NATIONAL ENERGY TECHNOLOGY LABORATORY

Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects

September 29, 2011

DOE/NETL-2011/1489

U.S. DEPARTMENT OF ENERGY

Disclaimer

Update of Recommended Project Finance Structures for the Economic Analysis of Fossil-Based Energy Projects

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Final

Contract No. DE-FE0004001
Activity 04001.341.01.09

Acknowledgements:

The participation of the following firms is gratefully acknowledged: Barclays Capital, Credit Suisse, Chadbourne & Parke LLP, Cooley Godward Kronish LLP, Flour Corporation, Milbank, Tweed, Hadley & McCloy LLP, Standard and Poor's, Hogan & Lovels LLP, and the Carlyle Group.

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List of Acronyms

BPS	Basis Points
COE	Cost of Electricity
CTL	Coal to Liquids
D/E Ratio	Debt to Equity Ratio
DSCR	Debt Service Coverage Ratio
EPC	Engineering, Procurement, and Construction
ESPA	Energy Sector Planning and Analysis
IPP	Independent Power Producer
IOU	Investor Owned Utility
IRROE	Internal Rate of Return on Equity
LCOE	Levelized Cost of Electricity
LIBOR	London Interbank Offered Rate
O&M	Operations and Maintenance
PFSM	Power Systems Financial Model
PPA	Power Purchase Agreement
SPE	Special Purpose Entity

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Introduction

In September of 2008, the Office of Systems, Analyses and Planning at the National Energy Technology Laboratory (NETL) developed a set of market validated financial assumptions for use in comparative economic analyses of commercial and advanced coal-based power and fuel systems, (NETL 2008). The financial assumptions included the required internal rate of return for the equity portion of the investment (IRROE), cost of debt, and the financing structure (debt/equity ratio), which are used in NETL's Power Systems Financial Model (PFSM) to calculate the levelized cost of production, e.g., cost of electricity (COE) or levelized COE. At the time of the report in late 2008, market, technology, and policy conditions were uncertain, and NETL recognized that an update of the report would be required in the mid-term.

In this update to the 2008 report, the financial parameters to be used in economic analysis studies are updated and the issue of technology risk premium is revisited. Profiles for distributing Total Overnight Costs over various Capital Expenditure Periods (e.g. 3 and 5 years) and project financing costs that are representative of actual energy projects are also re-evaluated.

Key Conclusions from 2008 Report

Project developers, financiers, project finance law firms, and engineering, procurement and construction (EPC) contractors were interviewed for the 2008 report. One key conclusion was that the "technology risk premium" for project finance is difficult to quantify because traditional project finance, e.g. non-recourse finance, is typically only available for projects employing commercially demonstrated technology. Before advanced technologies can obtain traditional project financing, technology risks must be mitigated, either through research & development and commercial demonstration, performance guarantees (or "efficacy insurance"), government loan guarantees, or other non-traditional finance structures and ownership such as public-private partnerships. In this update to the 2008 report, the issue of technology risk premium is revisited.

The 2008 report indicated that finance structure, required returns, and cost of debt were primarily influenced by the ownership structure of the project, either by Investor-Owned Utilities (IOU) or Independent Power Producers (IPP). IOUs obtain guaranteed, and capped, rate-base IRROEs from utility commissions and have the option of pursuing corporate rather than project-based finance. Corporate debt will typically be lower cost than project debt, since corporate debt is backed by recourse to the full assets of the company. The 2008 report indicated that typical finance structures for IOUs for a commercial technology project are a debt to equity (D/E) ratio of 50/50, 12 percent IRROE, and the cost of debt is the London Interbank Offered Rate (LIBOR) plus a premium of 100 basis points (bps) (or 1 percent). The basis for LIBOR in 2008 was 3.5 percent.

IPPs obtain non-recourse financing via a special purpose entity (SPE) ownership structure, in which the debt is backed only by the cash flows and the assets of the project itself, thus increasing the cost of debt. Financiers will require that a project meet a minimum debt service coverage ratio (DSCR) of 1.5-2.0, and may require a debt service reserve fund to be maintained. Given current market conditions, SPEs must negotiate long term power purchase agreements (PPA); prior to 2007, merchant plants that sold a portion of their generation into day-ahead and real time markets were financeable, but that is no longer the case. In order to obtain higher IRROEs required by private equity and institutional investors, these projects must have a higher degree of leverage. The 2008 report indicated that typical finance structures for IPPs for commercial technology projects are D/E of 70/30, 20 percent IRROE, and a cost of debt of LIBOR plus 300 bps.

In quantifying the impacts on finance structure of the technology risks associated with advanced power generation and fuel production systems, the 2008 report concluded that, in general, more equity would be required and the cost of debt would be increased. However, for IRROE, interviewees indicated that, for the case of IOUs, utility commissions would be unlikely to pass on the costs of technology risk to consumers, and thus the IRROE should remain at 12 percent. For the case of IPPs, private equity and institutional investors have a typical IRROE requirement in the range of 15-25 percent, and will (or will not) invest in projects that have risk commensurate with this level of return. Venture financiers will be willing to take on greater risk, with associated targets of 50 percent or more for return on equity, but will not invest the amounts of equity required for large, capitally intensive fossil energy projects.

The 2008 report indicated financing structures for high risk technologies for IOUs to be D/E of 45/55, 12 percent IRROE, and LIBOR plus 200 bps. For IPPs, the finance structure would be D/E of 60/40, 20 percent ROE, and LIBOR plus 500 bps.

The 2008 report also suggested that because advanced technology projects with un-mitigated technology risks will not be likely to obtain traditional financing, it may be misleading to quote a "high-risk" IRROE and finance structure. An alternative approach, which is considered in this report, may be to quantify the costs of technology risk mitigation, and use commercial project finance assumptions for IOUs and IPPs.

Current Market Conditions

During the preparation of the 2008 NETL report on recommended project structures, interviews indicated that the status of energy project finance, particularly for coal-based projects, was characterized by uncertainty due to uncertain government policy on CO_2 emissions. At the time, lenders were reluctant to commit to projects for which they could not price-in the risk for potential costs of operation. Since the release of the report in 2008, considerable new market uncertainties have impacted energy project finance due to the global credit crisis.

As of the date of this report, credit markets have eased and are again functioning, (Infocast 2011). During the crisis, the loan term, or tenor, for financed projects was considerably shortened – from 15 to 6-7 years, with the expectation that the loans would be refinanced. In normal conditions, lenders are faced with many risks that can be priced and properly allocated via contracts, including construction risks, warranty risk, counterparty[1], price and revenue risks. But technology risks must be minimal, well understood, and the risk properly allocated if possible. EPC wraps are required, and reserve funds for debt service, typically of six months,

[1] A counterparty is an entity with whom a contract is entered. Counterparty risk, or credit risk, is the risk that a party to a contract does not perform as required by the contract.

and operations & maintenance (O&M), typically of 3 months, are as a rule required. Projects may also be required to set aside or accrue capital expenditure reserves to fund required capital projects for major repairs or maintenance, particularly for new technologies. The certainty of cash flow and the debt service coverage ratio are key components of deals. Debt available to a non-recourse funded project will be sized to a minimum DSCR of 1.4-1.5.

Debt financing alternatives include the commercial bank market, the investment grade bond market, and the term loan B market. Leverage capacity for all types is driven by the commercial arrangements via the DSCR, and all have stringent loan covenant requirements[1]. Commercial bank loans have maturity of 7-15 years, risk tolerance is low-medium, external credit ratings are not required, the cost of debt is generally lower, and these loans require the tightest financial covenants and counterparty ratings. The cost of debt is priced at LIBOR plus 100-500 bps, depending on the risk profile of the project. The investment grade bond market is characterized by maturities of 20 or more years, bond ratings requirements of BBB- or higher, low-medium risk, and lower cost, but higher up-front fees. Loan covenant requirements may be less stringent, but the project must be rated as investment grade, and the ratings may take into account DSCR and other factors. The cost of debt for a given term is priced at the corresponding term US Treasury (10, 20, or 30 years), plus 1.5-2%. The term loan B market has a greater appetite for risk, with minimum credit ratings of B2/B, higher debt costs, and maximum 7 year maturity. The cost of commercial loans are generally LIBOR plus 250-300 bps with 1.5-2.0 percent upfront; bonds are currently priced at about 7 percent; term loan B's are priced at LIBOR plus 250-500 bps, with a LIBOR floor of 1.25-1.75 percent, but the steeply rising LIBOR forward curve should be taken into account when pricing term loans.

Equity markets are lagging the recovery of debt markets, (Infocast 2011). Equity investors are selective, and adverse to risk. In normal market conditions, private equity funds and institutional investors have limited risk tolerance, longer investment timeframes, and can provide the large capital resources required for energy projects. The level of risk aversion is pronounced in current market conditions. Venture capital firms have a higher tolerance for risk, but require higher returns, have shorter investment horizons, and will tend not to commit large amounts of capital to a single investment, (Bloomberg Energy Finance 2010). Utilities are beginning to invest again as project owners, but are reluctant to take on technology risk without government loan guarantees and public utility commission rate subsidies or cost past-through to consumers.

As has traditionally been standard practice in project finance, and now even more so, successful deals require creditworthy counterparties, parties with strong track records, and established relationships.

The EPC wrap guarantees price, completion date, and performance of the system, potentially with warranties of major components out to five years; yet it is only a limited mitigation of technology risk for advanced systems. Insurance products guaranteeing system performance –

[1] Loan covenants are contractual requirements intended to protect the lender in non-recourse project finance. Examples of covenants include: completion covenants, requiring that the project be completed according to approved plans and timelines; covenants not to amend fuel, PPAs, or O&M agreements; debt restrictions, prohibiting the project owner from incurring additional debt; financial covenants, requiring that DSCR, reserve accounts, and other financial operating ratios be maintained.

efficiency, reliability, O&M costs - over longer periods of time have been discussed, but such products don't yet exist, and would require highly customized terms and pricing, and would be very expensive.

One means of estimating the price of such a product might be to evaluate the costs of a required performance reserve fund tied to potential cash flow shortages. The cash flow shortages could be a result of late startup, low efficiency, high O&M costs, low capacity factor, etc. Such a scenario could be evaluated using the PFSM as follows: reduce the capacity factor, and, leaving the COE unchanged, note the change in cash flows for a given period – perhaps six months to a year, reflecting the period of time required to restore the system to full capacity. The total deficit in cash flows over the period would then be added to the debt reserve fund. The PFSM would then be run again at full capacity, and the additional cost of carrying the additional reserve, in terms of resulting COE differential, is evaluated. The resulting DSCR should be a minimum of 1.0 for this stress test. This total cost, or some fraction of it, would be indicative of the cost of insurance.

Although significant market-based uncertainties have arisen since 2008, government policy remains very important. To the extent that clarity in environmental and tax policy can reduce uncertainty, more project financing will be available for infrastructure projects of all types. Project finance lawyers, bankers, developers, and contractors have emphasized that uncertainty leads to delay in investment and innovation, and that private finance will take advantage of opportunities when risks in policy, technology and markets can be understood and properly priced into project deals.

Permitting of new coal-based plants remains challenging, and new gas supply and low gas prices are presenting very competitive economics for both coal and renewable energy projects. Coal to liquids (CTL) projects are showing promise, and several projects are currently in development. Merchant plants, i.e. IPP projects without complete hedging of power prices via PPAs, have not been financed since 2007; long term PPAs with solid counterparty credit are required for successful financing. There may be niche markets in which plants with some degree of merchant exposure can be financed, but this will not be the norm.

Interview Responses

Interviews for this report were conducted with project finance attorneys, debt and equity financiers, EPC contractors, project developers, and insurance companies. Questions were posed regarding commercial (low risk) and high risk technologies, debt terms and period of return for IRROE, the required DSCR, financing fees, and the distribution of capital costs over the capital expenditure period. The full set of questions is included in the Appendix.

Commercial Financial Structures

Interviews generally validated the commercial, low-risk finance structures developed in 2008 to be representative of industry standards. Because markets have not fully recovered since the financial crisis, one project attorney suggested that a D/E ratio of 70/30 for IPPs was too high on debt, but that markets were beginning to loosen and are returning to more normal conditions, so that 70/30 should again become standard.

A large global lender indicated that the premium over LIBOR for IPP projects should be closer to 250 bps than 300 bps, but that a range of 250-300 bps is reasonable. The banker remarked that although the LIBOR rate currently is close to zero, the forward curve rises steeply. It was suggested that a basis of 5.5 percent for LIBOR be used, plus the applicable basis premiums. (3.5 percent was the base LIBOR rate used in the 2008 report, which corresponded to then-current LIBOR rates). As will be discussed later in this report, it is recommended that the LIBOR rate assumption be maintained at 3.5%, to represent an intermediate between the current rate of near zero and the presumed future rate.

The banker also said the finance structures look reasonable, and that the crucial aspect for any deal on the lender's side is the DSCR. Investment grade deals will be sized to 1.4-1.5 DSCR, with a "stress test" ratio of no lower than 1.0. Most deals will require a debt reserve fund of 6 months.

In all project financing, leverage capacity is driven by the commercial arrangements, which determine the DSCR. There is a fundamental tension between debt and equity: the project must be sufficiently leveraged to meet IRROE targets with an allowable or competitive COE, and the minimum DSCR must be met for the degree of required leveraging.

The lender discussed both bank and bond funding. For IPP projects funded via non-recourse finance, US and European commercial banks will provide up to $1 billion for "investment grade quality" debt, although actual ratings through credit ratings agencies are not required. Indicative pricing for bank debt is LIBOR plus 250-300 bps, with a 1.5-2 percent upfront financing fee. The standard term through 2009 had been 5-7 years, but that is returning to 15 years, corresponding to the PPA.

Privately placed (or "144A Offering") project bonds are another debt funding mechanism. Such bonds required a minimum investment grade credit agency rating of BBB-. The bonds are typically acquired by institutional investors, with funding of up to $1 billion; total cost is currently in the range of 7 percent, risk tolerance is low-medium and the term corresponds to the PPA, 15-20 years or longer. Well structured, investment grade rated projects could benefit from the longer debt term and lower overall cost of debt. This may be a reasonable assumption for commercial technologies.

A private equity financier also confirmed that the commercial structures are generally reasonable. For the IOU case, the cost of debt was in the range of recent transactions, with a range of LIBOR plus 50-200 bps. For IPPs with long term PPAs (roughly equivalent to a credit agency rating of BBB- rating or better), the financier suggested using a cost of debt of U.S. Treasury plus 150 bps, where the 10 year treasury and 30 year treasury would be interpolated out to the life of the project. (The 10-year Treasury – LIBOR spread is roughly 100 bps.) The financier also recommended using a 5.5 percent as a LIBOR basis.

Table 1 shows project finance data from recently closed transactions. (An asterisk indicates that data were not available for a particular parameter.) For IOUs, the one quoted project D/E ratio is 45/55, with a 12.7 percent IRROE. Commercial IPP projects range from 80/20 to 65/35, and a higher risk technology IPP project with a loan guarantee is 60/40. Without a loan guarantee, another IPP higher risk technology project has less debt and more equity, at 55/45.

Table 1 Recent Financing Closures for Power Projects

Project Name	Owner Type/ Country	Type/ Sponsors	PPA	Capacity (MW)	Project Cost ($MM)	D/E Ratio	Equity	Debt	Financial Close Date
Oak Creek Units 1 and 2	IOU	Supercritical PC; Wisconsin Electric Power	Load serving[1]	615 MW expansion	2,700	45/55	12.7 percent	Project bonds: 20 year, 4.673 percent; 30 year 5.848 percent	2011
Virginia City Hybrid Energy Center	IOU	CFB, co-firing of coal and biomass; Dominion Resources	Load serving	585	1,800	*	12.3 percent	*	Ongoing
Taylorsville Energy Center	IPP	IGCC/co-production; Tenaska; DOE Loan Guarantee, Federal Tax Credit	Pending State of Illinois Legislative Active	630	3,500	60/40	*	$2.6 billion DOE Loan Guarantee	Ongoing/Status Uncertain
Trailblazer Energy Center	IPP	Supercritcal PC with CCS; Tenaska		Net 600		55/45	*	*	Ongoing
Bayonne Peaker	IPP	NGCC; Pure Energy Resources	15 year	512	640	65/35	*	LIBOR + 300 bps, 6 years plus construction	2011

[1] Power that is provided by an IOU under its load serving obligation with an associated regulated price.

Project Name	Owner Type/ Country	Type/ Sponsors	PPA	Capacity (MW)	Project Cost ($MM)	D/E Ratio	Equity	Debt	Financial Close Date
North Battleford Energy Center	IPP, Canada	NGCC	20 year	265	700	80/20	*	*	September 2010
Mirant Marsh Landing	IPP	NGCC	10 year	760	700	70/30	*	10 year term debt	October 2010
Hudson Ranch I Geothermal	IPP	Geothermal; Catalyst Renewables, Hannon Armstrong and GeoGlobal Energy	30 year	50	400	75/25	*	LIBOR + 350 bps, 5 year plus construction term	June 2010, ongoing permitting
Nuevo Pemex co-generation project	IPP, Mexico	NG co-gen, power and steam; GE Financial Services, Abengoa	20 year off take of steam and power by PEMEX	300	632	70/30	*	LIBOR + 412-562 bps; 6.5 year bullet repayment	June 2010
Shams 1 Solar	IPP, United Arab Emirates	Concentrated Solar; Masdar, Total and Abengoa Solar		125	1,000	60/40	*	*	March 3, 2011

* Indicates no data were available.

Source: Project Finance Magazine Issues 6/2010, 9/2010, 12/2010, 3/2011, Dominion Resources 2010 , and Public Data Sources

Table 2 shows the cost of debt, term, and up-front fees for several recently closed deals.

Table 2 Debt Financing 2009-2010

Sponsors	Date	Debt Size ($MM)	Tenor	Cost	Fees
Terra-Gen Power	2010	275	5 years	*	*
Confidential Wind Deal	2010	230	10 years	LIBOR + 300 bps	300 bps
Edison Mission Energy	2009	207	8 years	LIBOR + 387 bps	*
Midland Cogeneration	2009	375	7-9 years	LIBOR + 350-400 bps	150-225 bps
GenConn energy	2009	295	5-7 years	LIBOR + 350 bps	250 bps

* Indicates no data were available.

Source: Clapp 2009

Tenor of Debt and Period of Return for IRROE

During the global financial crisis of 2008-2009, industry standard loan tenors of 15 years were significantly shortened to 6-7 years, with the expectation that the debt would be re-financed. These shortened tenors put a strain on the ability of some projects to meet DSCR requirements. With the easing of credit, loan terms have returned to 15-18 years, which generally should correspond to the duration of the PPA.

The period of return for IRROE will differ by type of investor. Venture capital funds require a shorter period of return, from 3-5 years. Private equity funds require 7-10 years, and infrastructure funds, institutional investors, and pension funds allow 10-15 years or more. From VCs on one end of the spectrum to pension funds on the other, an increasing level of capital is available, and risk tolerance and IRROE requirements decrease. VCs tend to not be very active in capitally intensive project finance. IOUs as project owners generally have the longest time frames, corresponding to the life of the plant or the capital depreciation period.

Finance Structures for High Risk Technologies

Interviews generally confirmed the conclusion of the 2008 report that finance structures for high risk technology projects are difficult to quantify, since the projects may not be commercially financeable, and no representative structures exist to guide recommendations. However, the interviews were divided on how high risk could or should be hypothetically quantified.

Project finance attorneys thought that it could be misleading to quote a finance structure for a project that was not financeable. Instead, it was thought better to use the commercial structures for IOUs and IPPs, assume the construction of an "n^{th} plant," and provide a reasonable story of how to get there, be that via technology development, inclusion of redundancy for high risk components, or by other means.

Another approach might be to include a reserve fund for the high risk components, for O&M, capital expenditure, or reliability.

Although insurance products for project "efficacy" have been discussed in the industry, no such products exist, and even if there were such products, they would be highly customized and difficult to price – no simple rule of thumb would exist for pricing purposes.

The financiers interviewed considered the high risk structures from the 2008 report to be a reasonable means of expressing the cost of technology risk, as long as it was understood that these were not projects that could actually be financed in this manner. From a lender's perspective, less debt would be available for a high risk technology, and therefore less leverage would necessitate a higher COE to achieve a given IRROE target. The effect is to shift risk from debt to equity, reflecting the requirement that equity, and not debt, would need to assume the risk. The project would still need to meet the minimum DSCR of 1.4-1.5 for the given debt level, and a stress test of the DSCR, capturing degraded performance or higher O&M costs, should yield minimum DSCR of 1.0.

As for IRROE targets, although a risk premium would theoretically need to be placed on the equity IRROE in order to take on the additional risk, in practical terms, the existing types of investors – VCs, private equity, institutional and pension funds – have given risk/return requirements, and it may be unrealistic to assume that equity investors for capitally intensive IOU or IPP projects will be willing to take on such risk. Instead, the standard industry IRROEs for IOU and IPP projects should be used in the hypothetical finance structures, and the penalty on COE expressed through the decreased project leverage.

The developers and EPC contractors have experience with EPC wraps, which may provide up to 5 years of performance guarantees and warranties on major system components. It was thought that it might be possible to price efficacy insurance based on these warranties; but such coverage would be expensive.

The financing of CTL projects, and liquid fuels projects in general, was discussed with several project finance lawyers and a petrochemicals industry expert. There are CTL projects currently in the early stages of development, and the interviewees were in agreement that it is reasonable to expect that CTL may be financed in the near term with D/E of 50/50 and 20 percent IRROE. However, they said it was too early to accurately project a cost of debt, though LIBOR plus 400-500 bps might be reasonable. Two of the experts suggested that 70/30 might be achievable in the mid-term. Off-take agreements and price risk hedging will also be required as part of the financing terms of the projects. Price risks can be hedged by entering into financial forward or futures contracts on fuel products.

Required Debt Service Coverage Ratio

Requirements for DSCR have not been affected by the global financial crisis. Industry standards remain at 1.4-1.5. The minimum DSCR requirement is for any given year.

Cost of Financing

An interview with a commercial banker indicated that up-front financing fees for bank loans are closer to 2 percent than the currently assumed 2.7 percent. However, this may vary by the nature of the deal, and Table 2 presents data from deals in 2009-2010 that range in fees from 1.5 percent to 3 percent. Fees for privately placed bonds and term loans may be higher than for commercial loans.

Another financer indicated that debt financing fees are currently in the range of 2.5-3.5 percent, and that the 2.7 percent figure is reasonable.

There also may be fees associated with the sourcing of equity. If the project owners engage an equity placement agent or advisor to assist in securing equity financing, the project may pay a fee ranging from 2% for amounts under $2 million to 0.75% for amounts of over $5 million. For large projects that will be owned by an IOU or by a large development company, these entities may be the primary equity investors themselves, so that the placement fee is not relevant. If outside equity is sourced for such large projects, the project owners or developers may seek to secure equity financing with their own corporate staff. A reasonable assumption would be that IPP projects will carry a 0.75% placement fee on equity financing, while IOU projects will not carry an equity placement fee.

Distribution of Capital Costs during the Capital Expenditure Period

The EPC contractor interviewed for the report thought that the current capital distributions for 3 year and 5 year capital expenditure periods, as shown in Table 3, are reasonable. Generally, the distribution will be a bell curve or skewed-bell curve, with about 10 percent expended for upfront engineering in the first year for either the 3 or 5 years period, the largest single year expenditure will be in the 2nd year as operations move into the field and as major equipment and materials are procured, and the remaining expenditures will be relatively evenly distributed, but decreasing.

Table 3 Distribution of Capital Costs

Capital Expenditure Period	Year-by-Year Distribution
3 years	10 % - 60 % - 30 %
5 years	10 % - 30 % - 25 % - 20 % -15 %

Recommended Finance Structures

The recommended financial structures given current and anticipated near to mid-term project finance market conditions are reported in Tables 4 through 9.

The commercial structures for IOUs and IPPs remain the same as in the 2008 report, (NETL 2008), and the basis for LIBOR also remains at 3.5 percent. The assumed LIBOR rate is a mid-range value taking into account the current rates that are near zero and the steeply rising forward rates of 5.5 percent. For all cases, the loan term is assumed to be 15 years (assuming financing is obtained in the commercial bank market), financing costs are 2.7 percent for arranging debt, fees of 0.75 percent for arranging equity financing for IPP projects, and the distribution of capital costs over the capital expenditure period are as reported in Table 3, and with a required DSCR of 1.4-1.5.

If financing is obtained in the investment grade bond market, the loan term would be extended out to 20 years or longer. This may be a reasonable assumption for commercial projects. The cost of debt will be similar between the commercial bank and bond markets.

Interviews suggested that CTL projects can be treated as a commercial technology for the purposes of project finance, and will be financed in the near to mid-term with a structure such as the one shown in Table 6. The high-risk fuel case in Table 9 reflects additional technology risk, such as CCS.

Table 4 Financial Structure for IOU Commercial Projects

Type of Security	percent of Total	Current (Nominal) Dollar Cost
Debt	50	LIBOR plus 1 percent
Equity	50	12 percent

Table 5 Financial Structure for IPP Commercial Power Projects

Type of Security	percent of Total	Current (Nominal) Dollar Cost
Debt	70	LIBOR plus 3 percent
Equity	30	20 percent

Table 6 Financial Structure for Commercial Fuels Projects

Type of Security	percent of Total	Current (Nominal) Dollar Cost
Debt	50	LIBOR plus 4.5 percent
Equity	50	20 percent

The finance structures for high risk projects are shown in Tables 7-9, again with an assumed LIBOR basis of 3.5 percent. It is generally reasonable to use these structures to broadly reflect the shift from debt to equity due to increased technology risk, as well as the increased cost of debt, with the provision that the projects may not actually be commercially financeable with these structures.

However, the applicable commercial finance structures could also be applied in order to demonstrate the economics of "n^{th} plant" technologies. A description of the commercialization path from high risk to a low risk commercial technology should be used to justify the application of the commercial finance structures. It may also be reasonable to include reserve funds to cover performance shortfalls over the life of the project.

Table 7 Financial Structure for IOU High-Risk Projects

Type of Security	percent of Total	Current (Nominal) Dollar Cost
Debt	45	LIBOR plus 2 percent
Equity	55	12 percent

Table 8 Financial Structure for IPP High Risk Power Projects

Type of Security	percent of Total	Current (Nominal) Dollar Cost
Debt	60	LIBOR plus 5 percent
Equity	40	20 percent

Table 9 Financial Structure for High Risk Fuels Projects

Type of Security	percent of Total	Current (Nominal) Dollar Cost
Debt	40	LIBOR plus 6.5 percent
Equity	60	20 percent

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Appendix Interview Questions

The following questions were set by project finance lawyers, debt and equity financiers, EPC contractors, and developers.

1. What are the current typical finance structures for commercial fossil power projects (D/E ratio, IRROE, and cost of debt – premium over LIBOR) for IOUs and IPPs?
2. What is the typical debt term?
3. What is the typical period over which IRROE is evaluated?
4. How would you characterize the current and mid-term state of project finance for commercial coal projects (with and without CCS)?
5. Can a technology risk premium be quantified (for IRROE, D/E ratio and cost of debt), or must all technology related risks be mitigated before traditional project finance is available?
6. Perhaps an alternative would be to estimate or assume the costs of technology risk mitigation (as a percent of capital costs) via efficacy insurance, technology risk separation in a project, or non-traditional finance structures and factor this into the LCOE calculation, using "commercial" project finance assumptions. Can you comment on this approach?
7. Have there been changes in the required debt service coverage ratio of 1.5-2 since 2008-2009?
8. Have financing costs increased since 2008-2009? What are typical financing costs as a percentage of capital costs?
9. What are the typical distribution of capital costs over capital expenditure periods, of 3 years (for NGCC) and 5 years (coal, IGCC, CTL), excluding capital cost escalation?