re vision Supporting visionary renewable energy projects

# Economic Methodology for the Evaluation of Emerging Renewable Technologies

**Prepared by RE Vision Consulting, LLC**

**October 2011**

Document Prepared for DOE by:
RE Vision Consulting, LLC
www.re-vision.net
Project Manager: Mirko Previsic
Email Address: mirko@re-vision.net

# DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

This document was prepared by the organizations named below as an account of work sponsored or cosponsored by the U.S. Department of Energy (DoE). Neither DoE, RE Vision Consulting, LLC (re vision), any cosponsor, the organization (s) below, nor any person acting on behalf of any of them.

(A) Makes any warranty or representation whatsoever, express or implied, (I) with respect to the use of any information, apparatus, method, process or similar item disclosed in this document, including merchantability and fitness for a particular purpose, or (II) that such use does not infringe on or interfere with privately owned rights, including any party's intellectual property, or (III) that this document is suitable to any particular user's circumstance; or

(B) Assumes responsibility for any damages or other liability whatsoever (including any consequential damages, even if RE Vision or any RE Vision representative has been advised of the possibility of such damages) resulting from your selection or use of this document or any other information, apparatus, method, process or similar item disclosed in this document.

The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or RE Vision Consulting, LLC. The development of this document was funded by the United States Department of Energy.

Organization(s) that prepared this document:

RE Vision Consulting, LLC

## Table of Contents

# 1. Introduction

Sandia National Laboratory (SNL) is leading an effort to develop reference models for marine and hydrokinetic technologies and wave and current energy resources. This effort will allow the refinement of technology design tools, accurate estimates of a baseline levelized cost of energy (LCoE), and the identification of the main cost drivers that need to be addressed to achieve a competitive LCoE. As part of this effort, RE Vision Consulting is responsible for the assessment of cost and economic profiles of the technologies studied. In addition, Re Vision is leading a number of technical tracks within this program.

This document presents a methodology and a set of financing parameters for the benchmarking of emerging renewable technologies. These two fundamental questions guide the analysis that follows:

1. What is the current cost of energy from this technology and what financial incentives would encourage its adoption in the marketplace?

2. How does this technology compare to mature renewable technologies and what should R&D be focused on to create more competitive technologies in the long term?

An analysis that produces answers to these questions requires the use of two economic models, as establishing initial costs of electricity (CoE) requires focusing on the short term and evaluating the ultimate potential of technologies requires taking a long-term approach. The major differences between these two models are their risk profiles and their associated required returns of investment.

The cost of borrowing capital is largely a function of the perceived project risk by the investor. For example, since marine renewable technologies are at a relatively immature stage of technical development, investors consider this to be a high-risk sector. This high-risk profile translates directly into higher borrowing costs compared to more mature technologies.

This methodology presents two approaches for determining the CoE for emerging renewable technologies: Early Adopter and Commercial.

The *Early Adopter* CoE method takes project risks and higher borrowing costs into account when formulating the analysis. This approach fosters a better understanding of the present-day CoE for a hypothetical plant built today. This information enables policymakers to determine what types of price-support levels are needed to facilitate plant construction in today's marketplace.

The Early Adopter CoE may be determined by using a simple Internal Rate of Return (IRR) model. Allowing investors to quickly survey projects, IRRs are computed pre-tax and thus reflect an overall increase in CoE for an equivalent IRR. These tax benefits typically lower initial CoE because accelerated depreciation rules allow tax benefits to occur in the early phases of a project. IRR target rates of 12-20% have been observed in various Early Adopter renewable energy projects.

The *Commercial* CoE approach benchmarks the technology against other more mature technologies. This requires assuming that the risk level of the technology is similar to that of mature renewable technology sectors, such as wind or solar. Because of this assumption, financing terms for this method are the same or similar for both emerging and mature technologies. This way, policymakers may benchmark relative competitiveness for the emerging technology through comparisons with other more mature technology options.

 

The Commercial CoE includes the Technology CoE, which is determined by using a Utility Generator (UG) economic model. This assumes that the economic conditions for the future of the emerging technology are similar to those of mature energy projects built today. Financing of those projects is carried out using a mix of debt and equity. Taxation costs and benefits are also considered in the analysis.

These approaches to determining CoE are complementary in that they provide answers to different questions, thus separating perceived technology-related risks from a technology's long-term value. This issue has long generated confusion for stakeholders, as the variance of questions and answers has implied a larger than actual disparity between assessments.

No single method for modeling a power plant should be thought of as the correct way for every scenario. Mitigating factors, such as an organization's access to capital, its purchasing power, and specific contract terms, often determine project risks and the associated cost of money. The methodologies and rates chosen for this methodology represent "typical" practices and standards for the electric industry.

Energy costs may be computed in either Constant Dollars, which do not include the effects of inflation, or in Current Dollars, which do. When comparing different investment alternatives, the most economical option will not change regardless of which method is used. Results of financial models should be presented with indications as to whether Constant Dollars or Current Dollars are used, as well as the reference year for input cost data. For Current Dollar analysis, the assumed inflation rate should also be included.

When working with Constant Dollars, real interest rates are used; whereas when working with Current Dollars, nominal interest rates are used. The real rate (adjusted for inflation) is defined by this equation:

$$\text{real rate} = ((1 + \text{nominal rate})/(1 + \text{inflation rate})) - 1)$$

## 2. Commercial Cost of Electricity Calculation

The proposed methodology is based on Generally Accepted Accounting Practices (GAAP) for regulated utilities. The cost of electricity (CoE) is computed by levelizing a power plant's annual revenue requirements over the service life of the plant and dividing that by the plant's annual output.

Regulated utilities are permitted to set electricity rates (i.e., collect revenue) that recover fixed and operating costs and provide a regulated rate of return on investments in generation, transmission, distribution, and metering. This return must enable the Utility Generator (UG) to maintain its financial credit as well as to attract the capital required for replacement, expansion, and technological innovation. It must also be comparable to what is earned by other businesses experiencing similar risk.

The following steps and associated formulations are used to calculate the commercial CoE.

### *Step 1: Determine Annual Revenue Requirements*

Annual revenue requirements are simply equal to the costs incurred by the project each year. Yearly costs typically are comprised of the following components: Debt Principal, Debt Interest, Return on Equity, State Taxes, Federal Taxes, State Tax Incentives, Federal Tax Incentives, Accelerated Depreciation, Property Taxes, and Insurance. Over the life of the project, these revenue requirements may change and thus need to be brought back to Net Present Value (NPV) to properly levelize the annual cost.

In a regulated UG framework, the annual cost to operate the power plant is defined as its "annual revenue requirement" (i.e., the equivalent in revenue that would make the project break even). In a regulated market, the UG can adjust its rates to provide cost recovery for its assets with a stipulated return.

### *Step 2: Levelizing Annual Revenue Requirements*

Annual incurred costs are levelized by summing the NPVs for each year. The NPV is calculated using a discount rate that is determined by the cost of money. In this case, the capital finance structure (i.e., the mix of equity and debt known as the weighted average cost of capital) is used to calculate the pre-tax discount rate for the project. Using this pre-tax discount rate and the applicable composite tax rate (i.e., a single value for the combined state and federal tax), the after-tax discount rate can be determined and then used to calculate the NPV.

### *Step 3: Calculating the Fixed Charge Rate*

The Fixed Charge Rate (FCR) is the percentage of the total plant cost that is required over the project life per year to cover the minimal annual revenue requirements. This FCR concept can be compared to a fixed-rate home mortgage where a fixed annual payment pays off the principal and interest for a set term. The FCR is calculated in three steps:

1) Calculate Capital Recovery Factor (CRF) as follows:

$$CRF = \frac{Discount\ Rate}{(1 + Discount\ Rate)^{Book\ Life} - 1} + Discount\ Rate$$

This formula indicates that the CRF is a direct function of the Discount Rate (yearly cost of money) and the Book Life (project duration in number of years).

2) Calculate the levelized annual charges by multiplying the CRF by the NPV.

3) Calculate the levelized annual FCR by dividing the levelized annual charges by the Total Plant Investment (TPI) or Book Cost.

***Step 4: Calculating the Cost of Electricity***

The levelized cost of electricity is calculated by dividing the annual cost of the power plant by the Annual Energy Production (AEP). Since the annual Operating and Maintenance (O&M) cost and Levelized Overhaul and Replacement (LO&R) costs were not previously considered, they are found in the formula below, which computes the levelized cost of electricity (CoE) is:

$$COE = \frac{(TPI * FCR) + (O\&M) + (LO\&R)}{AEP}$$

where:

| | | |
|---|---|---|
| TPI | = | Total Plant Investment |
| FCR | = | Fixed Charge Rate (percent) |
| O&M | = | annual Operating and Maintenance cost |
| LO&R | = | periodic Levelized Overhaul and Replacement cost |
| AEP | = | Annual Energy Production |

The AEP is assumed to be constant for the life of the project.

## 3.1. Cost Components

The elements of the cost breakdown for a typical marine hydrokinetic power plant are described in this section. All capital expenditures are defined as installed cost and expressed in constant dollars with 2011 as the reference year. The installed cost includes shipping and commissioning cost elements. The cost breakdown structure outlined below allows comparing different generation alternatives and identifying cost components of a particular marine hydrokinetic power conversion design.

- *Development costs* are incurred through developing a power plant. These may include engineering services, permitting, equipment deposits, leasing costs, and other costs prior to construction.

- The *installed capital cost* is also known as the Total Plant Cost (TPC) for procuring and installing all components of the marine hydrokinetic power plant. This includes any devices, electrical infrastructure and interconnection, and port and maintenance facilities associated with the plant.

- *Construction loan interest* refers to interest incurred on loans during the first two years of construction.

- *Operational costs* are the levelized annual costs incurred each year after the Commercial Operation Date (COD), including repairs, both scheduled and unscheduled, personnel, insurance, and facilities.

 

- The *Total Plant Investment (TPI)* is the amount of capital required to build the power plant, where TPI = TPC + Construction Interest. Its present value is referenced to the COD and represents all the capital required up to the COD. The TPI does not include the development cost.

## 3.2. Income Taxation

This project assumes a federal rate of 35% and a state rate as shown in Table 1. The calculation of an effective (composite) tax rate (i.e., federal and state) is not simply an addition of federal and state taxes, as it reflects how a portion of state income taxes are deductible from overall federal taxes.

**Table 1 - State, Federal, and Effective Tax Rates**

| State | State Tax Rate | Federal Tax Rate | Effective Rate |
|---|---|---|---|
| CA | 8.84% | 35.00% | 40.75% |
| HI | 6.02% | 35.00% | 38.91% |
| MA | 9.50% | 35.00% | 41.18% |
| ME | 8.93% | 35.00% | 40.80% |
| OR | 6.60% | 35.00% | 39.29% |
| WA | 0.00% | 35.00% | 35.00% |

To simplify the analysis and make the model applicable to all markets within the U.S., an effective tax rate of 40% is used as an approximation.

What follows are the primary tax-related incentives for renewable energy power plants:

- Modified accelerated cost recovery system depreciation schedule
- Production tax credit
- Investment tax credit
- Renewable Portfolio Standards (RPS)/Renewable Energy Certificates (RECs)

Power plants that generate electricity from renewable energy resources qualify under the Internal Revenue Code section 168 for an accelerated cost recovery period under the Modified Accelerated Cost Recovery System (MACRS) depreciation schedule, as shown in Table 2. The IRS explicitly mentions solar, wind, and geothermal as examples of qualifying renewable resources.

**Table 2 - Modified Accelerated Cost Recovery System (MACRS) Depreciation Schedule**

| Year | Depreciation |
|---|---|
| 1 | 20.00% |
| 2 | 32.00% |
| 3 | 19.20% |
| 4 | 11.52% |
| 5 | 11.52% |
| 6 | 5.76% |

Tax-filing entities, such as corporations, may employ different tax depreciation assumptions for financial accounting (i.e., book) versus tax accounting purposes as long as these assumptions conform to GAAP. Accordingly, entities tend to apply more conservative depreciation assumptions (such as straight line depreciation) for financial accounting purposes to accentuate earnings; whereas they apply more accelerated depreciation assumptions for tax accounting to defer taxable income. This difference between the effective book and tax depreciation rates results in an annual variance between income taxes actually paid and those that would have been paid under book depreciation assumptions over the book life of the plant. The difference is referred to as deferred income tax.

A utility is not allowed to earn a rate of return on deferred taxes. A renewable energy project will show negative taxes in the first couple of years of operation (mainly because of accelerated depreciation). If a renewable energy project were treated as an individual entity, the negative values would need to be carried forward to future years that have actual tax obligations to which the deductions could be applied. If a renewable energy project is a part of a utility's generation assets, it is likely that tax deductions will have a significant net impact on the bottom-line of a utility or Independent Power Producer (IPP) in the early years of operation. For the purpose of calculating the cost of energy of marine hydrokinetics, these tax incentives are treated as direct benefits to the project during the year in which they occur.

The following are additional tax benefits that could improve the economic profile of marine hydrokinetic projects.

The Federal Government provides a Production Tax Credit (PTC) as an incentive for development of clean, renewable, domestic wind energy. Originally introduced through the Energy Policy Act of 1992, the PTC grants 1.5¢ per kilowatt-hour for the first ten years of operation to wind plants brought on line before June 30, 1999. The credit has been extended several times and rises with inflation.

The Investment Tax Credit (ITC) is a 30% tax credit for eligible equipment for small wind and solar power plants. It was extended to all facilities eligible for the PTC through December 31, 2012, with the option to take the 30% tax credit as a Treasury Department grant. The ITC may be taken *instead of* the PTC, but not in addition to the PTC.

Several states have set renewable portfolio standards for their publically owned utilities, which must source a certain percentage of their electricity generation from renewables by certain dates. This creates market demand for renewables. Although marine hydrokinetic power plants are not explicitly mentioned in all state laws, it is expected that they will eventually qualify as renewables, Renewable energy credits are certificates generated by renewables-sourced electricity and have varying market value. Their value and implementation vary in each state, and they create an additional market value for renewables.

There are several state-level investment tax credits that may apply to marine hydrokinetic projects. However, they are not explicitly addressed in this methodology.

 

## 3.3. Financing Assumptions

Table 3 shows a standard set of financing assumptions for characterizing these projects.

**Table 3 – Financing Assumptions**

| | |
|---|---|
| Evaluation Period | 20 years |
| Rate of Return on Equity RROE (real) | 9.7% |
| Rate of Return on Equity RROE (nominal) | 13.0% |
| Inflation Rate | 3.0% |
| Debt Fraction | 50% |
| Debt Interest Rate (nominal) | 8% |
| Debt Interest Rate During Construction (nominal) | 8% |
| Loan Term | 20 years |
| Corporate Tax Rate (combined Federal and State) | 40% |
| Depreciation (non-hydro renewables) | 5 year MACRS |

Renewables-specific tax benefits (except for accelerated depreciation) are not considered for this methodology because they are restricted by location, and hence difficult to generalize.

The above financial assumptions result in a FCR of 9.7%. Multiplying this figure by the upfront capital cost allows the annualized cost of the investment to be determined using a single factor. Dividing this annualized cost by the annual power production yields CoE.

## 3.4. Justification for Financial Assumptions

Most of the financial assumptions for this model are based on what the National Renewable Energy Laboratory (NREL) used for their Electricity Futures Study. This section outlines those assumptions.

• *Rate of Return on Equity* (RROE) has varied very little for the past 20 years, staying in the 10.0-12.9% range. During this period, the average awarded RROE has been 11.2%, though this varies from state to state and by type of ownership (investor vs. merchant). Additionally, The National Energy Technology Laboratory (NETL) recommends a 20% RROE for IPP development of fossil fuels-based resources. Taking these data together, this study uses a nominal 13.0% RROE, thus covering a wide range of corporations and electric generation projects.

• A *Debt Fraction* of 50% has been assumed for this study. The figure reflects data taken from a broad range of industry practices. While the NETL recommends debt ratios of 45-70%, the Edison Electric Institute reports investor-owned utilities as having recent aggregate Debt Fractions in the 55-60% range.

• This study assumes an 8% *Debt Interest Rate* as that estimate is in line with the Energy Information Administration's long-term corporate bond interest rate forecast of 7.6%. Furthermore, the cost of debt for project-financed facilities is often indexed to a benchmark interest rate, such as the London Interbank Offered Rate (LIBOR). Depending on the risk of a particular project, an additional 1-5% premium is typically added to the benchmark rate. Since LIBOR has averaged 4.3% for the past 20 years, and the Effective Federal Funds Rate has averaged 5.5% for the past 50 years, this approach supports assuming an 8% Debt Interest Rate.

 

# 3. Early Adopter Technology Cost of Energy Calculation

The proposed methodology to compute the Cost of Electricity (CoE) from early adopter plants is based on a simple Internal Rate of Return (IRR) assessment of the project's cash flows. This method adapts a Non-Utility Generator (NUG) model for the purposes of this project.

The key differences between Utility Generator (UG) and NUG models are:

- Whereas UGs traditionally have had an *Obligation to Serve*, providing reliable electric service, NUGs develop a project for its potential economic rewards and can sell power wholesale to a utility. NUGs may also sell to the customer or power pool on a retail basis.

- *Rates* for UGs are usually set using the revenue requirements approach, and NUGs set the prices as high as the market will allow.

- Customers of UGs bear the *Risks* associated with prudent investments. Since customers, not utilities, bear the risk, UGs earn a lower rate of return on investments associated with a monopoly. NUGs bear the risks associated with their investments but can mitigate them to the extent that they negotiate contracts for energy sales.

NUGs can be classified into different types; however, for purposes of this analysis, we assume that the NUG is selling power at a fixed contracted price to the service area utility through a power purchase agreement. This is the common structure for other renewable IPPs, such as wind. It has less risk than a full merchant power plant that bears an electricity price risk.

## 4.1. Development of an Economic Pro Forma for an NUG

Despite the variety of methods for evaluating Non-Utility Generator (NUG) power projects, all of them require calculating cash flows. The cash flows represent all revenues from the sale of electricity less the sum of all expenses, debt service and income taxes. The net cash flow represents cash available to equity holders. Thus, performing an IRR calculation on the net cash flows reveals the IRR for the whole project.

Because pilot and early adopter projects are considered risky investments, it is unlikely that it would be possible to secure any debt and it is assumed that these projects are financed with 100% equity.

The forecast of revenues over the service life of a power plant is one of the most critical aspects of the economic analysis. The analysis requires a forecast of market prices or a forecast of competitive contract prices with utilities. In a deregulated market, prices need to be forecast by time-of-day and time-of-year. Renewables are generally paid little for the capacity value of energy, so this methodology assumes only an energy component and a fixed average power sales price.

What follows is a snap-shot of a typical cash flow analysis. Figure 1 shows a model where taxation is considered. The model shown in Figure 2 does not consider taxation.

 

## Figure 1 – Example IRR Model (Including MACRS Accelerated Depreciation)

**Non-Utility Generator Model: Pilot Plant**

| | | |
|---|---|---|
| Plant Size: | 102,824 | kW |
| Total Plant Cost: | $ 256,883,398 | |
| Annual Plant Cost: | $ 5,690,349 | /yr |
| | | |
| Construction cost year 1: | $ 128,441,699 | |
| Construction cost year 2: | $ 128,441,699 | |
| Construction interest year 1: | $ 10,275,336 | |
| Construction interest year 2: | $ 10,275,336 | |
| Value of payments year 1: | $ 7,769,630 | |
| Value of payments year 2: | $ 6,756,200 | |
| Construction loan costs: | $ 14,525,830 | |
| | | |
| Total Plant Investment: | $ 271,409,229 | |
| | | |
| Estimate | | |
| Fixed PPA Energy Price/COE | $0.133 | /kWh |
| Target IRR | 0.15 | |

| Year | 0 | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|
| Annual Energy Production (kWh) | | 251920933 | 251920933 | 251920933 | 251920933 | 251920933 |
| Annual Revenue | | $ 33,389,448 | $ 33,389,448 | $ 33,389,448 | $ 33,389,448 | $ 33,389,448 |
| Fixed Annual Plant Cost (O&M) | | $ 5,690,349 | $ 5,861,059 | $ 6,036,891 | $ 6,217,998 | $ 6,404,538 |
| Book Value (straight line dep.) | | $ 256,883,398 | $ 239,757,838 | $ 222,632,278 | $ 205,506,719 | $ 188,381,159 |
| Annual Operating Costs | | $ 5,690,349 | $ 5,861,059 | $ 6,036,891 | $ 6,217,998 | $ 6,404,538 |
| Annual Operating Income | | $ 27,699,099 | $ 27,528,389 | $ 27,352,557 | $ 27,171,450 | $ 26,984,910 |
| MACRS Depreciation Schedule | | 20% | 32% | 19.2% | 11.52% | 11.52% |
| Depreciation | | $ 51,376,680 | $ 82,202,687 | $ 49,321,612 | $ 29,592,967 | $ 29,592,967 |
| Income Tax | | $ 11,079,640 | $ 11,011,355 | $ 10,941,023 | $ 10,868,580 | $ 10,793,964 |
| Net Total Taxes | | $ (40,297,040) | $ (71,191,332) | $ (38,380,590) | $ (18,724,387) | $ (18,799,003) |
| Net Annual Cash Flow | $ (271,409,229) | $ 67,996,139 | $ 98,719,721 | $ 65,733,147 | $ 45,895,838 | $ 45,783,914 |
| **Internal Rate of Return** | **15.00%** | | | | | |

## Figure 2 – Example IRR Model (No Taxes Considered)

**Non-Utility Generator Model: Pilot Plant - NO TAXES**

| | | |
|---|---|---|
| Plant Size: | 102,824 | kW |
| Total Plant Cost: | $ 256,883,398 | |
| Annual Plant Cost: | $ 5,690,349 | /yr |
| | | |
| Construction cost year 1: | $ 128,441,699 | |
| Construction cost year 2: | $ 128,441,699 | |
| Construction interest year 1: | $ 10,275,336 | |
| Construction interest year 2: | $ 10,275,336 | |
| Value of payments year 1: | $ 7,769,630 | |
| Value of payments year 2: | $ 6,756,200 | |
| Construction loan costs: | $ 14,525,830 | |
| | | |
| Total Plant Investment: | $ 271,409,229 | |
| | | |
| Estimate | | |
| Fixed PPA Energy Price/COE | $0.210 | /kWh |
| Target IRR | 0.15 | |

Solve for Cost of Electricity

| Year | 0 | 1 | 2 | 3 | 4 | 5 | 6 |
|---|---|---|---|---|---|---|---|
| Annual Energy Production (kWh) | | 251,920,933 | 251,920,933 | 251,920,933 | 251,920,933 | 251,920,933 | 251,920,933 |
| Annual Revenue | | $ 52,932,610 | $ 52,932,610 | $ 52,932,610 | $ 52,932,610 | $ 52,932,610 | $ 52,932,610 |
| Fixed Annual Plant Cost (O&M) | | $ 5,690,349 | $ 5,861,059 | $ 6,036,891 | $ 6,217,998 | $ 6,404,538 | $ 6,596,674 |
| Book Value (straight line dep.) | | $ 256,883,398 | $ 239,757,838 | $ 222,632,278 | $ 205,506,719 | $ 188,381,159 | $ 171,255,599 |
| Annual Operating Costs | | $ 5,690,349 | $ 5,861,059 | $ 6,036,891 | $ 6,217,998 | $ 6,404,538 | $ 6,596,674 |
| Annual Operating Income | | $ 47,242,261 | $ 47,071,550 | $ 46,895,719 | $ 46,714,612 | $ 46,528,072 | $ 46,335,936 |
| Net Annual Cash Flows | $ (271,409,229) | $ 47,242,261 | $ 47,071,550 | $ 46,895,719 | $ 46,714,612 | $ 46,528,072 | $ 46,335,936 |
| **Internal Rate of Return** | **14.98%** | | | | | | |

 

## 4.2. Financial Indicators

The net present value (NPV) and the internal rate of return (IRR) are financial measures of the project that reflect the present worth of profit over the service life and the profitability of the project, respectively.

**Net Present Value (NPV)**

The NPV represents the present value (or present worth) of profit using the time value of money. This calculation results from discounting the net cash flows at the minimum acceptable rate of return for the equity investor. The method is also referred to as the discounted cash flow method.

The net present value must be defined at a certain point in time. Frequently, the NPV is calculated at the commercial operation date. In this case, the total capital requirement (at the commercial operation date) is subtracted from the net cash flows that are discounted or brought back to the same date.

**Internal Rate of Return (IRR)**

The IRR addresses the profitability of a project. The IRR is defined as the discount rate that sets the present worth of the net cash flows over the service life equal to the equity investment at the commercial operating date.

An IRR of 20% does not necessarily mean that the net cash flows will represent 20% of the equity investment for each and every year of the service life. However, an IRR of 20% does mean that the equity investor will earn an equivalent of 20% of the outstanding balance each year. The balance will be reduced in some fashion over the life of the plant.

Many companies have a minimally acceptable IRR that must be met before a potential project is seriously considered. The minimum acceptable rate is known as the hurdle rate. It can be used to screen potential projects based on their IRR.

There are several caveats to be aware of when calculating the IRR:

- The IRR solution is a trial and error solution that is typically solved by a convergence routine available in spreadsheet software.

- The solution is based on solving an “n-th” degree polynomial that may have multiple real positive roots. More than one change in the sign of the coefficients of the net cash flows is an indication of multiple positive roots.

- Changes in the IRR are not scalar and a small change in the cash flows can have a large effect on the IRR.

- Comparisons of the IRR may be misleading. Although the IRR allows investors to rank options based on their potential rate of return, it does not take into account a project’s size. For example, it does not allow an analyst to capture a $1 million project with a 25% IRR and a $10 million alternative having a 20% IRR. An incremental analysis may be required.

 

## 4.3 Economic Model Assumptions

Although virtually no data are available in the public domain on the expected rates of returns from investors that finance early adopter projects, discussions with different financing experts in this field showed that expected IRRs are on the order of 12-20%. However, some of the experts discussed these expected returns in pre-tax terms and others incorporated the tax benefits coming from investing into renewable energy projects. Further complicating the issue is how some of the discussions centered on international projects for which a limited understanding of the tax benefits exists. To simplify matters, it was decided to target a pre-tax IRR of 15% and to compute the CoE based on that target. A 15% pre-tax IRR is equivalent to about a 22% IRR, if accelerated depreciation is considered as part of the investment. Additional tax benefits may accrue, depending on where the project is built.

Finally, it was felt that a 20-year project life was unrealistic with these early adopter technologies and the project duration was reduced to 15 years. Table 4 provides a summary of economic assumptions for the methodology.

**Table 4 – Summary of Economic Assumptions**

| | |
|---|---|
| Evaluation Period | 15 years |
| Rate of Return on Equity RROE (real) | 12.0% |
| Rate of Return on Equity RROE (nominal) | 15.0% |
| Inflation Rate | 3.0% |
| Equity Fraction | 100% |
| Debt Interest Rate During Construction (nominal) | 8% |
| Corporate Tax Rate (combined Federal and State) | N/A |
| Depreciation | Straight-Line |