10. Financial Assumptions

10.1 Introduction and Summary

This chapter presents the financial assumptions used in the EPA Platform v6. EPA Platform v6 models a diverse set of generation and emission control technologies, each of which requires financing[88], and incorporates updates to reflect The Tax Cuts and Jobs Act of 2017.[89] The capital charge rate converts the capital cost for each investment into a stream of levelized annual payments that ensures recovery of all costs associated with a capital investment including recovery of and return on invested capital and income taxes. The discount rate is used to convert all dollars to present values and IPM minimizes the present value of annual system costs. The discount rate is set equal to the weighted average costs of capital. Describing the methodological approach to quantifying the discount and capital charge rates in the EPA Platform v6 is the primary purpose of this chapter.

10.2 Introduction to Risk

The cost of capital is the level of return investors expect to receive for alternative investments of comparable risk. Investors will only provide capital if the return on the investment is equal to or greater than the return available to them for alternative investments of comparable risk. Accordingly, the long-run average return required to secure investment resources is proportional to risk. There are several dimensions to risk that are relevant to power sector operations, including:

- **Market Structure –**The risk of an investment in the power sector is heavily dependent on whether the wholesale power market is regulated or deregulated. The risks are higher in a deregulated market compared to a traditionally regulated utility market. Slightly more than half of U.S. generation capacity is deregulated (operated by Independent Power Producers (IPPs), or 'merchants').[90] IPPs often sell power into spot markets supplemented by near-term hedges. In contrast, regulated plants sell primarily to franchised customers at regulated rates, an arrangement that significantly mitigates uncertainty, and therefore risk.[91]

- **Technology** - 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 peaking combustion turbine is likely to be much riskier than an investment in a combined cycle unit. This is because a combustion turbine operates as a peaking unit and can generate revenues only in times of high demand, or via capacity payments, while a combined cycle unit is able to generate revenues over a much larger number of hours in a year from the energy markets as well as via capacity payments. An investor in a combined cycle unit, therefore, would require a lower return due to a more diversified stream of revenue, and receive a lower risk premium than an investor in a combustion turbine, all else equal.

[88] The capital charge rates discussed here apply to new (potential) units and environmental retrofits that IPM selects. The capital cost of existing and planned/committed generating units (also referred to as 'firm'), and the emission controls already on these units are considered sunk costs and are not represented in the model.

[89] The Tax Cuts and Jobs Act of 2017, Pub.L. 115-97.

[90] 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 2016 about 52% of all operating capacity is merchant and unregulated capacity.

[91] There is a potential third category of risk, where IPPs enter into long-term (e.g., ten years or longer), known-price contracts with credit worthy counterparties (e.g., traditionally regulated utilities). With a guaranteed, longer-term price, the risk profile of this segment of the IPP fleet is similar enough to be treated as regulated plants.

- **Leverage** - There are financial risks related to the extent of leverage. Reliance on debt over equity in financing a project increases the risk of insolvency. This dynamic applies to all industries, power included.[92]

- **Financing Structure** – Lastly, there are also financing structure risks (e.g., corporate vs. project financing), also referred to as non-recourse financing. There is no clear risk implications from the structure alone, but rather this element interacts with other dimensions of risks making considerations of leverage, technology, and market structure more important.

- **Systemic** – Systemic risk is when financial performance correlates with overall market and macro-economic conditions such that investment returns are poor when market and economic conditions are poor, and vice versa. For example, if investors are less likely to earn recovery of and on investments during recessions, then these risks are systemic, and increase required expected rates of return. This emphasis on correlated market risk is based on the Capital Asset Pricing Model (CAPM), which is used to produce key financial assumptions for EPA Platform v6. Other risks are handled in the cash flows and are treated as non-correlated with the market.

10.2.1 Deregulation - Market Structure Risks

As noted, the power sector in North America can be divided into the traditional regulated sector (also known as “cost of service” or “utility” sector) and deregulated merchant sector (also known as “competitive”, “merchant”, “deregulated”[93] or “IPP” sector).

Traditional Regulated

The traditional regulated market structure is typical of the vertically integrated utilities whose investments are approved through a regulatory process and the investment is provided a regulated rate of return, provided the utility’s investments are deemed prudent. In this form of market structure, returns include the return of the original investment plus a return on invested capital 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 equal.

Deregulated Merchant

In a deregulated merchant market structure, investments bear a greater degree of market risk, as the price at which they can sell electricity is dependent on what the short-term commodity and financial hedge 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, 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 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.[94]

Overall, there is ample supporting evidence for the theoretical claim that deregulated investments are more risky than utility investments. For example:

[92] We use the terms debt and leverage interchangeably.

[93] Wholesale generators cannot be economically unregulated; they can be Exempt Wholesale Generator (“EWG”) subject to FERC jurisdiction. The moniker of deregulated is used to convey greater market risk relative to regulated utility plants.

[94] In this documentation, the terms “merchant financing, “deregulated”, “IPP”, “non-utility” and “merchant” refer to this type of market structure.

All three large publicly traded IPPs[95] are rated as sub-investment grade[96] while all utilities are investment grade.

- All major IPPs have gone bankrupt over the last 15 years[97].

- Estimates of beta, a measure of risk using CAPM, leverage, debt costs, and weighted average cost of capital, consistently produce higher risk for deregulated power plants.

10.3 Federal Income Tax Law Changes

EPA Platform v6 incorporates updates to reflect The Tax Cuts and Jobs Act of 2017. The four most significant changes in the federal corporate income tax code are:

- **Rate** – The corporate tax rate is lowered 14 percentage points from 35%[98] to 21%; the 21% rate is in place starting in 2018 and remains in place indefinitely; the lower tax rate decreases capital charges in all periods and all sectors, all else held equal. When state income taxes are included, the average rate decreases 13.1 percentage points, from 39.2% to 26.1%. This applies to all sectors, utility and IPP.
- **Depreciation** – The new tax law expands near-term bonus depreciation (also referred to as expensing) for the IPP sector only until 2027; the utility sector is unaffected.
- **Interest Expense** – The new law lowers tax deductibility of interest expense for the IPP sector, which continues indefinitely; the utility sector is unaffected.
- **Net Operating Losses** – The new law limits the use of Net Operating Losses (NOL) to offset taxable income. This applies to all sectors, utility and IPP.

Other important features of the new tax law include:

- **Annual Variation of Provisions** - The legislation specifies permanent changes (tax rate and NOL usage limit) applying to both sectors, utility and IPP. The legislation also applies temporary changes that vary year-by-year through to 2027 (depreciation and tax deductibility of interest) (See Table 10-1) applying to the IPP sector only. This creates different capital charge rates for each year through 2027. We calculate these parameters for IPM run years 2021, 2023, 2025, and 2030 and thereafter. This set covers a wide range of financing conditions even though we do not estimate every year.

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[95] Dynegy Inc. Calpine Corp. and NRG Energy Inc are the three IPP's whose ratings were B2, Ba3 and Ba3 in 2016.

[96] Below minimum investment grade.

[97] Dynegy, Calpine, and NRG were bankrupt – i.e. the three large public IPPs were bankrupt. Also, Mirant (major IPP), Boston Generating (IPP), EFH (utility with large IPP component), and FES (utility with large IPP component) have been or are bankrupt.

[98] The average state income tax rate is 6.45 percent. State income tax is deductible, and hence, the combined rate is 26.1% (26.1=21+(1-0.21)*6.45).

Table 10-1 Summary Tax Changes

Parameter	Previous	2021[99]	2023	2025	2030 and Later
Marginal Tax Rate - Federal	35	21	21	21	21
Maximum NOL (Net Operating Loss) Carry Forward Usage	No limit. All losses in excess of income are carried forward and usable immediately.	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income	Carry Forward cannot exceed 80% of Taxable Income
Tax Deductibility of Interest Expense	100%[100]	IPP 30% of EBITDA; Utilities MACRS	30% of EBIT; Utilities MACRS	30% of EBIT; Utilities MACRS	30% of EBIT; Utilities MACRS
Bonus Depreciation[101]	0[102]	IPP 100%; Utilities 0%	IPP 80%[103]; Utilities 0%	IPP 40%[104]; Utilities 0%	0

- **Renewables** - The legislation has minor direct potential impacts on the renewable sector's tax credits via the Base Erosion Anti-Abuse Tax (BEAT). The maximum effect of BEAT could decrease the value of PTC and ITC by up to 20%[105]; estimates of the expected impact are not yet available, but are expected to be less. In addition, the total decrease in corporate income taxes may decrease tax credit appetite accordingly. Nevertheless, as we lack requisite data at this time we do not apply any additional changes to renewable financing beyond the above-mentioned changes, which affect all capacity types.

- **Utilities Versus IPPs** – As noted, the legislation treats utilities and IPPs differently. The new tax code exempts utilities from changes in tax deductibility of interest and accelerated depreciation. The financing assumptions used in IPM modeling are a blend (weighted average) of the utility and IPP average. The weighting is 70% utility and 30% IPP, and hence, the greatest weight is on the least affected sector. This partly mitigates the impacts of the changes.

- **Capital Charge Rates** – In the past, we calculated the blended capital charge rates by taking the weighted average of each input and calculating a single capital charge rate by technology and location. As a result of the legislation, combined with the IPM model's ability to vary capital charge rates by run year, the blended average is calculated for specific run years. In addition, we

[99] IPM run years in the near term are 2021, 2023, 2025, and 2030.

[100] No limit except losses in excess of income can be carried forward. The losses were limited to first few years.

[101] Referred to as expensing. If depreciation exceeds income in first year, it can be carried forward to succeeding years up to 80% of EBITDA.

[102] Bonus depreciation was available but only in the period before IPM runs, and only for new equipment.

[103] For thermal power plants coming on line in 2023, the 100% would apply only to costs incurred through end of 2022. We are hence assuming practically all capital costs are incurred prior to 2023.

[104] Remaining basis depreciated at MACRS schedule.

[105] https://www.congress.gov/115/bills/hr1/BILLS-115hr1enr.xml. "Part VII – Base Erosion and Anti-Abuse Tax, Sec 59A, Tax in Base Erosion Payments of Taxpayers with Substantial Gross Receipts, (b), (1), (B), (ii), (II) the portion of the applicable section 38 credits not in excess of 80 percent of the lesser of the amount …"

See also https://www.mwe.com/en/thought-leadership/publications/2017/12/renewable-energy-tax-bill-update-no-change-ptc-itc. A company's regular tax liability reflects certain credits that make it more likely that such a company is subject to the BEAT. However, the Bill provides that only 20 percent of the PTC and ITC be taken into account. Thus, 20 percent of the PTC and ITC might be denied depending on a company's BEAT status and relevant computations in a given year.

have changed the calculation for a given run year. We calculate the capital charge rates for utilities and IPPs, and then take the weighted average of the resulting capital charge rates rather than calculating one blended capital charge rate based on the weighted average inputs. This is because the functional relationship between the inputs and the capital charge rates is now different and it is less accurate to use the prior approach.

- **Discount Rates** – The discount rate equals the weighted average after tax cost of capital (WACC) and is affected by the change in the corporate income tax rate only. The discount rate is invariant over time, sectors, and technologies. Therefore, the calculation methodology for discount rate used in IPM is unchanged.

10.4 Calculation of the Financial Discount Rate

10.4.1 Introduction to Discount Rate Calculations

A discount rate is used to translate future cash flows into current dollars by considering 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.[106]

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. [107]

The real discount rate for all expenditures (capital, fuel, variable operations and maintenance, and fixed operations and maintenance costs) in the EPA Platform v6 is 4.25%.[108]

10.4.2 Summary of Results

The tables below present a summary of the key financial assumption for the EPA Platform v6. A description of these values and the attendant methodological approaches follow throughout the chapter.

[106] The discount rate is the inverse of compound interest or return rate; the existence of interest, especially compound interest creates an opportunity cost for not having dollars immediately available. Thus, future dollars need to be discounted to be comparable to immediately available dollars.

[107] For a perspective on the legal basis for utilities having the right to have the opportunity to earn such returns under certain conditions such as prudent operations, see *Bluefield Water Works and Improvement Co. v Public Service Comm'n 262 US 679, 692 (1923).* See also *Federal Power Comm'n versus Hope Natural Gas Co., 320 US 591, 603 (1944).*

[108] This rate is equivalent to the real discount rate for a combined cycle plant under hybrid 70:30 utility to merchant ratio assumption. It represents the most common type of thermal generation investment. This is also the hybrid real weighted average after tax cost of capital.

Table 10-2 Financial Assumptions for Utility and Merchant Cases

EPA Platform v6 - Utility WACC using daily beta for 2012-2015	
Parameters	**Value**
Risk-free rate	3.45%[109]
Market premium	6.30%[110]
Equity size premium	0.46%[111]
Levered beta[112]	0.53
Debt/total value[113]	0.51
Cost of debt	4.33%[114]
Debt beta	0.00
Unlevered beta[115]	0.33
Target debt/total value[116]	0.50
Relevered beta	0.52
Cost of equity (with size premium) [117]	7.20%
WACC	5.2%
EPA Platform v6 - Merchant WACC using 55% Target Debt	
Parameters	**Value**
Risk-free rate	3.45%
Market premium	6.30%
Equity size premium	1.21%[118]
Levered beta[119]	1.35
Debt/total value[120]	0.68
Cost of debt[121]	7.20%

[109] Represents 10-year historical average (2007- June 2016) on a 20-year treasury bond. See discussion of risk-free rate and market premium. The five year average (2012- June 2016) on a 20-year treasury bond is 2.70%. The five- (2012- June 2016) and ten-year (2007-June 2016) averages for the 30-year bond are 3.04% and 3.65% respectively.

[110] Represents the 10-year risk premium as of October 1, 2016 (A. Damodaran)

[111] Size premiums according to size groupings taken from Duff & Phelps 2016 Valuation Handbook. Equity size premium is based on weighted average of each company's equity size premium, weighted by each company's equity capitalization level.

[112] Levered betas were calculated using four years (2012-2015).

[113] Debt/total value ratio is the simple average of net debt to equity ratio for the past 5 years.

[114] Cost of debt is based on 5-year weighted average of debt yields for 17 utilities. The weights assigned are the equity share of each utility. The cost of debt using the approach described in the next footnote is 4.45%.

[115] Calculated using Hamada equation.

[116] Target debt/total value for utility case is based on historical 5 years of average D/E for utilities

[117] Cost of equity represents the simple average cost of equity. In the case of utility and merchant ROE, the decrease reflects primarily the lower beta.

[118] Size premiums according to size groupings taken from Duff & Phelps 2016 Valuation Handbook. Equity size premium is based on weighted average of each company's equity size premium, weighted by each company's equity capitalization level.

[119] Levered betas were calculated using five years (2012- June 2016) of historical stock price data. Weekly returns were used in the analysis.

[120] Debt/total value for merchant case is calculated as simple average of the 5-year total debt to total value for each IPP.

[121] Cost of debt is based on historical 5-year weighted average of yields to maturity on outstanding debt. Analyzed merchant companies did not issue long-term debt of 20 year or greater duration in the last five years in this analysis (2012-2016).

Debt beta[122]	0.18
Unlevered beta[123]	0.69
Target debt/ total value[124]	0.55
Relevered beta	1.19
Cost of equity (with size premium) [125]	12.16%
WACC	8.40%

Table 10-3 Weighted Average Cost of Capital

Utility Share	Utility WACC	Merchant Share	Merchant WACC	Weighted Average Nominal WACC	Inflation	Weighted Average Real WACC
70%	5.2%	30%	8.40%	6.16%	1.83%	4.25%

10.5 Discount Rate Components

The discount rate is a function of the following parameters:

- Capital structure (share of equity and debt)
- Post-tax cost of debt
- Post-tax cost of equity

The WACC is used as the discount rate and is calculated as follows:[126]

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

The methodology relies on debt and equity (common stock) because preferred stock is generally a small share of capital structures, especially in the IPP sector. Its intermediate status between debt and equity in terms of access to cash flow also tends not to change the weighted average.[127] Typically, net cash flows are used to fund senior debt before subordinated debt, and all debt before equity. Therefore, the risk of equity is higher than debt, and the rates of return reflect this relationship. Notwithstanding, consistent with our use of utility debt that has recourse to the corporation rather than individual assets, we use IPP debt that has recourse to the corporation rather than individual assets because the data are more robust.

10.6 Market Structure: Utility-Merchant Financing Ratio

With two distinct market structures, EPA Platform v6 establishes appropriate weights for regulated and deregulated financial assumptions to produce a single, hybrid set of utility capital charge rates for new

[122] Debt beta for DYN, CPN, and NRG calculated using the Merton model.

[123] Calculated using Hamada equation. In merchant case, it was modified slightly to include the riskiness of debt.

[124] The capitalization structure (debt to equity (D/E)) for merchant financings is assumed to be 55/45.

[125] Cost of equity represents the simple average cost of equity. In both the utility and merchant cases, the decrease primarily reflects the lower beta.

[126] Sometimes abbreviated as ATWACC. The pretax WACC is higher due to the inclusion of income taxes. Income taxes are included in the capital charges. All references are to the after-tax WACC unless indicated.

[127] Debt generally has first call on cash flows and equity has a residual access.

units. The EPA Platform v6, uses a weighting of 70:30, regulated to deregulated, based on recent capacity addition shares by market type (See Table 10-4).[128]

Table 10-4 Share of Annual Thermal Capacity Additions by Market

Entity	2012	2013	2014	2015	2016	Average
Regulated	70%	88%	60%	58%	64%	68%
Merchant	30%	12%	40%	42%	36%	32%

10.7 Capital Structure: Debt-Equity Share

10.7.1 Introduction and Shares for Utilities and IPPs

The second step in calculating the discount rate is the determination of the capital structure, specifically the debt to equity (D/E) or debt to value (D/V) ratio for utility and merchant investments.[129] This is calculated by determining the total market value of the company, and the market value of its debt and equity. The market value of the company is the sum of the market value of its debt and equity. We also determined the capital structure for the various technology types.

The target capitalization structure for utilities was assumed to be 50:50. This was based on the capitalization over the 2012 to 2016 period. The capitalization structure for merchant financings is assumed to be 55/45, reflecting the greater risk inherent to this market.[130]

10.7.2 Utility and Merchant

For utility financing, the empirical evidence suggests that utility rate of return is based on an average return to the entire rate base. Thus, EPA Platform v6 assumes that the required returns for regulated utilities are independent of technology. In contrast, the merchant debt capacity is based on market risk and varies by technology.

10.7.3 Merchant by Technology

Assigning merchant technology risk is difficult 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.[131] Nevertheless, we assigned merchant technology market risk as follows:

- **Combined Cycles** – The capitalization structure for merchant financing of combined cycles is assumed to be 55/45.

- **Peaking Units** – A peaking unit such as a combustion turbine is estimated to have a capital structure of 40/60. Peaking units have a less diverse, and therefore, more risky revenue stream.

[128] In contrast to new units, existing coal units can be classified as belonging to a merchant or regulated market structure. Hence, for retrofit investments, the EPA Platform v6 assumption is that coal plants owned by a utility get purely utility financing parameters coal plants owned by merchant companies get purely merchant financing parameters.

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

[130] The U.S.-wide average authorized equity ratio during the last 5 years (2012-2016) for 146 utility companies was 50.22%. Debt/total value for merchant case is calculated as simple average of the 5-year total debt to total value for each IPP.

[131] There were only three major IPP companies with traded equity. This is insufficient to conduct statistical analysis.

- **Coal Units** – A new coal unit is estimated to have a capital structure of 40/60, reflecting higher risk than a combined cycle unit. This is reflected in observed higher financing costs at the two IPP companies with coal, NRG and Dynegy, as compared to Calpine, which has no coal, only gas and geothermal. While statistical analysis cannot be performed with such a small sample size, it is supported qualitatively.

- **Fossil Units –** New, non-peaking fossil fuel-fired plants face additional risks associated with a potential cost on future CO_2 emissions, which the EIA handles by increasing the cost of debt and equity for new coal plants.[132] EPA Platform v6 extends this treatment of risk to new combined cycle plants.

- **Nuclear Units** — A new nuclear unit is estimated to have a capital structure of 40/60. There is high risk associated with a new IPP nuclear unit. This is supported by: (1) the financial challenges facing existing nuclear units, (2) the very limited recent new nuclear construction, (3) statements by financial institutions, and (4) the lack of ownership of nuclear power plants by pure play IPP companies. Of the three pure play companies only one has partial ownership of a single nuclear power plant. With this one exception, only utilities and affiliates of utilities own nuclear units.

- **Renewable Units** — A new merchant renewable unit is estimated to have a capital structure of 55/45. This is the highest debt share among the major classes of generation options, and therefore, the lowest cost of capital. This is in part because renewables have access to a third source of financing in tax equity. Tax equity receives the tax benefits such as ITC, PTC, losses available to defray income tax, over time by making a payment upfront. These benefits are not transferable to other companies. There is a risk that the tax credits may become less valuable over time (e.g., the company providing the tax equity does not have sufficient taxable income), or the project may not perform and have inadequate operations to generate expected PTC volumes. This risk is less than typical equity, since the tax credits value is not subject to as much variation as regular equity. These projects are also easier to hedge because they have zero variable costs, and hence, the annual volume of output is less uncertain, all else equal, and often receive support via power purchase agreements and renewable energy credits. Limits of relying on even greater debt include the scheduled lowering of the PTC and ITC over time, and the potential for performance problems.

Table 10-5 Capital Structure Assumptions

Technology	Utility	Merchant
Combustion Turbine	50/50	40/60
Combined Cycle	50/50	55/45
Coal & Nuclear	50/50	40/60
Renewables	50/50	55/45
Retrofits	50/50	40/60

10.8 Cost of Debt

The third step in calculating the discount rate is to assess the cost of debt.[133] The utility and merchant cost of debt is assumed the same across all technologies.

[132] 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

[133] Measured as yield to maturity.

Table 10-6 Nominal Debt Rates

Technology	Utility	Merchant
Combustion Turbine	4.33%	7.20%
Combined Cycle	4.33%	7.20%
Coal & Nuclear	4.33%	7.20%
Renewables	4.33%	7.20%
Retrofits	4.33%	7.20%

10.8.1 Merchant Cost of Debt

The cost of debt for the merchant sector was estimated to be 7.2%. It is calculated by taking a 5-year (2012-2016) 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 (2012-2016), 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.

10.8.2 Utility Cost of Debt

The cost of debt for the utility sector was estimated to be 4.33%. It is calculated based on the 5-year (2012-2016) average of a set of 17 utilities weighted by enterprise value (See Table 10-7).

Table 10-7 Utilities Used to Calculate Cost of Debt

Name
Ameren Corp
American Electric Power Co Inc.
Cleco Corp
CMS Energy Corp
Empire District Electric Co/The
Great Plains Energy Inc.
MGE Energy Inc.
Westar Energy Inc.
WEC Energy Group
Consolidated Edison Inc.
Southern Co/The
UIL Holdings Corp
Avista Corp
IDACORP Inc.
PG&E Corp
Pinnacle West Capital Corp
Xcel Energy Inc.

10.9 Return on Equity (ROE)

10.9.1 Introduction and Beta

The final step in calculating the discount rate is the calculation of the required rate of return on equity (ROE). The ROE is calculated using the formula:

ROE = risk free rate + beta x equity risk premium + size premium

The formula is the key finding of the CAPM and reflects that a premium on return is required as investment risk increases, and that premium is proportional to the systemic risk of the investment.[134] Systemic risk is measured by the impact of market returns on the investment's returns and is measured by beta.[135]

There are several additional aspects of estimating beta:

- **Time Period** – The most common practice is to use five years of historical returns to estimate beta.

- **Returns** – Daily returns are commonly used to estimate beta except for illiquidly traded stocks when weekly returns are used to avoid under estimating beta. The utility estimates presented use daily data and the IPP estimates used weekly estimates.

- **Unlevered Betas** - It is useful to estimate unlevered betas that eliminate the effects of leverage. This facilitates comparison across investments with different leverage levels, and allows recalculation to account for going forward changes in leverage levels. This recalculation involves a technique known as the Hamada[136] equation.

- **Debt Betas** - When a company is facing financial distress, the debt can become the new equity as part of corporate reorganization under the federal bankruptcy code. Hence, during the bankruptcy period, the debt trades like equity. There is a technique to adjust the beta by calculating a debt beta. This technique is employed because one of the three IPP companies, Dynegy, was having significant financial distress especially early in the 2012-2016 period.

10.9.2 Risk-Free Rate and Equity Risk Premium

The risk-free rate of return and equity risk premium are market parameters, and are not company-specific. They also determine the average market-wide level of returns on equity. Therefore, the average return of the market equals the sum of the risk-free rate of return and equity risk premium.

In this analysis, we use the Duff and Phelps 2016 Valuation Handbook, Industry Cost of Capital. Duff and Phelps recommends an estimate of 5.5% for the market risk premium[137]. At the same time, Duff and Phelps recommends a 4% risk-free rate. Thus the total is 9.5%.

The EPA estimates are based on the approach of using long-term averages for both the risk-free rate and the market risk premium. Specifically, EPA estimates the risk-free rate of return and the market risk premium based on 10-year averages. The risk free rate assumption is 3.45% which is the 10-year (2007-2016) average of U.S. Treasury 20 year bond rates. The market risk premium is the ten year average provided by Professor Damodaran of 6.3%[138]. The sum of the two is 9.75%, and is close to Duff and Phelps recommendation of 9.5%.

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[134] The financial literature on CAPM originally did not emphasize the size premium (also referred to as the liquidity premium). It emerged from later findings that the estimated required return was too low for small stocks (i.e., with low equity value).

[135] Beta is the covariance of market and the stock's returns divided by the variance of the market's return.

[136] In corporate finance, Hamada's equation is used to separate the financial risk of a levered firm from its business risk.

[137] Duff and Phelps, 2016 Valuation Handbook, March 2016, see also Client Alert, Duff and Phelps Increases U.S. Equity Risk Premium Recommendation to 5.5% Effective January 31, 2016.

[138] As of October 1, 2016.

10.9.3 Beta

Utility betas average 0.53 during the 2012 to 2015 period on a levered basis (see Table 10-8). This estimate is based on daily returns. This estimate was chosen because it was intermediate between the ten-year average and the 2012-2016 estimate when using partial year 2016 data. For example, the ten-year beta (2007-2016) is even higher at 0.60 daily, and the 2012-2016 partial year estimate is 0.5 because the partial year 2016 data is much lower than the 2012-2015 average.[139]

Table 10-8 Estimated Annual Levered Beta for S15ELUT Utility Index Based on Daily Returns[140]

Year	Levered Beta
2012	0.35
2013	0.70
2014	0.44
2015	0.62
2016 (through June)	0.25
Average (2012-15)	**0.53**

IPP betas average 1.35 based on weekly returns from 2012-June 2016. We did not observe issues with partial year 2016 data. After decreasing leverage from 68% to 55%, and adjusting the beta estimate, the beta decreases to 1.19. Even after correcting for the greater financial risk of IPPs due to higher leverage, the betas of IPPs are higher than utilities. The unlevered betas of utilities is 0.33 and of the IPPs is 0.69[141].

10.9.4 Equity Size Premium

It is observed that long-run returns of smaller, less liquidly traded companies have higher returns than predicted using the market risk premium. Therefore, an equity size of liquidity premium is added. Based on the 2016 Duff and Phelps Valuation Handbook there was a significant equity size premium for IPPs of 1.21% and a smaller premium for utilities at 0.46%.

10.9.5 Nominal ROEs

Utility

The utility ROE is 7.20% in nominal terms. The utility ROE is the single most influential parameter in the estimate of the discount rate because of the 70% weight given to utilities compared to IPPs, and the decrease in interest rates due to the tax shield on debt (debt interest payments are tax deductible).

The estimated utility ROE in EPA Platform v6 is lower than what state and federal commissions have awarded the shareholder-owned electric utilities recently.[142] In some cases, commissions use a different

[139] One-half weight to 2016.

[140] S15ELUT Index comprises of 22 utilities: American Electric Power Co. Inc., Great Plains Energy Inc., Westar Energy Inc., IDACORP Inc., PG&E Corp., Pinnacle West Capital Corp., Xcel Energy Inc., NextEra Energy Inc, Duke Energy Corp, Southern Co, Exelon Corp., Edison International, PPL Corp., Eversource Energy, First Energy Corp., Entergy Corp., Alliant Energy Corp., OGE Energy Corp., Hawaiian Electric Industries Inc., ALETTE Inc., PNM Resources Inc., and El Paso Electric Co.

[141] Unlevered betas are lower than levered betas. Levered beta is directly measured from the company's stock returns with no adjustment made for the debt financing undertaken by the company. The leveraged beta of the market equals one.

[142] SNL-based rate case statistics for 2012-2016 suggest nationwide average ROE rate of 9.93%.The Edison Electric Institute's Financial Update, Rate Case Summary, Q4 2015 reported average approved returns on equity of 9.6% the second lowest in its three decades of data.

approach or assumptions[143]. If it were shown that the existence of higher returns at other utilities prevented utilities receiving the estimated return here while still attracting sufficient capital, this could mean that the estimate here is too low. However, ICF's experience notes that the trend is to lower returns and this is a long-term analysis focused on cost of capital for future investments that can occur 25 years or more in the future.

IPP

The nominal ROE for IPPs is 12.16%. The IPP required ROE is sensitive to the amount of debt and the analysis assumes future delevering. Specifically, the IPP ROE assumes 55% debt rather than 68% debt, which is the 2012-2016 average.

10.9.6 WACC/Discount Rate

The WACCs are 5.2% in nominal terms for utilities and 8.40% in nominal terms for IPPs (see Table 10-3). Using a 70:30 utility/merchant weighting, the weighted average WACC under utility financing and merchant financing is a 6.16% WACC. The real hybrid WACC is 4.25%.

10.10 Calculation of Capital Charge Rate

10.10.1 Introduction to Capital Charge Rate Calculations

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 10-9 to Table 10-11 presents the capital charge rates by technology type used in EPA Platform v6. As discussed in section 10.3, the changes to the Tax Code have caused capital charge rates to vary by run year, therefore the tables below show the rates for the individual run years through 2030. Capital charge rates are a function of underlying discount rate, book and debt life, taxes and insurance costs, and depreciation schedule.

Table 10-9 Real Capital Charge Rate – Blended (%)[144]

New Investment Technology Capital Hybrid (70/30 Utility/Merchant)	2021	2023	2025	2030 and Beyond
Environmental Retrofits - Utility Owned	10.77%	10.77%	10.77%	10.77%
Environmental Retrofits - Merchant Owned	14.05%	14.05%	14.12%	14.54%
Advanced Combined Cycle	8.64%	8.64%	8.66%	8.77%
Advanced Combustion Turbine	9.02%	9.02%	9.02%	9.10%

[143] Some regulatory commissions use what is known as the dividend growth model. This model assumes that the current market price of a company's stock is equal to the discounted value of all expected future cash flows. In this approach, the time period is assumed to be infinite, and the discount rate is a function of the share price, earnings per share and estimated future growth in dividends. The challenge with using this approach is estimating future growth in earnings. Commissions rely on stock analyst forecasts of future growth rates for dividends. In other cases, commissions may allow for other parameters such as flotation costs (costs of issuing stock). We did not use this approach because it is less commonly used. There also appears to be a tendency of allowed rates of return as a group to be too low during periods with high financial costs and too high during periods of low financing costs. This may be to ensure comparability with similar utility companies. There is also a literature that indicates that as betas deviate from 1, the CAPM returns are too low and too high. We did not address these issues directly in part because the results were comparable to other results, with the exception of being lower than allowed returns.

[144] 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 1.83%. The future inflation rate of 1.83% 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 (2012-2016).

New Investment Technology Capital Hybrid (70/30 Utility/Merchant)	2021	2023	2025	2030 and Beyond
Ultra Supercritical Pulverized Coal without Carbon Capture[145]	10.96%	10.96%	11.01%	11.18%
Ultra Supercritical Pulverized Coal with Carbon Capture	8.31%	8.31%	8.32%	8.43%
Nuclear	8.31%	8.31%	8.33%	8.43%
Nuclear without Production Tax Credit	8.31%	8.31%	8.33%	8.43%
Nuclear with Production Tax Credit[146]	7.10%	7.09%	7.10%	7.19%
Biomass	8.14%	8.12%	8.12%	8.12%
Wind, Landfill Gas, Solar and Geothermal	9.79%	9.78%	9.77%	9.77%
Hydro	8.09%	8.09%	8.11%	8.21%

Table 10-10 Real Capital Charge Rate – IPP (%)

New Investment Technology Capital (IPP)	2021	2023	2025	2030 and Beyond
Environmental Retrofits - Merchant Owned	14.05%	14.05%	14.12%	14.54%
Advanced Combined Cycle	10.89%	10.89%	10.97%	11.33%
Advanced Combustion Turbine	11.83%	11.81%	11.81%	12.07%
Ultra Supercritical Pulverized Coal without Carbon Capture	14.05%	14.06%	14.23%	14.78%
Ultra Supercritical Pulverized Coal with Carbon Capture	11.22%	11.22%	11.27%	11.62%
Nuclear without Production Tax Credit	11.22%	11.22%	11.29%	11.62%
Nuclear with Production Tax Credit	9.71%	9.69%	9.71%	10.00%
Biomass	10.60%	10.56%	10.53%	10.53%
Wind, Landfill Gas, Solar and Geothermal	11.77%	11.73%	11.70%	11.70%
Hydro	10.61%	10.61%	10.67%	11.01%

Table 10-11 Real Capital Charge Rate – Utility (%)

New Investment Technology Capital Utility	2021	2023	2025	2030 and Beyond
Environmental Retrofits - Utility Owned	10.77%	10.77%	10.77%	10.77%
Advanced Combined Cycle	7.67%	7.67%	7.67%	7.67%
Advanced Combustion Turbine	7.82%	7.82%	7.82%	7.82%

145 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

146 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 v6 integrates 2,200 MW of new nuclear capacity at Vogtle nuclear power plant. Therefore, in EPA Platform v6 only 3,800 MW of incremental new nuclear capacity will be provided with this tax credit.

New Investment Technology Capital Utility	2021	2023	2025	2030 and Beyond
Ultra Supercritical Pulverized Coal without Carbon Capture	9.63%	9.63%	9.63%	9.63%
Ultra Supercritical Pulverized Coal with Carbon Capture	7.06%	7.06%	7.06%	7.06%
Nuclear without Production Tax Credit	7.06%	7.06%	7.06%	7.06%
Nuclear with Production Tax Credit	5.98%	5.98%	5.98%	5.98%
Biomass	7.08%	7.08%	7.08%	7.08%
Wind, Landfill Gas, Solar and Geothermal	8.94%	8.94%	8.94%	8.94%
Hydro	7.01%	7.01%	7.01%	7.01%

10.10.2 Capital Charge Rate Components

The capital charge rate is a function of the following parameters:

- Capital structure (debt/equity shares of an investment)
- Pre-tax debt rate
- Debt life
- Post-tax return on equity
- Other costs such as property taxes and insurance
- State and federal corporate income taxes
- Depreciation schedule
- Book life

Table 10-12 presents a summary of various assumed book lives, debt lives and the years over which the investment is fully depreciated. The book life or useful life of a plant was estimated based on publicly available financial statements of utility and merchant generation companies.[147]

Table 10-12 Book Life, Debt Life and Depreciation Schedules for EPA Platform v6

Technology	Book Life (Years)	Debt Life (Years)	U.S. MACRS Depreciation Schedule (Years)
Combined 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
Environmental Retrofits	15	15	15

Depreciation Schedule

For the utility sector, the U.S. MACRS depreciation schedules were obtained from IRS Publication 946 that lists the schedules based on asset classes.[148, 149] The document specifies a 5-year depreciation

[147] SEC 10K filings of electric utilities and 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 uses 30 years for power generation facilities.

schedule for wind energy projects and 20 years for electric utility steam production plants. These exclude combustion turbines and nuclear power plants, which each have a separate listing of 15 years. As a result of the tax code changes, the merchant sector is allowed to depreciate assets on an accelerated schedule through 2027. Accelerated depreciation is allowed starting in 2018 with 100% depreciation and phases out at 20% annual between 2023 and 2027.

Taxation and Insurance Costs

The maximum U.S. corporate income tax rate is 21%.[150] State taxes vary but the weighted average state corporate marginal income tax rate is 6.45%. This yields a net effective corporate income tax rate of 26.1%.

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

Insurance costs are approximately 0.3% on a national average basis.

[148] MACRS refers to the Modified Accelerated Cost Recovery System, issued after the release of the Tax Reform Act of 1986.

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

[150] Internal Revenue Service, Publication 542.