041	0.816	0.082	0.11
Texas Utilities	1.000	0.128	0.013	0.20
Union Electric Company	0.818	0.069	0.007	0.10
WI Energy Corp	0.724	0.128	0.013	0.06

Intermediate Variables (2):
D/E and NUG1,2,3

X / Common Book Equity
Debt/EqCnug1/EqCnug2/EqC

Company	D:Ec	N1c	N2c	B:M
Atlantic Energy Inc.	1.35	0.342	0.034	0.66
AEP	1.52	0.333	0.033	0.69
Baltimore Gas & Electric	1.15	0.162	0.016	0.77
Boston Edison Company	2.08	0.747	0.075	0.68
Carolina Power & Light	1.25	0.268	0.027	0.62
Centerior	1.90	0.117	0.012	1.02
Central Power & Light	1.21	0.042	0.004	0.61
Cincinnati Gas & Electric Compar	1.26	0.044	0.004	0.78
CMS Energy	2.14	0.942	0.283	0.49
Con Edison	0.89	0.249	0.025	0.70
Detroit Edison	1.70	0.068	0.007	0.64
Dominion Resources, Inc.	1.27	0.289	0.058	0.64
DPL	1.20	0.044	0.004	0.49
Duke Power	1.01	0.271	0.027	0.56
Florida Progress Corporation	1.08	0.122	0.012	0.61
FPL Group	1.24	0.481	0.048	0.58
General Public Utilities	1.25	0.679	0.085	0.78
Houston Lighting & Power	1.29	0.249	0.025	0.55
Kansas City Power & Light	1.17	0.043	0.004	0.61
New England Electric	1.03	1.792	0.179	0.59
Niagara Mohawk Power	1.87	0.302	0.045	0.85
NYSEG	1.29	0.094	0.009	0.74
Northern States Power	1.05	0.155	0.015	0.60
Ohio Edison	1.60	0.059	0.006	0.68
Pacific Gas & Electric	1.30	0.393	0.039	0.61
Pacificorp	1.77	0.064	0.010	0.63
Pennsylvania Power & Light	1.51	0.052	0.005	0.57
Portland General Corporation	1.47	0.344	0.069	0.86
Potomac Electric Power Compan	1.17	0.130	0.013	0.66
San Diego Gas & Electric	1.22	0.371	0.037	0.52
Southern	1.36	0.234	0.023	0.59
SCE Corp	1.26	0.904	0.090	0.60
Texas Utilities	1.40	0.153	0.015	0.71
Union Electric Company	1.00	0.076	0.008	0.57
WI Energy Corp	0.83	0.136	0.014	0.56

Regression Variables
D/E and NUG1,2,3

Company	X / Common Market Equity D:Em	NUG1	NUG2	% Energy NUG3
Atlantic Energy Inc.	0.883	0.224	0.022	0.010
AEP	1.053	0.231	0.023	0.000
Baltimore Gas & Electric	0.878	0.124	0.012	0.010
Boston Edison Company	1.415	0.508	0.051	0.100
Carolina Power & Light	0.777	0.167	0.017	0.065
Centerior	1.937	0.119	0.012	0.000
Central Power & Light	0.737	0.025	0.003	0.026
Cincinnati Gas & Electric Compar	0.989	0.034	0.003	0.000
CMS Energy	1.058	0.466	0.140	0.200
Con Edison	0.624	0.176	0.018	0.010
Detroit Edison	1.087	0.043	0.004	0.010
Dominion Resources, Inc.	0.808	0.185	0.037	0.078
DPL	0.592	0.022	0.002	0.002
Duke Power	0.568	0.152	0.015	0.008
Florida Progress Corporation	0.658	0.075	0.007	0.027
FPL Group	0.720	0.278	0.028	0.032
General Public Utilities	0.973	0.527	0.066	0.131
Houston Lighting & Power	0.715	0.138	0.014	0.160
Kansas City Power & Light	0.709	0.026	0.003	0.000
New England Electric	0.611	1.065	0.106	0.150
Niagara Mohawk Power	1.597	0.258	0.039	0.110
NYSEG	0.952	0.069	0.007	0.024
Northern States Power	0.630	0.093	0.009	0.013
Ohio Edison	1.095	0.040	0.004	0.000
Pacific Gas & Electric	0.796	0.240	0.024	0.240
Pacificorp	1.109	0.040	0.006	0.010
Pennsylvania Power & Light	0.866	0.030	0.003	0.098
Portland General Corporation	1.268	0.297	0.059	0.010
Potomac Electric Power Compan	0.768	0.085	0.009	0.001
San Diego Gas & Electric	0.641	0.194	0.019	0.060
Southern	0.810	0.139	0.014	0.000
SCE Corp	0.761	0.546	0.055	0.320
Texas Utilities	0.990	0.108	0.011	0.120
Union Electric Company	0.574	0.043	0.004	0.000
WI Energy Corp	0.471	0.077	0.008	0.000

Appendix B

Regression Results for Expanded Model

In section 3.3 we outlined the case for expanding our basic model to include potentially important variables that were not included in the original formulation. Previous studies have identified fuel mix and "regulatory climate" as among the more important sources of variation. We use the ratio of nuclear assets to total electric utility plant as a proxy for fuel mix, and Merril Lynch's rating of state public utility commissions as a proxy for "regulatory climate." In section 5.1 we summarize the important differences between the original regressions and this expanded model. In this appendix, we present the results of the expanded regression model.

Table B1. CAPM Results

	S1	N1	S2	N2	S3	N3
Intercept	0.0869	0.0859	0.0876	0.0864	0.0871	0.0860
	(9.875)	(9.386)	(9.985)	(9.387)	(9.985)	(9.447)
Debt/Equity	0.0067	0.0083	0.0071	0.0081	0.0062	0.0082
	(1.184)	(1.254)	(1.247)	(1.234)	(1.084)	(1.251)
NUG	-0.0026	-0.0012	0.0289	0.0247	-0.0108	-0.0104
	(-0.357)	(-0.154)	(0.463)	(0.353)	(-0.564)	(-0.427)
CWIP	0.0678	0.0551	0.0590	0 0.0514	0.0691	0.0547
	(4.012)	(1.956)	(2.876)	(1.881)	(4.133)	(2.052)
NUKE	-0.0023	-0.0028	-0.0029	-0.0028	-0.0010	-0.0020
	(-0.242)	(-0.276)	(-0.296)	(-0.272)	(-0.096)	(-0.189)
PUC	-0.0025	-0.0015	-0.0024	- 0.0016	-0.0027	-0.0015
	(-1.237)	(-0.567)	(-0.296)	(-0.587)	(-1.301)	(-0.557)
Adjusted R^2	0.4471	0.2229	0.4487	0.2258	0.4507	0.2274

Table B2. DCF Results

	S1	N1	S2	N2	S3	N3
Intercept	0.0688	0.0633	0.0708	0.0651	0.0689	0.0627
	(4.643)	(4.532)	(5.060)	(4.692)	(4.891)	(4.738)
Debt/Equity	0.0010	0.0214	0.0116	0.0200	0.0124	0.0217
	(1.024)	(2.126)	(1.279)	(2.014)	(1338)	(2.278)
NUG	0.0039	0.0079	0.1872	0.1220	0.0516	0.0656
	(0.313)	(0.660)	(1.879)	(1.159)	(1.674)	(1.847)
CWIP	0.0577	-0.0275	0.0207	-0.0294	0.0434	-0.0249
	(2.030)	(-0.639)	(0.632)	(-0.715)	(1.610)	(-0.642)
NUKE	0.0026	-0.0043	0.0011	-0.0032	-0.0048	-0.0097
	(0.157)	(-0.275)	(0.072)	(-0.207)	(-0.297)	(-0.638)
PUC	-0.0002	0.0062	0.0010	0.0058	0.0002	0.0061
	(-0.060)	(1.514)	(0.306)	(1.432)	(0.073)	(1.542)
Adjusted R^2	0.1514	0.0482	0.2409	0.0787	0.2235	0.1413

Table B3. EPR Results

	S1	N1	S2	N2	S3	N3
Intercept	0.0662 (3.448)	0.0596 (3.249)	0.0680 (3.800)	0.0623 (3.419)	0.0646 (3.694)	0.0578 (3.107)
Debt/Equity	0.0096 (0.783)	0.0240 (1.817)	0.0122 (1.059)	0.0210 (1.607)	0.0117 (0.935)	0.0234 (1.743)
NUG	0.0169 (1.060)	0.0216 (1.380)	0.3000 (2.352)	0.2311 (1.670)	0.0476 (1.144)	0.0479 (0.959)
CWIP	0.0229 (0.622)	-0.0816 (-1.446)	-0.0261 (-0.625)	-0.0774 (-1.431)	0.0225 (0.617)	-0.0612 (-1.121)
NUKE	0.0166 (0.785)	0.0081 (0.392)	0.0153 (0.772)	0.0106 (0.523)	0.0110 (0.501)	0.0051 (0.240)
PUC	-0.0037 (-0.819)	0.0042 (0.777)	-0.0015 (-0.359)	0.0033 (0.625)	-0.0031 (-0.677)	0.0039 (0.705)
Adjusted R^2	0.0390	0.0602	0.1618	0.0882	0.0449	0.0271

Table B4. Adjusted R^2 for 3 and 5 Variable Specifications

	Case	3 Variables	5 Variables
CAPM	S1	0.4521	0.4471
	N1	0.2632	0.2229
	S2	0.4562	0.4487
	N2	0.2653	0.2258
	S3	0.4543	0.4507
	N3	0.2697	0.2274
DCF	S1	0.2054	0.1514
	N1	0.0385	0.0482
	S2	0.2872	0.2409
	N2	0.0766	0.0787
	S3	0.2714	0.2235
	N3	0.1273	0.1413
EPR	S1	0.0664	0.0390
	N1	0.0945	0.0602
	S2	0.1983	0.1618
	N2	0.1241	0.0882
	S3	0.0877	0.0449
	N3	0.0721	0.0271

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