PROJECT FINANCIAL EVALUATION

Introduction to Financial Figures of Merit

An investor, energy policy analyst, or developer may use a variety of figures of merit to evaluate the financial attractiveness of a power project. The choice often depends on the purpose of the analysis. However, most begin with estimates of the project's capital cost, projected power output, and annual revenues, expenses, and deductions. A pro forma earnings statement, debt redemption schedule, and statement of after-tax cash flows are typically also prepared. Annual after-tax cash flows are then compared to initial equity investment to determine available return. For another perspective, before-tax, no-debt cash flows may also be calculated and compared to the project's total cost. The four primary figures of merit are:

Net Present Value: Net Present Value (NPV) is the sum of all years' discounted after-tax cash flows. The NPV method is a valuable indicator because it recognizes the time value of money. Projects whose returns show positive NPVs are attractive.

Internal Rate of Return: Internal rate of return (IRR) is defined as the discount rate at which the after-tax NPV is zero. The calculated IRR is examined to determine if it exceeds a minimally acceptable return, often called the hurdle rate. The advantage of IRR is that, unlike NPV, its percentage results allow projects of vastly different sizes to be easily compared.

Cost of Energy: To calculate a levelized cost of energy (COE), the revenue stream of an energy project is discounted using a standard rate (or possibly the project's IRR) to yield an NPV. This NPV is levelized to an annual payment and then divided by the project's annual energy output to yield a value in cents per kWh. The COE is often used by energy policy analysts and project evaluators to develop first-order assessments of a project's attractiveness. The levelized COE defines the stream of revenues that minimally meets the requirements for equity return and minimum debt coverage ratio. Traditional utility revenue requirement analyses are cost-based, ie., allowed costs, expenses, and returns are added to find a stream of revenues that meet the return criteria. Market-based Independent Power Producer (IPP) and Generating Company (GenCo) analyses require trial-and-error testing to find the revenues that meet debt coverage and equity return standards, but their COEs likewise provide useful information.

Payback Period: A payback calculation compares revenues with costs and determines the length of time required to recoup the initial investment. A Simple Payback Period is often calculated without regard to the time value of money. This figure of merit is frequently used to analyze retrofit opportunities offering incremental benefits and end-user applications.

Financial Structures

Four distinct ownership perspectives were identified for this analysis. Each reflects a different financial structure, financing costs, taxes, and desired rates of return. Briefly, the four ownership scenarios are:

Generating Company (GenCo): The GenCo takes a market-based rate of return approach to building, owning, and operating a power plant. The company uses balance-sheet or corporate finance, where debt and equity investors hold claim to a diversified pool of corporate assets. For this reason, GenCo debt and equity are less risky than for an IPP (see below) and therefore GenCos pay lower returns. A typical GenCo capital structure consists of 35% debt at a 7.5% annual return (with no debt service reserve or letter of credit required) and 65% equity at 13% return. Although corporate finance might assume the debt to equity ratio remains constant over the project's life and principal is never repaid, it is often informative to explicitly show the effect of the project on a stand-alone financial basis. Therefore, to be conservative, the debt term is estimated as 28 years for a 30-year project, and all the debt is repaid assuming level mortgage-style payments. Flow-through accounting is used so that the corporate GenCo receives maximum benefit from accelerated depreciation and tax credits.

Independent Power Producer (IPP): An IPP's debt and equity investment is secured by only the one project, not by a pool of projects or other corporate assets as is the case for a GenCo. In this project finance approach, a typical capital structure is 70% debt at 8.0% annual return (based on 30-year Treasury Bill return plus a 1.5% spread) and 30% equity at a minimum 17% return. A 6-month Debt Service Reserve is maintained to limit repayment risks. Debt term for an IPP project is generally 15 years, with a level mortgage-style debt repayment schedule. (For solar and geothermal projects that are entitled to take Investment Tax Credits, a capital structure of 60% debt and 40% equity should be considered.) Flow-through accounting is used to allow equity investors to realize maximum benefit from accelerated depreciation and tax credits. IPP projects are required to meet two minimum debt coverage ratios. The first requirement is to have an operating income of no less than 1.5 times the annual debt service for the worst year. The second is to have an operating income of about 1.8 times or better for the average year. Because debt coverage is often the tightest constraint, actual IRR may be well over 17%, to perhaps 20% or more. Likewise, with good debt coverage, negative after-tax cash flows in later years of debt repayment (phantom income) are low.

Regulated Investor-Owned Utility (IOU): The regulated IOU perspective analyzes a project with a cost-based revenue requirements approach. As described by the EPRI Technical Assessment Guide (TAG™), returns on investment are not set by the market, but by the regulatory system. In this calculation, operating expenses, property taxes, insurance, depreciation, and returns are summed to determine the revenue stream necessary to provide the approved return to debt and equity investors. Use of a Fixed Charge Rate is a way to approximate the levelized COE from this perspective. IOU capital structure is estimated as 47% debt at a 7.5% annual return; 6% preferred stock at 7.2%; and 47% common stock at 12.0%. Debt term and project life are both 30 years. Accelerated depreciation is normalized using a deferred tax account to spread the result over the project's lifetime. IOUs are not eligible to take an Investment Tax Credit for either solar or geothermal projects.

Municipal Utility (or other tax-exempt utility): The municipal utility uses an analysis approach similar to that of the IOU. Capital structure is, however, assumed to be 100% debt at 5.5% annual return, and the public utility pays neither income tax nor property tax.

Techniques for Calculating Levelized COE

The technique to be used for calculating levelized COE varies with ownership perspective. Two of the four ownership perspectives (IOU and Muni) employ a cost-based revenue requirements approach, while the other two use a market-based rate of return approach. The revenue requirements approach assumes a utility has a franchised service territory and, its rate of return is set by the state regulatory agency. The plant's annual expenses and cash charges are added to the allowed rate of return on the capital investment to determine revenues.

By contrast, the market-based approach (GenCo and IPP) either estimates a stream of project revenues from projections about electricity sales prices or proposes a stream as part of a competitive bid. Annual project expenses, including financing costs, are calculated and subtracted from revenues and an IRR is then calculated. The process of calculating the achieved IRR differs from the revenue requirements approach where the rate of return is pre-determined.

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COEs can be calculated for both revenue requirements and rate of return approaches. When pro forma cash flows in dollars of the day are projected for both approaches, the effects of general inflation are captured in debt repayment, income taxes, and other factors. Next, revenues are net present valued in current dollars. The NPV is then levelized to current dollars and/or constant dollars using appropriate discount rates for each. These are then levelized and normalized to one unit of energy production (kWh) to calculate current and constant dollar COEs. This document cites levelized constant dollar COEs in 1997 dollars.

Table 1 provides an example of the results that may be obtained for the technologies characterized in this document. The table shows levelized COE for the various renewable energy technologies assuming GenCo ownership and balance sheet finance.

Table 1. Levelized Cost of Energy for GenCo Ownership

		Levelized COE *(constant 1997 cents/kWh)*				
Technology	Configuration	1997	2000	2010	2020	2030
Dispatchable Technologies						
Biomass	Direct-Fired	8.7	7.5	7.0	5.8	5.8
	Gasification-Based	7.3	6.7	6.1	5.4	5.0
Geothermal	Hydrothermal Flash	3.3	3.0	2.4	2.1	2.0
	Hydrothermal Binary	3.9	3.6	2.9	2.7	2.5
	Hot Dry Rock	10.9	10.1	8.3	6.5	5.3
Solar Thermal	Power Tower	--	13.6*	5.2	4.2	4.2
	Parabolic Trough	17.3	11.8	7.6	7.2	6.8
	Dish Engine -- Hybrid	--	17.9	6.1	5.5	5.2
Intermittent Technologies						
Photovoltaics	Utility-Scale Flat-Plate Thin Film	51.7	29.0	8.1	6.2	5.0
	Concentrators	49.1	24.4	9.4	6.5	5.3
	Utility-Owned Residential (Neighborhood)	37.0	29.7	17.0	10.2	6.2
Solar Thermal	Dish Engine (solar-only configuration)	134.3	26.8	7.2	6.4	5.9
Wind	Advanced Horizontal Axis Turbines					
	- Class 4 wind regime	6.4	4.3	3.1	2.9	2.8
	- Class 6 wind regime	5.0	3.4	2.5	2.4	2.3

* COE is only for the solar portion of the year 2000 hybrid plant configuration.

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Financial Model and Results

The FATE2-P (Financial Analysis Tool for Electric Energy Projects) financial analysis model was used to analyze the data provided in the Technology Characterizations. This spreadsheet model was developed by Princeton Economic Research, Inc. and the National Renewable Energy Laboratory for the U.S. Department of Energy. FATE2-P can be used for either the revenue requirements or the discounted rate of return approach. It is used by the DOE renewable energy R&D programs for its planning activities. The model is publicly available, and has been used by a number of non-DOE analysts in recent studies. Other models will produce the same results given the same inputs.

The COEs in Table 1 were prepared using the FATE2-P model, assuming GenCo ownership. The results reflect a capital structure of 35% debt with a 7.5% return (with no debt service reserve or letter of credit required) and 65% equity at 13%. A 40% tax rate is assumed. Inflation was estimated at 3%, but electricity sales revenues were assumed to increase at inflation less one half percent, or 2.5%, corresponding to a real rate of -0.5%. In similar fashion, the Department of Energy's Annual Energy Outlook 1997 forecasts that retail electricity prices will decline by 0.6% real, assuming inflation of 3.1%. Anecdotal information from IPPs suggests that they also presently escalate their wholesale power prices at less than inflation.

Table 1 distinguishes between dispatchable and intermittent technologies to highlight the different services and value that each brings to the grid. COEs from the two types of services should not generally be compared.

By comparison, Table 2 shows COEs for year 2000 biomass gasification, to show how the financial requirements of the different ownership perspectives affect COE. The GenCo case is interesting to examine because it represents an evolving power plant ownership paradigm. The municipal utility (Muni) case is of interest because the lower cost of capital for Munis, combined with their tax-exempt status, makes them attractive early market opportunities for renewable energy systems.

Table 2. Cost of Energy For Various Ownership Cases for Biomass Gasification in Year 2000

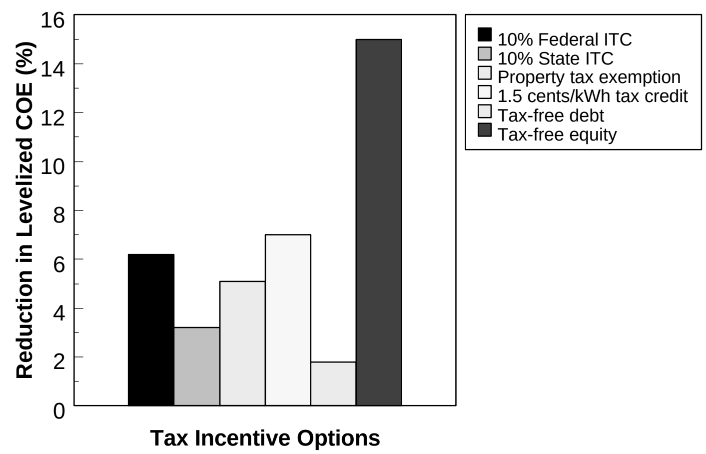
Financial Structure	Levelized Cost of Energy (constant 1997 cents/kWh)
GenCo	6.65
IPP	7.33
IOU	6.39
Muni	5.09

As discussed, calculating a levelized COE in the GenCo and IPP cases requires an iterative process. In this process, the goal is to identify the stream of revenues that is needed to ensure the project some minimally acceptable rate of return. This revenue stream is found by adjusting the assumption about first year energy payment (often termed the bid price) until the resulting total project revenues produce the required rate of return subject to meeting debt coverage requirements and minimizing phantom income for IPPs, and to meeting minimum equity returns for GenCos. In the analyses discussed here, the energy sales revenues are assumed to increase through the entire project life only at the rate of inflation minus one half percent (2.5%).

A few common assumptions underlie all the ownership/financing types. First, COE results are expressed in levelized *constant* 1997 dollars, consistent with the cost data in each TC, that are also stated in 1997 dollars. Second, general inflation is estimated at 3% per year, so annual expenses like operations and maintenance (O&M) and insurance escalate at 3% per year despite the fact that IPP and GenCo revenues increase at only 2.5%. Inflation also affects the values chosen for interest rates and equity returns. Tax calculations reflect an assumed 40% combined corporate rate (i.e.,

Tax Policy Analyses:
An Example Use of Financial Modeling

The effect of the tax code on the relative attractiveness of various electricity generating options can be analyzed by a financial model such as FATE2-P. A frequently mentioned goal of tax policy is to provide a "level playing field" for all technology options. One study, summarized in the figure, has shown that capital-intensive power projects, such as parabolic trough plants, pay a higher percentage of taxes than operating expense-intensive projects, such a fossil fuel technologies (through property taxes, sales taxes, etc.). Changes to the tax code have been suggested as a way to remove this potential bias.



Reference: Nathan, N.H., and R.A. Chapman, Tax Equity - Solar Electric Power Plants, National Power Company, Oakland, CA, for the California Energy Commission: 1994.

The graph shows the reduction in levelized energy cost for a number of possible tax system-based incentives. The 10% federal investment tax credit currently exists. The study cited in the figure compared taxes paid by solar thermal electric and fossil technologies. The analysis showed that approximate tax equity was achieved with a 20% federal investment tax credit and solar property tax exemption. Overall, this reduces levelized cost of energy by 20-30%. Although these results apply to the specific case tested, it shows the approximate level of tax incentives necessary to gain parity between solar thermal and conventional technologies. Since tax codes vary by state, each state could have a unique mix of additional tax incentives to provide incentives for solar for their unique tax environment.

federal at 35% and state at 7.7%, with state deductible from federal). In addition, depreciation periods and rates are those set by current law. Tax credits were used if set by law as permanent as of November 1997. Thus, the 10% Investment Tax Credit for solar and geothermal is included, but not the production tax credits for wind or closed loop biomass that are not available after mid-1999.

For the solar, dish hybrid cases and the early solar trough hybrid cases, the analyses in Table 1 assumed that natural gas costs $2.25/MMBtu in 1997 dollars and that it would escalate at 3% per year, equivalent to the inflation rate. The heat rate for the dish system was assumed to be 11,000 Btu/kWh in 2000 and 9000 Btu/kWh in 2005 and later. The trough TC included a heat rate in its hybrid system characterization.

Payback Period

For co-fired biomass a simple payback period was calculated instead of a levelized COE. As a retrofit opportunity, co-firing will be pursued by plant owners only if paybacks of a few years can be achieved. Simple Payback is defined as total capital investment divided by annual energy savings, to obtain years until payback. In simple payback, no consideration is given to the time value of money and no discount rates are applied to dollar values in future years. In the co-fire analyses, the simple payback is defined by comparing capital expenditures required for the retrofit with fuel cost and other savings. As an example, the technology described in the biomass co-fire technology characterization yields a 4.1-year payback in 2000.