8. Financial Assumptions

This chapter presents the financial assumptions used in the EPA Base Case v.5.13 along with an in-depth explanation of the theoretical underpinnings and methods used to develop the two most important financial parameters – the discount rate and capital charge rate. Investment options in IPM are selected by the model given the cost and performance characteristics of available options, forecasts of customer demand for electricity, reliability criteria and environmental regulations. The investment decisions are made based on minimizing the net present value of capital plus operating costs over the full planning horizon. The pattern of capital costs over time is determined using capital charge rates to represent the financing of capital investments. The net present value of all future capital and operating costs is determined with the use of a discount rate.

EPA Base Case v.5.13 uses real 2011 dollars (2011$) as its real dollar baseline.[50]

8.1 Introduction to Risk

The risk of an investment in the power sector is heavily dependent on market structure risks. The range of risks has increased due to deregulation, which has resulted in a greater share of U.S. generation capacity being deregulated IPP (Independent Power Producer) capacity.[51] For example, merchant IPPs selling into spot market have more market risk than regulated plants or IPPs having long-term, known-price contracts with credit worthy counter parties. There are also technology risks and financing structure risks (corporate vs. project financings). Lastly, there is financial risk related to the extent of leverage.

The risk, especially to the extent it is correlated with overall market conditions, is an important driver of financing costs. Other risks are handled in the cash flows and are treated as non-correlated with the market. This emphasis on correlated market risk is based on the Capital Asset Pricing Model (CAPM) and associated financial theory. This analysis takes into account differences in technology and market structure risks.

Differences between corporate and project financings are highlighted but no specific adjustment has been made for them.

8.1.1 Market Structure Risks

The power sector in North America can be divided into the traditional regulated sector (also known as “cost of service” sector) and deregulated merchant sector (also known as “competitive” sector).

Traditional Regulated

The traditional regulated market structure is typical of the vertically integrated utilities where generation (and transmission and distribution, abbreviated T&D) investments are approved through a regulatory process and the investment is provided a regulated rate of return. In theory, returns on investment in this form of market structure are cost plus regulated returns that are administratively determined. Returns are affected by market conditions due to regulatory lag and other imperfections in the process, but overall regulated investments are less exposed to the market than deregulated investments, all else held equal. In this report, the term “utility financing” refers to this type of market structure. A closely related market structure is the situation where a plant is built under a power purchase agreement (PPA) with a utility with known pricing that allows for a very high degree of investment amortization during the contract period. In such an arrangement, the risks are more credit- and performance-related and much less market-related.

[50] Unless otherwise indicated, all rates presented in this document are provided in real terms.

[51] SNL classifies power plants as merchant and unregulated if a plant in question was not part of any rate case. Based on this classification criterion, in 2012, about 52% of all operating capacity is merchant and unregulated capacity.

Deregulated Merchant

In a deregulated merchant market structure, investments bear the full or a very high degree of market risk as the price at which that they can sell electricity is dependent on what the short-term markets will bear. Return on investment in this form of market structure is not only dependent on the state of the economy, but also on commodity prices, as well as on capital investment cycles and remaining price-related regulation, e.g., FERC price caps on capacity prices. The capital investment cycle can create a "boom and bust" cycle which imparts source risk or uncertainty in the sector that can be highly correlated with overall macro-economic trends. The operating cash flows from investments in this sector are more volatile as compared to the traditional regulated sector and hence carry more business or market risk. In this documentation, the term "merchant financing" refers to this type of market structure.

8.1.2 Technology Risks

The selection of new technology investment options is partially driven by the risk profile of these technology investments. For instance, in a deregulated merchant market, an investment in a combustion turbine is likely to be much more risky than an investment in a combined cycle unit because while a combustion turbine operates as a peaking unit and is able to generate revenues only in times of high demand, a combined cycle unit is able to generate revenues over a much larger number of hours in a year. An investor in a combined cycle unit, therefore, would require a lower risk premium than an investor in a combustion turbine.

8.1.3 Financing Structure Risks and Approach

While investments in new units differ based on market structure and technology risks, differences also may occur because of financing schemes available. There are two major types of financing schemes:

Corporate finance

Corporate finance is a category of financing where a developer raises capital on the strength of the balance sheet of a company rather than a single project. In this type of financing, the debtors have recourse to the entire company's assets. Also, a common assumption is that debt is refinanced rather than repaid such that overall debt is eliminated.

Project finance

Project finance allows developers to seek financing using only the project as recourse for the loan. For instance, a project developer may wish to develop a new combined cycle unit but will seek to use project financing in such a way that if the developer defaults on the loan, creditors have recourse only to the project itself and not against the larger holdings of the project developer. This approach can be more risky for investors than corporate finance, all else being equal, because there is less diversification of assets than the assets held by a corporation (which can be thought as a collection of projects). However, there are some projects more suitable for project financing because: (1) they may have a self-sustaining revenue stream that is greater than the corporate average, or (2) risk is reduced through a long-term PPA with a credit-worthy counterparty such as a vertically integrated utility or a regulated affiliate of a merchant company. In this situation, debt principal is commonly assumed to be repaid at the end of the asset's useful life.

There are many benefits of a project financing structure but there are also costs associated with it. A project financing structure typically has higher transaction costs (and even higher debt costs as debt financing is largely privately placed), but it also solves some of the agency problems and underinvestment issues that corporate financed structures face.[52]

[52] For more information on project financing, see paper titled "The Economic Motivations for Using Project Finance" by Benjamin C. Esty, Harvard Business School, Feb 2003.

However, as noted above, this analysis does not make an effort to quantify the relative costs and benefits of one structure over the other. Rather, the approach is based on the premise that regardless of financial structure, each project has its own risks based on market structure and technology. Further, because corporate financing is more observable than project financing,[53] and has evolved in the power sector to the level of making key risk inferences possible (e.g., IPP and utility stock trades), assessment of market-correlated risks for the purposes of deriving the financial assumptions used in EPA Base Case v.5.13 were based on IPP and utility corporate financing.

8.2 Calculation of the Financial Discount Rate

8.2.1 Introduction to Discount Rate Calculations

The real discount rate for expenditures[54] (e.g., capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Base Case v.5.13 is 4.77%. This serves as the default discount rate for all expenditures.

A discount rate is used to translate future cash flows into current dollars by taking into account factors (such as expected inflation and the ability to earn interest), which make one dollar tomorrow worth less than one dollar today. The discount rate allows intertemporal trade-offs and represents the risk adjusted time value of money.

8.2.2 Choosing a Discount Rate

The choice of discount rate often has a major effect on analytical results. The discount rate adopted for modeling investment behavior should reflect the time preference of money or the rate at which investors are willing to sacrifice present consumption for future consumption. The return on private investment represents the opportunity cost of money and is commonly used as an appropriate approximation of a discount rate.

8.2.3 Discount Rate Components

The discount rate is a function of the following parameters:

- Capital structure (Share of Equity vs. Debt)
- Post-tax cost of debt (Pre-tax cost of debt*(1-tax rate))
- Post-tax cost of equity

The weighted average cost of capital (WACC) is used as the discount rate and is calculated as follows:

WACC = [Share of Equity * Cost of Equity]
+ [Share of Preferred Stock * Cost of Preferred Stock]
+ [Share of Debt *After Tax Cost of Debt]

The focal point is on debt and equity (common stock) because preferred stock is generally a small share of capital structures. Its intermediate status between debt and equity in terms of access to cash flow also tends not to change the weighted average.

[53] Project financing data is less observable as the securities, debt and equity, are usually not explicitly traded. Also, often key financing parameters are unavailable due to confidentiality reasons. Thus, the analysis is implicitly assuming that the corporate risks and financing costs are equal to the project risks. This is especially reasonable when the corporate activities are aggregations of projects.

[54] This rate is equivalent to the real discount rate for a combine cycle plant under hybrid 75:25 utility to merchant ratio assumption. It represents a most common type of investment.

8.2.4 Market Structure: Utility-Merchant Financing Ratio

The first step in calculating the discount rate was to determine proper utility-merchant financing ratio. In EPA Base Case v.5.13, a hybrid financing model is used that assumes future new unit development activity would be split 75:25 between utility financings and pure merchant financings. This is designed to reflect a shift in the market in ownership and risk profiles for power generation assets, and recent development trends and emphasis on long term contracts.[55,56] This approach assumes that new units are financed as a weighted average of utility and merchant financing parameters. For new units the assumption is that utility and merchant components get the 75:25 weights. However, since existing coal units can be classified as belonging to a merchant or regulated structure, for retrofit investments the EPA Base Case v.5.13 assumption is that plants owned by a utility get pure utility financing parameters, whereas plants owned by merchant companies get pure merchant financing parameters.

> *Example 1*: The debt to equity capital structure of a combustion turbine is 55/45 under utility financing and 40/60 under merchant financing. Under the assumption that utility and merchant components get 75:25 weights, the debt-to-equity ratio under hybrid financing is D = (0.75*55 + 0.25*40) = 51 / E = (0.75*45 + 0.25*60) = 49.
>
> *Example 2*: The debt to equity capital structure of a retrofit is 55/45 under both utility and merchant financing. Under the assumption that utility owned plants are financed through pure utility financing parameters, and merchant owned plants are financed through pure merchant financing parameters, the debt to equity ratio remains unchanged regardless of the ownership type. A full summary for all technologies appears in Table 8-1 below.

<u>Capital Structure: Debt-Equity Share</u>

The second step in calculating the discount rate is the determination of the capital structures (D/E)[57] shares for the various technology types using an appropriate utility-merchant financing ratio. The utility debt capacity (and returns) is assumed to be independent of technology type based on the theoretical assumption that regulation will provide an average return to the entire rate base. This assumption is supported by empirical evidence which suggests that utility rate of return is based on an average return to the entire rate base.[58] The merchant debt capacity is based on market risk where a base load plant is

[55] An alternate approach is to categorize the United States into the two previously discussed financial regions – Cost-of-service and competitive. The cost-of-service region will have capital charge rates based on utility financial assumptions and the competitive region will have capital charge rates based on merchant financial assumptions. Such an approach could result in overbuilding in the cost-of-service region due to lower capital charge rates in the absence of regulatory prohibitions of external sales. This is similar to the public vs. IOU financing arbitrage problem, i.e. what stops government utilities from supplying all power? In fact, there are formal and informal limits, and because fully characterizing these limits are extremely complex, the EPA Base Case v.5.13 uses a hybrid approach. For example, recent proposals in PJM explicitly limit capacity expansion by some entities to be such that the total capacity does not exceed internal requirements. (Source: Current MOPR modification proposal).

[56] Based on ICF research, current operating capacity in U.S. is approximately evenly split between IPP and utility owned generation. However, in the last five years (2008-2011), 62% of all large fossil plants were built by regulated companies. In addition, another 12% of all new entrants secured long-term PPA agreements in which the risk is expected to be similar to that of utilities generally. Thus, future capacity expansion has a lower merchant component than the existing mix which is closer to 52%.

[57] A project's capital structure is the appropriate debt capacity given a certain level of equity, commonly represented as "D/E," i.e., debt/equity. The debt is the sum of all interest bearing short term and long term liabilities while equity is the amount that the project sponsors inject as equity capital.

[58] The U.S. wide average authorized rate of return on equity, authorized return on rate base, and authorized equity ratio during last 5 years (2008-2012) for all 108 companies was 10.26%, 8.00%, and 48.32% respectively. For the subset of 50 utilities that completed new rate base cases without financing new generation capacity, those averages were only slightly lower with average authorized rate of return on equity, authorized return on rate base, and authorized equity ratio of 10.09%, 7.90%, and 47.43% respectively. The lack of a substantial difference between these averages suggests that authorized rates of return and equity ratios for regulated companies are not that responsive to differences in investment choices, and are more reflective of an entire company's rate base.

likely to have a higher debt capacity than a combustion turbine plant. Table 8-1 presents the capital structure assumptions used in EPA Base Case v.5.13.

Table 8-1 Capital Structure Assumptions in EPA Base Case v.5.13

Technology	Utility	Merchant	Hybrid
Combustion Turbine	55/45	40/60	51/49
Combined Cycle	55/45	55/45	55/45
Coal & Nuclear	55/45	65/35	58/43
Renewables	55/45	55/45	55/45
Retrofits	55/45	55/45	N.A.

The risk differences across technologies are implemented by varying the capital structure. As shown in Table 8-1 and discussed above, a peaking unit such as a combustion turbine is estimated to have a capital structure of 40/60 while a base load unit such as nuclear and coal is assumed to have a capital structure of 65/35. This is based on the expectation that less risky technologies can carry more leverage. As debt is less expensive than equity, this will automatically translate into a lower discount rate that is used in deriving capital charge rate for base load technologies, and a higher discount rate that is used in deriving capital charge rate for peaking technology, assuming other components of the capital charge rate calculation remain the same.

8.2.5 Debt and Equity Shares and Technology Risk

The capitalization structure for merchant financings was estimated to be 55/45 based on empirical analyses. This ratio is based on the assumption that the overall IPP risk was an average reflective of the risk profile of combined cycle units, which in turn was assumed to be intermediate between base load and peaking. The combined cycle technology is considered to have “average” market risk being an intermediate type technology. Also, in the aggregate, the five selected IPP companies[59] have more combined cycle capacity in their supply mix than any other technology. Additionally, going forward, it is expected that gas will continue to play an increasingly important role in the supply mix of both utilities and merchant companies, with combined cycle technology playing a dominant role. For all of these reasons, it is appropriate to use the ROE corresponding to a combined cycle facility.

Each generation technology was considered to have its own risk profile because base load technologies have multiple sources of revenues, both energy and capacity, which decreases risk and facilitates hedging relative to IPP peaking units. Nearly 75% of load is in LMP markets, and the liquidity of these electrical energy markets creates the potential for near-term cross commodity hedging if the plant has significant energy sales, i.e., if the plant is non-peaking. The potential for capacity revenue hedging is more limited than for energy. Hence, greater the base load share, the lower the asset risk. Additional differentiation among different technologies e.g. nuclear, versus coal, was not implemented because there is a lack of publicly traded securities that provide an empirical basis for differentiating between the risks, and hence, financing parameters for different activities.

There are two main mechanisms for reflecting the greater risk for peak load units and the lower risk for base load. First, the ROE could have been adjusted such that for a given target leverage the ROE would be higher for peaking units, and lower for base load units. For example, an unlevered beta and ROE (which assumes zero leverage) could have been calculated using the risk differentiated capital structures and then relevered at some target leverage. This would have yielded a different ROE for each technology but the same capital structure across all technologies.

The second option was to keep the same ROE while varying the capital structure. This method was adopted for EPA Base Case v.5.13. Thus, even though the leverage of peaking units was lowered, the ROE was not lowered. This raised the weighted average cost of capital and the resulting capital charge

[59] The merchant parameters are derived from market observations of five IPP companies – Merchant ROE.

rate. This effectively also raised the unlevered beta for peaking relative to combined cycle. For base load, leverage was raised without raising ROE, effectively lowering the unlevered beta and the cost of capital.

Debt and Equity Shares

The target capitalization structure for utilities was determined using US utility capitalization ratios derived from Bloomberg data. Similar CAPM parameters were used to estimate the ROE of the utility sector. The capitalization structure for utility financings was estimated to be 55/45 based on empirical analyses and this capitalization structure was assumed to be on average reflective of all technologies.[60]

Technology Risks

For the utility financing, EPA Base Case v.5.13 assumes that the required returns for regulated utilities are independent of technology. This is a simplifying assumption, and further empirical work may be warranted here.

Cost of Debt

The third step in calculating the discount rate was an assessment of the cost of debt. The summary of historical assessment of debt rates across merchant and utility entities is summarized in Table 8-2. The utility and merchant cost of debt is assumed to be the same across all technologies.

Table 8-2 Debt Rates for EPA Base Case v.5.13

Technology	Utility	Merchant	Hybrid
Combustion Turbine	5.72%	7.58%	6.19%
Combined Cycle	5.72%	7.58%	6.19%
Coal & Nuclear	5.72%	7.58%	6.19%
Renewables	5.72%	7.58%	6.19%
Retrofits	5.72%	7.58%	N.A.

Merchant Cost of Debt. The cost of debt for the merchant sector was estimated to be 7.6%. It is calculated by taking a 5-year (2008-2012) weighted average of debt yields from existing company debt with eight or more years to maturity. The weights assigned to each company debt yields were based on that company's market capitalization. During the most recent 5 years, none of the existing long-term debt exceeded twelve years to maturity, hence above average yields are based on debt with maturity between eight and twelve years.

Utility Cost of Debt

The cost of debt for the utility sector was estimated to be 5.7%. It is calculated by taking a 5-year (2008-2012) weighted average of debt yields from four long-term (20 years) Bloomberg Utility Indexes with different debt ratings. The four indices' debt ratings ranged from BBB- to A. The weights assigned to each index were based on the number of regulated companies with the same debt rating.[61]

[60] In the last 3 years, the average utility debt/equity ratio was approximately 1.23, which translates to 55/45 debt/equity ratio.

[61] In all, 29 different regulated companies were considered when assigning weights to the Bloomberg Utility Indexes. They are: Allete Inc., Ameren Corp., American Electric Power Co. Inc., Cleco Corp., CMS Energy Corp., Empire District Electric Co., Great Plains Energy Inc., MGE Energy Inc. Vectren Corp., Westar Energy Inc., Wisconsin Energy Corp., Consolidated Edison Inc., Northeast Utilities, Southern Co., UIL Holdings Corp., Avista Corp., IDACORP Inc., PG&E Corp., Pinnacle West Capital Corp., and Xcel Energy Inc.

Return on Equity (ROE)

The final step in calculating the discount rate was the calculation of a return on equity (ROE) using a weighted average ROE under utility financing (8.8% in nominal terms) and merchant financing (16.1% in nominal terms) at a 75:25 utility/merchant ratio. These utility and merchant ROE's are estimated assuming a 55:45 debt/equity ratio. This resulted in a hybrid ROE of 10.6% (nominal). This ROE is kept the same across each technology[62] but the risk differences across technologies are implemented through the capital structure. See the discussion of capital structures in subsection 8.3.2.5 "Debt and Equity Shares and Technology Risk", and subsection 8.3.2.5.1 "Debt and Equity Shares".

Merchant ROE. The Independent Power Producer (IPP) after tax return on equity parameter was estimated to be 16.1% (nominal). This was based on empirical analysis of stock price data of five pure play comparable merchant generation companies, namely NRG, Dynegy, Calpine, RRI Energy, and Mirant.[63] First, levered betas[64] (a measure of total corporate risk, which includes business and financial risk) for the five companies were calculated using five years (2008-2012) of historical stock price data. Five years is a standard time period. Weekly returns were also used as supplementary data in the analysis. Second, unlevered betas (a measure of business risk, i.e., those affected by a firm's investment decisions) were calculated using the estimated levered beta, the companies' market debt/equity ratio, and the riskiness of debt. The goal is to correctly handle business or systemic risk and financial risk. As most comparables historically had periods of financial distress, the unlevering[65] approach was modified to include the riskiness of debt, instead of purely using the Hamada equation.[66] The unlevered betas were then relevered[67] at the target debt/equity ratio of 55/45 to get the relevered equity betas and return on equity. The target debt/equity ratio of 55/45 is based on average levels of debt/equity ratios across merchant and regulated companies over the last 3 years (2010-2012). The return on equity was determined using the Capital Asset Pricing Model (CAPM).

The CAPM parameters used to estimate the ROE are as follows:

- Risk Free Rate[68] based on 20 year T bond rate: 3.8%
- Market Risk[69] Premium: 1926-2011: 6.62%
- Size[16] Premium: 1.14%

The risk free rate assumption of 3.8% represents a 5-year (2008-2012) average of U.S. Treasury 20 year bond rates. A common practice within the CAPM construct is to utilize the most recent U.S. Treasury 20-

[62] As indicated previously in Table 8-1 a 3% adder is applied to the cost of debt prior to adjustment for income taxes, and to cost of equity when calculating capital charge rates for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture technologies.

[63] Mirant and RRI Energy merged in December 2010 to form GenOn. Prior to their merger ICF analyzed these two companies separately, while after their merger the analysis was of the merged company. Dynegy Holdings began Chapter 11 proceedings on November 2011. The ICF analysis of Dynegy analyzed the company data until 2011. Parts of 2011 and 2012 data were not available for further analysis of Dynegy.

[64] Levered beta is directly measured from the company's stock returns with no adjustment made for the debt financing undertaken by the company.

[65] The unlevering process removes a company's financing decision from the beta calculation. The calculation therefore, attempts to isolate the business (operating risk) of the firm.

[66] The Hamada equation is described at http://www.answers.com/topic/hamada-equation as "A fundamental analysis method of analyzing a firm's costs of capital as it uses additional financial leverage, and how that relates to the overall riskiness of the firm. The measure is used to summarize the effects this type of leverage has on a firm's cost of capital (over and above the cost of capital as if the firm had no debt).

[67] The relevering process estimates the levered beta of the firm given a target capital structure and the pure business risks of the firm as determined from the unlevering process.

[68] Federal Reserve Statistical Release (H15 data), September 2012.

[69] Source: Stocks, Bonds, Bills, and Inflation, 2012 Yearbook Valuation Edition, Morningstar/Ibbotson's Associates.

year bond rate[70] which in September 2012 was 2.5%. Were EPA Base Case v.5.13 to adopt 2.5% as a risk free rate assumption, it would lower all nominal ROEs by 1.3%. Thus, capital investment would have a lower cost. The EPA Base Case v.5.13 assumptions deviate from that practice for several reasons:

- Current rates are unsustainably low due to the latest recession, and slow pace of recovery.
- Second, the EPA analysis begins in the year 2016; by that time the treasury yields are assumed to recover from their current low levels.
- The EPA Base Case financial assumptions are changed infrequently, and hence, it should not use temporary unsustainable assumptions.
- Merchant and utility cost of debt, debt-equity ratios, and historical betas are all calculated based on the last 5 years (2008-2012) of historical data. The same approach to calculate the risk free rate is used in order to remain consistent in its methodology.

The estimation of the IPP ROE described here is fairly close to what EIA has published. EIA estimates[71] an ROE of roughly 16% by 2012.

Utility ROE. The utility return on equity was calculated to be 8.8%. This was based on empirical analysis of the correlation of returns on the S&P utility Index vs. the broader S&P 500 market index for the previous five years (2008-2012) to determine the levered beta and then unlevering and relevering based on a process similar to that for merchant sector. The ROE is slightly lower than what state commissions have awarded the shareholder-owned electric utilities recently.[72]

8.3 Calculation of Capital Charge Rate

8.3.1 Introduction to Capital Charge Rate Calculations

EPA Base Case v.5.13 models a diverse set of generation and emission control technologies, each of which requires financing.[73]

The capital charge rate is used to convert the capital cost into a stream of levelized annual payments that ensures capital recovery of an investment. The number of payments is equal to book life of the unit or the years of its book life included in the planning horizon (whichever is shorter). Table 8-3 presents the capital charge rates by technology type used in EPA Base Case 5.13. Capital charge rates are a function of underlying discount rate, book and debt life, taxes and insurance costs, and depreciation schedule.

Table 8-3 U.S. Real Capital Charge Rates[a] for EPA Base Case v.5.13

New Investment Technology Capital	Capital Charge Rate
Environmental Retrofits - Utility Owned	12.10%
Environmental Retrofits - Merchant Owned	16.47%
Advanced Combined Cycle	10.26%
Advanced Combustion Turbine	10.63%
Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture[b]	12.57%

[70] An important source of statistics and common practices associated with calculating cost of capital with CAPM model is based on the Morningstar's 2012 issue of the Ibbotson® Cost of Capital Yearbook.

[71] See Electricity Market Module of NEMS, EIA Annual Energy Outlook, June 2012.

[72] SNL based rate case statistics for 2011 suggest nationwide average ROE rate of 10.3%.

[73] The capital charge rates discussed here apply to new (potential) units and environmental retrofits that IPM installs. The capital cost of existing and planned/committed generating units and the emission controls already on these units are considered "sunk costs" and are not represented in the model.

Advanced Coal with Carbon Capture	9.68%
Nuclear without Production Tax Credit (PTC)	9.44%
Nuclear with Production Tax Credit (PTC)[c]	7.97%
Biomass	9.53%
Wind, Landfill Gas, Solar and Geothermal	10.85%

Notes:

[a] Capital charge rates were adjusted for expected inflation and represent real rates. The expected inflation rate used to convert future nominal to constant real dollars is 2.0%. The future inflation rate of 2.0% is based on an assessment of implied inflation from an analysis of yields on 10 year U.S. Treasury securities and U.S. Treasury Inflation Protected Securities (TIPS) over a period of 5 years (2008-2012).

[b] EPA has adopted the procedure followed in EIA's Annual Energy Outlook 2013; the capital charge rates shown for Supercritical Pulverized Coal and Integrated Gasification Combined Cycle (IGCC) without Carbon Capture include a 3% adder to the cost of debt and equity. See *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013* (p.2), http://www.eia.gov/forecasts/aeo/er/pdf/electricity_generation.pdf

[c] The Energy Policy Act of 2005 (Sections 1301, 1306, and 1307) provides a production tax credit (PTC) of 18 mills/kWh for 8 years up to 6,000 MW of new nuclear capacity. The financial impact of the credit is reflected in the capital charge rate shown in for "Nuclear with Production Tax Credit (PTC)." NEEDS v.5.13 integrates 4,400 MW of new nuclear capacity at V C Summer and Vogtle nuclear power plants. Therefore, in EPA Base Case v.5.13, only 1,600 MW of incremental new nuclear capacity will be provided with this tax credit.

8.3.2 Capital Charge Rate Components

The capital charge rate is a function of the parameters that overlap in part with the discount rate such as the level of the capital investment and recovery of capital, but also include parameters related to the amortization of capital:

- Capital structure (Debt/Equity shares of an investment)
- Pre-tax debt rate (or interest cost)
- Debt Life
- Post-tax Return on Equity (ROE) (or cost of equity)
- Other costs such as property taxes and insurance
- State and Federal corporate income taxes
- Depreciation Schedule
- Book Life

Table 8-4 presents a summary of various assumed lives at the national level. The EPA Base Case v.5.13 assumes a book life of 15 years for retrofits. This assumption is made to account for recent trends in financing of retrofit types of investments.

Table 8-4 Book Life, Debt Life and Depreciation Schedules for EPA Base Case v. 5.13

Technology	Book Life (Years)	Debt Life (Years)	US MACRS Depreciation Schedule
Combine Cycle	30	20	20
Combustion Turbine	30	15	15
Coal Steam and IGCC	40	20	20
Nuclear	40	20	15
Solar, Geothermal, Wind and Landfill Gas	20	20	5
Biomass	40	20	7
Retrofits	15	15	15

Book Life

The book life or useful life of a plant was estimated based on researching financial statements of utility and merchant generation companies. The financial statements[74] typically list the period over which long lived assets are depreciated for financial reporting purposes. The research conducted broadly supports the numbers outlined in the table above.

Debt Life

The debt life is assumed to be on a 20 year schedule except in the case of combustion turbine and environmental retrofits where debt life is assumed to be on a 15 year schedule.

Depreciation Schedule

The US MACRS[75] depreciation schedules were obtained from IRS Publication 946[76] that lists the schedules based on asset classes. The document specifies a 5 year depreciation schedule for wind energy projects and 20 years for Electric Utility Steam Production plants. These exclude combustion turbines which have a separate listing at 15 years. Nuclear Power Plants are separately listed as 15 years as well.

Taxation and Insurance Costs

Corporate and State Income Taxes: The maximum US corporate income tax rate[77] is 35%. State taxes vary but on a national average basis, the state taxes[78] are 6.45%. This yields a net effective tax rate of 39.1%.

US state property taxes are approximately 0.9% based on a national average basis. This is based on extensive primary and secondary research conducted by ICF using property tax rates obtained from various state agencies.

Insurance costs are approximately 0.3%. This is based on estimates of insurance costs on a national average basis.

8.3.3 Capital Charge Rate Calculation Process

The capital charge rate is calculated by solving for earnings before interest, taxes, and depreciation (EBITDA) or pure operating earnings such that the project is able to recover the cost of equity as the internal rate of return over the lifetime of the project. The sum of discounted cash flows to the equity holders over the lifetime of the project, discounted at the cost of equity is set equal to the initial investment. Put another way, it creates an annuity value when multiplied by the capital investment to recover all capital related charges and provide an IRR equal to the required return on equity. The capital charge rate so calculated is defined as follows:

Capital Charge Rate = EBITDA/Total Investment

[74] SEC 10K filings of electric utilities and pure merchant companies. For example, Calpine's 10K lists 35 years of useful life for base load plants, DTE energy uses 40 years for generation equipment; Dynegy gives a range of 20-40 years for power generation facilities; Mirant reports 14-35 years for power production equipment; Reliant: 10-35 years.

[75] MACRS refers to the Modified Accelerated Cost Recovery System, issued after the release of the Tax Reform Act of 1986. It allowed faster depreciation than with previous methods.

[76] IRS Publication 946, "How to Depreciate Property", Table B-2, Class Lives and Recovery Periods.

[77] Internal Revenue Service, Publication 542.

[78] Represents weighted average state corporate marginal income tax rate.

In other words, the capital charge rate is the annuity charge that provides for the rate of return required on invested capital, resulting from pure operations.

The discounted cash flow to the equity holders of the project is characterized in terms of the Free Cash Flow to Equity (FCFE). FCFE is a valuation technique to estimate cash flows paid to the equity shareholders of a company after all expenses, reinvestment, and debt repayment have been made. The FCFE approach is suited for valuation of assets that have finite economic lives and where debt levels vary from year to year. In the FCFE approach, it is assumed that the asset has a finite life and debt reduces over time based on a mortgage-style repayment structure.

Specifically the cash flows to the equity[79] are calculated as follows:

Cash Flows to Equity[80] = EBIT (1-tax rate)
-Interest (1-tax rate)
+ Depreciation
-Capital Expenditures
-Working Capital Change[81]
-Principal Payments
+ New Debt Issued

[79] An alternative definition of free cash flow to equity is as follows:
Net Income + Depreciation –capital expenditures – working capital change – Principal Payments + New Debt Issued

[80] Property taxes and insurance are incorporated in cash flow calculations.

[81] NERA Economic Consulting estimates that working capital and inventory constitutes about 2% of direct capital costs. NERA also indicates that working capital and inventories (inventories refer to the initial inventories of fuel, consumables, and spare parts) are normally capitalized. Therefore, this item does not need to be in the capital charge rate. See "Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator", August 27, 2010.