DRAFT POWER PROJECT FINANCING ASSUMPTIONS FOR THE FIFTH POWER PLAN

INTRODUCTION AND SUMMARY

This paper describes the generating project financing assumptions proposed for use in the Fifth Power Plan. Project financing strongly affects the cost of project development and thus the Council?s forecasts of resource cost-effectiveness, power prices and cost implications of power, fish and wildlife policies. This paper proposes revisions to the mix of entities expected to develop future power generating facilities and to the financing and tax environment of these developers. The net effect of the proposed changes on cost of capital for new generation is as follows:

Table 1: Effect of proposed changes on developer-weighted cost of capital (%)

Resource	**4th Plan**	**Proposed 5th Plan**
Gas combined-cycle units	8.7%	7.8%
Gas peaking units	8.7%	6.8%
Wind	8.7%	8.1%
Coal	8.7%	6.8%
Solar Photovoltaics	8.7%	6.6%

The next section provides background regarding the significance of power project financing assumptions and the assumptions currently used by the Council. The proposed changes are described in the section that follows. The final section summarizes the proposed changes and sets forth questions that interested parties may wish to consider in responding to this paper.

BACKGROUND

Forecasting the cost of future generating resource options requires that assumptions be made regarding project financing. These assumptions include the type of entity expected to develop future projects, the mix of equity and debt financing used by these entities, the interest cost for debt financing, the return expected on equity investment, the term of debt financing, the discount rate for valuing future cash flows, and, for developers subject to income taxes, applicable tax rates.

The most recent review of the Council?s project financing assumptions was for the Northwest system adequacy and reliability study, released in March 2000[1]. For that study, debt interest rates and equity return assumptions were reduced by about a percentage point from values used in the Fourth Power Plan in recognition of declining interest rates. In addition, the assumed debt percentage for projects developed by independent power producers (IPPs)[2] was reduced from 80 to 60 percent based on reported examples of project financing. Other assumptions remained as adopted for the Fourth Power Plan.

In view of further decline in interest rates since 2000, the financial distress of many independent power producers, and the sense that the power generation sector of electric power industry is unlikely to fully transform to a deregulated structure in the near future, it is desirable to review the financial assumptions for use in the Fifth Power Plan.   Proposed updates to the principal financing assumptions for consumer-owned and investor-owned utility developers appear in the recent paperThe Discount Rate in the Fifth Power Plan (June 2003)[3]. These proposals are described, but not further analyzed in this paper. This paper proposes assumptions regarding the mix of developers likely to develop various types of generating projects and assumptions regarding typical financing of projects developed by independent power producers. In addition, changes to federal and state income tax assumptions are proposed.

ANALYSIS AND RECOMMENDATIONS

Project Developers

During the development of the Fourth Power Plan, a shift to independent, unregulated development of generating projects was clearly in evidence. However, because the Council believed that some resource development would continue on the part of consumer-owned utilities (COUs) and investor-owned utilities (IOUs), investor-owned utility financial assumptions were used to estimate future resource costs. IOU financing yielded a cost of capital midway between that of independent developers and that of consumer-owned utilities. This was intended to provide consistent financial assumptions across all resource types yet approximate the cost of resource development by a mix of developer types.

The Council?s Generating Resource Advisory Committee (GRAC) has recommended that resource-specific mixes of developer types be used in assessing future power generation costs for the Fifth Power Plan. The intent of this shift from the approach used in the Fourth Plan is to better simulate the expected cost of new resources and thereby improve the power price forecast (the principal application of these assumptions). The recommended mix is shown in Table 2 for resources thought to have the greatest potential impact on system resource mix and power prices over the next 20 years. These recommendations are based upon recent development experience and current trends. GRAC members believe that IPPs will continue to dominate combined-cycle plant development because of the relatively low capital investment required for this technology. In contrast, wind will continue to be dominated by independent developers because of the specialized skills required to site and develop wind power plants. Gas peaking units will continue to be developed predominantly by utilities because of the uncertain loading of these units, particularly in hydro-dominated systems and advantages accruing by closely-integrating these units with system operation. Future coal units, and solar photovoltaics are thought likely to be developed by utilities because of the capital-intensity of these technologies.

Table 2: Proposed Mix of Project Developers (%)

Resource	**COU**	**IOU**	**IPP**
Gas combined-cycle units [a]	20%	20%	60%
Gas peaking units	40%	40%	20%
Wind [b]	15%	15%	70%
Coal	40%	40%	20%
Solar Photovoltaics	50%	25%	25%

a. The initial GRAC combined-cycle plant recommendation was 15% COU / 15% IOU / 70% IPP. These have been adjusted to the smaller share of IPP development shown in accordance with the discussion of developer mix at the September 25, 2002 GRAC meeting.

b. The GRAC recommendation for wind financing was 5% COU / 5% IOU / 90% IPP. These values have been adjusted to reflect increasing utility interest in wind.

Project Financing

Important parameters affecting the cost of capital investment include the fraction of the investment covered by debt, the cost of debt and its term and expected return on equity. The proposed assumptions are summarized in Table 3.

Consumer-owned Utility Projects

Projects developed by consumer-owned utilities are typically fully debt-financed. We assume that this financing is by investment-grade 30-year bonds. Because interest rates have continued to decline since the Council?s project financing assumptions were last revised, the proposed cost of debt financing for COU projects is reduced to 4.9% (nominal)[4], compared to 6.5% used in the 2000 adequacy and reliability study and 7.5% used in the Fourth Plan. The derivation of this interest rate is discussed in the draft issue paper The Discount Rate in the Fifth Power Plan.

Investor-Owned Utility Projects

We assume that the projects developed by investor-owned utilities are financed using investment-grade[5] 30-year bonds. For its Fourth Power Plan and subsequent studies, the Council used a 50/50 ratio of debt to equity investment for investor-owned utilities. We propose to retain the 50% debt fraction, based on values appearing in recent IOU integrated resource plans. Because interest rates have continued to decline since the

Council?s project financing assumptions were last revised, the proposed cost of IOU debt is reduced to 7.3% compared to 8.7% used in the 2000 adequacy and reliability study. Based on values appearing in recent utility integrated resource plans, we propose to increase the assumed return on IOU equity financing to 11% from 10.3 % used in the Council?s adequacy and reliability study. See The Discount Rate in the Fifth Power Plan (June 2003) for further discussion of these proposals. These adjustments (including the proposed adjustments to income tax rates described below) will reduce the after-tax cost of capital for investor-owned utilities to 7.7%, compared to 7.9% used for the adequacy and reliability study and 8.7% used in the Fourth Plan.

Independent Power Producer Projects

We assume that the development and construction [6] of an independent generation project is financed with a 60/40 ratio of debt to equity investment. Debt incurred during development is assumed to be investment-grade short-term variable interest rate recourse (balance sheet) financing at an interest rate of 6.5%. At completion, development period expenditures, including debt interest, are typically refinanced with a mix of equity and long-term debt. The long-term debt is assumed to be investment-grade 15-year bonds secured by project assets, with a fixed interest rate of 7.8%. Required return on equity for both the project development and operating periods is assumed to be 15%. The resulting after-tax cost of capital for post-construction financing (including the proposed adjustments to income tax rates described below) is 8.8%. This is compared to 10.2% percent used for prior Council studies and 8.5% for the Fourth Plan.

Debt/Equity Ratio: For its Fourth Power Plan, the Council used a debt to equity ratio of 80/20 for independent power producers. This ratio was based on recommendations of members of the Fourth Plan GRAC. The 80/20 ratio was selected because it was believed that independent developers, unconstrained by economic regulation and facing highly competitive markets would push for the competitive advantages conferred by highly debt-leveraged financing. Subsequent information concerning the financing of actual independent projects suggested that while some projects were highly leveraged, many independent projects were characterized by lower debt percentages. Consequently, the Council reduced its assumed debt to equity ratio for independent projects to 60/40 for the adequacy and reliability study. Current information suggests that the majority of independent projects financed during the recent construction boom were more highly leveraged than this revised assumption would suggest. For example, the debt fraction of four firms specializing in independent generation development averaged 65% for the period 1997 - 2001 (See appendix). Published information concerning specific projects suggests that 80 to 90% debt financing has not been uncommon. Because high debt exposure is an important factor contributing to the current financial difficulties of many independent generation companies, it seems likely that lenders will demand higher equity contributions for future financing. Announced efforts by independent generating companies to reduce their debt exposure are consistent with this assertion. Hence we propose to retain the 60/40 ratio of debt to equity investment used by the Council for the adequacy and reliability study.

Project development debt interest rates: Debt to finance project development activities is often short-term with variable interest rates indexed to the London Interbank Offered Rates (LIBOR). We propose to model construction debt using an interest rate of 6.5 % [7]. The basis is the 5.2 % forecast rate for ten-year U.S. Treasury notes proposed for use as the basis for discount rates for the Fifth Plan[8]. The average 1993-02 historical differential between the 3-month LIBOR and 10-year Treasury rates is -1.04%. Applying this differential to the basis rate yields a forecast LIBOR of 4.16%. The forecast LIBOR is then adjusted by a loan rate differential. To assess representative future loan rate differentials, we rely on information concerning two AES combined-cycle projects on which construction commenced during 2001 when the developer?s credit rating was investment-grade. Construction of these projects, Southhaven and Caledonia, was financed at LIBOR plus 1.5% and 2.75%, respectively. Though apparently not indexed to LIBOR, the 2002 financing of the Calpine California peaking units might also be relevant, since the power purchase contract with California Department of Water Resources provides a high level of financial security comparable to what might be expected in the future. The construction loan rate for these projects is 2.6% above average 2002 LIBOR. Because of residual perception of risk associated with power plant development, future lenders will likely seek interest rates in excess of those associated with investment-grade financing during the previous construction boom. Hence we assume that LIBOR plus 2.5% is representative of future construction lending. With the forecast LIBOR, this differential yields an interest rate of 6.5% for construction debt.

Post-construction debt interest rates: Post-construction loans are typically long-term, fixed rate and are secured by project assets without recourse to the assets of the parent company. Because of these characteristics, post-construction loans generally command higher rates than development period financing. We assume that post-construction debt is investment-grade 15-year bonds secured by project assets, with a fixed interest rate of 7.8 %. The differential rate between minimum investment-grade (Baa/BBB) corporate bonds and 10-year Treasury notes for 1993-2002 averaged 2.1 %. This would yield 7.3% for future bonds of comparable risk. However, it seems likely that future lenders will seek higher than average interest rates for independent energy financing. For example, the weighted average interest rate of four recent (2002) refinancings of combined-cycle power plants is 80 basis points above average Baa/BBB corporate bond rates for the same period (See appendix). Assuming that this premium moderates over the next several years, we add a half percentage point to the 1993-2002 corporate Baa/BBB - 10-year Treasury differential, yielding the rate of 7.8%.

Expected return on equity investment: The capital asset pricing model (CAPM) can be used to estimate the expected return on investment for a firm. The return is calculated using the following equation:

Cost of equity capital = Risk free rate + (stock beta x market risk premium)

The forecast ten-year Treasury rate (5.2 %) is used as the risk-free rate, consistent with proposed discount rates for the Fifth Plan. The historical market risk premium for the US economy is about 7%. The return calculated using the CAPM reflects an average return for the investments, old and new for the company in question. However, the return on equity assumption being sought is for new independent (unregulated) investments, with presumably a higher return requirement than the average of older and regulated investments. The betas of firms specializing in independent generation should be more representative in this respect than firms for which independent generation is but a minor part of the business (most of the latter firms are dominated by regulated subsidiaries). Stock betas for firms for which independent generation is the bulk of their business range from about 1.75 to 2. These values yield an expected return on equity of 17.5 to 19 % using the CAPM. The stock beta for independent generation companies should decline as the industry is restructured in response to the events of the past several years, efforts are undertaken to reduce debt load, greater financial certainty is demanded of new power projects and other efforts are made to stabilize the industry. If we assume that betas for independent generating firms stabilize at 1.25 - 1.5, estimated return on equity requirement would range from 14 to 15.7%. We propose to use 15%. This expected return on equity is assumed to be representative of firms primarily engaged in independent power development as well as the independent energy segment of firms engaged in a broader range of activities.

Income taxes

Investor-owned utilities and independent generating companies are subject to federal and state income taxes. Because debt interest payments are deducted from gross revenues when calculating taxable income, federal and state corporate tax rates affect the net (i.e., after-tax) cost of capital. The Council has used 34% as the marginal Federal corporate income tax rate since the 1991 Power Plan, or earlier. We propose to shift to the current marginal Federal corporate income tax rate of 35% (for taxable annual income in excess of $10 million) for the Fifth Plan.

Except for analyses involving specific projects, the Council uses a single representative rate for state corporate income tax. The rate used in prior studies is 3.7%. The current corporate income tax rates for Idaho, Montana and Oregon are 7.6%, 6.75% and 6.6%, respectively. Washington has no corporate income tax, but does have a 3.62% public utility tax applied on gross receipts. The average corporate income tax rate for the four Northwest states, taking Washington as zero and weighting by electricity sales as an approximation for the geographic distribution of future plants, is 3.4%. However, analyses involving the entire WECC interconnected system (e.g. power price forecasting) are now the principal application of the Council?s project financing assumptions. For these analyses we propose to use 5.9%, the load-weighted average corporate income tax rate for the 13 states and provinces primarily comprising the WECC interconnected system.

CONCLUSIONS

The proposed project financing assumptions are compared in Table 3 to those used in the Council?s Fourth Power Plan.

Table 3: Summary comparison of project financing assumptions (nominal values, 2.5% inflation)

	COU **(4^{th} Plan)**	**COU** **(proposed)**	**IOU** **(4^{th} Plan)**	**IOU** **(proposed)**	**IPP** **(4^{th} Plan)**	**IPP** **(proposed)**
Debt fraction	100%	100%	50%	50%	80%	60%
Debt interest rate	7.5%	4.9%	9.7%	7.3%	9.7%	Const: 6.5% Oper: 7.8%
Debt term	30	30	30	30	15	15 [a]
Return on equity	--	--	10.3%	11%	17.3%	15%
Federal income tax	--	--	34%	35%	34%	35%
State income tax	--	--	3.7%	5.9%	3.7%	5.9%

General inflation rate	3.5%	2.5%	3.5%	2.5%	3.5%	2.5%
Wtd. after-tax cost-of capital	7.5%	4.9%	8.7%	7.7%	8.5%	8.8%

a. Long-term project debt for the operational period.

Interested parties are invited to comment on these proposals. Two issues of particular interest are the following:

- Many independent generating companies are in financial distress because of low power prices, high debt ratios, and other factors. The proposed financing assumptions for independent developers are intended to represent a more stable environment, several years hence when demand for new power generation is restored and power prices have firmed. Are these assumptions and the resulting financial assumptions reasonable?
- Power project financing may differ among resource types even for the same class of developer because of resource-specific risks. The Council is assessing the cost implications of several important resource-related risks, including those associated with short-term volatility of natural gas prices, long-term natural gas price trends and long-term carbon dioxide control. The findings of these risk analyses may lead the Council to adjust its findings with respect to resource cost-effectiveness. Are there persuasive reasons to adopt resource-specific financing assumptions prior to conclusion of this risk analyses? If so, what values should be used for key financing parameters and why?

APPENDIX: BACKGROUND DATA

Table A1: Fraction of long-term debt of firms specializing in independent electricity generation[3]

	AES	**Calpine**	**Mirant**	**Reliant**	**Average**
1993	81%	95%	--	--	88%
1994	68%	95%	--	--	81%
1995	71%	94%	--	--	83%
1996	75%	75%	--	--	75%
1997	78%	78%	--	--	78%
1998	79%	79%	66%	--	74%
1999	82%	68%	70%	70%	72%
2000	79%	68%	62%	42%	63%
2001	80%	81%	61%	16%	59%
2002	n/avail	79%	75%	57%	70%
Average 1997-01	**80%**	**75%**	**65%**	**42%**	**65%**

1. Data from Morningstar.com.

Table A2: Four recent project refinancings

Project	Description	Date/Financing	Source
Calpine Pasadena I & II	751 MW base, 787 MW peak gas-fired combined-cycle cogeneration plant	$400 M at 8.6% maturing in 2048	Calpine 2002 SEC 10K
Calpine Broad River	840 MW gas-fired combined-cycle plant	$300 M at 8.1% maturing in 2041	Calpine 2002 SEC 10K
Calpine Parlin	89 MW base, 119 MW peak gas-fired cogeneration plant	$50 M at 10.6%, maturing in 2014	Calpine 2002 SEC 10K
Calpine Newark	47 MW base, 58 MW peak gas-fired cogeneration plant	$37 M at 9.8%, maturing in 2010	Calpine 2002 SEC 10K

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[1] Northwest Power Planning Council. Northwest Power Supply: Adequacy/Reliability Phase I Report (Document 2000-4 (/energy/powersupply/2000-4/)).   March 2000.

[2] The term "independent power producers" is used in this paper for private developers of generating plants not subject to economic regulation. Included in this group are developers with contracts for the output of their projects and merchant power producers selling into the market without contracts.

[3] Available on the Council's website (/energy/powerplan/5/plan).

[4] All percentages used in this paper are nominal unless otherwise indicated. A 2.5% annual rate of general inflation is forecast.

[5] Moody's Baa or Standard & Poor's BBB rating, or better.

[6] "Development" is used generally to refer to the process of siting, permitting, financing, constructing and testing a new power project. "Construction Loan" is the term often used for debt financing of project development activities.

[7] The interest rate for construction debt is modeled as fixed, but at a rate representative of a variable rate.

[8] Draft issue paper The Discount Rate in the Fifth Power Plan (document 2003-8 (/energy/powerplan/5/2003-8/)). June 2003.