Market-Based IRP: It's Easy!!!

Making incorrect decisions in this period of restructuring transition could leave utilities with more inefficient plant or costly purchased-power contracts, either of which will increase stranded investment problems. Proper market-based valuation is not just a monopoly-based IRP issue: It affects decision making in a competitive environment even more profoundly.

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Integrated resource planning offers a way to compare a wide range of resource alternatives in a balanced manner. But IRP valuations are severely flawed: They do not permit balanced comparisons between unlike resources because they use incorrect, biased discount rates. Although discount rates must reflect financial risk, utilities typically use their weighted average cost of capital (WACC) as a proxy rate even though it is fundamentally wrong for comparing IRP alternatives.

Estimated discount rates probably did not affect resource choices in the past because the alternatives were similar to each other.[1] Today's resource alternatives, however—gas-fired turbines, DSM, renewables, purchased power and coal-fired base load plants—are technologically and institutionally diverse. If appropriate discount rates are used, the rank order of choices most likely will change from the order determined using the WACC as a discount rate.

I. Competition Increases the Need for Sound Valuation

The applicability of market-based valuation procedures described in this article is not limited to monopoly-based IRP; indeed they affect decision making in a competitive environment even more profoundly.

Regulatory oversight is not likely to disappear in the near future, even as we move to partial competition.[2] In such an environment, correct valuation of resource alternatives, including power-purchase options, becomes crucial. The use of conventional engineering-oriented analysis by utilities and regulatory bodies will only continue the current perceived preference for gas and other fossil fuels over renewable technologies.[3]

Some contend that IRP valuation becomes irrelevant under a competitive model since utilities will simply purchase power from the lowest-cost providers. These decisions, however, will require sophisticated valuation procedures, which are more complex than, say, price comparing the firm's contract for stationery or cleaning supplies. Fuel and power contracts invariably require the valuation of uncertain future cost streams whose financial properties will vary with the underlying generation technology—whether owned by a utility or an outside provider.

Sub-optimal resource acquisitions in the current transition period could leave utilities with more inefficient plant or costly power-purchase contracts, which increase future stranded-investment problems. Correct valuation affects decision making in a competitive environment even more profoundly for two reasons:

(1) The cost of mistakes increases in a competitive environment; absent monopoly power, investment errors ultimately have a more dramatic impact on sales; and (2) The range of resource options, each with unique financial characteristics, dramatically increases, thus increasing the complexity of valuation requirements. This is not unlike the problem faced by financial analysts and investors who must correctly value a broad spectrum of investment alternatives (using risk-adjusted procedures) to assemble optimal portfolios.

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It is naive to expect that the mere act of developing competitive markets will bring with it brilliant (or even "correct") investment analysis. Competition does not ensure this: Witness the near collapse of the U.S. steel industry and the loss of pre-eminence by U.S. automakers. Numerous observers have attributed these failures to myopic capital-budgeting analyses which indicated that continued use of existing process technology was the "least-cost" strategy. As a consequence, decision makers deferred important strategic investments until it was too late to maintain world competitive leadership. Similar analytic flaws have hampered diffusion of other new process technologies.

Even as we move to a restructured environment, it is important to continue to develop theoretically appropriate valuation procedures. A competitive market, with no fuel-adjustment clause, will increase utilities' needs for appropriate valuation tools.

This article gives regulators and utility managers an intuitive understanding of why the WACC is an inappropriate discount rate and shows the consequences of using it. The article also provides a range of appropriate IRP discount rates, which are estimated using standard, noncontroversial finance procedures that are widely taught and widely used in unregulated firms. IRP procedures *must* include a process for estimating appropriate discount rates.

The basic reason that the WACC is wrong is that it measures something fundamentally different from what regulators and managers want to know: It reflects the investors' assessment of their discount rate or required rate of return. But regulators and managers want to know what a resource plan will cost. The financial risks associated with IRP cost streams, which must form the basis for IRP discount rates, are significantly different from the risks associated with the returns on utility debt and equity, which form the basis for the WACC. While many think that sensitivity analysis properly handles the issue of IRP risk, the fact of the matter is that it does not.

Utility planners are used to the idea of valuing (discounting) all IRP cost streams at a firm's WACC even though this produces results that have no economic interpretation—sort of like using the wage history of, say, tailors in Hong Kong, to estimate the firm's future O&M costs. Using the WACC in this manner makes little sense and is contrary to modern finance theory, which values uncertain future cash flows using market-based rates derived from a capital asset pricing model (CAPM).[4]

This finance approach is in sharp contrast to *engineering economics* procedures used by utility planners. These make no attempt to reflect risk properly and, instead, use the WACC as a *proxy*. Although planners and regulators are increasingly aware that this approach is incorrect, they continue to base decisions on the results the WACC provides and seem reluctant to embrace the more reliable finance-oriented approaches, apparently hoping that the associated errors are not too serious. As we shall see, however, using the WACC leads to highly biased IRP results.

Section II, below, discusses, in an intuitive manner, why the WACC is the wrong discount for IRP. Section III describes the essential elements of market-based discounting and presents a set of risk-adjusted discount rates for major IRP cost categories, thus enabling planners to immediately test the effect that correct discounting would have on IRP decisions. Section IV discusses the results of applying proper discounting to a recent IRP plan, and Section V concludes.

II. The Problem with the WACC

Generally speaking, the WACC is not relevant to evaluating IRP alternatives and there is no role for it in valuing IRP cost streams.

The evidence in support of this assertion is basically irrefutable: It includes textbooks references, numerous papers in leading academic journals and several complete Electric Power Research Institute volumes on proper discounting of cost or revenue requirement streams. [5] This literature concludes quite plainly that the WACC is inappropriate for valuing IRP cost streams, which have heterogeneous risk characteristics, and hence must each be valued at a discount rate that reflects its own risk—i.e., each resource must be discounted at its own risk-adjusted discount rate.

The use of different discount rates for different specific project cost components is widespread in finance. You get better results when you group costs into separate risk categories and discount each at its own appropriate risk-adjusted discount. If the various cost categories are homogeneous with respect to risk, then the categories can be collapsed into a single discount rate.[6] Even in this case such a "composite" discount rate will most likely be very different from the WACC.

The WACC is a weighted average of the required market cost of debt and equity—the market's discount rate for the investors' *net cash flows* (earnings, interest payments, deferred taxes and depreciation), thus reflecting the firm's business risk as leveraged by its debt.

The following four subsections illustrate the flaws of the WACC in greater detail.

A. The WACC Is Precisely the Wrong Rate

The WACC can probably be estimated with more accuracy than the market-based discount rate for a particular IRP cost. Yet estimation precision does not make the WACC the correct discount for IRP cost streams: It is the proverbial right estimate of the wrong rate, as illustrated below.

Let's assume that all utilities in the U.S. use the same expected fuel price in their planning and that each discounts this forecast at its own WACC, so that each obtains a different WACC-based present value cost. This means that the same *expectation*—future fuel prices—has a different value to each firm, even though the fuel is purchased in a single commodity fuel market at a single price.

Furthermore, since the WACC varies directly with the firm's business and financing risk, this fuel price expectation is worth more to lower-risk firms (having a lower WACC), leading us to the somewhat absurd conclusion that the present value fuel cost varies for each firm as a function of the risk of its asset portfolio and the level of its indebtedness.

This conclusion obviously makes little sense. Projected fuel prices have a *unique* market value that is independent of the purchaser's cost of capital, and depends only on the systematic risk of the projected cost stream. In other words, fuel futures must trade at a single price which reflects the futures-market's consensus of the risk involved. Although different buyers may have different perceptions of the systematic risks involved, their WACC—the average return on the rest of their portfolio—is irrelevant.

B. The Crux of the Matter: How the WACC Distorts Results

Traditional WACC-based IRP procedures can lead to pretty silly results because they fail to recognize simple risk differentials that materially affect present value. This point is illustrated by **Table 1** using projected fuel outlays from a recent IRP filing. Column A shows the projected gas outlays; these will obviously vary with changing gas prices. Consistent with the common practice, the IRP filing discounts these outlays at the WACC (9.4 percent) for a present value of about $388 million.

Now let's consider a hypothetical case under which one of the firm's suppliers is willing to deliver the needed gas at a *fixed price* that is 20 percent above the prices used in Column A (see Table 1, Column B). If the supplier is substantial enough so that the default risk of the contract offer can be ignored, then the gas outlays under this guaranteed fixed-price contract are riskless.

Standard IRP procedure would value this fixed-price offer just as it does the variable-price outlays of Column A—it would discount the fixed annual outlays at the WACC. Since the fixed prices are higher, their present value will be higher as well—$466 million as compared to $388 million for the spot-price projections. This result will therefore convince planners that the fixed-price contract is not the "least-cost" alternative.

But the WACC-based comparison makes little sense. It is equivalent to an investor concluding that junk bonds are a better deal than U.S. Treasury bonds on the basis that they are expected to pay 12 percent—$120 per year for each $1000 investment—while U.S. obligations pay only 6%, thus requiring a *$2000* investment to yield $120. Obviously this investor needs to consider the risk differentials prior to committing his or her portfolio to junk bonds on the expectation that these will yield more retirement income. The

Table 1: Valuing Projected IRP Gas Outays (Spot Prices Versus a Fixed-Price Contract)

	Annual IRP Gas Expense ($ Millions)	
Year	A Given Projected Spot Prices	B Given Fixed- Price Contract
1992	$0.5	$0.6
1993	$0.5	$0.6
1994	$0.9	$1.1
1995	$1.0	$1.2
...	...	...
2009	$147.5	$177.0
2010	$143.0	$171.6
2011	$136.2	$163.5
2012	$160.6	$192.7
Present Value Analysis		
1. WACC-Based Results:		
WACC	9.4%	9.4%
WACC-Based Value	**$388.0**	$466.0
2. Market-Based Results:		
Appropriate Discount Rate	0.60%	3.0%
Market-Based Value	$1,260.0	**$1,072.3**

WACC-based IRP approach similarly ignores the obvious risk differences between the two fuel cost streams which can only be valued using a market-based approach.

Under a market-based approach, the riskless fixed-price contract is easy to value: Its annual costs (Column B) are guaranteed and default by the supplier is so unlikely that the possibility can be ignored. Do these conditions sound familiar? Indeed this contract sounds a lot like a riskless U.S. treasury bond, which means that its expected costs must be discounted not at the WACC, but at the post-tax riskless rate of return paid on U.S. Treasury obligations.(This rate is estimated later at three percent.)

Now we can correctly compare the fixed-price offer to the spot-price outlays. The correct present value of the fixed contract, estimated using a discount rate of three percent, is $1,072 million. This is the price at which this riskless futures contract would trade in the capital markets, implying that anyone could buy it with capital raised at the riskless rate.

The variable-price gas stream must also be valued at its risk-adjusted discount rate (0.6 percent, as derived subsequently). So doing yields a present value of $1,260 million. The market-based analysis therefore suggests that the fixed-price contract is somewhat more attractive.

The market-based results of Table 1 lead to two important conclusions:

(1) The true present value cost of the spot-price outlays is more than triple the WACC-based estimate ($1,260/$388) so that the WACC significantly understates the cost of gas-based generation;

(2) The expected cost of the fixed-price contract is $188 million less than the spot-price outlays, yet the WACC-based approach indicates that it is expected to cost more! In a sense, this is how the WACC biases against low-risk renewables and in favor of higher-risk fossil-based generation. The relative costs of

fossil-based resources can only be understood by discounting all IRP cost components at their appropriate market-based discount rates.

C. The WACC Reflects the Risk of the Firm's Net Cash Flows, Not its Costs

The WACC reflects the risk of the firm's net cash flows, since it is the investor's required return, or discount rate, for those cash flows. It makes no sense to use this rate to value the firm's costs. This section illustrates this point by showing how revenues, costs and net cash flows interact. It also illustrates a second point: why the cost streams of very risky projects must have discount rates *below* the riskless rate. The illustration is based on three hypothetical firms (**Figures 1, 2 and 3** on next page). I overview the three figures first, and then discuss each in more detail.

The three firms have identical revenue streams: Each averages $150, which is therefore its *expected* value. However, as shown in Figures 1, 2 and 3, the revenues are risky: They rise and fall with cycles in the economy and their peaks and troughs are not predictable.

By contrast, the firms have different cost streams, even though the expected (average) cost in each case is $120. The firm in Figure 1 has costs that follow the revenues so that net cash flows (revenues minus costs) are riskless. That is, even though neither the revenues nor the costs is exactly predictable, we know they move in unison, thus producing riskless profits.

The shape of the cost streams changes as we move to Figure 2, which shows a cost stream that is riskless: It is always $120, independent of the state of the economy (and hence the revenues). The costs in Figure 3 are also not predictable. They move directly *opposite* to the revenues—we only know that they will rise when revenues fall.

As a result of the changing *time-shape* of the cost stream, the net cash flow becomes increasingly risky as we move from Figure 1 to Figure 3. The net cash flows in Figure 1 are riskless—they are always $30 independent of the economy. The net cash flows in Figures 2 and 3 also average $30, but are riskier because they fluctuate unpredictably.[7] Since the expected net cash flow is the same—$30 for each firm—investors would obviously prefer the less risky firm in Figure 1.

For the sake of illustration, we might assume that the annual percentage variation in the revenue streams equals the year-to-year variability of returns to a broadly diversified market portfolio (e.g., a Standard & Poor's Index Fund), and arbitrarily assign a 10-percent rate of return to such a portfolio (see **Table 2** on next page).[8] This allows us to set the required return or discount rate for the revenues at 10 percent as well, since we have assumed that their risk equals that of the broadly diversified portfolio. We can now see whether the utility practice of valuing cost streams at the WACC makes any sense.

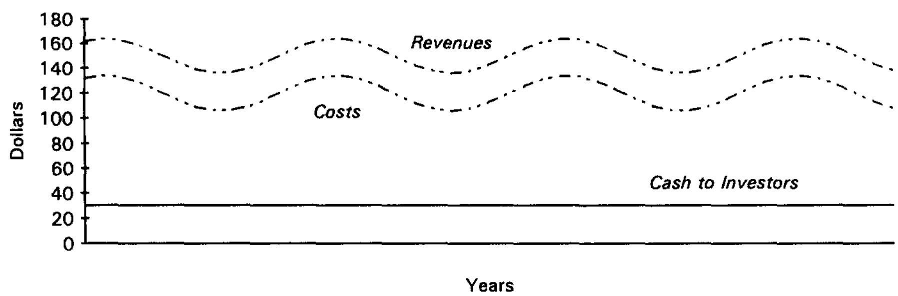


Figure 1: Risky Revenues and Costs with Riskless Net Cash Flows

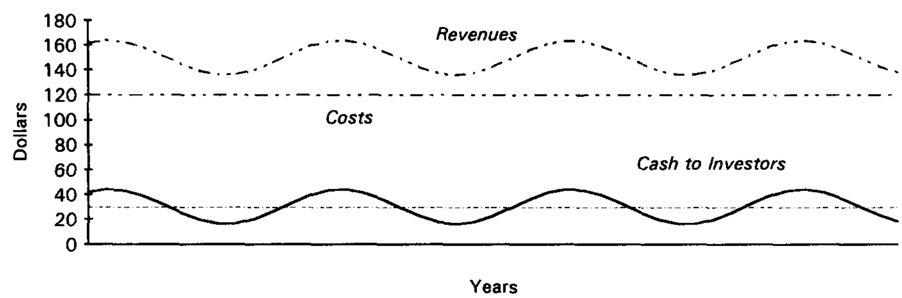


Figure 2: Risky Revenues, Riskless Costs and Risky Net Cash Flows

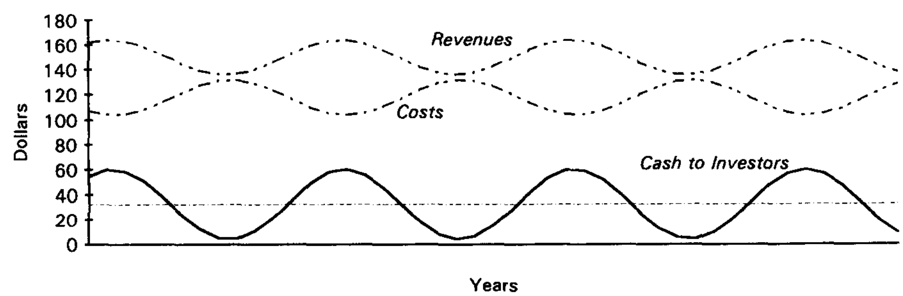


Figure 3: Risky Revenues with Counter-Cyclical Costs

Figure 1: Risky Costs and Riskless Profits

The costs associated with this firm's projects are $120 on average, but they are risky. In fact, they are riskier than the revenues because they show a greater *percentage* change, year to year (they fluctuate by approximately $30, or 25 percent, around a mean of $120 while the revenues fluctuate equally around a mean of $150, a 20 percent variation). This might suggest a discount rate for the costs in the range of, say, 12 percent, as compared to the 10 percent we have set for the revenues. However, as previously discussed this firm is able to produce a constant net cash flow to investors because the costs follow the revenues closely. This firm has no fixed costs—only risky variable costs. So while the firm's costs and revenues are both risky, the firm is *riskless* from the investor's perspective since it produces a constant $30 profit stream during both good and bad economic times.

What would be the cost of capital or the WACC for this firm? It would have to be at, or very near, the riskless rate earned on U.S. government obligations since, to

Table 2: The Relationship of Risky Cash Flows and Discount Rates in Figures 1-3

	Figure 1	Figure 2	Figure 3
I. Revenues			
Assumed Risk Level (Variability)	Percent annual variability similar to broad market index	Percent annual variability similar to broad market index	Percent annual variability similar to broad market index
Trend	Cyclical	Cyclical	Cyclical
Illustrative Pre-Tax Discount	10% (6% riskless + 4% risk-premium)	10% (6% riskless + 4% risk-remium)	10% (6% riskless + 4% risk-premium)
Illustrative Post-Tax Discount[a]	7%	7%	7%
II. Costs			
Assumed Risk Level (Annual Variability)	Somewhat greater than revenues	Constant—No annual variability	Somewhat greater than revenues
Trend	Cyclical	Constant	Counter-Cyclical
Illustrative Pre-Tax Discount	12% (6% riskless + 6% risk premium)	6% (riskless rate)	0% (6% riskless - 6% risk premium)
Illustrative Post-Tax Discount[a]	9%	4%	0%
III. Net Cash Flows			
Assumed Risk Level (Annual Variability)	Constant	Riskier than broad market index	Much riskier than broad market index
Trend	Cyclical	Cyclical	Cyclical
Illustrative Pre-Tax Discount or WACC	6% (riskless)	18%	24%
Illustrative Post-Tax Discount or WACC[a]	4%	12%	16%

a. Assumes 33% tax rate

an investor, the annual returns from this firm seem riskless. We have arbitrarily set the riskless rate at 6 percent, pre-tax (see Table 2).

An important point of Figure 1 is this: The firm's managers would be committing a grave error if they used the WACC to value the costs of a proposed project addition. Quite simply, the WACC of this firm is at or near the riskless rate (4 percent post-tax, see Table 2), but the project costs certainly are not riskless and should therefore be discounted at a rate above the riskless rate (i.e. nine percent post-tax). Using the four percent post-tax WACC to discount the costs will therefore *overstate* their present value (because smaller discount rates raise present values). By overstating costs in this way, the WACC will therefore lead to the rejection of new projects that are cost effective.

Figure 2: Constant (Riskless) Costs, Risky Profits

The firm in Figure 2 has the same revenue stream, but invests in projects that have no variable costs—all the costs are known and fixed at $120 over time, independent of economic activity. The difference between this firm's risky revenues and *constant* costs is a risky net cash flow stream that fluctuates with economic cycles. This illustrates an important point—constant or "riskless" costs are not riskless to the firm when revenues fluctuate cyclically. Indeed the firm is made *riskier* to investors by the fixed costs as compared to the variable costs of Figure 1.

This is similar to the risk a homeowner faces when he or she obtains a mortgage. The payments are fixed and must continue even if the owner becomes unemployed. However, a mortgage that allowed the borrower to skip payments in the event of unemployment would better track income (revenues), just like the costs of Figure 1, and hence would be more desirable to the borrower. Indeed some borrowers would be willing to pay a higher interest rate for such a recession-proof mortgage, implying that they would discount its costs at a *higher* rate. The lender, too, would use a higher rate, since the proceeds of such a loan are riskier than a fixed-payment loan—the borrower is likely to miss making payments during bad economic times.

This mortgage example illustrates that: (1) a fixed payment stream is riskier to the borrower (and less risky to the lender) than an income-tracking payment stream; (2) both borrower and lender discount the fixed payment stream at a lower rate; (3) both borrower and lender discount the variable, income-tracking payment stream at a higher rate. Similarly, the revenue-tracking costs of Figure 1 are like the recession-proof mortgage: They decline when the firm's income declines and are hence less risky and more desirable to the firm. They are discounted by the firm at a higher rate, and hence have a lower value than the fixed costs of Figure 2.[9]

The WACC in Figure 2 would appear to lie well above the riskless rate of return (and, it would appear, above the 12 percent we assigned to the costs of Figure 1). Let's assume, again for illustration only, that the WACC or required investor return in Figure 2 is 18 percent.[10] So while the costs in Figure 2 have a smaller discount, the profits have a higher one. If managers used the 12 percent post-tax WACC to discount project costs they would be significantly *understating* them relative to their correct valuation at the riskless rate. This might lead managers to accept projects that should be rejected.

Figure 3: Counter-Cyclical Costs, Very Risky Profits:
The costs in Figure 1 are cyclical, while those in Figure 2 are constant. Figure 3 continues the trend by showing the case of *counter-cyclical* costs. These are especially risky: Even though they average $120, as before, they *rise* as the economy (and hence the firm's sales) decline. This yields a profit stream that averages $30, as before, but is *considerably* more risky because the year-to-year percentage fluctuations are greater.

Fuel is a commodity with counter-cyclical costs. The discount rate for such cost streams lies *below* the riskless rate. This happens because counter-cyclical costs have a negative financial beta[11]—but it also has intuitive appeal since it continues the trend of

lowering the discount on costs as the firms gets riskier. The intuition is as follows:

(1) The cost streams have gone from cyclical in Figure 1, to constant (Figure 2), to counter-cyclical (Figure 3);

(2) As they have gone from cyclical to counter-cyclical these costs have served to make the firm steadily riskier;

(3) Over this range the discount on costs has decreased steadily. It has gone from 12 percent (6 points above riskless) in Figure 1, to 6 percent, the riskless rate, in Figure 2;

(4) This trend continues into Figure 3 where the discount will lie *below* the riskless rate;

(5) We can estimate this rate more closely: The costs in Figure 3 have the same variability as the costs in 1, but the trend is reversed so that the discount will now be six points *below* the riskless rate, just as the discount in Figure 1 was six points above the riskless.

Now we turn to the WACC in Figure 3. It is riskier and hence must be above the WACC of Figure 2. Let's assign it a value of 24 percent because the profits are so risky. In the absence of automatic fuel adjustment, the WACC for utilities would also have been higher historically,[12] absent managerial strategies to control fuel-price risk.

What happens if we use this WACC to value costs? We would be using a discount of 16 percent (post-tax, see Table 2) when we should be using zero percent. This has the effect of arbitrarily understating the present value of the costs, which, in turn, means that we would accept projects that might otherwise be rejected. In other words, the standard WACC-based procedure masks the true cost of the Figure 3 expenses. The situation is similar to the case of Figure 2, only worse.

Figure 3 is analogous to fossil-based technologies, where fuel costs are discounted at the WACC, thereby masking their true cost. This practice seems especially meaningless since gas outlays—the riskiest IRP cost streams—are generally not even reflected in the WACC as a result of automatic fuel adjustment clauses which eliminate this as a risk to shareholders.[13]

And although these counter-cyclical fuel costs have been discussed in terms of the firm, the picture is no different for ratepayers. Ratepayers have cyclical income streams not dissimilar to the revenues of Figure 1. During good economic times ratepayers feel, and are, wealthier—their homes have greater value as do their other investments, which increases their borrowing capacity. When fuel price movements are plotted against personal income they look roughly similar to the costs in Figure 3. The fuel adjustment clause doesn't change risk, it only allocates it between shareholders and ratepayers.

D. Why Regulators Might Continue to Rely on WACC-Based IRP Results

While WACC-based present values have no economic meaning in an IRP context, as we have seen, it seems that regulators and planners continue to rely on them. They may be doing so for several reasons:

1. ***Regulators and planners hope that using WACC-based present values is OK.*** After all, "it has always been done this way." This leads to the feeling that the errors created are only of academic interest, and that relying on WACC-based results will not significantly affect decision making.

In fact, the WACC is not OK, although it may have been satisfactory in the past in an environment of homogeneous technology options. It can readily be shown that in such a setting, using the WACC as a proxy rate probably worked fairly well, in that it did not alter decision outcomes—i.e., the resource selection decision was probably independent of the discount rate used.[14]

But this is not the case today, given the broad range of technological options with varying risk characteristics. For example, the evidence suggests that the true market-based present value of future gas payments is at least *double* the WACC-based present values most commissions use in IRP. This leads to misallocation of resources because gas-based generation appears less costly than it really is relative to other options. In fact, using the WACC *systematically* biases IRP results in favor of fuel and maintenance cost streams, which makes expense-intensive, fossil-based technologies appear less costly relative to capital-intensive renewables and DSM.

For example, the evidence suggests that the true market-based present value of future gas payments is at least double the values most commissions use in IRP.

Some practitioners think that WACC-based results are OK if we ignore the fuel price risk, but this is not so; the WACC is incorrect even if projected fuel prices are assumed to be certain.[15] Moreover, the WACC also understates the cost of other relatively fixed outlays as was illustrated in Figure 2. For example, it underestimates the true, market-based present value of coal outlays, which are relatively "safe," by about 40 percent and the cost of fixed maintenance outlays by 20 percent. The point is that the WACC is inappropriate for virtually all IRP cost streams. It is *not OK*—even for relatively riskless or fixed-cost streams.

2. ***Regulators and planners assume that sensitivity analysis is the cure for a flawed WACC-based present value analysis.*** If the WACC is incorrect, then "sensitivity analysis" will show this by testing how sensitive the results are to changes in assumptions.

In fact, sensitivity analysis is an engineering concept that cannot rehabilitate a defective present value estimate. There is very little that sensitivity analysis can do to correct the mistaken picture obtained when the true present value of a stream of gas payments is double the value estimated with a flawed WACC-based approach.

Sensitivity can help identify the most sensitive parameters in an analysis *if*: (i) it is performed at the correct discount rate;[16] (ii) the cross-correlation among variables is correctly specified so that the analysis does not examine nonsense scenarios such as higher fuel prices coupled with higher demand or lower fuel prices coupled with higher discount rates; (iii) the sensitivity ranges are based on some historic movement of the parameters—e.g., the standard deviation of gas prices is about 38%[17] versus 20% for coal. A 10% sensitivity range for both fuels thus represents a full standard deviation for coal but only a one-half standard deviation for gas; it does not contain much useful information.

3. ***Regulators and planners think that market-based discounting is too complex***— i.e., that finance theory is not accessible to most engineering-oriented system planners.

Capital market theory is the basis of modern finance. Several economists who made significant contributions towards its development were awarded the Nobel Prize in Economic Science in 1990.[18] Yet it is not necessary to be conversant in capital market theory in order to use market-based discount rates. Indeed the remainder of this paper presents a practical approach to correct IRP discounting without getting into the details of the CAPM.

E. Risk-Adjusted Discounting: An Overview

Risk, as it pertains to IRP, can be thought of as the annual variability in a particular IRP cost stream. However, risk involves not just the degree of variability, but, as we saw in Figures 1, 2 and 3, it reflects the extent to which the cost stream co-varies *systematically* with the returns that would be obtained on a broadly diversified portfolio of assets.[19] This measure of risk, called *systematic risk*, is the basis for valuing assets. In the case of common stock, the systematic risk is statistically measured by an equity beta.

Fuel is a high-risk cost stream. It is risky not just because fuel prices fluctuate over time, but, as Figure 3 illustrated, because they do so in a negative systematic manner relative to the economy and the returns on other assets. When fuel prices rise, the economy, and hence returns to other assets, decline. This systematic covariance is important. A cost stream, such as fuel, that co-varies *negatively* with the economy produces the worst possible set of expectations for the firm and its ratepayers since this cost will be at its highest when the economy is doing poorly, and ratepayers are feeling the pressures of recession—low incomes and depressed home values.

Fuel is a high-risk cost stream, not just because fuel prices fluctuate over time, but because they do so in a negative manner relative to the economy.

Many IRP cost streams are more constant year to year and hence less risky—for example, fixed maintenance and various contractual obligations will exhibit less systematic variation relative to returns on a broadly diversified market portfolio. The firm will have to cover its fixed maintenance and similar obligations each year unless it experiences financial problems. The risk of these costs is therefore similar to the risk on the firm's obligation for paying long-term interest. As a consequence, they can be valued (discounted) at the firm's post-tax cost of debt. Capital-intensive renewables, such as photovoltaics, are less risky because the costs are almost entirely in the form of up-front capital outlays, thus eliminating any systematic risk.

The market-based present value of a risky cost stream such as fuel will be higher than an equal, but less risky fixed-maintenance stream, indicating that the risky stream is less desirable. This can be observed in the case of home mortgages where borrowers voluntarily pay a premium for fixed- over adjustable-rate mortgages (ARMs), which are probably riskier to them.

Market-based discounting represents a *financial economics* approach to valuation which differs from the traditional engineering economics (WACC-based) approaches used in IRP. Finance uses the term *present value* in a market-oriented sense, as the *mar-*

ket value of a future stream of benefits or costs. For example, the present value estimate of the fixed contract in Table 1 can be interpreted to mean that this contract would trade for $1.072 billion—assuming the estimate is correct.

Estimating the present value of a cash flow stream therefore entails estimating its market-based discount rate. This is true for all cash flow streams, whether a projected fuel outlay or expected dividend stream. In the case of the dividend stream, the present value is readily observable: It is the price of the share of stock. Stock price, therefore is a futures price on the dividend stream which enables us to estimate the implied discount rate directly.

In the case of most IRP cost streams we cannot observe a futures price directly, although we can usually estimate the discount rate by comparing the cost stream to some other cost stream, *e.g.*, the firm's interest payments, which has a known level of systematic risk *and* a known discount rate. This procedure yields reasonably reliable results for the fixed-cost categories such as fixed maintenance and contractual obligations.

In the case of fuel outlays, however, there are no direct comparisons and a beta estimate is usually required.[20] Beta is the mathematical measure of systematic risk—it is the expected percentage variation in the IRP cost stream when returns to a broadly diversified portfolio change by 1%. A beta for fuel and a range of appropriate fuel discount rates is given later,[21] although this paper does not address beta estimation in detail.

F. Engineering Economics—Use of Proxy Discount Rates

Engineering economics defines present value mechanistically, as the result of a discounting computation *at a given discount rate.* The present value idea in engineering economics is therefore generic and arbitrary. Analyses sometimes give several "present values" computed at different arbitrary discount rates, giving the idea that the discount rate is simply a parameter which can be varied to see how the results come out. Another common practice in engineering economics is to use the WACC of the project sponsor as a *proxy* discount.

These engineering economics concepts were developed more than 50 years ago[22] as a practical means for engineers to select between project alternatives: an escalator versus an elevator, a large electric motor as compared to a smaller motor with a fly wheel, and, perhaps in simpler times, a coal-fired versus an oil-fired plant. The approach yields rule-of-thumb answers which sufficed in a previous technological era, but which are not sufficiently refined to provide reliable decision support in the case of IRP which involves complex project alternatives with highly diverse risk characteristics.

III. The Essentials of Market-Based IRP Valuations

This section of the article lays out the essential steps to estimating market-based discount rates. The procedure involves categorizing the IRP outlays into distinct risk categories. Generally speaking these categories are:

(1) *Gas Fuels*: These have counter-cyclical risk in the sense that higher fuel prices have historically caused the economy, and hence the returns on other assets, to decline. While the fuel-adjustment clause shifts fuel-price risk away from shareholders and onto ratepayers, this does not eliminate the risk and regulators must deal with it. Using historic risk measures, the CAPM post-tax discount rate for this category ranges from about 1% to about 3%.[23]

(2) *Other Riskless Costs*: Depreciation tax shelters and other tax benefits are essentially riskless—they will accrue as long as the firm continues to operate. Coal prices also appear to be systematically riskless historically (although this does not mean that use of coal involves no uncertainties). In some cases it may also

make sense to assume that future gas prices are riskless. The discount rate for this category is the post-tax riskless rate of return, currently about 3%.

(3) *Debt-Equivalent Costs*: Fixed maintenance and fixed contractual obligations fall into this category. Such outlays will be made as long as the firm generates sufficient income to cover them, which is similar to the default risk on the firm's bonds. This means that debt-equivalent costs should be discounted at a rate close to the firm's post-tax cost of debt— estimated at 5.3 percent for A-rated utilities.

(4) *Cyclical Costs:* This category includes variable O&M which rises and falls with output and with levels of economic activity. Where these outlays are significant relative to the others it may make sense to estimate the discount rate more precisely using a beta estimate. Otherwise, the post-tax WACC, a cyclical discount rate, can be used as a proxy.

A. Estimating Risk-Adjusted IRP Discount Rates

Deriving risk-adjusted discount rates involves correctly categorizing the risk of the cost stream and then applying the discount rates shown in **Table 3**. These are generally applicable in today's environment and, while they may change somewhat in a particular situation, they are undoubtedly better than using the WACC. These values may also change over time as inflation affects financial rates of return but they can easily be adjusted by re-estimating the corporate cost of debt and the riskless rate as discussed later. We can begin with the two easiest rates to estimate—the rates for debt equivalents and riskless outlays.

1. *Estimating the Discount Rate for Debt Equivalents.* Estimating the present value of debt equivalents is simple. Any cash flow whose risk is similar to the default risk on the firm's debt would be discounted at the firm's post-tax cost of debt. For example, this approach is commonly used for valuing leases, which are considered debt equivalents.[24]

A number of IRP cost categories —e.g., fixed maintenance and fixed contractual obligations, are also debt equivalents. The fixed payments of these categories are discounted at the post-tax cost of debt, 5.3 percent (Table 3). These payments will be made as long as the firm has sufficient income to cover them—a risk that is precisely analogous to the default risk faced by bondholders. While this makes intuitive sense, it can also be demonstrated more analytically.

Consider a firm with a WACC of 12%, that issues 10-year, 8.5%

Table 3: Market-Based Discount Rate Estimation

Item	Discount Rate	Estimation Procedure
1. Riskless Rate		
Market Yield on Govt. Obligations	6.2%	Look-up yields on long-term government bonds
Less: Term Premium Adjustment	1.5%	Textbooks/EPRI: Average historic term premium
Riskless Rate of Return for CAPM (R_f)	4.7%	Subtraction
2. Post-Tax CAPM Rates:		
Coal Outlays	$R_{f\text{-}post} = 3.0\%$	R_f + empirical Beta estimate $\beta = 0$.
Gas Outlays	1% - 3%	R_f + empirical Beta estimate β ranges from -0.5 to 0.0
3. Post-Tax Derived Rates		
Fixed 'Debt-Equivalent' Outlays	5.3%	By convention—post-tax cost of debt
Fixed Capital Additions	6.3%	Estimate: Debt-equivalent + 1%
Variable O&M Costs	9.4%	Estimate: WACC
Coal-Based Purchased Fuel	4.3%	Weighted average: 80% fuel + 20% variable O&M
Gas-Based Purchased Fuel	2.4%	Weighted average: 80% fuel + 20% variable O&M

debt[25] which is fully subscribed to by investors at the face value of \$1000 per bond. The firm's tax-rate is 37% so its after-tax interest payment is \$53.55 per year for each \$1000 bond investment (\$1000 × 8.5% × (1-.37) = \$53.55). We know that the market-based present value of the 10-year stream of debt-service payments must be \$1,000 since this is the sum investors willingly put up in return for these annual payments. Note that the firm also values the stream of payments at \$1000 since this is the sum it accepts up front in return for the future stream of payments.

The known, \$1000 present value of each bond is found by discounting the annual debt-service payments (including principal repayment in the last year) at 5.355%— the post-tax cost of debt; estimating this present value at the WACC (9% post-tax), by contrast, yields \$766— which we know must be incorrect. The present value of debt-service outlays therefore cannot be found at the WACC. Neither can the present value of any other IRP outlay.

In a sense this illustration may be somewhat obvious since it merely shows that when the debt-service payments are discounted at the cost of debt, the present value is \$1000. Yet the example serves to illustrate two important points: (i) bondholders charge 5.3%, not the WACC, for accepting the default risk on the firm's debt; and (ii) both the firm *and* the bondholders use the same discount rate— each discounts the debt payments at the post-tax rate of 5.3% to arrive at the same market value for each bond—\$1000.[26]

Cost streams for debt are no different from those for any other fixed, debt-equivalent obligation; these are all discounted at the cost of debt, not the WACC. The recipient of a fixed contractual payment would implicitly use the cost of debt when taking on such an obligation. (The after-tax cost of debt is correct even where there is no actual "recipient." Had there been a "recipient," he or she would have used 5.3 percent as the rate of discount).

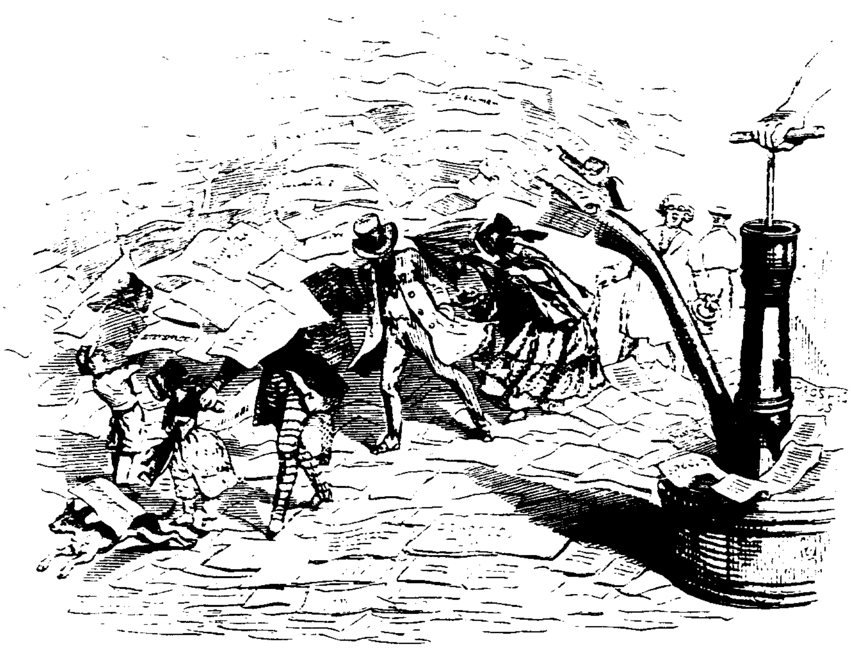
2. *Estimating the Discount Rate for Riskless Cash Flows.* Using similar logic, it becomes clear that IRP payments which are systematically *riskless* must be discounted at the post-tax riskless rate earned on U.S. treasury obligations. The riskless rate of return can be estimated using the following steps (see Table 3):

(a) Estimate the riskless market-yield by looking up the prevailing yields on long-term government bonds.[27] A recent *S&P Bond Guide* gives this yield as 6.2%;

(b) Adjust the riskless yield by subtracting a *term premium* of 1.5 percentage points;[28]

(c) The *pre-tax* riskless rate (R_f) for most IRP evaluations therefore would be 4.7% (6.2% - 1.5% = 4.7%).[29] Discounting, however, requires *post*-tax rates; the post-tax riskless rate ($R_{f\text{-post}}$) is 3%, as shown for coal in Table 3.[30]

3. *Estimating the Discount Rate for Gas Outlays.* The discount rate for gas outlays ranges from 0.6 percent to 4.3 percent (Table 3), based on CAPM estimates and a



The present value of a revenue stream is tricky to estimate.

market observation discussed in the next subsection. The historic CAPM estimate yields a discount of 0.6 percent (using b = - .05).[31]

The CAPM-derived rate for gas is below the riskless rate. There is evidence that this is appropriate. Fuel prices have historically co-varied *negatively* with the economy[32] and with the returns investors obtain on other investments.[33] Negatively correlated cost streams will have negative betas. Standard application of CAPM theory tells us that cost streams with negative betas must have discount rates below the riskless rate of 3 percent.

The historic negative co-variance between fuel and the economy is also observed by Robert Lind, who concludes: "Our energy-economic models predict that higher energy costs will result in a lower GNP. Therefore there can be a reasonable presumption that [the benefits of fuel saving investments] will correlate negatively with GNP,"[34] and that "[w]e have argued that when energy prices rise, the return to investments in general will go down."[35]

These factors suggest that there exists, in Professor Lind's words, a "reasonable presumption" that fuel betas will be negative so that the discount rates can be no greater than the riskless rate—about 3.0%.

4. Gas Discount Rates: Additional Market Evidence. Additional evidence exists which can help us estimate the rate at which to discount future gas outlays. Enron Power Services offers 20-year fixed-price contracts for gas at the rate of $3.50 per MMBtu.[36]

This market observation can be used to derive a discount rate for gas-price forecasts without the necessity of estimating a beta. We can begin by assuming that the Enron offer is riskless, i.e., that because of the firm's size the default risk on this contract offer can be ignored. If this is the case, the present value of the offer is easy to estimate: It is the present value of the fixed price stream, discounted at the riskless rate of return (3%).

The present value of the $3.50 payment stream using the riskless rate is $52.07 per MMBtu (**Table 4**). To the extent that Enron's offer is predicated on unbiased expectations, this value must equal the present value of *any* expected (unbiased) gas-price stream. This idea allows us to approximate the discount rate for any stream of risky gas-price forecasts since any unbiased forecast will have the same present value as Enron's riskless price forecast.

Swanson's survey of well-head gas-price forecasts indicates expected annual real gas-price growth rates ranging from 1.71% to 5.65%, with most forecasts clustered in the 3% to 4% region.[37] Table 4 shows three gas price streams projected using real growth rates of 1%, 3%, and 4%, which convert to *nominal* growth rates of 4%, 6%, and 7% (assuming 3% inflation).

Estimating the implied discount rate for the projected gas prices is equivalent to asking this question: At what discount rate do these risky price forecasts yield a present value of $52.07? Assuming the middle range estimate (6% nominal growth) is a consensus that represents an unbiased *expected* value of future gas prices, the results of Table 4 suggest that the appropriate discount rate for future gas prices is 3.4% since this rate produces a present value of

Table 4: Comparing Risky Gas-Price Forecasts to a Fixed-Price Contract

		Fixed-Price Offer ($/MMBtu)	Projected (Risky) Gas Price ($/MMBtu)		
			Nominal Growth Rate		
Period	Year	20-Year	1.040	1.060	1.070
1	1994	$3.50	$2.10	$2.10	$2.10
2	1995	$3.50	$2.18	$2.23	$2.25
3	1996	$3.50	$2.27	$2.36	$2.40
4	1997	$3.50	$2.36	$2.50	$2.57
...	...	...	...	...	...
17	2010	$3.50	$3.93	$5.33	$6.20
18	2011	$3.50	$4.09	$5.65	$6.63
19	2012	$3.50	$4.25	$5.99	$7.10
20	2013	$3.50	$4.42	$6.35	$7.59
Riskless Discount Rate		***3.00%***			
Implied Discount Rates			***1.600%***	***3.380%***	***4.268%***
Present Values		**$52.07**	**$52.07**	**$52.07**	**$52.07**
10-Year Present Value		—	$23.01	$22.79	$22.69

$52.07, equivalent to that of the fixed-price offer. Table 4 also suggests that if the low-growth forecast is correct, the appropriate discount rate is 1.6% while a discount rate of 4.3% is correct if the high-end forecast is accepted. Thus the results of Table 4 suggest a nominal gas discount of about 3.4% with a likely range of about 2% to 4%, just slightly above the historic-based CAPM range (0.6% to 3%).[38]

So, which discount rate do we use for gas? Let's see how the evidence adds up. The market evidence provided by the Enron offer, coupled with the historic empirical analysis, gives us a reasonable idea of how to discount future gas outlays. It tells us that: (1) the WACC is definitely too high, but this is no surprise; and (2) a rate in the range of 2% to 4% is reasonable and conservative. Where the precise number lies in this range is probably a function of individual belief about the future. The upper range is appropriate if one believes that gas prices will rise faster than the mid-range forecasts, or that gas will be considerably *less* risky in the future as compared to the past. The lower range makes sense if one believes that gas prices will rise more slowly, or that historic fluctuations will diminish only somewhat. When all of this is thrown into the hopper, judgment says that a 3% riskless rate is probably "safe," but that 2% is more in keeping with historic trends.[39]

5. Other Derived Post-Tax Rates:* (a) *Fixed Capital Additions: Table 3 shows a value of 6.3%, estimated as the debt-equivalent rate plus one percentage point. Capital additions are assumed to be fairly predictable, although they may have a significant systematic risk component because: (i) a growing economy may increase demand so that the capital addition must either be made sooner or must be larger than anticipated; and (ii) there is a possibility that the cost of capital assets rises during good economic times.

This discount rate may therefore be dependent on the type of capital addition. Where fixed capital additions represent a relatively small share of the total outlays (as in **Figure 4**) the discount is not likely to alter the decision outcome. Where this is not the case, the discount rate for this category may have to be estimated more carefully.

(b) *Variable O&M:* Variable O&M costs probably co-vary cyclically to the extent that labor and other rates rise during good economic times. This suggests a rate above the debt equivalent. Although a beta could be empirically estimated, the relatively small size of these costs (as in Figure 4) does not seem to warrant such a detailed analysis. As an alternative, the WACC can probably be safely used as a proxy rate, except in special cases where this cost category is larger.

(c) *Purchased Power:* Purchased power contracts often consist of two components: fuel and O&M. One method for dealing with such combined cost groups is to use the weighted average of the discount rates for fuel and variable O&M. The values in Table 3 are such a weighted average of the fuel discount rate (80 percent)

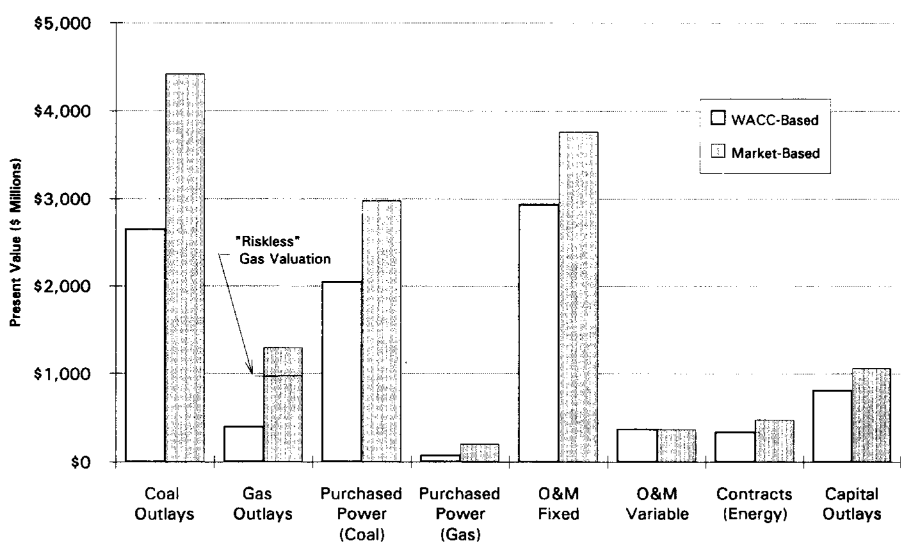


Figure 4: WACC-Based and Market-Based Present Value IRP Costs.

and the variable O&M discount rate (20 percent).

IV. Present-Value IRP Results

A. A Case in Point

This section uses a recent IRP filing to illustrate how the application of market-based discount rates alters present-value costs. Figure 4 shows the WACC-based and market-based results. An additional valuation which uses the discount estimated from the Enron fixed price contract (three percent) is also given.

The WACC-based present values of the proposed IRP plan total $9.7 billion, but this value has no economic interpretation, as previously discussed. The correct value of this IRP is more closely approximated by the market-based results which total $15.4 billion.

The WACC-based results thus understate the true, market-based cost of this plan by over $5.5 billion. The major source of understatement for the WACC results is in the costs of fuel (about $3.8 billion, including the 80-percent fuel component in "Purchased Power") and, to a lesser degree, "Fixed O&M" and "Contracts" ($1 billion). An important conclusion of this analysis therefore is that the fossil-based costs of the plan in Figure 4 are considerably higher than the WACC-based analysis indicates. It would be incorrect to adopt this plan on the assumption that the expected present-value cost is only $9.7 billion—this plan has an expected cost in the neighborhood of $15 billion, and possibly more when contingencies are added.

B. Valuing Contingencies

The IRP costs of Figure 4 do not reflect contingencies such as carbon taxes or environmentally required retrofits, which can have a significant present value. For example, suppose we assume that a 30-percent carbon tax will be imposed on coal, beginning in the year 2000. This is one-half the rate considered in a European proposal several years ago.[40] If the

likelihood of such a tax being imposed is 60 percent, then this contingency has a present value of over $1 billion.[41]

The potential cost of future retrofits to meet emissions requirements is likewise significant. For example: Consider the possibility that this firm may have to expend $600 million to meet new emissions requirements 10 years from now. The present value of such an outlay is $224 million, *even if the likelihood of this happening is only 50 percent* ($600 million x $0.5/1.03^{10}$). Clearly such contingencies need to be valued and added to the present-value cost estimate.

IV. Conclusion: Why the Market-Based Approach Yields Better Present-Value Estimates

Using market-based discount rates to value IRP cost streams is not difficult and does not introduce any significant computational problems. The estimation approaches shown in this paper are widely used. Utility planners tend to be professional engineers to whom the idea of using different discount rates for different cost components seems strange, even though the approach is common in project valuation and is shown even in introductory finance textbooks.

The financial approach provides a vast improvement over the present practice of using the WACC, which produces results that have no economic interpretation. The advantages of discounting each type of cost stream at its own discount rate are obvious—it allows for more precise discount rate estimation. Just as we wouldn't use the price of, say, steel to estimate future coal prices, we shouldn't use a single discount rate such as the firm's WACC to discount a set of IRP cost streams, each of which has a unique associated risk cost.

Some of the discount rate estimates are "firmer" than others. The treatment of fixed costs as debt equivalents, for example, does not leave much room for error. In the case of gas, there may be some uncertainty as to whether past variability will hold in the future and this may affect the discount rates to some extent. Yet even in this case, the market-based estimates are considerably more reliable than using the WACC, which is *known to be wrong*. Thus we might debate whether the correct rate for gas is one percent, two percent or, even four percent, but any rate in this range, which is known with a relatively high degree of certainty, will lead to a much more reliable result than using the WACC—which is typically in excess of nine percent.

Given the increasing competitiveness of electricity markets, use of the WACC—known to be the wrong discount—to support decision making hurts shareholders as much as ratepayers. It does not result in good decision making and its use will lead utilities to make suboptimal decisions for both self-generation and power purchases. ■

Endnotes:

1. Shimon Awerbuch, *The Surprising Role of Risk and Discount Rates in Utility Integrated-Resource Planning,* ELEC. J., March 1993, 20-33.

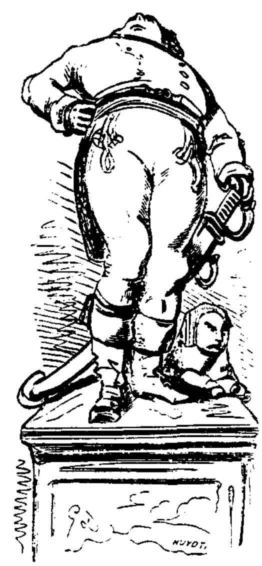
2. *E.g., see* Alfred E. Kahn, *Can Regulation and Competition Coexist?* ELEC. J., Oct. 1994, at 23-35.

3. *Id.* As Kahn notes, at 24, it is unreasonable to expect a competitive market to provide for socially desirable aims such as environmental protection (or promoting renewables), and efficient regulatory policies which promote these objectives will be required. This suggests a continued role for public policy making, albeit, using regulatory mechanisms that work more efficiently with market forces.

4. The classic single-factor (Sharpe) model is most widely used although multiple-factor models may be more appropriate in some settings.

5. *See* Awerbuch, *supra* note 1, at n. 9.

6. Talbot argues that component discounting is inappropriate on the basis that his analysis, which uses nominal data, does not find that fuel is sufficiently risky from a societal point of view, although it confirms that it is risky from a market point of view. *See* Neil Talbot, Financial Economics and Renewable Energy (Oct. 1993) (paper presented at NARUC-DOE Regulatory Conference on Renewable Energy, Savannah, Ga.).



Component discounting is *axiomatic* and hence not subject to empirical proof. In other words, even though his analysis, when adjusted for inflation, indeed confirms the riskiness of fuel from the societal perspective, this empiricism has no bearing on the appropriateness of component discount rates. Moreover, the WACC is incorrect whether fuel is risky or not.

7. Although they follow movement in the economy as a whole.

8. In Table 2, the 10-percent return on a broadly diversified market portfolio is arbitrarily derived as a riskless rate of six percent, plus a four percent risk premium.

9. They are also discounted at a higher rate by the recipients, since to them this variable payment stream is riskier, like the recession-proof mortgage is to the lender.

10. This would yield a present value of the net cash flows that is smaller than the present value of the cash flows in Figure 1-a, which makes sense: Investors prefer the firm in 1.

11. For the complete derivation *see* NEIL SEITZ, CAPITAL BUDGETING AND LONG-TERM FINANCING DECISIONS app. 11-a (Dryden, 1990) and THOMAS COPELAND AND FRED WESTON, FINANCIAL THEORY AND CORPORATE POLICY 414-16 (Addison-Wesley, 1988).

12. Roger Clarke, *The Effect of Fuel Adjustment Clauses on the Systematic Risk and Market Values of Electric Utilities,* J. OF FINANCE, May 1980, at 347-58, plus *Discussion,* by Richard Bower, 383-85.

13. *Id.*

14. Shimon Awerbuch and Alistair Preston, *We Do Not Have the Cost Concepts Necessary For IRP,* ENERGY POL., Nov. 1995 (forthcoming).

15. In which case they would look like the costs of Figure 2, which are not correctly valued by the WACC.

16. This is illustrated using the example of a junk bond and a Treasury bond in Awerbuch, *supra* note 1.

17. Which implies that 66 percent of the observed fuel prices will be within 19 percent above and below the mean.

18. Hal Varian, *A Portfolio of Nobel Laureates: Markowitz, Miller and Sharpe,* J OF ECON. PERSPECTIVES, vol. 7, no. 1, Winter 1993, at 159-69.

19. Covariance between the cost stream and the returns to a diversified market portfolio (which can be positive or negative) is defined as $s_c \times s_m \times r_{c,m}$, where s_c is the standard deviation of annual changes in the cost stream, s_m is the standard deviation of annual returns to the market portfolio, and $r_{c,m}$ is the correlation between the cost stream and the market portfolio.

20. An empirical procedure which allows the discount rate to be estimated without first estimating a beta is presented below.

21. Beta is a measure of the covariance or co-movement between a cash flow and a broadly diversified market portfolio. The beta for such a portfolio, (which measures the covariance with itself) will equal 1.0, by definition, while the beta for riskless U.S. government obligations, (whose variability is zero) is 0.0. These two points define the security-market line along which lies the required return for cash flows with various betas or systematic risk levels. Beta can be greater than 1.0, and, in the case of risky costs, can be less than 0.0. By knowing the beta of a fuel-cost stream the discount rate can be derived from the security-market line.

22. Although EPRI formalized them in its Technical Advisory Group around 1978!

23. Some more recent market evidence, derived from current fixed-price futures offers, suggests a rate that may be somewhat higher—perhaps four percent, as discussed subsequently.

24. *See, e.g.*, RICHARD BREALEY AND STEWART MYERS, PRINCIPLES OF CORPORATE FINANCE 473-74 (McGraw Hill 1991).

25. This is the yield on A-rated utility bonds. *See* STANDARD & POOR'S BOND GUIDE, Dec., 1993.

26. Differential tax rates on individuals and corporations can create an exception to this 'symmetry' requirement.

27. STANDARD & POOR'S BOND GUIDE, Dec. 1993. Numerous other sources also provide this data, including the various Federal Reserve Board publications.

28. This is the historic difference between long-term and short-term treasury rates. *See* FRANK K. REILLY, INVESTMENT ANALYSIS AND PORTFOLIO MANAGEMENT 46 (Dryden Press, 3rd ed., 1989), and ELECTRIC POWER RESEARCH INSTITUTE, CAPITAL BUDGETING NOTEBOOK 7-31 (Draft Report, RP-1920-03, Nov. 1990).

29. This rate can be used directly in the case of coal outlays, since the empirical evidence suggests that prices have historically been systematically riskless. Awerbuch, *supra* note 1, at 30.

30. $R_{f\text{-post}} = 4.7\% \times (1 - .37) = 3\%$.

31. The CAPM can be written as:

$$R_{gas} = \{R_f + \beta gas \times Rp_m\} \times \{1 - \tau\},$$

where the variables are defined as follows:

R_{gas} is the post-tax market-based discount rate for gas;

R_f is the expected (pre-tax) riskless rate of 4.7 percent;

β_{gas} is the measure of market risk

for gas; empirical estimates are in the range of -1.0 to -0.5 (Awerbuch, *supra* note 1, and -0.45, Talbot, *supra* note 4);

RP_m is the expected risk premium for a diversified market portfolio—about 7.5 percent above the long-term riskless rate (EPRI, *supra* note 27, at 7-19; Reilly, *supra* note 26, at 45);

τ is the marginal tax rate, which we have taken as 37 percent.

If $\beta = -0.5$, the post-tax, nominal CAPM discount rate for gas is:

$$R_{gas} = \{R_f + \beta_{gas} \times RP_m\} \times \{1 - \tau\}$$
$$= \{.047 - 0.5(.075)\} \times \{.63\} = 0.6\%.$$

We can also use the CAPM to replicate the coal discount rate:

$$R_{coal} = \{R_f + \beta_{coal} \times RP_m\} \times \{1 - \tau\} =$$
$$\{.047 + 0.08(.075)\} \times \{1 - .37\} = 3\%.$$

32. *See, e.g.*, Julio Rotemberg, The Effects of Energy Price Increases on Economic Activity (Nov., 1993) (Energy Policy Workshop, MIT Center for Energy and Environmental Policy Research).

33. *The Hidden Picture*, US NEWS & WORLD REPORT, April 29, 1991, at 50.

34. Robert C. Lind, *A Primer on the Major Issues Relating to the Discount Rate for Evaluating National Energy Options*, in DISCOUNTING FOR TIME AND RISK IN ENERGY POLICY at 63 (Robert C. Lind, Kenneth Arrow, et. al., eds., Resources for the Future, Johns Hopkins U. Press, 1982).

35. *Id.* at 89.

36. Geoffrey Roberts, Prefiled Testimony, Colorado PUC, Docket 93I-098E, March 1994, at 4.

37. Sam Swanson, Prefiled Testimony, Colorado PUC, Docket 93I-098E, March 1994.

38. There are a number of explanations for this small difference, including the possibility that the Enron fixed-price offer is based on risk expectations that differ from the past, or that it is based on a price forecast at the low end of the forecast range or that Enron made a mistake. It is also possible that this offer is not viewed as riskless, in which case the estimated discount probably indicates an upper bound on the appropriate gas discount rate.

39. This rate, somewhat above the historic-based rate, is "safe" also because the demand for electricity may decline somewhat when gas prices are high, which makes this stream somewhat less risky (for ratepayers) than the historic beta analysis would suggest.

40. ELECTRICAL WEEK, Oct. 28, 1991, at 16.

41. S. Awerbuch, Risk Adjusted IRP: As Easy as ABC, Table 7 (April 1994) (NARUC-DOE Fifth National Conference on IRP, Kalispell, Mont.).