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The Surprising Role of Risk in Utility Integrated Resource Planning

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The Surprising Role of Risk in Utility Integrated Resource Planning

Integrated resource planning, as currently practiced, has a fatal flaw: the revenue-requirements method of evaluating new capacity options improperly ignores risk features. When risk is properly accounted for, the cost of supposed 'high-cost' resources — photovoltaics, for example — drops dramatically while the cost of supposed 'low-cost' resources like natural gas-fired generation goes up.

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Integrated resource planning is rapidly emerging as the preferred planning process for electric utilities. Under IRP, planners project the initial and annual operating costs of different resource options and compare them using the revenue-requirements method (RRM) — a project-evaluation technique that discounts future costs (i.e., revenue requirements) into present values. The discount rate used for these computations is usually the firm's weighted-average cost of capital (WACC) — the weighted-average cost of the firm's equity and debt. The project alternative with the lowest present-value revenue requirement (PVRR) (i.e., lowest costs) emerges as the economic choice.

Below, I argue that the widespread use of the WACC as the discount rate for project alternatives is inconsistent with textbook finance, and leads to distorted results and sub-optimal decisions. The magnitude of the errors is quite significant — easily on the order of 50% or greater for some technologies. The article also demonstrates that sensitivity analysis does not improve the estimates obtained by discounting at the WACC.

Finally, the article develops a set of proxy or composite discount rates which can be used as a guide for evaluating particular types of projects. Such proxy estimates will serve as a significant improvement over the current practice of using the WACC.

I. The Revenue-Requirements Method

Unregulated firms typically seek projects that maximize the present value of *net cash flows* (NCF). NCF is the difference between inflows and outflows; it is the cash flow stream that investors see. In contrast, the RRM identifies resources that minimize outflows or costs. Outflows are the revenue requirements, which include capital outlays,[1] fuel, labor, maintenance, property taxes, inventory and overhead costs, changes in working capital, future capital additions, and the effect of federal income taxes. These are projected over the life of the asset, then discounted using the firm's WACC.

The WACC is the investor's discount rate; it is appropriate to use to project the firm's net cash flows. It reflects the full measure of operating risks coupled with the financing risks. As such, applying it to the revenue requirements of a particular project is incorrect for two reasons:

- because the WACC is an average, it obscures risk differences among resource options;
- while the RRM examines only the costs (or outflows), the WACC reflects the risk of the *net* cash flows. The two cost streams can have very different risks, hence should be evaluated at very different discount rates. The following section illustrates the fallacy of discounting at the WACC, using the example of a financial portfolio.

A. Financial Portfolio Example

Consider the case of an investor with a financial portfolio expected to yield 10%. This individual is comparing two opportunities: a newly issued U.S. Treasury bond yielding 7.0%, and a low-quality corporate "junk bond" with a 16% coupon selling at $500 — half of its face value. For the purpose of illustration, financial assets are assumed to differ little from fixed assets. From an investment evaluation perspective, the most significant difference between the two types of assets is that financial assets generally trade in highly efficient markets while most corporate fixed assets do not. Here we assume that all assets are liquid and are widely traded at market-determined, risk-adjusted prices.

If this hypothetical investor were to follow the usual RRM practice of using the WACC, he or she would evaluate the two opportunities using the portfolio's average 10% return as a discount rate. **Table 1** shows the results: the proceeds of the T-bond have a discounted value of $772, roughly half the $1,456 present value of

Table 1: Annual Cash Flow and Present Value for Two Investments[a]
(Using the investor's WACC)

Year	$1,000 Junk Bond (16% coupon)	$1,000 Treasury Bond (7% coupon)
1	$160	$70
2	160	70
3	160	70
4	160	70
5	160	70
6	160	70
7	160	70
8	160	70
9	160	70
10	160	70
11	160	70
12	160	70
13	160	70
14	160	70
15	$1,160	$1,070
Present value of annual proceeds (at 10% WACC)	$456	$772
Less: Initial Outlay	$500	$1,000
Net Present Value	$956	($228)

a. For simplicity we assume that each bond matures in 15 years.

the junk-bond proceeds, thus supporting the erroneous and naive conclusion that the junk bond is preferable to the T-bond. Using net present value (NPV) — defined as the present value of the stream of cash flows minus the initial outlay — does not alter the result.

Any method for valuing these two investments that shows the junk bond to be more desirable or a "better deal" must be flawed since both are widely traded. In addition, the WACC-based present-value analysis leaves several unanswered questions:

- Does the negative NPV suggest the investor will "lose money" with the T-bond, thus making it a poor choice for this investor?
- Are Treasuries appropriate only in portfolios with average returns of 7% or lower?

Treasury bonds, in fact, are appropriate for any investor who prefers their particular risk-return combination. The T-bond reduces the portfolio's risk, whereas the junk bond, which *promises* a higher yield (i.e., the investor *may* earn a higher return), carries higher risk. The "correct" present value is market based: it is the price at which the security trades. Investors continually determine this value using their risk-adjusted discount rate, which in our example is 7% for T-bonds and, as we later show, 32.5% for junk bonds. As a result of such risk adjustments by investors, the junk bond is priced lower than the T-bond, even though its promised annual payment is considerably higher. Accordingly, discounting the expected cash flows of each investment at the portfolio's 10% WACC distorts matters by incorrectly suggesting that the T-bond is less valuable or "profitable."

The portfolio's average return — its WACC — is not relevant for evaluating investment opportunities, as the example above has shown. Yet this is *precisely* how utility planners evaluate alternative-energy investments under the RRM. As a result, the process

is biased towards lower cost, higher yielding, higher risk investments just as the previous illustration favored the junk bond. Viewed in the context of utility-resource options, the T-bond *seems* more costly: it requires $1,000 outlay for a $70 annual payment stream, while the junk bond promises to deliver $320 for each $1,000 outlay. Yet T-bonds are widely purchased by investors who do not mind paying more for their expected stream of interest payments, because they know the investment is secure. This bond example is no different from the capacity choices utilities face.

The RRM demonstrates how risk — one of the most important cost components — is ignored in the process: RRM focuses on simple *promised* $/kWh. Some electricity-generating options, which *seem* more costly under RRM, may offer lower levels of operating and financial risk and hence, like the T-bond, should not be rejected out of hand. Sensitivity analysis does not mitigate the problems inherent in the WACC, as discussed below.

B. Sensitivity Analysis

Sensitivity analysis is widely used to study the effects of uncertainty in IRP project selection. This section illustrates that when sensitivity analysis is performed using the WACC, it does not improve the estimates. **Table 2** extends the junk bond/T-bond example from Table 1, and assumes that projected bond payments are reduced by 10%, 25%, and 67.5%.[2]

Does sensitivity analysis improve the original answer? Not really. After reducing the cash inflows by 10% for both investments, the junk bond is still valued higher. In fact, it seems *less* risky: the 10% cash-flow reduction lowers its NPV a mere 15.2% (from $956 to $811), compared with the T-bond's 33.8% reduction! If these were two electricity-generation investments, attention would be focused on the high variability of PVRR for the "T-bond" generator, even though this is the lower yielding and less risky alternative. This misleading outcome occurs because the sensitivity ranges have been arbitrarily chosen (10% in this case), regardless of the fact that the T-bond will never show this much variability.

Increasing the sensitivity spread does little to improve the answer. With a 25% sensitivity adjustment the junk bond still seems preferable, while the T-bond still looks riskier: its net value drops by almost 85%. Moreover, the junk bond's calculated "present value" is still $592 above the market's estimate, while the T-bond's is $421 less than the market's assessment.

Investors determine market values by applying some discount rate to *expected* cash flows. In a perfect market, securities sell at a NPV equal to zero. Although we cannot know with certainty the exact values used by investors, the previous example indicates that they arrived at a consensus present value of $500 for junk bonds and $1,000 for Treasuries, and that these are the prices offered, making the net present values zero.

In the case of electric-utility capacity investments, we do not have the benefit of an observed market price and thus cannot directly check our estimated present values. In our example, however, we can determine the magnitude of the sensitivity adjustment needed to get the market-based result (i.e., NPV equals zero). As **Table 2** shows, we obtain this result for junk bonds only by increasing the sensitivity up to an unusually high 65.7%.

At this sensitivity range, the T-bond is quite undervalued, which renders the sensitivity outcomes meaningless. This results from using the same discount rate and arbitrary sensitivity range for both investment choices and ignoring the lower risk of the T-bond. While intuitively appealing, sensitivity analysis must be applied very carefully. However, even when all of these problems are addressed, the results will still be useless if the wrong discount rate is used. Some of the common pitfalls of sensitivity analysis are discussed at **Inset 1** on page 27.

Table 2: Sensitivity Analysis for Two Bond Investments (Using the investor's WACC (10%))

	16% Junk Bond Sensitivity[a]				7% Treasury Bond Sensitivity[a]			
Year	0.0%	−10.0%	−25.0%	−65.7%	0.0%	−10.0%	−25.0%	−65.7%
1	$160	$144	$120	$55	$70	$63	$53	$24
2	160	144	120	55	70	63	53	24
3	160	144	120	55	70	63	53	24
4	160	144	120	55	70	63	53	24
5	160	144	120	55	70	63	53	24
6	160	144	120	55	70	63	53	24
7	160	144	120	55	70	63	53	24
8	160	144	120	55	70	63	53	24
9	160	144	120	55	70	63	53	24
10	160	144	120	55	70	63	53	24
11	160	144	120	55	70	63	53	24
12	160	144	120	55	70	63	53	24
13	160	144	120	55	70	63	53	24
14	160	144	120	55	70	63	53	24
15	$1160	$1044	$870	$398	$1070	$963	$803	$367
Present value of proceeds:	$1456	$1311	$1092	$500	$772	$695	$579	$265
Less: Initial outlay:	$500	$500	$500	$500	$1000	$1000	$1000	$1000
Net present value:	$956	$811	$592	$0	($228)	($305)	($421)	($735)
Percent change:	—	−15.2%	−38.1%	−100.1%	—	−33.8%	−84.6%	−222.2%

a. The sensitivity factors are used to adjust the annual payments for each bond downwards.

II. The Importance of the Discount Rate

Correctly assessing risk and estimating discount rates is increasingly important as utility planners face an expanded range of technological and institutional options. The case of a firm evaluating new projects is not unlike the investor considering additions to a financial portfolio. The firm is a portfolio of investment projects, each with its own risk-return profile. Intuitively, any project can be spun off into its own corporation which would trade at its own risk-adjusted discount rate. When compared to the securities market, however, the market for such projects is less perfect and the determination of risk and expected returns is more difficult.

The WACC, which is analogous to the average return on a financial portfolio, reflects management decisions and changes in the business environment. For example, when a firm announces a risky new venture, its WACC immediately rises, whereas a low-risk project reduces WACC.[3] The WACC reflects the overall cost of the firm's funds at any point in time. However, it is not a correct measure for evaluating new projects, each of which must be evaluated at its own risk-adjusted discount rate.

A. Discounting in IRP

The IRP process is comparative — planners are more interested in the *relative* ranking of alternatives and less concerned with *absolute* present values. As a result, there has been an understandable tendency to downplay the importance of detailed discount-rate estimation for individual options, since it has always been assumed that small changes in the discount rate will not affect the outcome.

This tendency has not been problematic in the past, when technology options were quite limited, consisting primarily of fossil-based combustion technologies with a fairly similar mix of variable and fixed costs. Under these circumstances, the resource acquisition decision is undoubtedly independent of the discount rate. **Figure 1** illustrates that the present value revenue requirements for the fossil technologies (combustion turbines, combined-cycle, and coal) are nearly parallel over the potential range of discount rates, making the IRP decision insensitive to this rate. Indeed, most conventional technologies will have similarly shaped cost curves.[4]

However, as Figure 1 shows, the revenue requirements for photovoltaics, or indeed any capital-intensive technology, are quite different. The cost mix for such technologies consists mostly of sunk capital outlay coupled with low operating costs. Discount-rate changes now affect the revenue requirements differently. As a result, the IRP decision is now quite sensitive to the discount rate used. Close attention must be paid to ensure that outcomes are not biased against renewables, and in favor of low-capital, fuel-intensive technologies with high variable costs.

III. Proper Application of Discount Rates in IRP

Utilities today have a broad range of technology options, including conventional generation, conservation, and demand-side management, as well as solar and other renewables. These technologies present different risk profiles,

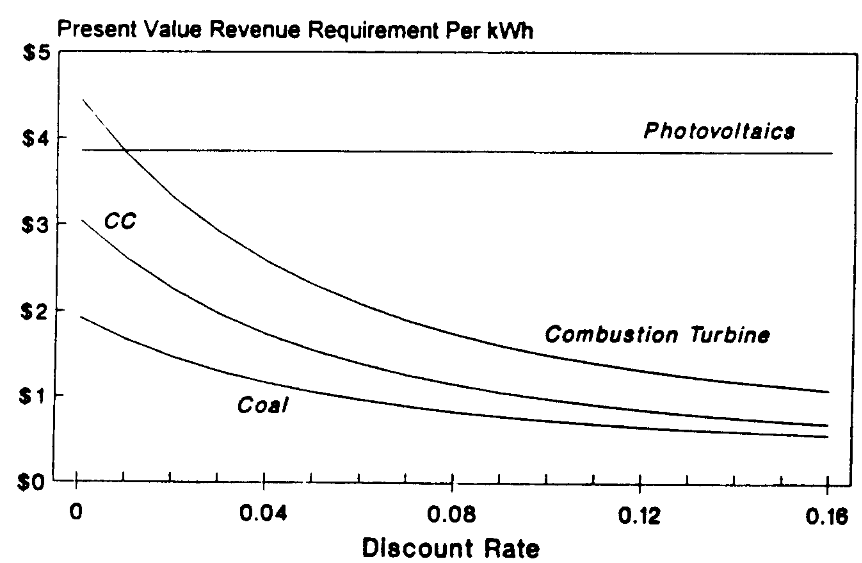


Figure 1: The Role of Discounting in RIP: Present Value Revenue Requirements Versus Discount Rate

and can be undertaken in a variety of institutional or business arrangements. For example, the utility can own the project or solicit bids from independent power producers.[5] This broad range of risk-reward profiles is not adequately addressed by the WACC.

A textbook requirement for using the WACC as the discount rate is that:
(1) a project's risk is identical to the overall risk of the firm's existing portfolio of projects, and
(2) the project will be financed using the same mix of debt and equity the firm currently uses.[6]
These conditions of homogeneity may have held in the past when technology choices were more limited. In such environments, discounting outflows at the WACC probably did not distort outcomes very much, as shown in Figure 1.

But there is a more powerful reason why WACC is inappropriate for IRP. In addition to conditions (1) and (2) above, WACC is applicable only when the project-selection criteria focus on the present value of *net cash flow*, not present value of revenue. This issue is not widely understood, since it is not often relevant: investment analysis usually focuses on net cash flows, not outflows. In this regard, the RRM is somewhat unique in that it focuses only on the outflows.[7] This has significant implications.

The correct risk-adjusted discount rate for any set of project revenue requirements is their opportunity cost. Estimating the discount rate applicable to such a given set of revenue requirements therefore involves estimating its riskiness. The procedures involved are not dissimilar to the capital asset pricing model-based approaches already used by some regulators to estimate equity betas[8] and the cost of capital. Similarly, project discount rates cannot arbitrarily be "chosen," but rather must be estimated carefully using a well-defined body of theory and practice.[9] The project discount rate reflects financial risk, which

can be defined as the variability (i.e., standard deviation) of project returns or cash flows over time.[10] This implies that correctly estimated risk-adjusted discount rates will most likely be different for different technologies.

IV. Correct Discounting of Revenue Requirements

The WACC reflects the overall net cash-flow risk faced by investors who generally do not care about cash inflow and outflow components. It makes little sense to apply *their* discount rate to the revenue cash outflows which will invariably have a different risk profile.

A. The Risk of the Revenue Requirements

Projects with highly variable year-to-year net cash flows must promise higher returns in order to attract investor interest. Yet this view of risk is inappropriate for the RRM, given its focus on revenue requirements. For example, even low-risk projects (as defined by stable *net* cash flows) can have highly risky outflow components.

Figure 2 (next page) shows the inter-relationship of inflows, outflows, and net cash flows. Projects A and B both have identical risky (unpredictable) revenues which are known to vary with the economy as a whole. The outflows are also unpredictable. The *expected* (average) value of the inflows is $115 for each project, while the outflows average $95 in each case. Investors can therefore *expect* a net cash flow of $20 per year ($115 - $95), on average, from either project.

Although the *expected* NCF is $20 for both projects, the similarities end there. The two projects exhibit very different levels of risk for investors. For Project A, the outflows rise and fall with the inflows. When the economy is prospering and revenues rise, the outflows rise as well. In fact, since this project generates the same net cash flow under all economic conditions, investors would consider it to be riskless, and would value it using the riskless rate of return obtainable on U.S. Treasury obligations. Ratepayers, on the other hand, who see only the project's outflows, are faced with a much riskier proposition. The risk-free discount rate does not make sense for their cash flow profile.

The outflows of Project B, by comparison, move opposite to its inflows, which would be typical for any production process whose principal input has a counter-cyclical price (i.e., its price rises when the economy is in decline). Energy is such an input — when its price rises, the value of other assets in the economy begin to fall. As a result of these counter-cyclical costs, the NCF for Project B is highly variable.

Standard capital-market theory dictates that investors prefer Project A and will discount the NCF of Project B at a higher rate of return to compensate for its added risk. This will lower Project B's risk-adjusted present value relative to Project A. However, as we have already seen, the discount rates investors apply to the NCF of either project is entirely incorrect for the outflows. Indeed, if investors knew the individual cash-flow components of each project, and wanted to develop the project's value from these components, they would discount the components, each at its own correct rate, not the discount rate applied to the NCF.[11] (See **Inset 2**, page 28-29.)

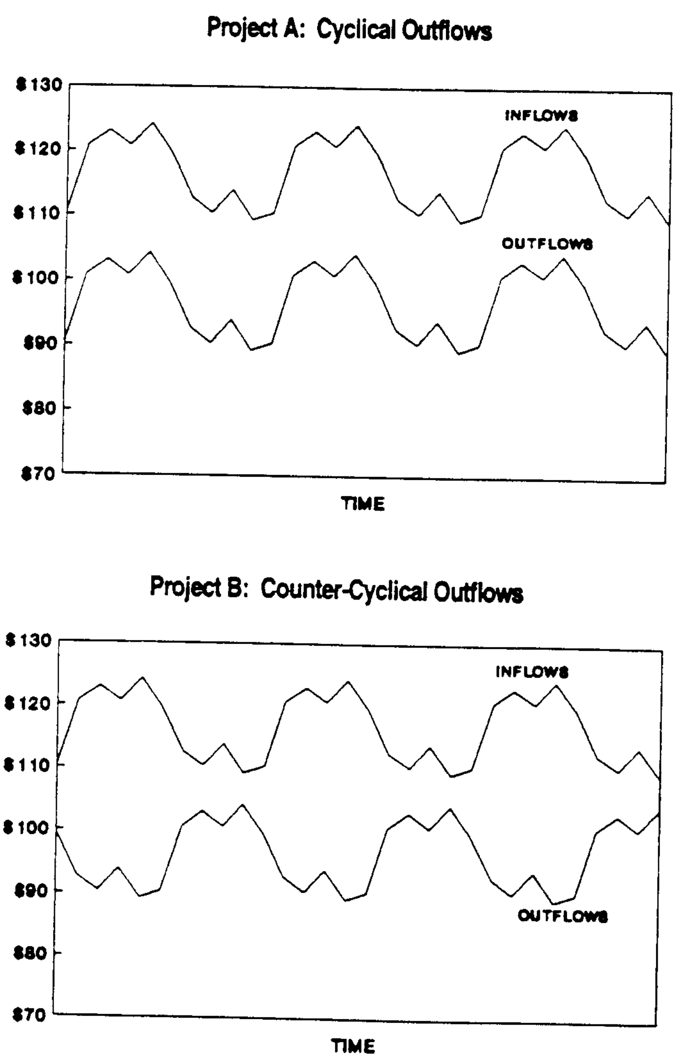


Figure 2: Cash Flow and Project Risk.

B. Valuing Cash-Flow Components

Let's take a closer look at how these two projects are valued. Both have the same *expected* NCF — $20 — but Project B is riskier. Rational investors prefer Project A and its stable $20 payment, which implies that its present value must be higher. We can now examine what this means in terms of the individual cash-flow components.

Suppose Projects A and B represent two electricity-generating options. Revenues, which remain the same independent of which option is chosen, reflect the unpredictable but cyclical demand for energy faced by the firm. The NCF each year equals inflows less outflows, and the present values are similarly defined: the present value of the net cash flow equals the present value of the inflows less the present value of the outflows.

Since the revenues are identical in each case, and since the NCF of Project A is greater, it follows that the outflows of Project A must have a *smaller* present value than those of Project B. This implies that the outflows of Project B must be discounted at a *lower* rate, a conclusion rigorously derived by analysts who find that in order to correctly adjust for risk, "The cost streams of riskier projects should be discounted at *lower* (and even negative) discount rates."[12]

Applying this rule to Figure 2 yields results that make sense: the outflows in Project B are discounted at a lower rate, which makes their present value a larger (negative) number. This, in turn, yields a smaller risk-adjusted present value for the NCF of Project B — as it should, since B is less desirable than A. **Inset 2** illustrates this result quantitatively.

Inset 1: Sensitivity Analysis

Most finance texts warn of the pitfalls of sensitivity analysis and simulation (sometimes called scenario analysis).[1] Unless used with considerable care, these techniques can easily "lead managers into a trap."[2] Here are some of the common pitfalls encountered with these techniques:

1. Variables do not move in isolation: e.g., changing inflation assumptions will alter expectations for all prices, costs, and revenues, as well as discount rates. Fuel prices, likewise, do not change in isolation, nor does the demand for electricity, so that studying the sensitivity to one or two variables is meaningless. Correctly estimating the interrelationships of variables, both cross-sectionally and longitudinally, is often complex.[3] In the context of expected economic conditions and load growth, sophisticated modeling techniques would be required beyond those available to most utility planners.

2. Present-value analysis deals with *expected cash flows*, a requirement that is masked in the scenario process, where incorrect *most likely* or *modal* outcomes are typically used instead.[4] These can bias the outcomes significantly.

Consider three possible sales forecasts — high, medium and low (say 600, 400, 200 units per year). If each outcome is equally likely, the expected sales level is 1200/3 = 400 units. Next, assume that the middle and lower outcomes each have a 40% chance of occurring, while the high projection has a 20% chance of happening. Now the *expected value* is:

$$0.2(600) + 0.4(400) + 0.4(200) = 360 \text{ units per year,}$$

although most analysts will still use the incorrect (400 units) figure.

3. The problem of estimating expected values is exacerbated whenever projected cash flows depend on multiplicative combinations of other stochastic variables.[5] For example, revenues are the result of unit price times units sold, and fuel outlays equal unit cost times units consumed. The two variables in each case are not independent, which frequently results in biased estimates of expected revenues or outflows.

Consider the following case: A firm expects to sell 100 units at $3 each or 300 at $1; the outcomes are equally likely. Expected unit sales therefore is: (100+300)/2 = 200 units. Expected price is ($1+ $3)/2 = $2. What is expected revenue? Most managers assume that expected revenue is expected unit sales times expected price: 200 units @ $2 = $400. But the correct expected revenue is $300, (100 x $3 + 300 x $1)/2, not $400.

4. Sensitivity studies typically define several scenarios or outcomes, such as, "pessimistic/optimistic" or "high-load/low-load" although no one knows how to define these. Indeed it is difficult to determine a useful high/low range. For example, will a fuel-price variation of plus-or-minus 10% communicate useful information to managers? If the historic standard deviation of fuel costs is 25%, will this sensitivity range be helpful? One popular method for addressing this problem is to produce a probability distribution of PVRR results. This must be done at the risk-free discount rate. The resulting present-value range is difficult to interpret, and potentially quite misleading since it ignores the ability of shareholders to diversify. This broader picture of possible outcomes does not necessarily facilitate decisions as has been observe:

> Because the whole edifice is arbitrary, managers can only be told to stare at the distribution [of PVRR values] until inspiration dawns. No one can tell them how to decide or what to do if it never dawns.[6]

Recall that in the junk bond example, it took a 65.7% sensitivity adjustment to obtain the "correct" answer. Utility investments, however, are made in imperfect markets, so we can never know the "correct" answer with certainty.

5. Although it is difficult, project evaluation must be done on a *marginal basis*. The analysis must show the outcome for each scenario, *with and without* new investment.[7] Scenario and sensitivity analyses do not generally do this.

Notes:

1. A useful and detailed discussion of the limitations of sensitivity analysis and simulation is given in A. Herbst, The Handbook of Capital Investing 275-79 (Harper Business 1990). These problems are also reviewed in R. Brealey and S. Myers, Principles of Corporate Finance (4th ed. McGraw-Hill); R. Rao, Financial Management: Concepts and Applications 353-355 (Macmillan 1992)); and N. Seitz, Capital Budgeting and Long-term Financing Decisions 205, 240 (Dryden Press 1990).

2. Brealey and Myers, *supra* note 1, at 228.

3. *Id.* at 215-19.

4. Herbst, *supra* note 1 at 276.

5. *Id.*; Brealey and Myers, *supra* note 1 at 218-19.

6. *Id.* at 228.

7. Seitz, *supra* note 1 at 240-41.

V. Application to Integrated-Resource Planning

A. Implications for Revenue Requirements

Desirable projects are those which improve the cost-risk performance of the firm. Such projects share an important attribute: the present value of their revenue requirements, discounted at the *correct risk-adjusted rate,* is lower than that of less desirable projects.[13] This condition will *not* hold when revenue requirements are discounted at the WACC. Forward-looking firms already recognize that in order to prosper in an increasingly competitive environment, they must not permit mechanisms such as the WACC to improperly bias the IRP process towards inefficient investments.

Standard capital-market theory tells us to discount low-risk cash inflows at a lower rate than higher risk inflows. This is quite intuitive: the promised cash flows of a risky investment should be more heavily discounted than those of, say, a U.S. Savings Bond. For cash *outflows,* the discounting arithmetic is reversed, as we just saw: the cash outflows of risky projects are discounted at a *lower* rate.[14] The implication for utility planning is that risky fuel outlays must be discounted at lower rates than, say,

Inset 2: Valuing Cash Flow Components

This brief discussion illustrates that the investor's discount rate, which is applicable to the project's net cash flows, is not the correct rate for the revenue requirements. The example uses the projects in **Figure 2** with one slight modification: we now assume that they are one-year projects. This makes it easy to compute present values (PV). The PV of each project is given by: $PV_{net} = PV_{in} - PV_{out}$.

We can describe the outcomes for these one-year projects as follows: while the cash flows are unpredictable, we know that if the inflows of Project A are high the outflows will be high as well (Figure 2). The reverse holds for Project B where the occurrence of high inflows means outflows will be low (the correlation coefficient between outflows and inflows is -1.0). The *expected* or average inflows are $115 for either project, while the *expected* outflows are $95. The *expected* net cash flow = $115 - 95 = $20 in each case, although the risk is much higher for Project B, which is why A is preferred by investors.

To simplify matters, let us assume that the inflows follow the returns on a broadly diversified financial portfolio. This allows us to set $r_{in} = r_m$, where r_{in} is the correct risk-adjusted discount rate for the inflows, and r_m is the return on a broadly diversified market portfolio such as the 'S&P 500', assumed to be 12%. To fully specify the problem we need only set the risk-free rate, r_f, obtainable on U.S. government obligations, which is taken at 5%. The table to the right gives the computations, which are described below:

Component Present Values for Project A

1. The net cash flow of this project will be $20 under any outcome. Since there is no risk, investors will value it by discounting at the risk-free rate:

   PV_{net} = $20/1.05 = $19.05.

This is the market-value investors place on Project A.

2. PV_{in} is obtained by discounting the expected inflow at r_{in}=12%:

   PV_{in} = $115/1.12 = $102.68.

3. PV_{out} is determined by subtraction:

   $PV_{out} = PV_{in} - PV_{net}$ = $102.68 - 19.05 = $83.63

4. If we were to value the outflows directly, what discount rate would we use?

Using PV_{out} = (Expected outflow)/(1+r_{out}), we can solve for the correct discount rate, r_{out}, consistent with the value of PV_{out} derived in step 3:

   r_{out} = (Expected outflow)/PV_{out} - 1 = 95/83.63 - 1 = .14.

Discounting Cash-Flow Components, One-Year Project*

	Project A ("Safe")	Project B ("Risky")
Expected Inflow	115.00	115.00
Expected Outflow	95.00	95.00
Expected Net	$20.00	$20.00
PV_{in}	102.68	102.68
PV_{out}	83.63	96.96
PV_{net}	$19.05	$5.72
r_{in}	12%	12%
$Beta_{in}$	1.0	1.0
r_{out}	14%	–2%
$Beta_{out}$	1.23	–1.0
r_{net}	5%	250%
$Beta_{net}$	0.0	35.0

* Market rate of return: $r_m = 12\% = r_{in}$
Risk-free rate: r_f = 5%

outlays for property taxes, thus raising their PVRR.

It is convenient to group project outflows by risk categories. The capital-related flows (taxes, insurance, etc.) are relatively low risk. They will materialize as forecast as long as technology or regulatory requirements (e.g., emission controls) do not change sufficiently to render the asset so uneconomic that it must be removed from the rate base. Operating outflows, however, especially those for fuel, are riskier.[15] Oil prices in the post-embargo environment move *counter-cyclically*, as do the outflows of Figure 2,[16] suggesting that oil-based generation may be considerably riskier than generating with capital-intensive technologies.

Under current practice, risky fuel expenses are discounted too heavily (using the WACC), which masks their importance and overstates their desirability relative to less risky capital outlays. This is particularly important for comparisons involving relatively low-risk renewable technologies which have virtually no annual cash outflows. Properly analyzed, risky fuel outlays[17] should reduce the project's desirability by raising its PVRR. Capital market theory therefore suggests that fuel outlays be discounted at lower rates.

So while the investor's discount for the net cash flows of this project is 5%, the revenues must be discounted at 12% and the revenue requirements at 14%. So doing yields the correct value for each component: \$19.05=102.68 - 83.63. This result is dependent only on the assumed values for r_f and r_m.

Discounting the revenue requirements at r_{net} = 5%, as planners typically do, yields: PV_{out}=95/1.05=\$90.48, higher than the correct value, which, in turn, understates the net cash flow: NET = 102.68 - 90.48 = \$12.20.

Present Values for Project B

The counter-cyclical outflows of this project make its NET riskier. We do not directly know r_{net} as we did above, and so the computations follow a slightly different path:

1. The correlation coefficient of the outflows with the inflows (and with a diversified market portfolio) is -1.0, so that $Beta_{out}$=-1.0 as well.[1] Since we know $Beta_{out}$, r_{out} can be derived using the CAPM: r_{out} = .05 - 1.00(.12-.05) = -.02, which is smaller (and even negative[2]) as compared with the comparable discount rate in Project A. This illustrates that the revenue requirements of risky projects must be discounted at *lower* rates.

2. Now, PV_{out} = \$95/(1 + r_{out}) = \$95/(1-.02) = 96.96 (as compared to \$83.63 in Project A).

3. PV_{net} = 102.68 - 96.96 = 5.72, less than the equivalent value for Project A. Investors place a lower value on this project — while it has the same *expected* NET (\$20), the NET is risky.

4. We can now close the loop and compute the r_{net} as:

r_{net} = (Expected NET)/PV_{net} - 1 = \$20/\$5.72 - 1 = 2.50 (250%), which reflects the high degree of risk for the net cash flows. We can also derive $Beta_{net}$ = (2.5 - .05)/.07 = 35.0.

5. Finally, we use Booth's result[3] to check that the present values are consistent:

$$r_{net} = (PV_{in}/PV_{net}) \times r_{in} - (PV_{in}/PV_{out}) \times r_{out}$$

So doing yields an identity of r_{net} = .05 for Project A, and 2.5 for Project B.

This example illustrates that outflows of riskier projects must be discounted at a *lower* rate,[4] which could become negative in the case of strongly counter-cyclical outflows. In each case the validity of the results can be evaluated using Booth's relationship.

Notes:

1. Beta(out,mkt) = the covariance of the outflows with the inflows (or the market, per our assumption) divided by the variance of the inflows. We can rewrite this in terms of the correlation coefficient:

$$Beta(out,mkt) = r(out, mkt)S(out)S(mkt)/S^2(mkt),$$

where, r(out,mkt) is the correlation coefficient between the outflows and the inflows (or outflows and the market), S() is the standard deviation and S^2() the variance.

Since we have made S(in) = S(mkt) = S(out), this entire expression reduces to:

$$Beta(out,mkt) = r(out,mkt) = -1.00.$$

2. This yields a present value of the outflows that is *greater* than their future value, which makes sense: the outflow is so highly counter-cyclical that it behaves like insurance— if the markets go down this payment goes up. This places its value at a premium, above the future value.

3. *See* L.D. Booth, *Correct Procedures for Evaluation of Risky Cash Outflows*, J. of Fin. and Quant. Anal., June 1982, at 287-300.

4. Similar results can be found in the case of a multi-year project, although this problem must be solved using a spread sheet.

Consumers usually prefer "safe" predictable outlays over risky ones. In the home-mortgage market, for example, most consumers willingly pay the premium for a fixed rate in order to avoid the risk associated with adjustable-rate mortgages, thus in essence discounting the "safer" outflows at a higher rate. Presumably, consumers would prefer relatively fixed (or at least known) future electric rates to those that fluctuate dramatically due to fuel, all else being equal. Given an equal stream of predictable capital charges as compared to fuel prices, most consumers would rather be obligated to pay the former. Yet this is not the result obtained with the WACC — it equalizes the two streams contrary to consumer preference.[18]

VI. Implementation

Project revenue requirements can be grouped into several risk components as illustrated in **Table 3**. For some of the components it is convenient to calculate the discount rate from an estimated cash-flow beta using standard procedures.[19] The discount rate for other cash-flow components is commonly estimated through a judgmental or "ad hoc" procedure,[20] or using common practice, e.g., certain fixed payments, such as those for fixed O&M or property taxes, are commonly considered "debt-equivalent" cash flows[21] which can be discounted at the firm's after-tax cost of debt. Similarly, certain inflows, such as the tax shields provided by depreciation or investment tax credits, are riskless and can hence be discounted at the after-tax risk-free rate.[22]

The component cash-flow approach allows us to estimate directly discount rates for various revenue-requirement categories, and thus provides a more precise framework for dealing with a set of risk-diverse outflows. The method is commonly accepted, although not frequently implemented since it requires greater sophistication. Any cash flow can be statistically evaluated to estimate a beta, although such rigor is particularly important only in the case of major outflow components, such as fuel. And even in the case of fuel outlays, a rough approximation of the fuel discount rate in IRP is far better than using the WACC, which is generally much too high as a fuel discount rate, and hence significantly biases outcomes in favor of fuel-intensive technologies.

Table 3 indicates a set of discount rates for use on various revenue-requirement categories. The cash flows fall into four convenient risk categories:

1. *Counter-Cyclical (Risky) Outflows*. These are the fuel outlays which generally co-vary negatively with other assets in the economy, and with utility company revenues, to the extent these are cyclical. Fuel outlays are risky because their price rises when the firm's revenues are declining, as illustrated in Figure 2, Panel B.

The discount rate for this category of cash flows is based on an estimated cash-flow beta using standard techniques. Existing data on fuel outlays by electric

Table 3: Nominal Discount Rates For Various After-Tax Cash Flow Components

Cash Flow	Beta[a]	Suggested Discount Rate	Estimation Method
Counter-Cyclical Risk			
Oil and Gas	−0.5 to −1.25	1.0%	Econometric-CAPM
Coal	−0.2 to −0.4	5.0%	
Debt-Equivalent Cash Flows[b]			
Property Taxes	—	5.5%	By Convention
Insurance	—	5.5%	
Fixed O & M	—	5.5%	
Working Capital	—	5.5%	
Riskless Cash Flows[c]			
Depreciation Tax Shields	—	6.5%	By Convention
Tax Credits	—	6.5%	
Pro-Cyclical Risk			
O&M (Variable)	—	8.5%[d]	Judgmental

a. Estimated cash-flow betas using 7% risk free rate, 14.0% expected market return
b. Based on 9% cost of debt and 39% combined, federal-state income tax rate
c. Discount rate based on long-term Treasury rate minus 1.5% term premium
d. Uses the firm's after-tax WACC. Based on 10.4% pre-tax WACC with 50% debt and 10% preferred stock

utilities for the period 1982-91 yield a beta estimate for various fuel types ranging from -0.20 for coal to about -1.25 for gas and heavy fuel oil. This suggests that coal, historically, is relatively less risky than oil and natural gas. Using the CAPM, the estimated fuel betas produce discount rates ranging from 3.3% to 3.7% for coal, to about 0.5 % to -0.9% for oil/gas. Table 3 suggests a proxy rate of 0.0% for oil/gas and 3.5% for coal.

2. *Debt-Equivalent Cash Flows.* These outflows, which include payments for fixed O&M, property taxes, and other relatively predictable outlays, have low risk levels, similar to the bond-interest payments made by the firm.[23] These payments are valued as if they were debt obligations — they are discounted at the after-tax cost of debt as previously discussed.

3. *Riskless Cash Flows.* These include the tax shields resulting from use of energy and other tax credits, accelerated depreciation allowances, and interest deductibility. These tax benefits will accrue as long as the firm has sufficient offsetting income, a fairly riskless assumption in the case of regulated utilities. These benefits or inflows are discounted at the after-tax risk-free rate.

4. *Cyclical Outflows.* These cash outflows behave like those in Panel A of Figure 2. They include most variable O&M expenses. Given the cyclical nature of labor costs and the fact that repairs are sensitive to output, we can assume that these outflows are at least somewhat cyclical — they vary with the firm's net cash flows and can therefore be discounted at the firm's after-tax WACC. It would be useful to estimate the risk of these outflows more closely by examining actual historic outlays.

A. Illustrative Results

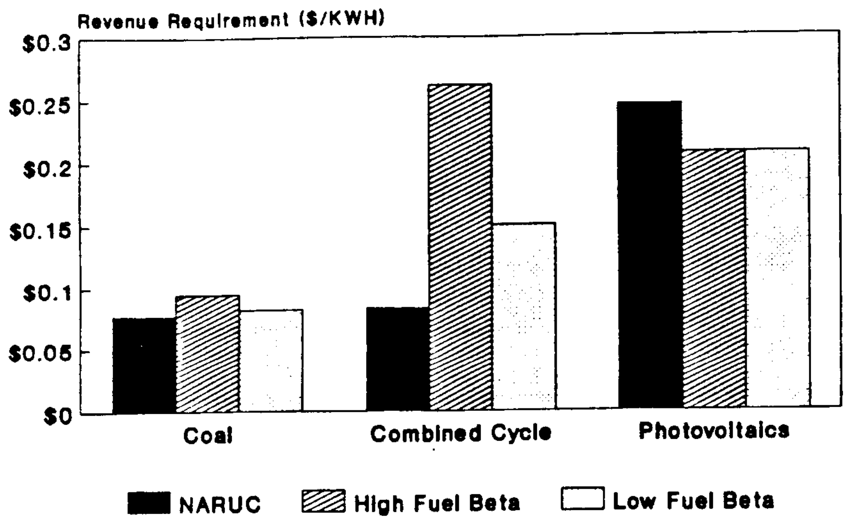
This section compares an illustrative set of risk-adjusted results to a more traditional analysis prepared by the Finance and Technology Committee of the National Association of Regulatory Utility Commissioners (NARUC).[24] The relevant assumptions are listed in **Table 4**. **Figure 3** shows the NARUC base case and the risk-adjusted revenue requirements for coal-fired steam, combined cycle, and photovoltaics. The risk-adjusted results are given for the higher and lower beta estimates shown in Table 3. The discount rates are also given in Table 3. Environmental externalities are not included in the estimates. The dif-

Table 4: NARUC Base-Case Assumptions

Subhead	
General*	
Cost of Equity	12.0%
Percent Equity	50.0%
Cost of Debt	9.0%
Percent Debt	50.0%
Overall WACC	10.4%
Post Tax	8.9%
Marginal Tax Rate	38.0%
Coal*	
Total Capital Costs	$1,200/kW
Fuel Escalation Rate	0.9% (real)
Inflation Rate	5.0%
Capacity Factor	80.0%
O&M Costs	$0.008/kWh
Gas Combined Cycle*	
Total Capital Costs	$500/kW
Projected Fuel Costs	$0.0196/kWh
Fuel Escalation Rate	1.0%
Capacity Factor	30.0%
O&M Costs	$0.0068/kWh
Inflation Rate	5.0%
Photovoltaics*	
Total Installed Capital Costs	$7,000/kW
Expected Life	30 years
Projected Fuel Costs	0
Capacity Factor	27.0%
O&M Costs	$0.005/kWh
Risk-Adjustment (CAPM) Assumptions	
Return on Risk-Free U.S. Government Obligations	7.0%
Expected Market Return	14.0%

* Source: NARUC [1991]

Figure 3: Traditional and Risk-Adjusted Revenue Requirements



ference between the risk-adjusted and the NARUC estimates derives from including the market-determined cost of risk which is primarily affected by fuel-price risk.

The risk-adjusted revenue estimates for coal and gas are higher than NARUC's base case, since the latter implicitly discounts the fuel outlay at the 10.4% WACC. This understates the present value of this outflow significantly.[25] The risk-adjusted results for photovoltaics are below the NARUC base-case values primarily because of the treatment of capital costs. Relative to other revenue requirements, these capital charges are less risky, as shown in Table 3, and will accrue as long as the technology does not become so obsolete that it must be abandoned by the utility. Dollar for dollar, capital outlays must have a lower PVRR.

B. Composite Discount Rates

The component cash-flow approach requires that the revenue requirements be disaggregated into risk categories. It may be useful to develop an overall "composite" discount rate for the revenue requirements of various technologies which produces a PVRR equivalent to that found with the component cash-flow approach. The "composite" rate could then be applied to the annual revenue requirements without disaggregation, as the WACC is used now. Using the NARUC base-case conditions yields the following nominal composite rates: coal-fired steam = 6.5%; combined cycle = 4.5%; photovoltaics = 11.5%. These results mirror the assumed 7% spread between common stocks and riskless T-bills.

VII. Conclusion

The IRP process is designed to identify projects that minimize the present value of costs. This differs from ordinary project-evaluation procedures which maximize the present value of net cash flows. The correct discount rate for IRP evaluations must reflect the varying risk of individual cash-flow components. As currently implemented, the RRM favors expense-intensive over capital-intensive technologies, which makes photovoltaics and other renewables appear less attractive relative to conventional generation.

A framework for evaluating revenue requirement components can help produce better cost estimates in IRP. While rigorous econometric techniques are not always practical, even proxy discount rates, correctly applied to individual cash-flow components, can greatly improve the results.

It is important for planners to begin using discount rates that reflect risk levels of revenue requirement components. The current practice of discounting all outflows using a single discount rate, the WACC, is clearly unsatisfactory and should be abandoned. ■

Endnotes:

1. Planners typically use annual depreciation and earnings components, although these have a present value equal to the initial capital outlay.

2. The sensitivity analysis looks only at the down-side risk since bonds cannot pay *more* than promised.

3. Share values will rise or fall, in response to a project announcement, depending on the project's perceived risk and expected return. This result is seen in the Gordon growth model: P = D/(k-g), where "P" is the current price, "D" is next year's dividend, "k" is the investor's risk-adjusted discount rate for this firm, and "g" is the expected dividend growth rate.

A new project that is riskier than the average risk of the firm will raise k above its previous value. Unless such a project also contributes to proportionately higher levels of D and/or g, the new project will cause P to drop. Conversely, the firm can undertake a new project with a lower expected return than its current portfolio, *without losing share value,* as long as the project causes investors to reduce their estimate of k proportionately. Projects with positive risk-adjusted net present values increase P because incremental project risk is outweighed by the new venture's expected return.

4. Using levelized costs instead yields curves that, though shaped differently, are similarly parallel.

5. In which case, the project has properties more analogous to a lease. *See* S. Awerbuch, Determining a Bid Price for PV-Generated Electricity Under an IPP Agreement, (Report Prepared Under Contract to Sandia Natl. Laboratories, Mar. 1992).

6. R. RAO, FINANCIAL MANAGEMENT: CONCEPTS AND APPLICATIONS 358-60 (Macmillan 1992).

7. Sometimes project outflows are the focus even for unregulated firms, as when managers are seeking the lowest-cost production method, given that revenues are unaffected by the method chosen.

8. Beta is a measure of financial risk. It can be defined as the covariance of project returns with returns to a widely diversified portfolio of assets, divided by the variance of returns on that asset. Betas are widely reported for stocks, but a different form of beta can be computed for individual assets, J.C. Van Horne, Financial Management and Policy 211 (Prentice-Hall 1982); N. SEITZ, CAPITAL BUDGETING AND LONG-TERM FINANCING DECISIONS 261 (Dryden Press 1990); and cash flows, T. COPELAND AND F. WESTON, FINANCIAL THEORY AND CORPORATE POLICY 416 (Addison Wesley 3d ed. 1988).

9. For examples, *see* Seitz, *id.* at ch. 8, 12; R. BREALEY AND S. MYERS, PRINCIPLES OF CORPORATE FINANCE ch. 9 (McGraw Hill 1988); and T. COPELAND AND F. WESTON, FINANCIAL THEORY AND CORPORATE POLICY ch. 10 (Addison Wesley 3d ed. 1988). The Electric Power Research Institute has also addressed appropriate discount-rate estimation under the RRM. *See e.g.*, ELEC. POWER RES. INST., CAPITAL BUDGETING NOTEBOOK 9-13 to 9-22 (RP 1920-03, Nov. 1990); ELEC. POWER RES. INST., EVALUATING THE EFFECTS OF TIME AND RISK ON INVESTMENT CHOICES: A COMPARISON OF FINANCE THEORY AND DECISION ANALYSIS (P-5028, Jan. 1987; ELEC. POWER RES. INST., CAPITAL BUDGETING FOR UTILITIES: THE REVENUE REQUIREMENTS METHOD ch. 2 (EPRI EA4879 Oct. 1986); ELEC. POWER RES. INST., ANALYSIS OF RISKY INVESTMENTS FOR UTILITIES (EA-3214, Sept. 1983).

10. Where diversification is practical, risk is more correctly defined as the co-

variance of project returns with returns to a broadly diversified market portfolio.

11. Discount rates for a set of cash inflows, outflows, and net flows are not independent. Booth develops the analytic relationship. *See* L.D. Booth, *Correct Procedures for Evaluation of Risky Cash Outflows,* J. OF FIN. AND QUANT. ANAL., June 1982, at 287-300. Additional discussion can be found in Seitz, *supra* note 8 at app. A and Copeland and Weston, *supra* note 9 at 414-16.

12. Copeland and Weston, *supra* note 9 at 416.

13. The risk-return point for such projects will always lie above the CAPM capital-market line, i.e.: for their given level of risk, such projects generate above-average returns.

14. *See, e.g.*, Copeland and Weston, *supra* note 9; EPRI Capital Budgeting Notebook, *supra* note 9.

15. The regulated firm may not "see" this risk directly as a consequence of fuel-adjustment which shifts most of the fuel-price risk to ratepayers, although the total risk remains unaltered.

16. U.S. News & World Report, "The Hidden Picture," Apr. 29, 1991, at 50.

17. Fuel outlays are risky to utilities and their ratepayers to the extent that escalating prices prevent total outlays from being reduced quickly enough in response to declining demand. Coal exhibits less fuel-price volatility, although the possibility of carbon taxes significantly raises the cost uncertainty for this fuel as well.

18. This would also be the shareholders' preference, were it not for the fuel-adjustment clause.

19. *See* note 8, *supra*.

20. Rao, *supra* note 6.

21. Brealey and Myers, *supra* note 9 at 473-74.

22. *See, e.g.*, Elec. Power Res. Inst., *supra* note 9 at 3-12, 3-14.

23. Some authors include tax shields in this category as well.

24. Natl. Assn. of Reg. Util. Comm'rs, Electric Power Technology: Options for Utility Generation and Storage, Prepared by the Staff Technology Subcommittee, Finance and Technology Committee, Feb. 1991.

25. The risk-adjusted estimate for conventional technologies may overstate costs to the extent that managers can switch fuels, or mothball plants when prices get too high. Under this view, the fuel-price distribution is truncated at the upper end. Such fuel-switching options are not reflected in these estimates. For estimates of their value, *see* B.F. Hobbs, J. Honious, and J. Bluestein, *What's Flexibility Worth: The Enticing Case of Natural Gas Cofiring,* ELEC. J., Mar. 1992, at 37.