LBNL-63434

ERNEST ORLANDO LAWRENCE
BERKELEY NATIONAL LABORATORY

Wind Project Financing Structures:
A Review & Comparative Analysis

John P. Harper, Birch Tree Capital, LLC
Matthew D. Karcher, Deacon Harbor Financial, L.P.
Mark Bolinger, Lawrence Berkeley National Laboratory

Environmental Energy
Technologies Division

September 2007

The work described in this report was funded by the Office of Energy Efficiency and Renewable Energy, Wind & Hydropower Technologies Program of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231.

Disclaimer

Acknowledgements

The work described in this report was funded by the Office of Energy Efficiency and Renewable Energy, Wind & Hydropower Technologies Program of the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The authors would particularly like to thank Steve Lindenberg, Alejandro Moreno, and Jack Cadogan (retired) of the U.S. Department of Energy for their support of this work. For contributing information and reviewing earlier versions of this manuscript, the authors thank (in alphabetical order, by last name): Jeff Chester (Kaye Scholer LLP), Karlynn Cory (NREL), Mike Davies (FreeStream Capital LLP), Ed Ing (Law Offices of Edwin T.C. Ing), Tim MacDonald (Meridian Investments), Alejandro Moreno (U.S. DOE), Ric O'Connell (Black & Veatch), Kevin Pearson (Stoel Rives LLP), Liz Salerno (AWEA), Ryan Wiser (LBNL), and one anonymous reviewer. Of course, any remaining errors or omissions are the sole responsibility of the authors.

Table of Contents

Executive Summary

Wind power capacity in the United States has grown substantially in recent years. From 1998 through 2006, almost 9,900 megawatts ("MW") of new wind capacity was added, accounting for 85% of the 11,575 MW cumulative total capacity as of the end of 2006. In 2006 alone, 2,454 MW of new wind capacity was installed, representing a 27% increase in cumulative capacity.

This rapid expansion has required the mobilization of a tremendous amount of capital to finance wind project costs. Roughly $18 billion (in real 2006 dollars) has been invested in wind project installation in the U.S. since the 1980s, with more than $3.7 billion invested in 2006 alone. Looking ahead, wind project developers will need to raise close to $6 billion in 2007 in order to finance the expansion projected by the American Wind Energy Association ("AWEA"), and the required amount of capital will likely continue to increase in future years if market growth continues.

The financing of new wind projects varies from that of fossil-fueled power projects due to the different cost characteristics of each. Specifically, wind projects are capital-intensive to build but have no ongoing fuel costs, while fossil-fueled power projects are less capital-intensive (per unit of production) but have higher operating (e.g., fuel) costs. Furthermore, whereas Federal tax incentives for fossil-fueled power plants can be (and generally are) distributed throughout the entire fuel cycle (e.g., from exploration and extraction to transportation, power production, and emissions controls), tax incentives for wind projects are instead targeted almost exclusively at the power production stage. The two principal Federal tax incentives available to wind projects are the production tax credit ("PTC") and accelerated depreciation deductions (together with the PTC, the "Tax Benefits"). These Tax Benefits provide a significant value to wind projects, but also complicate wind project finance, since most wind project developers lack sufficient Federal income tax liability to use the Tax Benefits efficiently.

In response, the wind sector has developed multiple financing structures to attract various investors to projects, manage project risk, and allocate Tax Benefits to entities that can use the Tax Benefits most efficiently. Some of these structures are intended to attract actively involved large equity investors with a strategic interest in the wind sector, labeled here as "Strategic Investors." Others are designed to tap into more-passive equity capital from "Institutional Investors," which are primarily interested in the Tax Benefits. Still others enable developers and equity investors to layer on debt financing to leverage their equity exposure and returns.

This report surveys the seven principal financing structures through which most new utility-scale wind projects in the United States have been financed from 1999 to the present, excluding projects owned by investor-owned and publicly-owned utilities where the project becomes part of the utilities' internal generating portfolio and rate base. The report defines utility-scale wind projects as those designed to sell electricity directly to utilities or into power markets on a wholesale basis. The report does not cover financing structures used for smaller community-based wind power projects, though it may have some indirect utility for parties considering such projects, as several financing options used for smaller projects are derived from structures first conceived for larger projects. Finally, this report is relevant only to the U.S. market, since the presence and structure of the Tax Benefits have driven the development of financing structures in ways not applicable for other national markets.

The report has three primary objectives: (1) to survey recent trends in the financing of utility-scale wind projects in the United States, (2) to describe the seven principal financing structures through which most utility-scale wind projects have been financed from 1999 to the present, and (3) to explain each structure's relative impact on the levelized cost of wind energy. The year 1999 is used as a starting point because it marks the recent upsurge in wind power growth in the United States.

The seven structures, summarized briefly in Table ES-1, feature varying combinations of equity capital from project developers, third-party tax-oriented investors (both Strategic and Institutional Investors, jointly known as "Tax Investors"), and commercial debt. Their origins stem from variations in the financial capacity and strength, as well as the business objectives, of wind project developers. The structures have received various names in the industry. The names given in this report are intended to reflect a defining characteristic. For the first three structures in Table ES-1, it is the nature of the Tax Investor. The Pay-As-You-Go ("PAYGO") structure name reflects the delayed timing of the Tax Investor contribution. For the three structures involving leverage, the name refers to the type of debt financing provided. Other names are feasible and in use; care should therefore be taken to specify structures other than solely by name.

Table ES-1. Description of Seven Financing Structures

Financing Structure Name	Project Capital Structure	Likely Equity Investors	Brief Description of Structure Mechanics
Corporate	All equity	Developer (corporate entity)	Corporate entity develops project and finances all costs. No other investor or lender capital is involved. Corporate entity is able to utilize Tax Benefits (no flip).
Strategic Investor Flip	All equity	Developer and Strategic Investor	Strategic Investor contributes almost all of the equity and receives a *pro rata* percentage of the cash & Tax Benefits prior to a return-based flip in the allocations.
Institutional Investor Flip	All equity	Developer and Institutional Investor	Institutional Investor contributes most of the equity and receives *all* of the Tax Benefits and, after the developer has recouped its investment, *all* of the cash benefits, until a return-based flip in the allocations.
Pay-As-You-Go ("PAYGO")	All equity	Developer and Institutional Investor	Institutional Investor finances much of the project, injecting some equity up-front and additional equity over time as the PTCs are generated. Includes a return-based flip in the allocations.
Cash Leveraged	Equity and debt	Developer and Institutional Investor	Based on the Strategic Investor Flip structure, but adds debt financing. Likely involves Institutional Investors, rather than Strategic Investors. Loan size/amortization based on the amount of cash flow from power sales.
Cash & PTC Leveraged	Equity and debt	Developer and Institutional Investor	Similar to the Cash Leveraged structure, but the loan size and amortization profile are based on the cash flow from power sales *plus* a monetization of the projected PTCs from the project.
Back Leveraged	All equity (but developer uses debt outside of the project)	Developer and Institutional Investor	Virtually identical to the Institutional Investor Flip, but with the developer leveraging its equity stake in the project using debt financing.

The list of financing structures shown in Table ES-1 and covered in this report is not intended to be exhaustive. Various permutations of these structures, as well as other structures altogether, are possible. That said, the initial construction costs of *most* new utility-scale wind projects in the United States from 1999 to the present have been financed using one or another of these structures.

To compare the levelized cost of wind energy under each structure, a simplified Excel-based pro forma financial model of an indicative or template wind power project was constructed. The template project is based on a set of assumptions intended to reflect market conditions for projects coming on-line in 2007 and 2008 for items such as non-financing capital costs, operating costs, energy production, taxes, and revenue flows. The template project is then customized to reflect each financing structure. For the six financing structure involving third-party equity or debt capital, the analysis includes assumptions for: (1) the cost and terms of debt (if any); (2) the cost and terms of equity from Tax Investors; and (3) any financing-related transaction, or "soft" costs. The model then estimates the power prices needed to comply with those terms. For these six structures (i.e., all but the Corporate structure), the model calculates the minimum 20-year levelized cost of energy ("LCOE") that yields the 10-year internal rate of return ("IRR") requirement for the Tax Investors in each structure, while not violating any lender constraints.[i] For these structures, the 10-year Tax Investor IRR is used as a key metric, as it is a key negotiating point between developers and investors.[ii] For the Corporate structure, the model calculates the minimum LCOE that yields the developer's 20-year IRR target. Using a 20-year target for the Corporate structure is consistent with the assumption that the developer, as sole project participant, evaluates the project on a longer-term basis than do pure Tax Investors. The use of a standardized template project enables the observed variations in LCOE to reflect the impact of the different financing structures.

Table ES-2 summarizes key inputs and outputs from the model for each structure. The key inputs listed are the project costs, the Tax Investor's 10-year IRR target (except for the Corporate structure, where the relevant input is the developer's 20-year IRR target), and the assumed interest rates and tenor of debt for the three structures using debt financing. Discussion of these and other debt and equity financing input assumptions are described in Chapter 4 and Appendix B. The outputs are the 20-year LCOE, the Tax Investor's 20-year IRR, and the developer's 10-year and 20-year IRR (again, except for the Corporate structure, where the developer's 20-year IRR target is a model input). In practice, negotiations with Tax Investors focus principally on the Tax Investor's IRR. The developer's return calculations are presented (in both IRR and NPV terms) primarily for informational purposes, though some Tax Investors will monitor the developer's return to ensure a reasonable allocation of project returns between the parties.

---

[i] In turn, for each structure involving third-party Tax Investor capital, the developer's return in the model (and in actual negotiations) is the residual, or what is left after satisfying the Tax Investor's return requirements. In practice, developer returns also reflect relative project attributes, e.g., capacity factors, power prices, etc.,

[ii] To simplify the modeling task, the model treats the 20-year Tax Investor IRR as an output. In reality, the Tax Investor's 20-year IRR is linked to its 10-year IRR and both IRR targets are highly negotiated between the Tax Investor and the developer and will reflect market conditions.

As shown in Table ES-2, our analysis finds significant variation – ranging from $48 per megawatt hour ("MWh") to $63/MWh – in the 20-year LCOE required under the various financing structures. This variation is principally a function of:

(1) financing-related transaction costs (shown in Table ES-2 as "soft costs");
(2) assumed 10-year Tax Investor IRR target rates, and Corporate 20-year IRR target; and
(3) the relative terms of each structure (not shown in Table ES-2, but discussed in Chapter 3 and Appendix B), including the level of equity contributions and pre- and post-flip allocations of both cash and Tax Benefits.

Table ES-2. Project Costs, Investor Returns, and LCOE by Financing Structure

	Cash & PTC Leveraged	Cash Leveraged	Institutional Investor Flip	Back Leveraged	PAYGO	Strategic Investor Flip	Corporate
Assumed Installed Project Costs							
Hard Cost ($/kW)	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Soft Cost ($/kW)	229	215	183	183	183	183	125
Total Cost ($/kW)	1,829	1,815	1,783	1,783	1,783	1,783	1,725
Tax Investor After-Tax Return (The 10-year target IRR is a model input, while the 20-year IRR is a model output)							
10-Year Target IRR	9.25%	9.00%	6.50%	6.50%	6.50%	6.50%	N/A
20-Year IRR	9.67%	9.29%	7.12%	7.12%	7.02%	7.02%	N/A
Assumed Loan Terms (For those structures using leverage; Table B3 has details)							
All-in Interest Rate	6.70%	6.70%	N/A	6.70%	N/A	N/A	N/A
Tenor (maturity)	15 years	15 years	N/A	calculated	N/A	N/A	N/A
Developer After-Tax Return (Except for the Corporate 20-year IRR, the developer returns are all model outputs)							
10-Year IRR	9.25%	9.00%	0.00%	-10.08%	5.75%	6.50%	6.64%
20-Year IRR	33.15%	30.58%	10.44%	11.91%	11.52%	37.44%	10.00%
20-Year NPV *($000 @ 10%)*	7,208	7,540	1,578	4,673	7,811	20,745	0
20-Year Levelized Cost of Energy (LCOE)							
Nominal $/MWh	48	50	53	53	59	61	63

Although these results are intended to be illustrative of current market conditions, they are, of course, a function of the modeling assumptions. These assumptions, which are merely indicative and do not reflect a specific project, are detailed in Chapter 4 and in Appendix B. Using a different set of input parameters will generate different results.[iii] Finally, the model does not undertake detailed tax-oriented partnership accounting analysis. Accordingly, the returns should not be assumed as likely for specific projects using the various financing structures. Instead, the comparative nature of the analysis means that these LCOE results are best considered relative to

[iii] For example, the template wind project assumes a 36% net capacity factor (as described further in Appendix B). Capacity factor, a measure of energy production, is an important determinant in the profitability of a wind project, as it drives both revenue and PTC generation. Reducing the capacity factor to 32% causes the calculated LCOEs to rise anywhere from 13% to 20% to compensate for the lower wind production. The relative relationships among the LCOE for the individual financing structures, however, do not change.

one another – i.e., to illustrate the relative impact of financing structures – rather than individually or on an absolute basis.

Table ES-2 suggests that leverage at the project level provides the lowest required LCOE, with the Cash & PTC Leveraged structure coming in at $48/MWh. In other words, given the assumptions used in the analysis, our template project – when financed using this structure – requires a flat $48/MWh for the next twenty years of operation to cover its capital and operating costs, and to meet the return requirements of the Tax Investor as well as the financing terms of the debt provider. The next-lowest LCOE is found with the Cash Leveraged structure, at $50/MWh (with the slightly higher LCOE reflecting slightly less leverage, due to the absence of PTC-backed debt).

The fact that the two structures with the lowest LCOEs have project debt is not unexpected, and suggests that leveraged structures should be popular in the market. Debt has a cheaper cost of capital than does equity. Other matters held equal, the more debt a project can secure, the lower the LCOE. This is true despite the fact that, as reflected in Table ES-2, required equity returns are higher when leverage is involved, to account for the extra risk that is imposed on equity providers when debt is used. Moreover, the investors still receive the full amount of the Tax Benefits as if the project had been financed with all equity and no debt. Additionally, the interest payments on debt are tax-deductible, so they increase the tax loss (which equates to tax *benefits* for the Tax Investor) in the early years of the project.

Interestingly, this finding is not consistent with actual market practice. Most new wind projects have not featured project-level debt. In 2006, for example, only about 20% of the deals in the market appeared to include project-level debt. Many developers and Tax Investors prefer other structures. The reasons given vary, but include both factors in favor of other structures (perceived simplicity, standardization, speed) and factors against using debt (perceived cost, complexity, loss of control, little-improved IRR). This divergence in the implications of our LCOE results from market practice suggests that while the generic cost assumptions used for the model may reflect general market conditions, project-specific cost assumptions are central in the decision on financing structure. Factors not easily quantifiable in a financial model, e.g., a parent company's corporate financing strategy and project risk considerations, also play major roles.

The Institutional Investor Flip and Back Leveraged structures have the next lowest LCOE at $53/MWh. These all-equity structures are identical with the exception of the developer's company-level debt in the Back Leveraged structure. Because this debt is not at the project level, the project returns, Tax Investor returns, and required LCOEs do not differ between these two structures. The only variation is in the developer's returns. For the Institutional Investor Flip structure, the developer has no return on its capital prior to the flip point due to the allocation of cash under the structure. In the Back Leveraged structure, the developer has a negative 10-year IRR (reflecting repayment of the company-level debt). Twenty years out, the developer under the Back Leveraged structure has a 20-year IRR (11.9%) that is about 150 basis points higher than the developer's 20-year IRR (10.4%) using the Institutional Investor Flip structure. This reflects the positive impact of leverage on returns.

The PAYGO structure – where the Tax Investor pays the developer an annual amount equal to a fixed percentage of the PTCs generated – is found to be the next-cheapest, with a LCOE of $59/MWh. This LCOE, as well as the developer's own return, are greatly affected by the assumed PTC payment percentage (in reality, the specific payment rate is set to achieve the negotiated respective return requirements).

The Strategic Investor Flip structure has the next highest LCOE, at $61/MWh. The LCOE is highly dependent on the Strategic Investor's target return requirement. As the Strategic Investor does not take development-stage risks, and only contributes funds when the project is operational, the return requirements should be lower than required for a Corporate structure investment (in which the Corporate entity takes development risks). The equity return to the developer under the Strategic Investor Flip structure is artificially magnified by the small amount of capital contributed. Finally, the Strategic Investor Flip structure results in a higher LCOE than does the Institutional Investor Flip structure because the former provides the developer with a pre-flip pro rata return on investment, whereas the latter only provides the developer with a pre-flip return *of* its investment.

The highest LCOE of $63/MWh resulting from the analysis is associated with the Corporate structure, and is largely a function of the fact that the model assumes a 20-year target return for the developer/Corporate entity of 10%. A developer's return requirement is used under this structure in part because there is no involvement by a separate Tax Investor. A single owner bears all of the project risks – i.e., there is no separation of the risks (and returns) between two equity parties, with one party having lower risks and, hence, lower returns, than the other. In this way, the 10% developer's target return might be thought of as a blended equity hurdle rate, reflecting a melding of the typical returns to Tax Investors and developers in other all-equity structures. The single return figure also can be viewed as a blend of developer's equity and lower-cost debt sourced at the corporate level. Other things held equal, a decrease in the developer's required return will reduce the corresponding LCOE.

Variations in the LCOE across financial structures (assuming the same underlying template project) reflect the different assumptions made about the equity returns and debt financing costs required by Tax Investors and lenders in the marketplace. Investors and lenders require higher returns to invest in wind projects that use structures deemed more risky, e.g., those that defer returns until later in the life of the project, or that use leverage. Thus, assuming all other cost and operating parameters are held equal,[iv] the LCOE for a given financing structure is a proxy for the relative cost of equity and, if used, debt financing for the project. As with other maturing sectors, the cost of financing becomes a competitive differentiator among project developers. Those with access to cheaper money will be able to offer lower-cost power to their customers.

The variation in LCOE across structures also indirectly touches upon an apparent contradiction of the wind financing marketplace. Financial theory suggests that an efficient market will eliminate differences in net financing costs, returns, and LCOE across different financing structures, once all risks and costs are taken into account. However, the U.S. wind sector has seen an expansion in the types of wind financing structures available to project developers, as

[iv] This assumption is important: variations in other assumptions about the underlying template project – including turbine and balance-of-plant costs, capacity factors, and operating costs – will also impact the resulting LCOE.

well as variations in the relative popularity across structures over time and among different developers and capital providers. These attributes suggest that inefficiencies and differing risk perceptions remain in financing wind projects.

More broadly, this analysis highlights the fact that developers decide which financing structure best meets their needs for a given project based on multiple considerations. The decision reflects both the developer's own relative ability to use the Tax Benefits and to provide the capital funding, as well as the financial robustness of the project itself, e.g., whether debt leverage is needed to boost projected returns to satisfy return requirements. The amount of time before the next expiration date of the PTC has also played a role: pending PTC expiration dates led some developers earlier in the decade to adjust their financing strategies and shy away from debt so as to avoid transaction delays and increase the prospects of meeting in-service deadlines for the PTC. Secondary factors also influence the decision, e.g., the relative preference for realizing value up-front via a development fee or capital gain on the sale of the project, or over time from the net cash flows from operations. The relative importance of these various considerations, however, differs from developer to developer and from project to project. Furthermore, some developers' preferred financing structures have evolved over time, especially as their own financial situations have changed. In short, there is no single "correct" structure for all developers for all projects for all time.

That said, the varying rationales for each financing structure can be illustrated by looking at the decision process faced by wind developers in choosing a financing structure. Table ES-3 provides a list of several key corporate and project-level considerations. Depending on a given developer's views on each consideration, one or more financing structures are likely to be more suitable than other structures to meet the needs of the developer. Table ES-3 lists several non-exhaustive scenarios with differing combinations of these developer considerations. The financing structure(s) most typically used for each scenario is identified in the final column. Section 3.8 describes the scenarios in more detail.

Table ES-3. Wind Developer Financing Structure Decision Matrix

Scenario	Developer can use Tax Benefits	Developer can fund project costs	Developer wants to retain stake in project ownership / ongoing cash flows	Developer wants early cash distributions	Project has low projected IRR	Project already exists (refinancing / acquisition)	**Most suitable financing strategy or structure:**
1	No	No	No	Yes	N/A	No	**Sell project to a Strategic Investor**
2	Yes	Yes	Yes	No	No	No	**Corporate**
3	No	Limited	Yes	No	No	No	**Strategic Investor Flip**
4	No	Limited	Yes	Yes	No	No	**Institutional Investor Flip**
5	No	Limited	Yes	No	Yes	No	**Cash Leveraged *or* Cash & PTC Leveraged**
6	No	Limited	Yes	Yes	No	Yes	**Institutional Investor Flip**
7	No	Yes	Yes	Yes	N/A	Yes	**Pay-As-You-Go**
8	No	Limited	Yes	Yes	Yes	No	**Back Leveraged**

For example, a developer that cannot use a project's Tax Benefits, does not have the financial resources to carry the project through construction, and prefers an early return rather than an ongoing stake in the project will likely find it most convenient to sell the entire project to a Strategic Investor (Scenario 1). A second developer in a similar position but more interested in retaining a long-term stake in the project than in an early cash-out might instead pursue the Strategic Investor Flip structure (Scenario 3) or, if the project returns look low, the Cash Leveraged or Cash & PTC Leveraged structures (Scenario 5). Which of these two leveraged structures is used will generally reflect project economics (i.e., whether the incremental PTC monetization is needed to achieve requisite equity returns), as well as the relative interest of Tax Investors in taking on the incremental contingent financial obligations associated with PTC debt. A developer lacking the ability to use the Tax Benefits, but with more cash to invest and interested in both a long-term stake *and* early cash returns, instead might opt for the Institutional Investor Flip or the Back Leveraged structures (Scenarios 4 and 8), with Back Leverage employed to reduce the developer's stake and/or to boost the developer's return. Those developers that own existing projects but are seeking Tax Investors to monetize the Tax Benefits might opt for the Institutional Investor Flip or Pay-As-You-Go structures (Scenarios 6 and 7), with the choice depending in part upon how quickly the developer wants to recoup its investment in the project. Finally, for a developer (or its corporate parent) willing to commit the cash resources and able to use the Tax Benefits efficiently on its own, the Corporate structure (Scenario 2) may prove to be most advantageous.

This interplay of a variety of considerations, both monetary and qualitative, underscores the value of ongoing monitoring of wind project financing trends. Even in the short period since 1999, financing structures have risen and declined in their relative popularity among developers and investors. The current diversity of financing structures is in response to the evolving needs of developers and new investors in the wind sector. Existing financing structures will continue to evolve, and new structures will be developed to meet the emerging needs of the market. This ongoing evolution, combined with the prospect of external developments – e.g., Congressional changes to the structure or existence of the PTC – and the fact that choice of financing structure can, as demonstrated in this report, have a significant impact on LCOE, suggests that it will be useful for the U.S. Department of Energy to stay abreast of changes in the market and to periodically review the impact of financing structures on the cost of wind energy.

1. Introduction

After a long period of relative stagnation that began in the late 1980s and lasted throughout much of the 1990s, the U.S. wind power market has grown rapidly in recent years (Figure 1). From 1998 through 2006, almost 9,900 MW of new wind capacity was added, accounting for 85% of the 11,575 MW cumulative total at the end of 2006. In 2006 alone, 2,454 MW of new wind capacity was installed, representing a 27% increase in cumulative capacity.

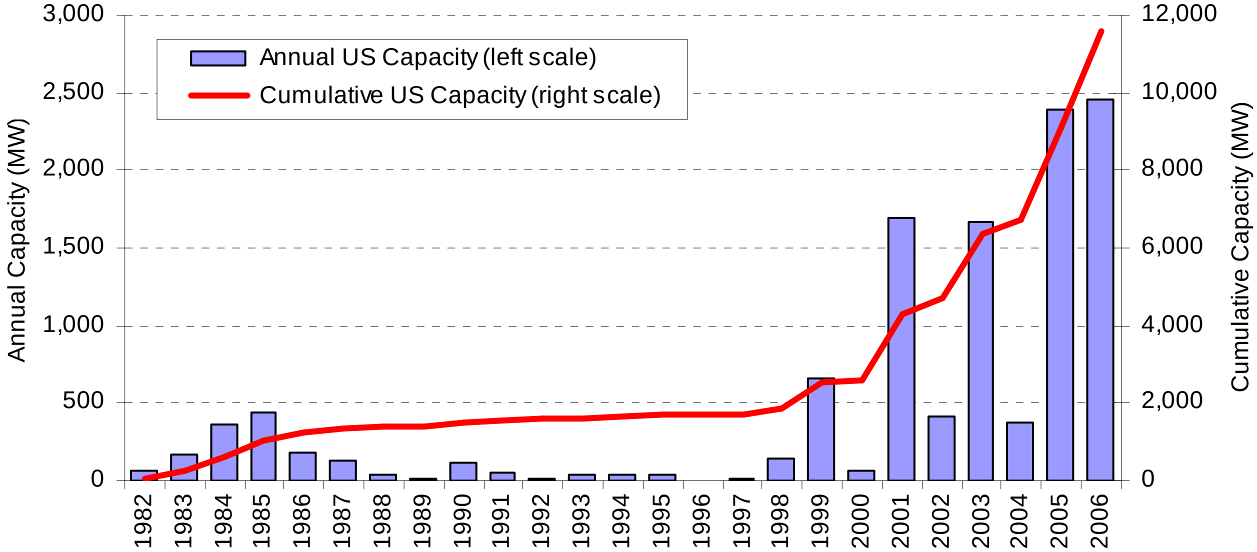

Figure 1. Annual and Cumulative Growth in U.S. Wind Power Capacity

The boom in this segment of the renewable energy market shows no signs of slowing in the near term. AWEA's August 2007 forecast projects record growth of more than 3,000 MW of new wind capacity in 2007.[1] Furthermore, anecdotal evidence indicates that the major wind turbine manufacturers have sold much, if not all, of their production capacity through early 2009, suggesting that 2008 could be another record year for U.S. wind power installations.

The rapid expansion in U.S. wind power capacity in recent years has required the mobilization of a tremendous amount of capital to finance project costs. Roughly $18 billion (in real 2006 dollars) has been invested in new wind projects in the U.S. since the 1980s, with more than $3.7 billion invested in 2006 alone.[2] Looking ahead, wind project developers will need to raise close to $6 billion in 2007 in order to finance the expansion projected by AWEA, and the required amount of capital will likely continue to increase in future years if market growth continues. Moreover, these figures do not include financing raised to support acquisitions or refinancings of existing wind turbine assets.

[1] AWEA Quarterly Market Report dated August 8, 2007, available at http://www.awea.org/newsroom/releases/AWEA_Quarterly_Market_Report_080807.html
[2] See Ryan Wiser and Mark Bolinger (2007), *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*, available at http://eetd.lbl.gov/ea/ems/reports/ann-rpt-wind-06.pdf

Accessing sufficient amounts of capital to finance the build-out of wind project pipelines has historically been a challenge for many wind developers, due in large part to the importance of Federal tax incentives to the project's return. Specifically, qualifying commercial wind projects are eligible to receive a 10-year stream of Federal production tax credits ("PTCs"), and can also depreciate (for tax purposes) the vast majority of project assets using an accelerated 5-year schedule. These two major Federal tax incentives, described in more detail in Text Boxes 1 and 2, are collectively referred to in this report as the project's "Tax Benefits." As a general rule of thumb, investor returns from a wind project often derive as much or more from these combined Tax Benefits than from cash revenue from the sale of power and renewable energy credits ("RECs").[3]

Text Box 1. The Federal Production Tax Credit

As authorized by the Energy Policy Act of 1992 and amended over time, Section 45 of the Internal Revenue Code provides a production tax credit for power generated by certain types of renewable energy projects, including wind power. For wind power, the PTC provides an inflation-adjusted 1.5¢ per kilowatt hour ("kWh") credit for a 10-year period. The credit amounts vary for other renewable power technologies. For 2007, the IRS announced the inflation-adjusted PTC rate at 2.0¢/kWh, or $20/MWh. To qualify to receive the credit, a project must meet several factors to demonstrate that the turbines have been placed in service. Certain limitations exist on use of the PTC in combination with other public sector incentives. There are also ongoing requirements, including that power from the project must be sold to an unrelated party.

Together with state-level renewable portfolio standards, the PTC has been a key driver of wind power development in the United States. The PTC enhances equity returns to owners of wind and other qualifying projects by providing an additional financial benefit not directly tied to power prices. In practice, however, competitive pressures have led developers to pass most of the benefits of the PTC though to utility customers by charging less for the project's power output.

Since its original expiration in mid-1999, the PTC has subsequently expired and been extended several times. In recent years, the Energy Policy Act of 2005 modified the credit and extended it through December 31, 2007. In December 2006, the credit was extended for another year through December 31, 2008 by Section 207 of the Tax Relief and Health Care Act of 2006.

Historically, most wind project developers have been small single-purpose entities without a tax base of sufficient size to make efficient use of the Tax Benefits generated by a wind project. As a result, for several years, one of the few options available to such developers was to develop a project up to the point of construction and then sell it to a larger entity with not only access to the capital required to build the project, but also a tax base large enough to efficiently use the project's Tax Benefits.

More recently, as the market has grown and matured, multiple financing structures have been developed in order to attract various investors to projects, manage project risk, and allocate Tax Benefits to entities that can use them most efficiently. These structures balance the varying needs for financial return, risk, and operating control presented by wind power project developers, tax-oriented investors, and, where utilized, debt providers.

While these new financial structures have enabled more wind power projects to attract capital, the diversity in the purpose, framework, and economics of such financing structures has made comparing the cost of energy from wind projects more opaque. Traditional tools for assessing relative costs across projects include comparing the price per MWh of the electricity sold or the IRR of the investors in the projects. These new wind financing structures, however, feature varying allocations of investment obligations, risk, and cash and Tax Benefits, both among the owners and over time. As a consequence, the structures effectively create different returns for

[3] As wind project installed costs have increased in recent years, the returns coming from accelerated tax depreciation – which is tied to installed costs – have become a larger proportion of the overall Tax Benefits relative to the PTC benefits, which are tied to electricity output and are independent of installed costs.

Text Box 2. Accelerated Depreciation

Section 168 of the Internal Revenue Code provides a Modified Accelerated Cost Recovery System ("MACRS") through which certain investments in wind (and other types of) projects can be recovered through accelerated income tax deductions for depreciation. Under this provision, which has no expiration date, certain wind project equipment – including the turbines, generators, power conditioning equipment, transfer equipment, and related parts up to the electrical transmission stage – may qualify for 5-year, 200 percent (i.e., double) declining-balance depreciation. A typical rule of thumb is that 90% - 95% of the total costs of a wind project qualify for 5-year MACRS depreciation, with much of the remaining amount depreciated over 15 years.

Along with the PTC, this Federal depreciation incentive enhances equity returns to owners of wind and other qualifying projects by providing an additional financial benefit. This value – equal to between one-third and one-half the amount of revenue that can be earned through a long-term power purchase agreement – enables wind developers to charge less for power, while still generating competitive returns for equity investors.

Depreciation deductions in excess of net income generated by a project can be carried forward to future years under certain circumstances. However, due to the time value of money and the fact that a significant share of overall project returns come from accelerated tax depreciation and PTCs, it is important for an investor to be able to utilize such Tax Benefits in the years in which they are generated.

the various investors. In turn, this creates uncertainty over what structure is being assumed in the presentation of any given return or cost of energy figure. The different risk and timing profiles for a project's cash returns and Tax Benefits further complicates these assessments.

The purpose of this report is three-fold: (1) to survey recent trends in the financing of utility-scale wind projects in the United States, (2) to describe in some detail the seven principal financing structures through which most utility-scale wind projects (excluding utility-owned projects) have been financed from 1999 to the present, and (3) to help understand the potential impact of these seven structures on the effective cost of energy from wind power.[4] The year 1999 is used as a starting point because it marks the advent of the recent expansion in wind power growth in the U.S. (see Figure 1).

The remainder of this report is organized as follows. Chapter 2 provides a historical overview of the recent evolution of wind project financing in the U.S., providing a broader context for the financing structures examined in this report. Chapter 3 describes the seven structures principally used in the market. The chapter reviews the impetus for and application of each structure, and presents a schematic diagram of the mechanics of each structure and of the flow of key benefits streams. Chapter 4 introduces an Excel-based pro forma financial model (described in more detail in Appendix B), and presents the results of using the model to compare the levelized cost of energy under each structure. Chapter 5 concludes the report with some broader assessments of the financial model review and of current trends in the development of wind power projects that may affect how future wind projects are financed.

Before proceeding, three notes on the scope of this work merit mention:

1) This report is focused on the financing of large utility-scale wind projects designed to sell electricity directly to utilities or into power markets on a wholesale basis. As such, it does *not* review how investor-owned or publicly-owned utilities finance their own wind projects, where the project becomes part of the utilities' internal generating portfolio and rate base.

[4] This report is intended – in part – to assist policy makers in the U.S. Department of Energy ("DOE") in understanding how financing structures used in the wind power marketplace affect the cost of wind energy. It is not intended to replace the DOE's ongoing internal evaluations of the cost of energy from various electric power generation technologies, though the authors hope that this report will help to inform that work.

2) This report also does not cover financing structures used for smaller community-based wind power projects, or for distributed generation or behind-the-meter wind power projects. Several reports have been released that profile the financing options – which are typically simpler than those presented here – available to these smaller projects.[5] Still, this report may have some indirect utility for parties considering such projects, as several financing options used for smaller projects are derived from structures first conceived for larger projects.

3) Finally, this report is relevant only to the U.S. market, since the presence and structure of the Tax Benefits have driven the development of financing structures in ways not applicable to other national markets.

[5] For example, see http://www.energytrust.org/RR/wind/OR_Community_Wind_Report.pdf and http://www.elpc.org/documents/WindHandbook2004.pdf

2. A Recent History of Modern Wind Project Finance

The financing of utility-scale wind power projects in the United States has evolved significantly in the last ten years, reflecting a widening and deepening of the capital markets for wind power. Prior to roughly 1999, the financing community generally perceived the wind market as exotic, i.e., complex, small, and risky. Earlier difficulties and financial losses experienced by projects and manufacturers had soured the market for several years. Few financial institutions were interested in the sector. There were relatively few financing transactions, the structures were simple, and debt and equity terms were expensive. In contrast, the market now features multiple new equity and debt sources, offers developers and capital providers a variety of tested financing structures from the simple to the highly complex, includes more and larger transactions, and has recorded a marked reduction in the cost of equity and (to a lesser extent) debt. Overall, these changes mark the transition of the wind industry from one perceived to be essentially a niche sector by the capital markets to a substantive, increasingly mature, market. These changes have reinforced the growth of the U.S. wind market and are likely to endure, absent unforeseen technical problems or broader financial market changes.

There have been three principal developments in financing trends and structures in the U.S. wind market since the burst of wind project development in the 1998/1999 time period. These developments, along with variations on these themes, have fostered the creation of the multiple financing structures profiled in this report. Two concern the equity side: (i) the entrance of large companies with strong balance sheets interested in actively developing and owning wind power projects ("Strategic Investors") and, (ii) the entry of large, but more-passive investors principally interested in investing in wind projects for the Tax Benefits ("Institutional Investors").[6] The third development has been the entry of multiple European commercial banks to compete for wind project debt financing opportunities in the United States market.

While these developments cannot be tied to a particular moment in time, two distinct phases in wind project financing practices from 1998 to the present can be described. The first phase was from 1998 through 2002, when Strategic Investors dominated the market. The year 2003 was somewhat of a transition year, while 2004 through 2006 saw the second and third developments described above – i.e., the entry of Institutional Investors and the expansion of debt offerings – come into full force.

This chapter describes the evolution of modern wind project financing within these two distinct periods, followed by more detailed observations on specific developments within the equity and debt markets. The purpose is to provide the context required to better understand the seven specific financing structures described in detail in Chapter 3.

[6] Typically (but not always), both Institutional *and* Strategic Investors can use the Tax Benefits. The primary differences between the two groups of investors concern their relative level of control and participation in project management and the integration of the wind project investments with their main business activities.

2.1 1998-2002: Strategic Investors Dominate the Market

The 1998/1999 time period marked the beginning of the current era of substantial new growth in U.S. wind power capacity (see Figure 1). For the ten years prior to 1998, annual capacity additions had been modest, averaging around 40 MW per year. Driven in part by the then-scheduled expiration of the PTC on June 30, 1999, however, the wind sector added more than 800 MW of new capacity in 1998 and 1999. Half of this increase was concentrated in the four Lake Benton and Storm Lake projects in Minnesota and Iowa, respectively. All were developed by a single independent developer (Enron Wind). Averaging 100 MW each, these transactions were among the largest in the world at the time. The remaining capacity additions in that period were through much smaller projects. Utilities such as PacifiCorp, Public Service Company of Colorado, Platte River Power Authority, and Madison Gas & Electric installed projects for their own account. A few private independent developers ("developers" or "sponsors") and utility subsidiaries developed the remaining utility-scale projects. Little capacity came on line after June 30th, 1999 through the end of 2000, as the Congress did not renew the PTC until late in 1999, and developers needed time to develop a new round of projects.

The financing structures for most wind projects during this period were not complex. Although the PTC was available to projects coming on line prior to June 30, 1999, most developers lacked the financial strength to fund a project or to make efficient use of the Tax Benefits. As a result, their main financing option was simply to sell the project to those few unregulated subsidiaries of electric power utilities that were entering the wind market during this time as Strategic Investors – i.e., investors with experience in the power sector who intended to take an active, if not controlling, management role in wind projects. Although only a handful of such entities were in the market during this period, e.g., FPL Energy, Edison Mission Energy, and Cinergy, the equity market was dominated primarily by these Strategic Investors, who used their internal financial resources to fund the equity share of capital costs (and all of the costs if no project-level debt was used). Institutional Investors – i.e., those entities interested in passively investing in wind projects primarily for the Tax Benefits – had not yet entered the market to any significant degree. Indeed, GE Capital was the only major Institutional Investor in the market during this period.

While a few projects used debt financing to fund a portion of the capital costs, there were only a small number of debt providers interested in the sector. One institution, Fortis Capital, drew upon its success in financing European wind projects to dominate wind sector debt financing in the United States. Plain-vanilla, uncomplicated, construction and senior term debt financing were the principal offerings. A few deals included PTC loan monetizations. This new type of debt allowed a project to borrow against PTCs generated by the project. Such monetizations require the owner receiving the PTCs to commit to make periodic equity contributions for the term of the PTC loan, if needed to support the related debt service obligations. While PTC loan monetizations can be attractive in boosting the amount of debt that a project can support, the number of PTC loan monetizations completed in this period was limited by the few developers and Strategic Investors with the requisite financial strength and willingness to provide the related guarantees.[7] Overall, much of the new capacity added from 1998-2000 was financed on balance sheet, with no project debt (i.e., using the Corporate structure described later in Section 3.1).

New capacity additions surged in 2001, as developers raced again to complete projects prior to the new December 31, 2001 expiration date of the PTC. A major equity-related development occurred in this year. Shell, a multi-national petroleum company, entered the U.S. wind market as a Strategic Investor. A few electric utilities also made their first acquisitions of wind projects as investors (rather than for internal generation purposes). These included American Electric Power and Entergy. Equity financing structures did not change significantly, however. In each case, these new investors typically acquired wind projects developed initially by smaller, independent developers unable to utilize the Tax Benefits. In most cases, the larger Strategic Investor acquired the projects outright. Joint venture collaborations involving two larger companies were used for some projects, but this structure was the exception rather than the rule. Also in 2001, bond market financing was used for the first time to finance a large wind project. A group of public utility districts in Washington State sourced $70 million in non-recourse tax-exempt bond financing to pay for the costs of the Nine Canyon wind project.[8] The bond was notable in that the proceeds directly financed construction costs, rather than being merely a take-out of other construction debt.

There was little new project activity in 2002, as the PTC was not available for part of the year and the electric sector grappled with problems of overcapacity and financial strains from the previous excess in thermal capacity, as well as disenchantment with power sector financings related to the Enron collapse. Several utility-based Strategic Investors and some early European lenders withdrew from the market in reaction to these financial strains. These power sector issues, the uncertain prospects for extension of the PTC, and the perceived complexity of wind projects relative to other tax credit investment opportunities (e.g., tax credits supporting affordable housing) all restrained interest by potential Institutional Investors.

2.2 2003-2006: Rise of the Institutional Investor

The burst of new capacity additions in 2003 fostered paradigm shifts in the debt and equity markets for wind projects. New projects grew in average size, requiring more capital. Several new, independent developers entered the sector around this time. With little or no ability to make efficient use of the Tax Benefits, some of these developers nonetheless sought structures that allowed them to finance their projects in a tax-efficient manner, while retaining an ownership stake. With many of the earlier utility-based Strategic Investors still financially constrained due to the difficulties in the merchant power sector, developers of larger projects sought tax-oriented Institutional Investor capital.

Three developments assisted in this effort. First, from September 11, 2001 through the end of 2004, the Federal Government offered a temporary bonus depreciation option for certain assets, including wind projects, first placed in service during that period. This incentive was put in place to boost economic growth after the 9/11 terrorist attacks. By boosting the near-term return to investors, this incentive enhanced the attractiveness of wind and other capital investments.

[7] Section 3.6 provides more background on the PTC loan monetization concept.
[8] See the Energy Northwest Nine Canyon project: www.energy-northwest.com/generation/nine_canyon.php

Second, private letter rulings issued by the Internal Revenue Service ("IRS"), while officially only pertinent to specific transactions and not intended to set precedents, nevertheless also helped to resolve investor questions regarding ambiguities in the interaction of the PTC with state incentives, as well as the viability of some of the tax-oriented financing structures being implemented. Finally, financial intermediary firms such as Babcock & Brown and Meridian Investments, with experience in mobilizing tax-oriented equity, entered the wind sector to assist in sourcing capital for new projects. As a result of this confluence of events, 2003 and 2004 saw the closing of the first large transactions involving simple partnership flip structures. Institutional Investors remained few in number, however. Most projects in these years were still financed using the simplest equity structures, i.e., via internal corporate funds, or by sale of the project outright to a larger Strategic Investor.

Debt-financing structures also deepened and matured beginning in 2003. The entry of additional commercial banks at both the arranging and participant levels facilitated new transactions and loan facilities, and pushed interest rate margins lower. Lenders began to offer bridge financing, such as turbine supply loans and construction loans, as means to compete for term-lending opportunities. Debt arrangers devised different loan facilities to enable single projects to attract capital from both commercial banks and institutional lenders (e.g., insurance companies).

The year 2003 also saw the first debt financing of a portfolio of new wind projects. In this type of structure a holding company houses the interests in several wind projects, and the financing is obtained at the holding company level (rather than for each project individually). Portfolio financings can offer developers several benefits. These include potential transaction cost savings by negotiating a single set of financing documentation, more favorable financing terms due to perceived lower aggregate risks of the portfolio, and the enabling of financing of projects otherwise too small or risky to attract financing on their own.

In addition, a transaction in 2003 combined two different financing sources for the first time: PTC debt financing and Institutional Investor equity capital. The transaction required the three parties contributing funds to the project – the developer, the Institutional Investor, and the lender – to identify and allocate project risks. In particular, the lender and the Tax Investor had to craft their respective rights and risks with respect to the PTC debt financing. Previous transactions had involved simpler, bilateral negotiations between just two entities, e.g., between a buyer and a seller of a project, or between an owner and a lender.

Since 2003, these financing trends have continued, stimulated by the broader expansion of the overall wind sector and the focus of project developers on developing larger and more-costly projects. While a 100 MW wind project was stunning in 1998/99 and still unusual in 2003, such projects were commonplace by 2006. The evolution towards larger projects reflects multiple factors, including economies of scale in development costs and an up-scaling of turbine size.[9] Most importantly, the effort, cost, and time to develop wind projects do not increase in step with project size; thus, developers have been able to reduce costs on a per-MW basis by focusing on

[9] According to Wiser and Bolinger (2007), the average turbine size installed in 2006 was 1.6 MW (with turbines exceeding 2 MW used for many projects), which is more than double the 0.7 MW average turbine size installed in 1998/99.

larger projects. For their part, Tax Investors also have been able to achieve economies of scale in financing by deploying larger blocks of capital in single transactions.

Increased project development activity has put upward pressure on turbine prices in the last few years. The demand for turbines both nationally and globally has led to a scarcity of supply. At the same time, the cost of building a turbine has increased due to higher global prices for manufacturing inputs such as steel. In response, turbine manufacturers have raised prices and required developers to make early turbine commitments and cash down-payments in order to secure access to turbines. In addition to turbine price increases, interconnection costs have risen for projects being sited further away from transmission lines. All of these factors have raised wind project financing requirements substantially since 1999. AWEA estimated that the 663 MW of capacity installed in 1999 represented some $700 million in investment, resulting in an average cost of $1,056 per kilowatt of capacity.[10] By contrast, AWEA estimated that $4 billion in investment capital was mobilized to finance the 2,454 MW installed in 2006, yielding an average cost of $1,630 per kilowatt of capacity.[11] Anecdotal information suggests that installed costs for some projects in 2007 and 2008 could reach or exceed $2,000 per kilowatt of capacity.

2.3 Recent Equity Financing Developments

Wind developers have responded to this increased development pace and associated increase in capital requirements in various ways. Changes have taken place both at the project level and at the corporate level. Most directly, fewer developers have the internal capital to cover their project capital expenses. Instead, more third-party equity is being tapped, and at earlier points in the development life-cycle, to finance projects than in earlier years. Separately, companies seeking to enter the wind sector in the U.S. are using their financial strength either to offer development financing directly to smaller developers or to buy them outright.

A key method for financing new construction has continued to be the single-entity, all-equity financing structure, referred to herein as the “Corporate” structure. This reflects both a continuing pattern and two newer trends. The largest investor in the U.S. wind market, FPL Energy, continues to finance the initial construction costs of its projects using internal funds.[12] At the same time, several other large developers that have entered the market in the last few years also have used internal funds to cover at least the initial capital costs of their projects. These large developers include foreign companies, e.g., BP, Iberdrola, Acciona, and Enel, as well as domestic entities such as PPM Energy and Horizon Wind Energy. The ability to finance new construction without having to tap third-party capital has emerged as a useful competitive advantage by reducing transaction costs and time to operation.

The continued use of this form of financing structure has been accentuated by the marked consolidation in the industry since 2002. Large entities, including especially foreign entities,

[10] See www.awea.org/news/news000430w2k.html

[11] See www.awea.org/newsroom/releases/Wind_Power_Capacity_012307.html

[12] In the last few years, FPL Energy has closed several privately-placed long-term debt refinancings of portfolios of its existing and new projects. The refinancings appear principally to be limited-recourse in nature, but include credit support from FPL Energy on certain aspects. In August, the company was reported as considering a tax equity monetization for five projects, including one under construction.

have forged alliances with, or acquired outright, several smaller developers as a way of obtaining a pipeline of project investment opportunities. Previously, these smaller developers had either sold their projects outright to Strategic Investors, or partnered with Tax Investors. This consolidation trend has accelerated in the last few years: at least thirteen mergers or acquisitions totaling 35,000 MW of wind project pipeline were announced in 2006, compared to nine such transactions totaling 12,000 MW in 2005 and just four transactions totaling 4,000 MW from 2002 through 2004.[13] In July 2007, Goldman Sachs sold its 100% share interests in Horizon Wind Energy to EDP-Energias de Portugal SA, the largest utility in Portugal, in a transaction valued at $2.7 billion.[14] One of the largest wind developers in the U.S., Horizon expects to have over 1,500 MW gross installed wind capacity by the end of 2007.

Separately, some investor-owned utilities such as MidAmerican Energy and Puget Sound Energy have become interested in directly owning wind power generation capacity, and have acquired several projects from developers. Their motives vary, but include an ability to use the Tax Benefits, and a willingness to use their own internal corporate funds to finance capital costs. In addition, some utilities are seeking outright project ownership in part because their state regulators allow them to earn a return on the investments. Another incentive is a desire to avoid potential complications with rating agencies wanting to reflect credit risks of buying power from unrated project entities by establishing a debt equivalency value for power purchases.

At the same time, Institutional Investor capital sources have increasingly been asked to finance new construction. In 2006, thirteen companies developed 99% of the 2,454 MW of new wind projects.[15] Of these thirteen companies, only five had the tax appetite to retain ownership of their projects;[16] the remaining eight partnered with Tax Investors to make efficient use of the projects' Tax Benefits. JPMorgan Capital Corporation, a leading Institutional Investor in wind projects, estimates that third-party Tax Investor financing was tapped for 1,291 MW of new construction in 13 transactions from 2003 through 2005.[17] By contrast, the firm has estimated that 15 tax equity transactions were closed in 2006 alone, with an aggregate value of about $3.1 billion.[18]

Along with deal flow, the number and capacity of Institutional Investors also have expanded since 2003. Whereas there were only three prominent Institutional Investors in 2003, tax equity transactions in 2006 involved 13 participants. Moreover, more participants are showing a willingness and capacity to structure and lead a transaction. Of the thirteen participants, six firms acted as lead investor in transactions, up from only one or two just three years earlier.

The increases in the number and quality of Institutional Investors reflect several factors either specific to the wind sector or broader in nature. Wind sector-specific factors include greater familiarity with wind technology, the implicit comfort of seeing major multinational corporations

[13] Wiser and Bolinger (2007), op. cit.
[14] See: http://www.edp.pt/EDPI/Internet/EN/Group/Investors/News/2007/Com02072007.htm.
[15] These figures focus on the project owner at the point at which projects are financed and built; they do not reflect sales by smaller developers to the final owners that may have occurred at earlier stages of project development.
[16] See "The Tax Equity Market" in Chadbourne & Parke, LLP's April 2007 *Project Finance Newswire*, available online at http://www.chadbourne.com.
[17] JPMorgan Capital Corporation presentation, AWEA Wind Power Finance & Investment Workshop, April 2006.
[18] See Chadbourne & Parke, LLP, op. cit.

such as GE, Siemens, and Goldman Sachs assume leading roles in manufacturing and/or project development, the creation of more tools for analyzing wind resource risk, and a standardization of financing structures. Broader market factors in the rise of Institutional Investors include an increasing comfort that Federal and state tax and other incentives for renewable power will remain in place or be expanded, Congressional action in 2003 that granted investors the ability to use the PTC against alternative minimum tax obligations during the first four years of a wind project, and declining attractiveness of alternate tax-oriented investment opportunities for Institutional Investors (e.g., in the low-income housing sector).

Such broadening of the investor pool has added to the competitiveness of the market for capital. Developers have been able to secure equity financing from Tax Investors at steadily lower rates. At the AWEA wind power conference in May 2003, Meridian Investments estimated that Institutional Investor returns would need to be in the range of 12-13% in order to attract capital for wind projects. Currently, the requisite ten-year equity hurdle rates for high-quality, well-structured transactions has declined to less than 7% for all-equity deals and less than 10% for leveraged deals.[19] This decline is not likely to be reversed, absent the emergence of a previously-unforeseen material technical issue with wind technology, a major project default with implications for other projects, broader capital market changes, or the like. At the same time, further material declines may be limited as project returns approach rates of alternate investments such as low-income housing and even risk-free Treasury securities.

2.4 Recent Debt Financing Developments

Debt has remained mostly a secondary consideration in the financing activity of recent years. When developers have sought third-party capital, securing a Tax Investor typically has been the primary, if not only, goal. While there have been a few debt-leveraged projects each year, these transactions have represented the minority of the financings.

Several factors account for this. A key factor has been the reluctance of leading Institutional Investors to invest in projects that include limited-recourse debt at the project level. Specifically, they have been uneasy with the allocation of cash flow and control between project lenders and the Institutional Investors in loan default situations. The concern is the potential risk of their up-front equity investment being squeezed out by lenders seeking to recover the value of their loans. Additionally, some Institutional Investors fear that the increased transaction costs associated with debt may erode much of the value associated with leverage. There is also a timing issue associated with debt. Debt leverage not only costs more up-front, it also takes more time to close the financing transaction. The repeated expirations in the PTC, and short-term renewals of several of the PTC extensions, have given a competitive advantage to developers not needing to obtain debt financing as a condition of commencing construction.

With term debt not in high demand, the debt market has expanded principally in the types of loan financing made available to project developers. Several developers, for example, have accessed shorter-term turbine supply loans, construction financing, and letter of credit support from

[19] See Chadbourne & Parke, LLP, op.cit.

several commercial banks in support of their new wind projects.[20] Additionally, lenders committed to limited-recourse financing for several transactions in 2006 using the Back Leveraged structure. The Back Leveraged financing structure – with debt incurred by the developer, rather than at the project level (described in more detail later in Section 3.7) – balances developer interest in using leverage with reticence by Institutional Investors in seeing debt at the project level. The Back Leveraged structure does not affect project-level returns or risks, since the debt only finances a portion of the developer's equity contribution to the project company. These debt facilities principally assist the developer by stretching its capital, thereby enhancing its ability to expand operations. Developers and investors are also beginning to tap debt financing to refinance existing projects. FPL Energy has issued private limited-recourse secured bonds and notes for two portfolios of existing projects.[21]

While term debt financing has not been the primary financing tool, the number of institutions providing debt financing of all types, as well as the average size of loan transactions, has risen in recent years. Eleven financial institutions acted as lead arranging lender for debt transactions in the wind sector that closed in 2006. This was up from earlier years when only two or three lenders were willing and able to assume such lead-arranging functions. Transaction loan commitment amounts in 2006 routinely were in the hundreds of millions of dollars; one developer secured $1 billion in construction loan facilities to support a portfolio of projects. Anecdotal information by loan arrangers at industry conferences indicate that the number of banks participating in loan syndications and average loan participation levels have both risen as well since 1998/1999. Overall, the expanding pool of debt arrangers competing to arrange debt financing for projects suggests a continuation of current trends. Banks are competing to provide debt capital at competitive rates and are innovating in terms and structures in order to win such competitions.

European commercial banks have dominated lending activity in the U.S. wind sector. One bank, Fortis, virtually originated the term cash flow and PTC monetization debt financing structures in the U.S. market during the 1998-2001 time period. Since then, the informal mantle of most-active lead arranger has always been held by one or another European bank such as Dexia Crédit Local or HSH Nordbank. Of the eleven institutions that led one or more debt financing syndications in 2006, only three were U.S. financial institutions, and one of those three only acted as a lead arranger for a transaction developed by an affiliate. A few insurance companies also have provided institutional debt financing, but the majority of project leverage has come from commercial banks.

Relative to the dramatic decrease in equity returns, debt terms have not changed as significantly. The typical loan term (or duration) remains a function of the length of the underlying power and REC purchase agreements. For projects with long-term power purchase agreements (e.g., twenty years) with creditworthy utility buyers, commercial bank lenders are willing to extend loans with

---

[20] Jeff Chester presentation ("Wind Power Market Overview 2006") at Infocast's *Wind Power Finance & Investment Summit 2007*, La Jolla, CA, February 7-9, 2007.

[21] http://www.fplenergy.com/news/contents/05020.shtml, http://findarticles.com/p/articles/mi_m0EIN/is_2005_Feb_9/ai_n9509206. Also, see Form 8-K filing by FPL Group, Inc. to the U.S. Securities & Exchange Commission, June 26, 2006, http://www.psc.state.fl.us/library/filings/06/05916-06/05916-06.pdf.

a term of up to fifteen years. Institutional lenders, e.g., insurance companies, have been willing to go as long as nineteen years for comparable transactions. For projects involving shorter term power purchase agreements (“PPAs”) or utilizing power marketing contracts in lieu of power purchase agreements, loan terms are shorter and/or involve mandatory prepayments using any excess cash flow.

The standard debt service coverage ratio (“DSCR”)[22] has widened slightly from 1.40:1 in 1998/99 to 1.45:1 more recently. The increased DSCR reduces default risk by lowering the borrowing capacity of the project. Anecdotal information suggests that commercial bank interest rate margins over their cost of funds have declined by approximately 50 basis points (0.5%) from 2003 through 2006. Commercial banks currently quote interest rate spreads for high-quality projects of 110-125 basis points over the London InterBank Offer Rate (“LIBOR”) in the early years of a loan. Some lenders raise these margins gradually in later years, e.g., up to 200 basis points over LIBOR for the final years of a fifteen-year loan. Institutional lenders such as insurance companies sometimes quote spreads over U.S. Treasuries, but most debt discussions are LIBOR-based.

2.5 Summary

The increased depth and richness of equity and debt financing capacity available to the wind sector is likely to continue. Broadly stated, equity and debt capital now is more readily available than the supply of new high-quality wind projects able to utilize such capital. In contrast with market conditions of barely a decade earlier, capital is now chasing projects. This upheaval has fostered the development of the various financing structures profiled in the next chapter. To the extent that this situation endures, capital providers will continue to innovate financing terms and financing structures as means to secure new financing opportunities.

[22] Calculation of the DSCR may vary across projects, but as a general rule it is operating cash divided by total debt service (i.e., principal and interest).

3. Description of Current Financing Structures

Financing structures currently used in the U.S. wind sector can be distinguished by five principal characteristics.[23] These include the following:

- *Tax Appetite*: ability of the project developer to make efficient use of the Tax Benefits.
- *Capital Strength*: ability of the project developer to fund the initial construction costs.
- *Leverage*: whether project-oriented limited-recourse debt financing is utilized.
- *Timing of Funds*: whether equity funds provided under the structure are provided by a Tax Investor at the outset or on an installment (i.e., "pay-as-you-go") basis tied to generation of PTCs by a project.
- *Management*: the division of management responsibilities among the several investors.

These principal characteristics or considerations manifest themselves in various combinations among different wind projects, which give rise to a variety of financing structures.

In the United States, most new utility-scale wind projects constructed since 1998 (and not directly owned by a local electric utility) have used one of seven structures to finance the capital costs. This chapter describes each of these structures in detail. The simplest structure is a single investor, all-equity approach dubbed the Corporate structure. Three other all-equity structures – the Strategic Investor Flip, the Institutional Investor Flip, and Pay-As-You-Go – are more complex, in that they make use of equity from both the developer and one or more Tax Investors. The final three structures – Cash Leveraged, Cash & PTC Leveraged, and Back Leveraged – build upon previous structures by introducing debt financing at either the project or developer level.[24] In addition to describing each of these structures both textually and schematically, this chapter discusses each structure's rationale for use, the types of investors that find it appealing (and why), and its relative frequency of use in the market. The chapter concludes with a generalized summary of how a developer might choose one structure over another.

The financing structures identified in this report are not intended as a comprehensive list. Various permutations of these structures,[25] as well as other financing mechanisms altogether,[26] are possible. That said, the initial construction costs of *most* new utility-scale wind projects in the United States from 1999 to the present have been financed using one or another of these structures.

---

[23] Adapted from a Milbank, Tweed, Hadley & McCloy LLP presentation, AWEA Wind Power Finance & Investment Workshop, September 2004.

[24] It is worth noting that some of these structures have been called various names in the industry. The names given in this report are intended to reflect a defining characteristic. For three of the four all-equity structures, it is the nature of the Tax Investor (i.e., Corporate, Strategic, Institutional). The Pay-As-You-Go structure name reflects the delayed timing of the Tax Investor contribution. For the three structures involving leverage, the name refers to the type of debt financing provided. Other names are feasible and in use; care should therefore be taken to specify structures other than solely by name.

[25] For example, developers continually explore different ways of using debt financing. Also, some developers initially finance a project using one structure, then refinance it via another structure at a later date.

[26] For example, given the report's focus on project-level financing structures, financings by companies tapping external debt financing at the corporate level or portfolio financing structures are beyond the scope of this report.

Before proceeding, it should be noted that the descriptions and reviews of the various financing structures presented here do not include formal legal analyses of their tax and accounting implications. The authors are not attorneys or accountants, and the information presented here should not be considered as formal legal or accounting advice. Instead, the information presented here is at a general level and is not specific to a particular project or investment. Though the report identifies certain important aspects relating to partnership issues associated with the financing structures described here, project developers, investors, and others are strongly encouraged to seek tax and accounting counsel prior to undertaking a particular project or investment.

3.1 Corporate Structure

Description

The Corporate structure is characterized by a single developer/investor with the financial strength to fund all of the project costs and sufficient tax appetite to use all of the project's Tax Benefits. The Corporate parent developer/investor typically establishes a special purpose entity to house the assets of the project. This structure, which continues to be one of the most widely used in the wind sector, represents the simplest way to own and operate a project. All of the initial capital costs are funded by the parent company using internally generated funds from other operations, and all of the project's net cash flows and Tax Benefits flow back to the parent. The parent provides the funds in the form of equity to the project company. No additional investors or limited-recourse debt financing are involved (at least initially) at the project level. The parent exercises full management control over the project (although it is not uncommon even for this type of developer/investor to engage an outside firm to perform day-to-day operational and maintenance duties).

Figure 2 provides a schematic representation of the Corporate structure. Entities are identified by bold print. Shaded boxes represent the three types of financial benefits accruing from the wind project: distributable cash, taxable losses/gains, and PTCs. The underlying boxes with percentages show how the respective financial benefit is allocated to the investors (in this case, there is only one developer/investor). The project company generates both cash revenue and PTCs from the sale of electric power. It may also generate cash revenues from REC sales, though this analysis assumes that the PPA price includes the purchase of both the electricity and any RECs. Operating expenses are deducted from revenues to generate cash available for distribution. Non-cash tax-deductible expenses (principally depreciation in this structure, though interest on debt also falls into this category) generate taxable losses. In this structure, there is just one investor. Accordingly, the schematic shows the Corporate parent funding 100% of the costs of the project as equity in the project company. In turn, 100% of each of the distributable cash, taxable losses & gains, and PTCs flows back to the Corporate parent.

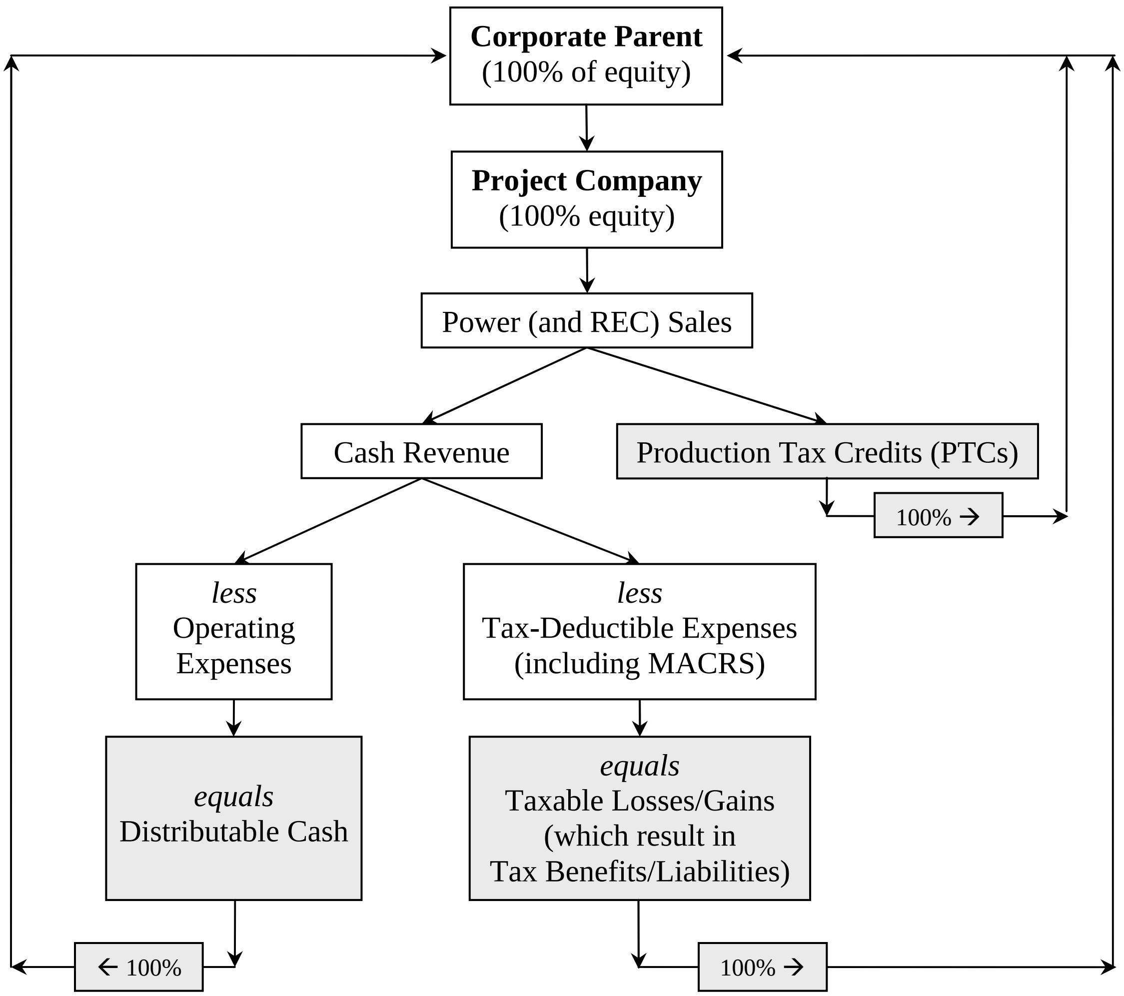

Figure 2. Schematic of Corporate Structure

Rationale for Use

The advantage of this structure relative to other structures is its simplicity. Funding, accounting, and management issues are not complicated by the need to inform or seek approval from lenders or other investors. All of the financial and other benefits of ownership flow to the single owner. This structure is the most time-efficient and incurs the least amount of out-of-pocket transaction costs. In the wind sector, these aspects have become key ways in which large developers have secured several competitive advantages. The repeated expirations and extensions of the PTC earlier in the decade forced developers to focus their efforts on projects most likely to be completed prior to the next expiration date, as they had no guarantees that the PTC would be renewed. Without the need to identify and negotiate for third-party capital, such companies enjoy more flexibility and time to finish development of their projects.

Earlier in the decade, some corporate investors leveraged their financial strength still further. The ability to internally develop and finance entire projects provides a significant negotiating advantage when acquiring projects from smaller developers lacking the internal wherewithal or time to mobilize the capital to finish projects prior to the next PTC expiration date. Under time pressure from the pending PTC expiration date, and not wanting to face the risk that the PTC will not be renewed, some smaller developers opted to accept a discounted price for selling the rights to their projects. This type of market power was more pronounced in the 1998-2003 time period when there were few such buyers and the PTC lapsed three times (before subsequently being extended retroactively in each instance). This market dynamic is less apparent in recent years, as more investors have entered the market and confidence has grown that the PTC will be extended.

Other Strategic Investors have used their financial strength to fashion on-going relationships with smaller developers as a means of securing a pipeline of future investment opportunities, rather than acquiring potential projects one at a time. The larger company will offer to provide financial support to the smaller developer to finish the development of one or more projects in exchange for a first right of refusal to acquire or invest in the projects. The multiple outright acquisitions in the last few years of smaller development companies by larger companies entering the sector are further examples of the use of financial strength to competitive advantage.

Lastly, the larger, financially strong developers have placed down-payments to acquire rights for deliveries of wind turbines from turbine manufacturers. With a scarcity of wind turbines in the marketplace, the advance payments to secure deliveries prior to the next PTC expiration date have been another means by which larger developers have used their financial strength to enable their projects to be completed on schedule. In some cases, large turbine orders have enabled developers to acquire turbines at lower costs than competitors, which has provided a further competitive advantage in competing for utility purchase contracts.

Investor Type

The companies using this structure most commonly are large, financially strong, and have significant and predictably recurring income tax obligations. They have the cash flow to undertake the full investment and the ability to utilize the Tax Benefits in the years in which they are generated by the project. Companies using the Corporate structure typically have strategic reasons to be investing in the wind sector. They view it as a core part of their business plan, rather than simply a convenient means to reduce tax obligations. In effect, they are Strategic Investors that prefer to maintain full ownership without any other investors. FPL Energy is the most prominent example, as it has used this structure to finance the initial costs of most of its wind projects.[27]

Use of the Corporate financing structure often reflects a broader, corporate-wide decision to fund all corporate investments at the parent level, rather than individually at a project level. This financing strategy reduces financing costs, e.g., rates and transaction costs, to the lowest levels available to the Corporate parent investor, since the risks of any single investment, be it in a wind project or other uses of corporate cash flow, are aggregated with all other company-wide investments and are supported by the company's aggregate cash flow from current and future operations. Electric utilities and petroleum companies historically have taken this approach for

---

[27] Section 2.4 notes FPL Energy's use of debt financing and portfolio financings to refinance portfolios of existing and planned projects and reported current consideration of tax-equity financing for a portfolio of existing and new projects.

all but their most risky investments. The Corporate financing structure enables decisions on project development to be separate from decisions about the best means to finance the project; it allows the parent investor to time the financing based on broader financial market conditions. In particular, the Corporate financing structure can be used as an interim measure, as the company retains the flexibility of a later partial refinancing via the capital markets using other financing structures such as the Pay-As-You-Go or leveraged portfolio financing structures.

Frequency

The Corporate financing structure is the most commonly utilized structure in the U.S. In large part, this reflects the use of this structure by FPL Energy, which alone has accounted for a major portion of all wind projects brought on-line in recent years.[28] A few other developers have initially used this structure for some projects, but then shifted to other financing structures after their ability to make efficient use of the Tax Benefits changed. For one reason or another, most other developers have found it useful or necessary to tap third-party equity or debt capital to finance their projects. The recent entry of several large foreign developers into the U.S. market and the related consolidation of the sector by large financially strong players suggest that the Corporate structure will continue to be widely utilized going forward. At the same time, it will increasingly be employed not as the final structure, but rather as an interim means to get wind projects built and into operation pending later refinancings. To the extent that the foreign entities have insufficient U.S. tax appetite, such refinancings likely will involve Tax Investors.

3.2 Strategic Investor Flip

Description

The Strategic Investor Flip financing structure is the simplest version of the structures involving capital from Tax Investors ("Tax Equity"). The name of the structure reflects the fact that it has been used primarily by Strategic Investors seeking an active role in wind projects. The project developer negotiates a percentage ownership share by the Strategic Investor. Under this structure, the initial funding of project costs and allocations of project cash flows and Tax Benefits are shared on the same percentage basis, or pro rata, as the respective ownership of the parties. In effect, this partnership structure is similar to a basic 50/50 joint venture structure. However, three key elaborations set it apart from a conventional joint venture.

The first key difference is that the Tax Investor provides almost all of the project equity, and in turn is initially allocated almost all of the cash and Tax Benefits. For example, with an undercapitalized developer, the Tax Investor might contribute funds for up to 99% of the total project cost, while the developer provides the remaining 1%. Under this structure, the Tax Investor and developer are initially allocated the same respective 99% and 1% shares of the distributable cash and Tax Benefits. There have been transactions where the Tax Investor's initial contribution and allocation has been as high as 99.9%; there is speculation that pending guidance from the IRS may address the acceptability of such high ratios for future transactions.

[28] See http://www.fplenergy.com/portfolio/wind/map.shtml for a map of FPL Energy's wind facilities.

The second elaboration, relative to a traditional joint venture, involves the concept of a "flip" in the percentage allocations of the project cash flows and Tax Benefits after a certain point in the life of the project. This point (the "Flip Point") typically is expressed as the point at which the Tax Investor has received sufficient cash flows and Tax Benefits to reach a pre-negotiated IRR on its investment. After the Flip Point, the percentage allocations of project cash flow and Tax Benefits change to a second set of numbers that allocate most project flows away from the Tax Investor in favor of the developer. The Flip Point and the pre- and post-flip allocations are negotiated by the two parties. The Flip Point is usually projected to be reached on or shortly after the tenth anniversary of the project's commercial operation date. The tenth anniversary is used as a marker date, since the PTC is available only during the first ten years of operations. As developers utilizing this structure typically do not have the ability to utilize Tax Benefits efficiently, they do not want the flip to occur prior to year ten.[29] A common post-flip sharing amount is simply to invert the original percentage allocations. It may, however, be necessary to allocate more of the post-flip flows to the Tax Investor to achieve the overall twenty-year IRR targets required by the Tax Investor.[30] It is also possible to have a second, later, Flip Point and to have the inversion of the percentage allocations be staged across the two Flip Points. For example, a transaction could include an initial 99%/1% allocation that flips to 20%/80% on the first Flip Point and then to 5%/95% at the second Flip Point. A minimum 5% retention by the Tax Investor is increasingly seen as important to avoid a potential IRS challenge to the allocation of Tax Benefits.

The third difference is that the Strategic Investor Flip structure often includes an option for the project developer to purchase the ownership interests held by the Tax Investor after the Flip Point. In order to comply with tax code requirements, for the Tax Investor to record the investment as a true equity investment (and to recognize the consequent Tax Benefits), most projects set the purchase price on at least a "fair market value" basis. The purchase option typically is structured to first be available on or after the Flip Point has been reached. The reduction in the allocations of cash flow thereafter and the exhaustion of the Tax Benefits serve to reduce the fair market value of the Tax Investor's ownership interests after that point and, consequently, the price that must be paid by the project developer for such interests.

Under this structure, no limited-recourse debt financing is sought either at the project level or outside of the project company. Management control over the project is negotiated. In transactions using this structure, the project developer usually retains broad management control prior to the Flip Point. However, it is not uncommon for the Tax Investor to exercise majority control pro rata with its ownership and funding percentages. The partnership agreement typically provides for certain limited rights for the owner with the lower percentage allocation, e.g., veto rights with respect to major corporate decisions.

Figure 3 provides a schematic representation of the Strategic Investor Flip structure. Specifically, the schematic shows the relative percentage equity contributions from the project developer and the Tax Investor into the project company to fund initial construction costs. The

---

[29] Note that after the Flip Point, most of the Tax Benefits – i.e., all of the PTCs and most of the depreciation deductions – have been utilized, which means that the developer is really being allocated cash and *tax liabilities*.

[30] These 20-year IRR targets are typically only slightly higher (e.g., less than 100 basis points or 1% higher) than the 10-year targets.

shaded percentage boxes show the pre- and post-flip allocations of cash flow and the various Tax Benefits back to the developer and the Tax Investor. The first percentage in each box is the pre-flip allocation to the associated investor, while the percentage after the forward slash represents the allocation to the associated investor after the Flip Point. Although the equity contribution and pre- and post-flip allocation percentages shown in Figures 2-8 match those used in the modeling analysis presented later in Chapter 4, in actual practice these percentages will vary from project to project and should therefore be considered illustrative.

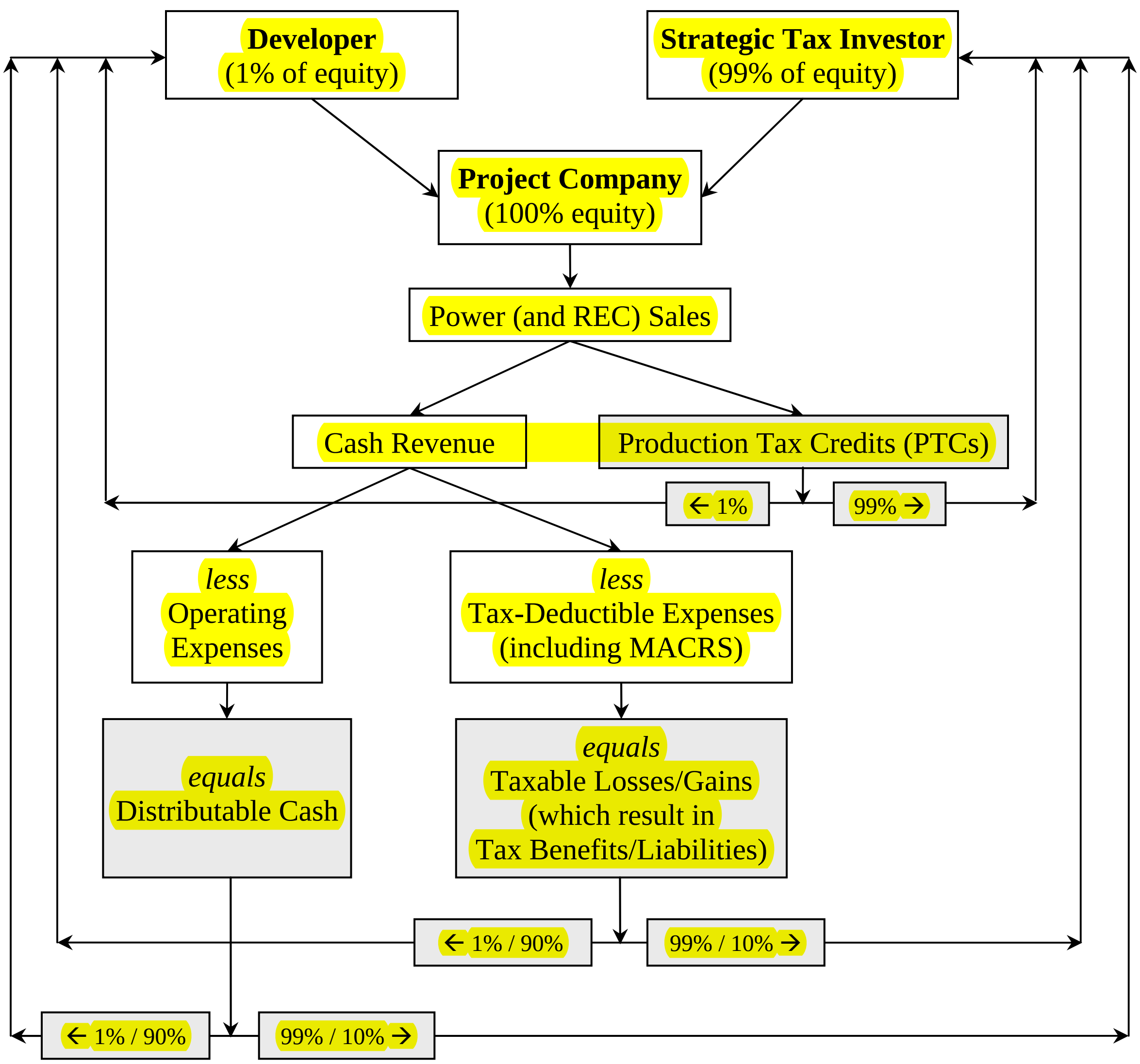

Figure 3. Schematic of Strategic Investor Flip Structure[31]

[31] Figures 3, 4, 6, and 7 are adapted from a June 2006 Meridian Clean Fuels presentation titled *Comparing Alternative Structures for Tax Equity Investments in Wind Projects*.

Rationale for Use

The Strategic Investor Flip structure was one of the first structures to be developed to attract third-party equity able to utilize the Tax Benefits, while allowing the developer to retain an interest in the project. Its virtue is its relative simplicity. All financial flows prior to the Flip Point, both in and out of the project company, are on the same pro rata basis as ownership. The structure is useful for those project developers lacking both the financial strength to fund initial capital costs and the appetite for the Tax Benefits, but who are nonetheless unwilling to simply sell the project outright. In effect, the Tax Investor buys the majority of the project and gets the lion's share of the aggregate Tax Benefits during roughly the first decade of operation, when most of the Tax Benefits are generated. The project developer receives most of the cash and the remaining Tax Benefits generated thereafter; the developer also typically has an option to repurchase the shares held by the Tax Investor at that point. The investor is made comfortable that the project developer has the incentive to manage the project capably during this first period, as the project's success is key to the Flip Point occurring on schedule and the developer realizing the long-term value thereafter. The Flip Point historically has been designed to occur near the end of the ten-year period during which the PTCs are generated. The rise in turbine and other capital costs may be leading the Flip Point for some transactions to be extended by a few years to enable the Tax Investor to reach its negotiated target return. Changes in negotiated power prices and underlying interest rates also will affect the relative positioning of the Flip Point by affecting the residual amount of cash flow, and taxable income or loss, distributed to the Tax Investor.

Investor Type

Project developers opting to use this structure typically have a business plan that calls for them to evolve into larger entities over time. They are not content simply to receive a single up-front development fee, but wish to develop a pool of projects that will generate cash flow over time. Some closely-held developers view the structure as a means to develop cash flows that will support their families in later years. Other privately-held developers look toward the possibility of listing their companies on a public stock exchange and note that market valuations tend to favor ongoing contractually-based revenue streams over irregular, one-time development fees.

For their part, Tax Investors can be attracted to this structure as it enables them to partner with capable, if cash-poor, project developers. Some Tax Investors believe that making the project developer wait for its returns until after the Flip Point motivates good project management. The structure gives preferred return rights to the Tax Investor and, in so doing, allocates much of the risks of a wind project to the developer. If the wind resource proves weaker than first thought, if turbine technical availability proves less than promised, or if maintenance costs are higher than projected, the effect on the Tax Investor is mitigated by the fact that it is receiving virtually all of the cash flows and Tax Benefits that are generated by the project until the Flip Point, and the Flip Point will be delayed until the Tax Investor reaches its IRR target. This structural risk mitigant can be very attractive to potential Tax Investors just entering the market and desiring to reduce the risk of solitary investments. Though primarily used by Strategic Investors, this financing structure can also be of interest to more-passive Institutional Investors (acting as Tax Investors) seeking to maximize their initial investments and to lock in a particular return. For example, some life insurance companies, with their need to match investments with future year policy payment obligations, favor this structure for these reasons.

Frequency

The Strategic Investor Flip financing structure was employed for a few transactions early in the decade, but does not appear to be in frequent use currently.[32] Though it has elements of interest to both Tax Investors and developers, there are limitations. At least one Tax Investor currently in the market discounts the structure's utility, considering it to be little different from the Corporate structure. For developers, this structure obliges them to wait ten or more years to receive any substantive cash flow (other than through whatever up-front development fee is feasible given the project economics and any ongoing management fees charged by the developer for overseeing project operations). Other financing structures have since been developed that meet the developer's needs more effectively. In particular, the Institutional Investor Flip financing structure (described next) has proven more attractive to developers with capital to invest, as it enables such developers to put more of their capital to work and also recoup their investment more quickly, without being saddled with unwanted Tax Benefits. Separately, several of the medium-scale wind project developers that might otherwise have utilized the Strategic Investor Flip structure have instead solved their project financing needs by agreeing either to sell their projects or to be acquired outright by larger Strategic Investors.

3.3 Institutional Investor Flip

Description

The Institutional Investor Flip Structure is also known as the "PAPS" structure (Pre-tax, After-tax Partnership Structure), the "A/B" structure (after the two classes of investors in the partnership agreement for such transactions), or the "Babcock & Brown" structure (in recognition that this investment firm often has utilized this structure for its many transactions). It is similar to the Strategic Investor Flip structure, in that the project developer brings in a separate Tax Investor to use the Tax Benefits, and there is a Flip Point at which the allocations of cash and Tax Benefits change.

Beyond these similarities, there are several important differences. First, the name of the structure reflects the fact that it was devised to bring in less-active, more-passive equity capital from Institutional Investors. Second, in contrast to the Strategic Investor Flip, the cash and Tax Benefits are initially allocated in different percentages than each investor's respective equity contributions. In other words, the allocations are not pro rata with the initial capital contributions. Specifically, in exchange for the developer contributing a greater portion of the initial equity capital (e.g., 30% - 40% of the total), *all* of the distributable cash from the project is initially allocated to the developer until it recovers its capital. This typically takes place over the first four to six years of the project. Note that this initial allocation does not provide the developer any return *on* its investment, but only a return *of* its investment. After the developer has recouped its initial investment, 100% of the cash is then allocated to the Tax Investor until

[32] Some developers of smaller community wind projects are using versions of this structure.

the Flip Point is reached. Separately, the Tax Investor is allocated 100% of the Tax Benefits from the outset of project operations. The two parties adjust the initial contributions and the project allocations so that the Flip Point – the point at which the Institutional Investor achieves its targeted IRR – is projected to be reached on or shortly after the end of year ten. The initial contributions also will vary across projects, depending on the relative returns generated from cash flows versus PTCs.[33] Once the Flip Point has been reached, a majority of the cash and Tax Benefits, typically around 90%, are allocated to the developer. The post-flip sharing percentages are sized to provide the Tax Investor with a targeted 20-year return, so they vary depending on the specifics of the project. The general assumption is that the 20-year return is, at a minimum, slightly higher than the 10-year return (e.g., by 50 - 70 basis points).

This structure does not include any limited-recourse debt financing at either the project or company level. The developer usually maintains broad management control over routine project operations. The Tax Investor has voting rights or veto power with respect to major decisions. After the Flip Point has occurred, it is not uncommon for the Tax Investor's right to be limited still further.

Figure 4 provides a schematic representation of the Institutional Investor Flip structure. Specifically, the schematic shows the relative contributions from the project developer and the Tax Investor into the project company to fund initial construction costs, as well as allocations of cash flows and Tax Benefits to each party. As discussed above, this structure features two Flip Points for cash allocations (though just one Flip Point for Tax Benefits): initially all cash goes to the developer until it recoups its investment in the project company; thereafter, all cash goes to the Tax Investor until it reaches its target return, at which point the second flip (in the allocation of both cash and Tax Benefits) occurs.

Rationale for Use

The Institutional Investor Flip structure was developed to address limitations of the Strategic Investor Flip for various types of developers and investors. Specifically, some developers have capital to invest and the interest in doing so, but lack the ability to use the Tax Benefits. For such investors, the Strategic Investor Flip, with its pro rata link between the percentage amount of capital invested and receipt of cash and Tax Benefits, does not give them the means to invest capital without being saddled with unwanted Tax Benefits.

Another more recent driver has been the entry of cash-based investors ("Cash Investors") into the wind sector. These are typically Strategic Investors but can be Institutional Investors or even ratepayer-funded state clean energy funds; the distinction is their preference for a cash-based return as opposed to one comprised primarily of Tax Benefits. Foreign-owned utilities entering the U.S. market are examples of this group. In some cases, these Cash Investors team with undercapitalized developers to jointly act as the project sponsor. In other cases, the Cash

[33] A wind project with a robust capacity factor (enabling the developer to offer a lower power purchase price) will generate more PTCs and less cash. In comparison, the same size project, but in a lower wind region (obliging the developer to seek a higher power purchase price), will generate fewer PTCs but more cash. Since the cash and PTCs are allocated differently in this financing structure, the parties adjust their initial contributions to compensate as needed.

Investors have acquired either the project development rights or simply acquired the smaller developer outright so as to become the sole project sponsor. For such Cash Investors, the Strategic Investor Flip structure is not suitable, since it would require only a small amount of capital and not provide a substantive share of the cash flow until after the Flip Point. The Institutional Investor Flip structure enables a Cash Investor to put more capital to work. At the same time, the structure enables the Cash Investor to receive a preferred cash flow early in the project, thereby both lessening its longer-term exposure, while also recycling funds to support new wind projects. For their part, many Institutional Investors like the structure because it obliges the project developer to invest more capital than with the Strategic Investor Flip, thereby becoming more vested in the success of the project. As an all-equity structure, it also allows developers and Institutional Investors to avoid the time, expense, governance, and cash flow allocation issues of debt financing.

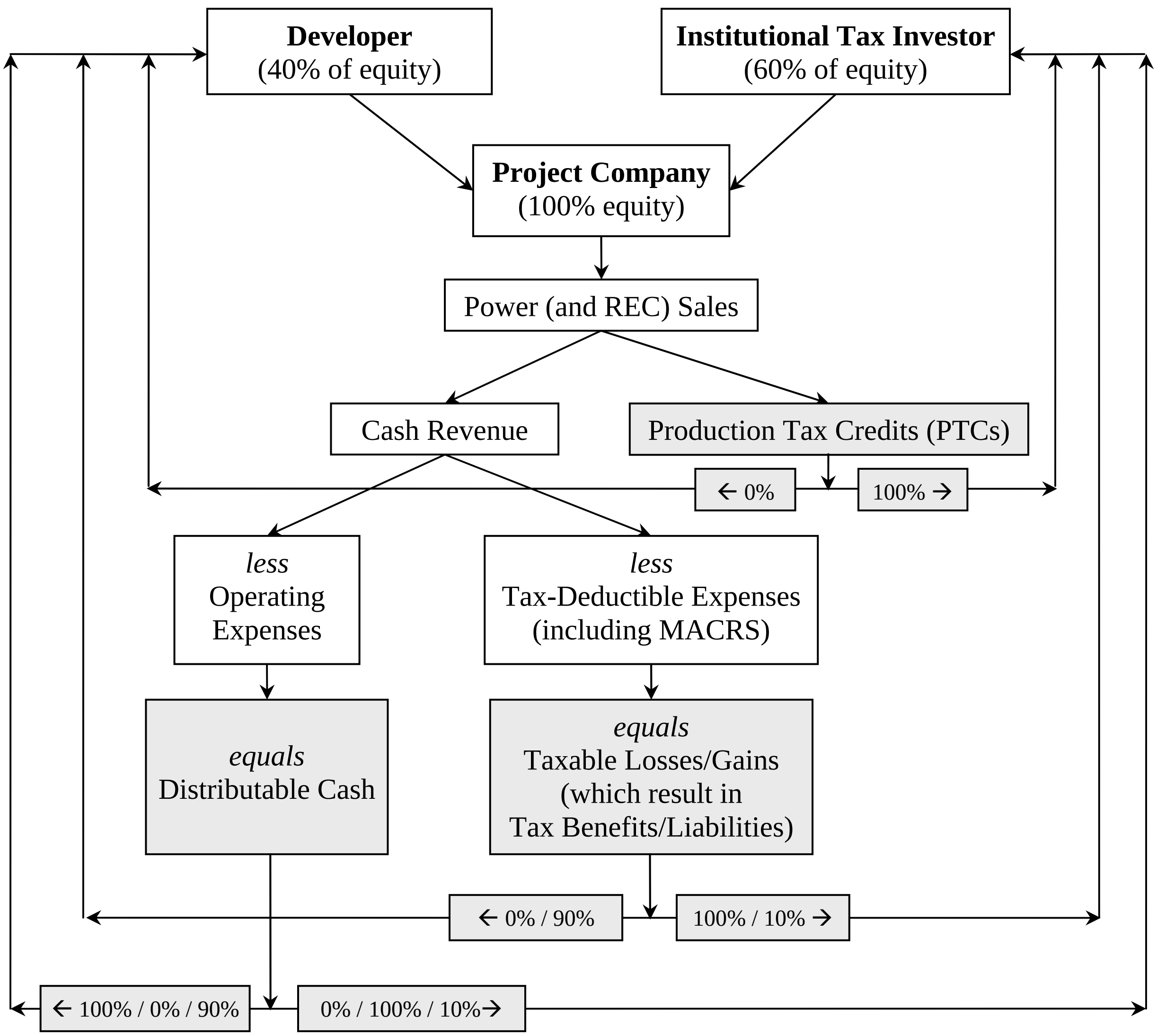

Figure 4. Schematic of Institutional Investor Flip Structure

Investor Types

The Institutional Investor Flip is designed to enable developers to attract passive equity investment from large corporate entities with large, recurring, and reasonably predictable tax obligations. To date, these have been comprised primarily of banks and insurance companies. Tax-oriented Institutional Investors active in the wind sector have included JPMorgan Capital Corporation, GE Financial Services, Wells Fargo, Morgan Stanley, Union Bank of California, New York Life, Prudential, Wachovia Securities, and U.S. affiliates of AEGON, NV, among others. These investors have experience with other tax-oriented investments, and seek the additional return offered by wind projects.

As mentioned, Cash Investors are making targeted investments in wind, but do not want to base their return primarily on Tax Benefits. This financing structure enables these entities to participate in this sector. Some Cash Investors have similar strategic goals as Strategic Investors, but lack the tax capacity to use all of the Tax Benefits. Examples include foreign utilities such as Enel and Iberdrola.[34] Alternatively, some Cash Investors are more akin to Institutional Investors, but lack tax appetite; examples include Babcock & Brown Wind Partners and ArcLight Capital.

Frequency

For the last several years, those developers seeking third-party financing (and not simply selling their projects outright) have most commonly used the Institutional Investor Flip structure. Of the 13 transactions involving tax equity investors reported closed from 2003 through 2005, ten used this structure. It remained a popular structure in 2006. Such repeated use has spurred increasing comfort with this structure, as well as some standardization of transaction documentation.

3.4 Pay-As-You-Go

Description

The underlying structure for Pay-As-You-Go ("PAYGO") is *very* loosely based on the Strategic Investor Flip Structure, with three main differences. Under the PAYGO structure, (i) the developer contributes roughly half (40%-60%) of the initial capital required (compared to the much lower percentages in the Strategic Investor Flip structure), (ii) the allocation of pre-flip cash and Tax Benefits do not match the percentage of equity contributions, and (iii) in addition to its up-front equity contributions of 40-60% (i.e., the amount not covered by the developer's investment), the Tax Investor makes annual payments equal to a pre-determined value of the PTCs generated (e.g., 80–90 cents per dollar of PTCs generated), thereby effectively increasing its equity contributions over time. Actual percentage equity contributions both initially and over time will vary by the relative value of individual projects, as well as the associated depreciation treatment.

---

[34] In July, 2007, Iberdrola announced an agreement to acquire a utility in the Northeast. The acquisition may enable Iberdrola to use some Tax Benefits internally and thereby enable its wind project subsidiaries to use the Corporate financing structure for more projects for longer periods.

The structure allows the Tax Investor to defer a portion of its equity investment over time and reduce risk by only paying for actual PTCs generated.[35] The PTC payments can be structured as incremental equity injections into the project company. More commonly, they are structured as delayed payments for the ownership interests received from the outset in the project company, with the payments made directly to the developer outside of the project company. In some cases, there are two ongoing payments, with one being a fixed annual obligation, and the other varying in amount according to the level of PTCs generated. In all cases, an important tax consideration is to structure PAYGO transactions to avoid any doubt that the Tax Investor acquires its full ownership interests upon its initial investment in the project, so as to minimize later challenges to the allocations of the Tax Benefits between the developer and the Tax Investor. Some IRS private letter rulings in connection with similarly structured transactions involving the Section 29 non-conventional fuels credit suggest that the IRS may want the net present value of the up-front cash plus the fixed annual contributions to exceed 50% of the net present value of the Tax Investor's total investment in the project.

The pre-flip cash and Tax Benefit allocation percentages under the PAYGO structure are not pro-rata with the equity contributed and are not aligned with each other. The Tax Investor initially receives 100% of the Tax Benefits, but only a majority of the distributable cash, e.g., 70%-80%. The developer receives the balance of the distributable cash prior to the Flip Point. As with the other structures, the terms are structured to cause the Flip Point to be met soon after the first ten years of operations. The periodic deferred equity payments are included in the calculation of the Tax Investor's net IRR, even though they most often occur outside of the project company. After the Flip Point, the cash and Tax Benefit allocation ratios are realigned, with the developer receiving almost all (e.g., 90%-95%) of both the cash and Tax Benefits.

This structure contains no limited-recourse debt financing at either the project or the equity holding company level. The developer usually maintains management control over routine project operations. The Tax Investor has voting rights or veto power with respect to major decisions. After the Flip Point has occurred, the Tax Investor's rights typically are limited still further.

Figure 5 provides a schematic representation of the PAYGO structure. The schematic shows the relative equity contributions of the project developer and the Tax Investor, as well as allocations of cash flows and Tax Benefits to each party. As discussed above, some portion of the PTC value (85% in Figure 5) flows – most often outside of the project company, as shown here – from the Tax Investor to the developer in the form of delayed payments for the Tax Investor's initial equity interest in the project company.

[35] Note that the PAYGO structure is distinct from a PTC monetization to support debt service under the Cash & PTC Leveraged structure (described in more detail in Section 3.6).

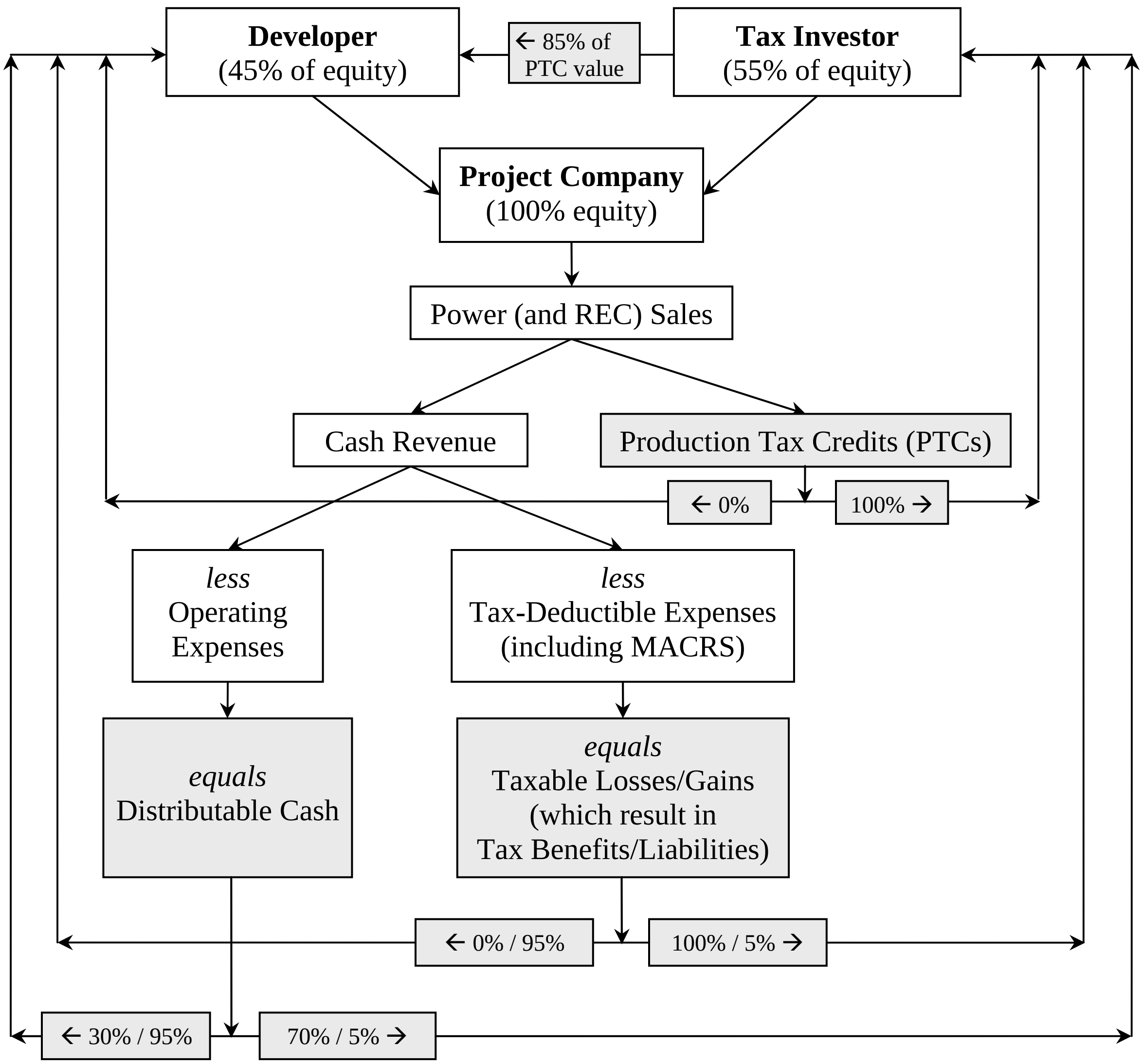

Figure 5. Schematic of Pay-As-You-Go Structure

Rationale for Use

The PAYGO structure typically has not been used in connection with the initial financing of projects, as other structures can generate higher initial percentage contributions from Tax Investors and, if used, lenders. The structure instead is finding use in connection with the refinancing of existing wind projects. Several such scenarios have emerged. For developers that initially financed their projects using the Corporate structure, refinancing with the PAYGO structure can raise capital for other corporate purposes or reduce the investment stake in the projects. The structure also enables developers to maintain a significant amount of capital at work in their projects, while focusing their return on the cash flows (including the monetized PTC payments), rather than the Tax Benefits. Another use has been by existing wind project owners whose tax situation has changed (e.g., via a corporate divestiture) such that they are no longer able to use the Tax Benefits efficiently. The PAYGO structure enables them to maintain ownership and control, rather than being forced to sell the projects outright. Lastly, Cash

Investors desiring to acquire existing wind project assets but lacking tax appetite can use the structure to tap Tax Investor capital to finance a portion of the acquisition costs.

Investor Types

This structure works best for developers with the capital available to invest, but who need a cash-based return as they do not have tax liabilities to offset. This structure allows the developers to maintain a long-term ownership interest in their projects. In these situations, the developers desire to remain active owners of their projects and thus typically look for an Institutional Investor, i.e., a passive financial partner, to act as the Tax Investor for the project. Foreign companies entering the market also may find it useful. For example, Energias de Portugal, S.A. initially considered using a form of this structure to finance a portion of the costs to acquire Horizon Wind Energy, LLC from Goldman Sachs earlier this year.[36]

Tax Investors can find the PAYGO structure useful if they are uncertain about the amount of PTCs projected to be generated. Such uncertainty might rise from insufficient wind resource data, new turbine technology, an inexperienced operator, or some other project risk. In each case, the PAYGO structure reduces the exposure of the Tax Investors to the risk that the PTCs ultimately generated will prove less than projected at the time of their initial investment. A developer comfortable with such risks can fund initial construction, while still achieving an efficient use of the Tax Benefits. These structural risk mitigants also might be attractive to potential Tax Investors just entering the market and desiring to reduce the risk of investing in a single project.

Frequency

To date, the structure has not been used to finance a new project. PPM Energy has used a version of the structure to refinance existing projects after the sale of a corporate affiliate that previously had used the Tax Benefits. Aside from this example, the structure likely will see use mostly in connection with the acquisition of existing assets by foreign or other Cash Investors unable to use the Tax Benefits.

3.5 Cash Leveraged

Description

The Cash Leveraged structure is based on the same underlying structure as the Strategic Investor Flip structure, but features a layer of debt added at the project level.[37] The loan is provided on a limited-recourse, i.e., project finance, basis. Accordingly, it is sized to be repaid from the cash flow generated by the project and secured by the project's assets. The initial percentage equity

---

[36] See "EDP Enters U.S. Market with Acquisition of Horizon Wind Energy," March 27, 2007, Renewable Energy Access.com, www.renewableenergyaccess.com/rea/news/story?id=47894.

[37] The Strategic Investor Flip has been the basis for most leveraged wind transactions closed since 1999. A few transactions have used a basic joint venture structure (without a flip) or the Corporate structure as the base structure, i.e., they have not used third-party Tax Investor capital. The sponsor of a large transaction that closed financing this year reportedly initially considered combining leverage with a version of the Institutional Investor Flip structure.

funding contributions by the developer and the Tax Investor are the same as with the all-equity Strategic Investor Flip, but the amount of the initial equity capital required is decreased by the amount of the debt. In turn, the loan principal and interest payments decrease the amount of distributable cash available to the investors. The overall project capital costs rise by the amount of initial closing costs associated with the loan facility such as legal fees, technical consultants, etc., and with any lender-required cash reserves such as debt service or maintenance reserves.

The percentage of debt varies across projects, but is commonly around 40-60% of total project costs.[38] For any given project, the size of the loan is a function of the projected cash flows and loan terms. The most important loan terms are the tenor (i.e., the number of years the loan is scheduled to be outstanding), the interest rate, and the DSCR. Section 2.4 provides background on current market levels for these loan terms. Table B3 in Appendix B describes the debt assumptions used in the template model of this report.

The management and control issues between the equity investors are consistent with those found in the Strategic Investor Flip structure, with one important difference: the impact of the customary lender covenants on project governance. Specifically, the lender will have a first lien on the assets, first rights to cash generated, and approval rights with respect to major operating decisions. This measure of control afforded the debt provider is a direct result of the lower cost associated with these funds. A general rule of finance is the lower the risk, the lower the return. In this case the lender is providing low-cost capital, so to reduce its risk, a priority position and increased rights are required.

Figure 6 provides a schematic representation of the Cash Leveraged structure. Specifically, the schematic shows the relative contributions from the project developer, the Tax Investor, and the lender into the project company to fund initial construction costs, as well as pre- and post-flip allocations of cash flows and Tax Benefits to each party. Debt service payments are deducted from the cash flows, with the residual distributed to the developer and Tax Investor. In addition, interest payments on the debt are tax-deductible, thereby increasing taxable losses (or, in later years, reducing taxable gains).

Rationale for Use

Developers seek limited recourse project debt for two principal reasons: to boost equity returns and to reduce required equity contributions. All other things held equal, adding debt to a project will increase equity returns (because debt is typically cheaper than equity). This may be important for some projects where the returns otherwise are marginal or unattractive. This might occur, for example, if a project is in a marginal wind regime, has higher interconnection costs, or has been obliged by local market conditions to accept a lower-than-desired power purchase price.[39] Developers also use this structure to reduce the amount of equity required under the Strategic Investor Flip structure.

[38] For example, as presented in Chapter 4, our analysis of this structure finds that, given our modeling assumptions, the template project is able to support 45% debt financing (compared to 61% debt for the Cash & PTC Leveraged structure, described next).

[39] Note, however, that a lower-than-desired power purchase price will not be able to support as much debt as would a higher power purchase price. Even so, any leverage that can be added to the project may boost returns.

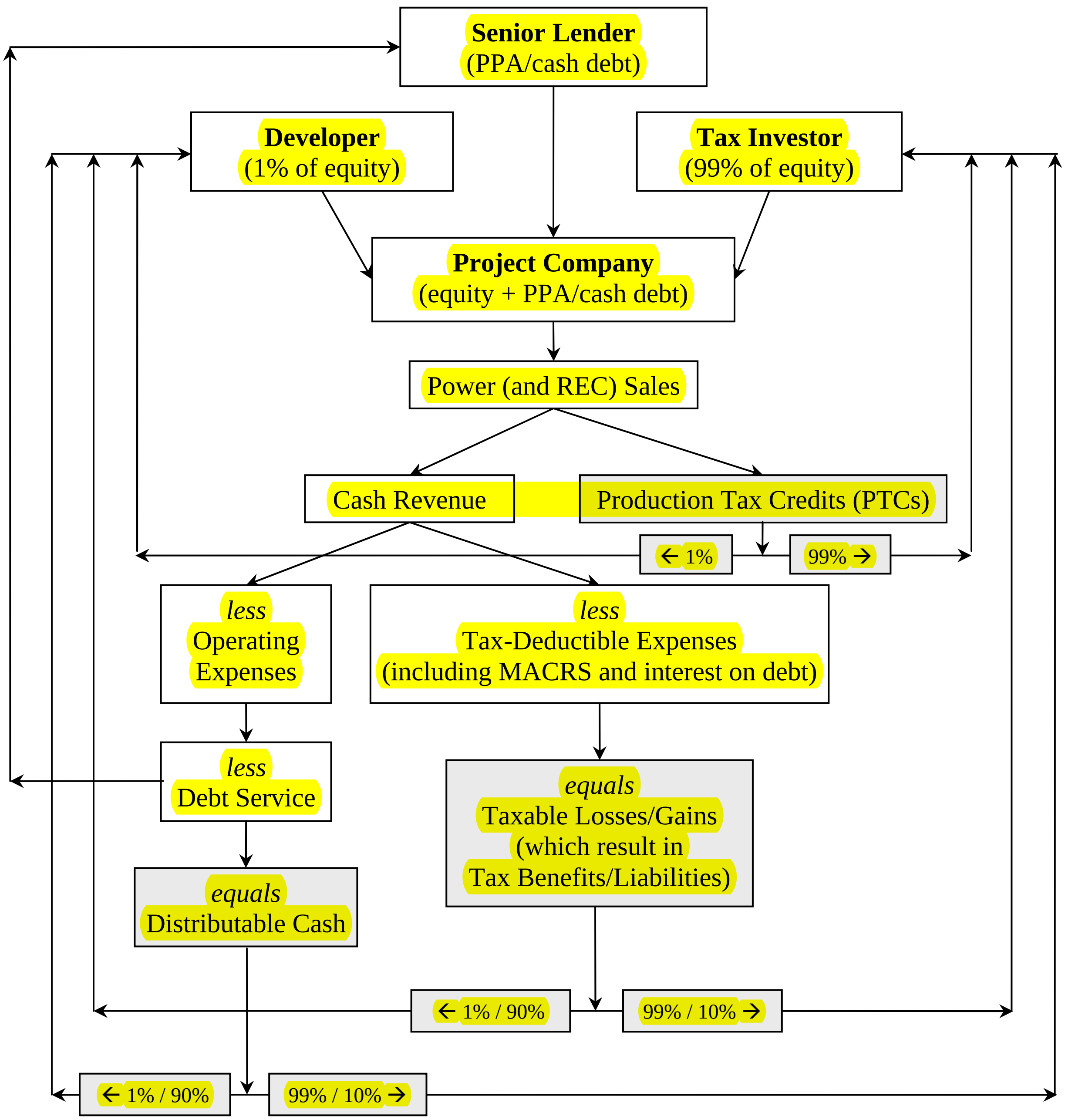

Figure 6. Schematic of Cash Leveraged Structure

Investor Type

Developers seeking project debt often have a general corporate strategy of minimizing their capital investments in individual transactions. They are comfortable in their ability to access debt efficiently and to work through Tax Investor concerns, such that they are comfortable that they can realize the promise of the improved project returns possible with leverage. These are typically developers with prior experience in using debt, perhaps in conventional power projects.

Developers who have tapped term debt include Invenergy Wind, UPC Wind, enXco, and Noble Environmental Power.

While the structure itself is an adaptation of the Strategic Investor Flip (at least in a mechanical sense, with pro rata allocations), developers using the structure typically seek to retain substantive control of their projects and are not looking for an active Strategic Investor. Instead, more passive Institutional Investors are typically the type of Tax Investors sought by developers. The use of debt on a project can, however, limit the pool of Tax Investors that are willing to invest. Some Tax Investors are more comfortable with all-equity structures. Such investors do not want to have to contend with a lender in case a project encounters financial stress. They do not want to worry about being squeezed out of a transaction, i.e., losing their equity investment, if lenders elect to foreclose on the project company. The potential for such an "equity squeeze" can arise since their share interests in the project company usually are pledged to the lender as part of the collateral security for the loan. Such Tax Investors prefer to retain the flexibility of contributing additional funds to support a project in distress without having to coordinate such support with a lender. For these entities, the additional up-front costs and controls associated with debt outweigh the lower cost of capital. Timing may also be an issue for some investors: closing on debt financing not only costs more up-front, it also takes additional time to close relative to an all-equity deal. In contrast, other Tax Investors are comfortable with having debt at the project level, believing that the lender's initial due diligence and on-going monitoring of project operations are likely to result in better-structured deals and thereby reduce their own risks. Tax Investors who have invested in wind transactions involving leverage include the Union Bank of California, AEGON-affiliated life insurance companies, and JP Morgan.

Frequency

Although term debt is used in the market, levered structures are currently in the minority for financing wind projects. All-equity structures are more common. Short-term turbine supply loans and construction loans have been used more frequently, but these are replaced by equity upon the project commencing operations.

3.6 Cash & PTC Leveraged

Description

The Cash & PTC Leveraged structure is the same as the Cash Leveraged structure but with an additional layer of debt – based on expected PTCs – at the project level. In this structure, both the cash-based loan and the PTC-based loan are secured by the project assets and assignments of contract rights. The term of the PTC loan is ten years, corresponding to the period in which the PTC can be claimed. As a tax credit used by the project owners, the PTCs do not generate cash at the project level that can be used to repay project-level debt. Thus, the debt service payments of the additional debt will eat into (and sometimes exceed) the cash flow cushion created by the DSCR for the cash-based loan. In response, lenders typically require that the Tax Investor provide a contingent guarantee to make periodic additional equity investments into the project company on an as-needed basis. The amount of such injections for any period is capped at the amount of PTCs actually generated in that period. In some cases, the obligation is capped at the lower of either the PTCs received by the Tax Investor or the actual debt service payment shortfall. Lenders usually focus on the credit-worthiness of the guarantee by the Tax Investor, since the Tax Investor makes the lion's share of the equity contributions (e.g., 99%) under this structure. On occasion, lenders will seek such commitments from the developer as well as the Tax Investor.[40] Such injections essentially create a second contingent cash flow stream that lenders are willing to rely upon to support an incremental PTC loan. With this incremental source of project-level cash flow, projects using the Cash & PTC Leveraged structure can support debt for up to 50% to 65% of total project costs, compared with the 40% to 60% levels under the Cash Leveraged structure.

This structure differs from the PAYGO structure described in Section 3.4. Even though both involve periodic equity payments whose amounts are linked to the amount of PTCs actually generated, the source and role of such periodic injections vary. Under the Cash & PTC Leveraged structure, the lender provides a PTC loan to complete the initial funding, and both owners (albeit mostly the Tax Investor) make periodic equity contributions directly to the project company to help repay the PTC-based loan, if necessary. In contrast, under the PAYGO structure, no debt is involved, so the developer provides more initial funding. Further, just the Tax Investor makes incremental periodic equity contributions based on the PTCs received, and such payments go directly to the developer.

In the analysis of this structure presented in Chapter 4, the cash and PTC-based loans are treated separately, in the interest of transparency. In practice, rather than having two separate loans, most lenders create a single, customized loan amortization schedule that aggregates the cash flows and the PTC-related equity contributions. The aggregate debt service payments are sized during the first ten years to be supported by both the project's cash flow and the incremental contingent equity contributions from the Tax Investor. The subsequent debt service payments are sized to be covered just by the project's cash flow. As with the Cash Leveraged structure, there are lender covenants and restrictions on the project. The additional PTC-based loan amount generally does not lead lenders to tighten these restrictions, other than imposing covenants related to the periodic contingent equity contribution obligations. These incremental covenants can be difficult to negotiate, however, as the Tax Investor and the lender reconcile competing interests in the event of project financial stress.

Figure 7 provides a schematic representation of the Cash & PTC Leveraged structure. Specifically, the schematic shows the relative contributions from the project developer, the Tax Investor, and the lender into the project company to fund initial construction costs, as well as pre- and post-flip allocations of cash flows and Tax Benefits to each party. Debt service payments – for both the Cash and PTC tranches – are paid from project cash flows prior to allocating the residual cash flow to the developer and Tax Investor. In addition, interest payments on the debt are tax deductible, thereby increasing taxable losses (or, in later years, reducing taxable gains). To the extent that there is not enough cash to repay the PTC debt, the Tax Investor (and sometimes) the developer make pro rata equity contributions into the project company sufficient to support the PTC debt; these incremental contingent contributions are shown as dotted arrows parallel to their original equity contribution arrows.

[40] For tax reasons, the developer may want to contribute its small percentage share regardless of the lender's requirements so as to preserve the relative allocations of the cash flows and Tax Benefits between the owners.

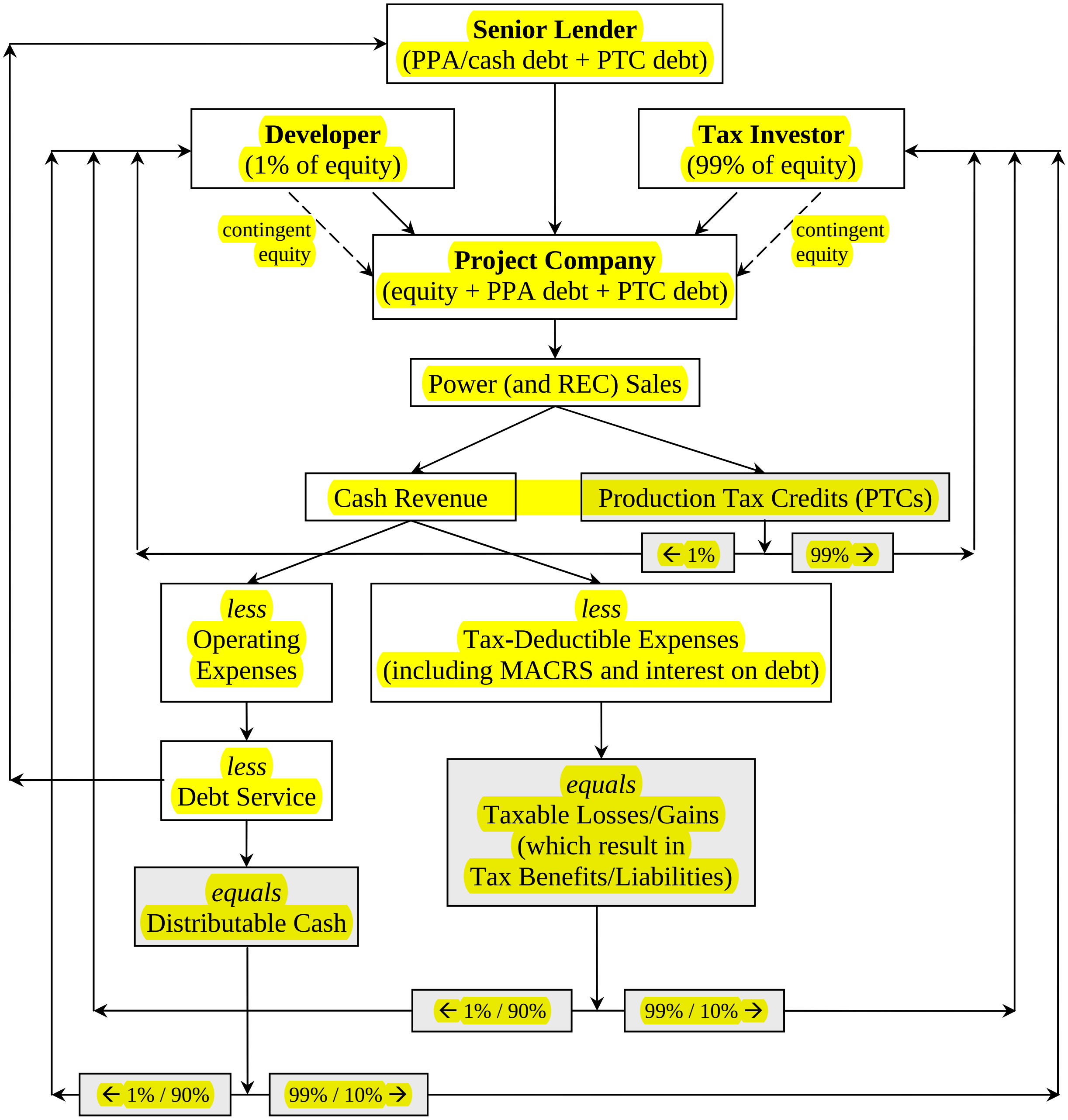

Figure 7. Schematic of Cash & PTC Leveraged Structure

Rationale for Use

The general rationale for use of debt has been previously discussed. Namely, the lower cost of debt capital boosts project returns and requires less up-front investment from equity participants. This structure maximizes the use of leverage by including a PTC-based tranche of debt that is supported by a pledge of ongoing contingent equity infusions.

Investor Type

Developers considering the Cash & PTC Leveraged structure are especially comfortable with using debt to leverage their equity investment and believe that the IRR boost from the incremental PTC debt merits the added complexity. As with the Cash Leveraged structure, they usually have prior experience in using debt, want to retain substantive control of their projects, and seek passive Institutional Investors to be the Tax Investor in the transactions. However, the inclusion of a PTC tranche of debt limits the pool of potentially interested Tax Investors still further, because few Tax Investors have been willing to assume the contingent obligation surrounding future capital contributions.

When judging a project opportunity, an investor will compare the expected rate of return against its cost of capital. This evaluation becomes problematic with an obligation to fund uncertain amounts at unknown dates in the future, as far out as ten years from the present. Because there is generally great uncertainty about future cost of capital and even availability of funds, many Tax Investors prefer the certainty of making just one initial investment over making an initial investment *and* a series of potential future contributions. As a result, few Tax Investors are willing to guarantee to provide ongoing equity contributions in support of a PTC loan monetization. In addition to the concerns about a lender squeezing out their equity interest in the event of project difficulties, they dislike the obligation to potentially make ongoing contributions in support of a loan – particularly if the project is not performing well (i.e., when such contributions are most likely). Given such issues, relatively few Tax Investors have proved willing to sign up for this structure.

Frequency

This type of structure, involving both a Tax Investor separate from the developer, and a PTC loan, is rarely seen in the market. Two different developers each used this structure to finance a project in 2002 and 2004. Invenergy Wind also used a version of the structure to finance a portfolio of three projects in 2005.[41] No other such transactions are believed to have been done. As loan documentation and terms are worked out that address Tax Investor concerns, however, there are indications that this structure may be utilized for some projects in 2007-08.

3.7 Back Leveraged

Description

The Back Leveraged structure is the same as the Institutional Investor Flip structure, but with a layer of debt outside of the project company at the level of a holding company for the interests of the developer. The developer pledges its ownership interests in the project company to secure the debt, and uses the debt to fund part of its initial capital contribution. As the debt is at the developer level, it does not have an impact on the economics at the level of the project company. The debt provider has no recourse to the project company, other than via the pledge of the developer's equity share interests. The underlying structure and allocations to each party remain the same as in the Institutional Investor Flip structure. Loan covenants typically include provisions to sweep excess developer cash flow to make loan prepayments. As a result, while

[41] Presentation by Jim Murphy, Invenergy Wind Finance Company, Renewable Energy Finance Forum, June 2005.

the nominal loan maturity may be comparable to the 15-year maturity under the other debt structures, the effective maturity often is significantly shorter, e.g., as short as four to six years.

Figure 8 provides a schematic representation of the Back Leveraged structure. Specifically, the schematic shows the relative equity contributions from the project developer (which in turn, is partly financed by back leverage) and from the Tax Investor into the project company to fund initial construction costs, as well as pre- and post-flip allocations of cash flows and Tax Benefits to each party. The developer repays its borrowed equity stake out of the cash flow allocated to it.

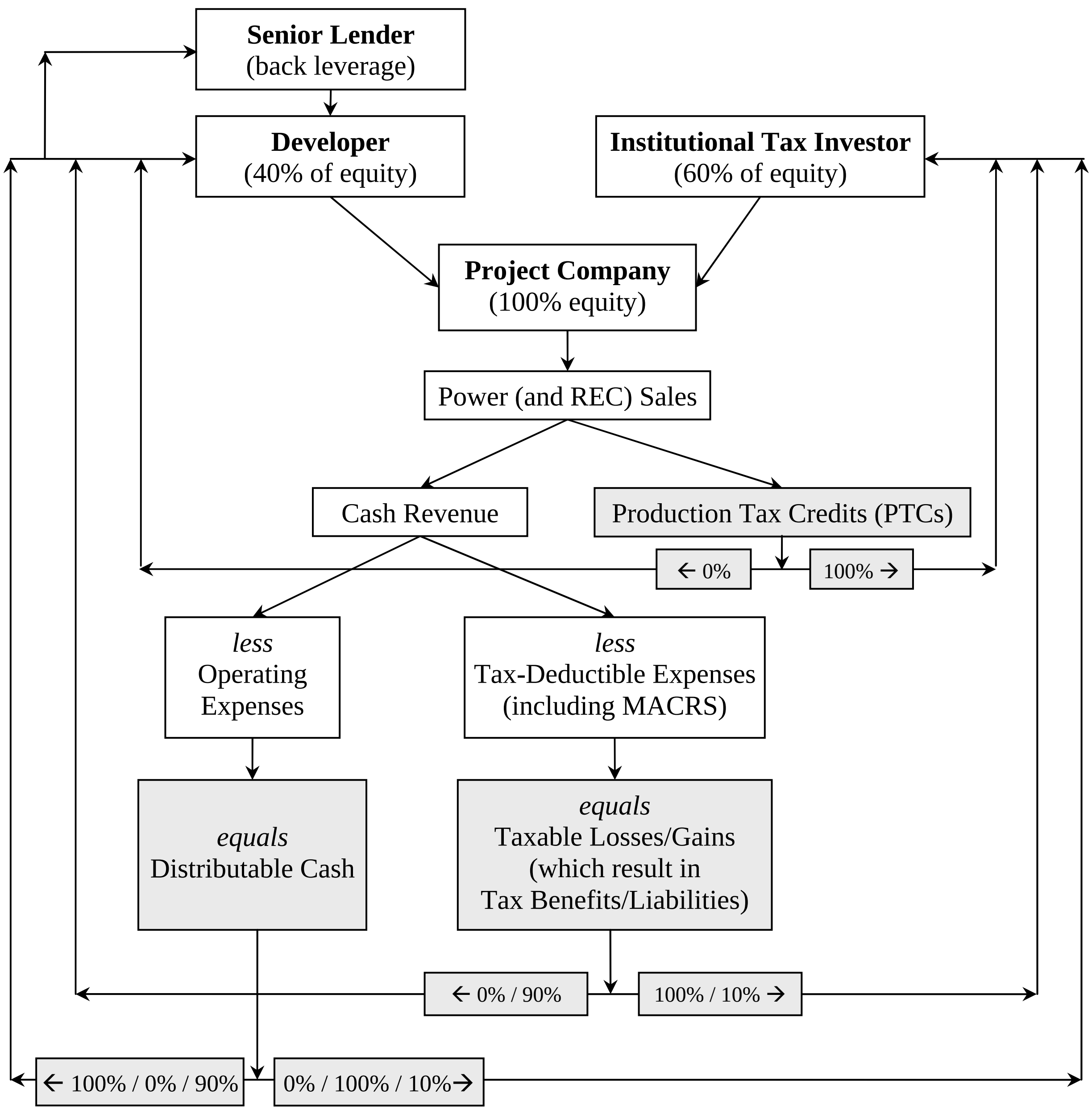

Figure 8. Schematic of Back Leveraged Structure

Rationale for Use

The Back Leveraged structure allows the developer to increase its long-term IRR by securing lower cost capital with which to fund its initial equity contribution. It also allows undercapitalized developers to increase their equity participation in a project. Lastly, it has been used by developers interested in using debt, but desiring to keep the direct project assets unencumbered. For example, a developer might use the structure as an interim measure to finance initial construction costs, pending a later refinancing as part of a portfolio.

Investor Type

This structure is used by developers that either have limited capital or who have the financial resources to invest but that want to reduce their cost of funds. The Tax Investors are not impacted by this type of financial engineering at the developer level. Indeed, they may not participate in or even see the loan documentation. Developers using this structure typically seek passive Institutional Investors to be the Tax Investor for their transactions.

Frequency

This structure is becoming more common in the market. It allows developers to increase their ownership in a project and capture the relative economic benefits of debt. It also satisfies the Tax Investor market preference for all-equity projects.

3.8 Summary: Choosing a Structure

The seven financing structures profiled in this chapter are the principal means by which most large-scale wind projects (excluding utility-owned projects) are currently financed in the United States. These structures vary in several respects, including the contractual flow of funds and obligations among the financing parties, their relative utility for different types of project developers and investors, the timing of funding, their frequency of use, and (as will be shown in the next chapter) their impact on the project's cost of energy.

Project developers typically make the decision on which financing structure best meets their needs for a given project based on a number of considerations. The decision reflects both the developer's own relative ability to use the Tax Benefits and to provide the capital funding, as well as the financial robustness of the project itself, e.g., whether debt leverage is needed to boost projected returns to satisfy return requirements. Earlier in the decade, the amount of time before the next expiration date of the PTC also played a role; pending PTC expiration dates led some developers to adjust their project development and financing strategies so as to increase the prospects of meeting PTC deadlines. As this pressure has abated more recently, the number of financing options being created and used has increased. Developers have become more confident that the PTC will be renewed, and have increased their financial ability to support more and longer lead-time development projects. Secondary factors also influence the financing decision, e.g., the relative preference for realizing value up-front via a development fee or capital gain on sale of the project, or over time from the net cash flows from operations.

The relative importance of these various considerations differs from developer to developer and from project to project. Furthermore, some developers' preferred financing structures have evolved over time, especially as their own financial situations have changed. In short, there is no single "correct" structure for all developers for all projects for all time.

Notwithstanding the above, one can illustrate, in general, the varied rationales for each financing structure by looking at the (hypothetical) decision process facing wind developers in choosing a financing structure. Table 1 below provides a list of several key corporate and project-level considerations. Depending on a given developer's views on each consideration, one or more financing structures are likely to be more suitable than other structures to meet the needs of the developer. The table provides several scenarios that represent differing combinations of these developer considerations. The financing structure(s) most typically used for each scenario is identified in the final column. It is important to note that the table is generalized and focuses on just a few key considerations. Other factors can lead a developer to opt for a different financing structure than that suggested in the table.

Table 1. Wind Developer Financing Structure Decision Matrix

Scenario	Developer can use Tax Benefits	Developer can fund project costs	Developer wants to retain stake in project ownership / ongoing cash flows	Developer wants early cash distributions	Project has low projected IRR	Project already exists (refinancing / acquisition)	**Most suitable financing strategy or structure:**
1	No	No	No	Yes	N/A	No	**Sell project to a Strategic Investor**
2	Yes	Yes	Yes	No	No	No	**Corporate**
3	No	Limited	Yes	No	No	No	**Strategic Investor Flip**
4	No	Limited	Yes	Yes	No	No	**Institutional Investor Flip**
5	No	Limited	Yes	No	Yes	No	**Cash Leveraged *or* Cash & PTC Leveraged**
6	No	Limited	Yes	Yes	No	Yes	**Institutional Investor Flip**
7	No	Yes	Yes	Yes	N/A	Yes	**Pay-As-You-Go**
8	No	Limited	Yes	Yes	Yes	No	**Back Leveraged**

Scenario 1 typifies smaller developers lacking the financial or technical wherewithal to carry a project through construction into operation. Such developers commonly adopt a business strategy that focuses on early project development, with the goal being to sell their projects to larger entities prior to construction. Earlier in the decade, this was the only real alternative for developers unable to carry their own projects into operation. Larger developers on occasion have taken this approach as well as a means of maintaining business teams, generating cash flow to support operations, or to meet the requirements of key utility clients desiring to own wind projects outright. Purchasers of these projects – which are often Strategic Investors – might then use one of the other financing structures discussed in this report to finance the project.

Scenario 2 portrays a simple Corporate structure, where the developer has the financial resources to fund the project, efficiently use the Tax Benefits, and desires a long-term ownership stake for strategic reasons. This is the most common wind project financing structure in the United States (in terms of installed capacity), though only a handful of large developers are able to make use of it.

Scenarios 3 and 4 pertain to all-equity flip structures, where the developer cannot fully fund the project or use its Tax Benefits, but nevertheless desires a long-term ownership stake in the project. The Strategic Investor Flip structure (Scenario 3) may be useful for developers with limited or no long-term capital to invest and not needing significant early cash flows. This structure has been used by some of the "community wind" projects in the Midwest, in addition to some larger projects earlier in the decade.

If instead the developer has some cash to invest but would like to recoup its investment, in cash, sooner than possible under the Strategic Investor Flip structure, then the Institutional Investor Flip structure (Scenario 4) may be more useful. This scenario also may make sense if the developer has received development-stage financing from an equity source focused more on financing developers than projects; such equity sources often prefer a shorter investment cycle and have a higher requisite return than investors focused on long-term returns from project operations. Developers receiving equity financing from sources unable to use the Tax Benefits generated from project operation, e.g., pension funds, might also like this structure, to the extent that such sources also want to see significant cash distributions earlier than available under the Strategic Investor Flip structure. If such a developer desires to finance a portion of its capital investment (either to preserve cash or boost returns) using "back leverage," then Scenario 8 – the Back Leveraged structure – is a relevant structure.

Scenario 5 represents a leveraged version of Scenario 3, where the intent is to boost project IRRs. The choice of which leverage structure to use generally reflects the relative project economics, i.e., whether the incremental PTC monetization is needed to achieve requisite equity returns. It can also reflect other factors, such as the relative interest of Tax Investors in the specific project and the incremental contingent financial obligations associated with PTC debt. For reasons already discussed, the use of leverage at the project level has been relatively uncommon over the past few years, but may become more common in the future.

Finally, Scenarios 6 and 7 refer to a developer that owns an existing project but seeks a Tax Investor to monetize the Tax Benefits, e.g., due to a detrimental change in the developer's tax credit appetite, or simply to free up cash. Such a developer might opt either for the Institutional Investor Flip or the Pay-As-You-Go structure, with the choice depending in part upon how much cash the developer wants to receive at the outset and in part on the perceived relative transaction costs and complexity of the two structures. The use of these structures for refinancing projects is becoming more common as developer consolidation, often involving foreign entities without U.S. tax liability, increases.

As noted, these scenarios are simplified to illustrate key differences. Specific developers likely will have additional or other considerations in connection with specific projects or with their overall corporate goals that will impact the choice of financing structure. Other permutations of the various considerations identified here also are possible.

4. The Impact of Financing Structure on the Levelized Cost of Wind Energy

In addition to describing the mechanics of each of the seven financing structures, a principal purpose of this report is to analyze the levelized cost of energy ("LCOE") from each structure, on a relative basis. For this report, the LCOE is defined as the minimum required nominal 20-year power purchase price (with no escalation) that enables the project to cover its operating costs while also satisfying the requirements of lenders (if any) and equity providers. This chapter begins with a brief overview of the pro forma financial model used for the LCOE analysis. More detail on the model is provided in Appendix B. The chapter then presents and discusses the results of the LCOE analysis.

4.1 Overview of Pro Forma Financial Model

To facilitate comparisons of the impact of each financing structure on the cost of wind energy, the authors developed a simplified Excel-based pro forma financial model. The model uses a template of an indicative wind project as the common basis for illustrating the effects of each financing structure. The purpose of the model is to understand the principal differences across financing structures. The model is not derived from an actual wind project financial model (such models are considerably more detailed), nor does it attempt to portray a specific project in a particular region of the country. It also does not portray how the agreed-upon allocations of the Tax Benefits may be adjusted to comply with IRS tax partnership accounting requirements (Appendix C provides an introduction to these requirements). Instead, the model simply provides a platform to compare the structures to each other.

The authors developed three sets of assumptions to first define the template wind project and then to differentiate between the financing structures:

(1) *Market assumptions* reflect the broad market conditions experienced by virtually all utility-scale wind projects developed and financed in the last several years. For example, it is assumed that the template project uses proven technology to generate electricity for sale on a long-term, wholesale basis to a creditworthy utility, and that the project owners make full use of the project's Tax Benefits in the year they are earned.

(2) *Common assumptions* are those that are project-specific – i.e., narrower than market assumptions – yet nevertheless common to all seven financing structures analyzed. These include assumptions about turbine and other "hard" project costs, net capacity factor, O&M costs, marginal income tax rates, and depreciation schedules.

(3) *Structure-specific assumptions* are those that vary among the financing structures and therefore differentially impact the LCOE for each structure. These assumptions relate primarily to the cost of financing (equity and, if used, debt, as well as any transaction or "soft" costs associated with the financing) as well as the relative equity contributions and pre- and post-flip allocations of the project's cash and Tax Benefits among the relevant investors. The specific assumptions about equity rates of return and debt terms are indicative of current market conditions; they are not reflective of particular projects.

Appendix B describes the market, common, and structure-specific assumptions used in the template model, and lists the specific values used for these input assumptions.

The model itself consists of a single Excel workbook. Each financing structure is housed in its own worksheet. Based on the assumptions described above and in Appendix B, the model solves for the levelized cost of energy for each structure involving third-party equity that yields the specified Tax Investor after-tax return target at the end of ten years, while not violating minimum DSCRs or other lender constraints (for those structures also employing leverage).[42] The use of a 10-year term for the Tax Investor's return target is industry standard, since that term also coincides with the duration of the PTC. For the Corporate structure, which does not use external financing, the model solves for the levelized cost of energy that yields the developer's after-tax return target at the end of twenty years. A twenty-year period is used in this case, as it matches the industry's default assumption for the life of a wind project. For all of the structures, measuring investor returns on an after-tax basis is standard in the industry, given the tax-oriented nature of the equity investment.

The modeling process adopted for this report starts with assumed return targets, equity contribution ratios, and cash and Tax Benefit allocations and then solves for the power sales price required to satisfy these targets and constraints. Developers initially follow a similar approach (i.e., starting with assumptions about the cost of financing) to evaluate the viability of potential projects and to arrive at a starting point for power price negotiations. However, this is the reverse of the process that actually occurs when external financing is arranged. By that time, the developer typically already has negotiated a PPA. In such cases, the developer seeks to maximize its residual return in the negotiations with financiers. Tax Investor return targets are negotiated based on the set PPA price, subject to what can be attained by varying (within the confines of tax law) the equity contribution ratios and pre- and post-flip cash and tax allocations. Since, however, the purpose of this report is, in part, to analyze the potential impact of financing structures on the cost of wind energy, this report takes the first approach.

For more details on the structure of the model and on the input assumptions, see Appendix B.

4.2 Levelized Cost of Energy Comparisons

Table 2 summarizes the highlights of the modeling analysis, including key inputs and results. The key inputs listed are the project costs, the Tax Investor's 10-year IRR target (except for the Corporate structure, where the relevant input is the developer's 20-year IRR target), and the assumed debt interest rates and tenor for the three structures using debt financing. The outputs are the 20-year LCOE, the Tax Investor's 20-year IRR,[43] the developer's 10-year and 20-year IRR (again, except for the Corporate structure, where the developer's 20-year IRR target is a model input), and the developer's 20-year NPV. For those financing structures involving

[42] In turn, the developer's return is the residual, or what is left after satisfying the Tax Investor's return requirements in the negotiations between the developer and the Tax Investor. In practice, developer returns also reflect relative project attributes, e.g., capacity factors, power prices, etc.

[43] To simplify the modeling task, the model treats the 20-year Tax Investor IRR as an output. In reality, the Tax Investor's 20-year IRR is linked to its 10-year IRR and both IRR targets are highly negotiated between the Tax Investor and the developer, and will reflect market conditions.

independent Tax Investors, the negotiations focus principally on the Tax Investor's IRR. The developer's return calculations are presented for informational purposes, though some Tax Investors also assess the developer's returns to ensure a reasonable allocation of project returns between the parties.

Key inputs and results include:

- Total project costs are assumed to be relatively similar across all structures, with roughly $100/kW difference between the most expensive and least expensive structures. The leveraged structures are the most expensive – assumed to be nearly $1,830/kW – due to the closing costs and reserve accounts associated with debt.[44] Conversely, the Corporate structure is assumed to be the cheapest – at $1,725/kW – as it incurs no debt-related transaction costs and, unlike the all-equity structures involving third-party Tax Investors, does not utilize construction debt or incur equity closing costs.

- For the six structures other than the Corporate structure, the Tax Investors' 10-year target IRR (which our analysis assumes is always met on schedule) reflects the input assumptions, while the 20-year Tax Investor IRR is an output from the model, and is generally only slightly (i.e., 30-50 basis points) higher than the 10-year target, illustrating the degree to which Tax Investor returns are front-loaded and the post-flip reallocation of most cash and Tax Benefit flows to the developer. The developer's IRR (both 10- and 20-year) is an output of the model (except for the Corporate structure), and varies across structures as well as over time.

- For the Corporate structure, the developer's 20-year IRR target is the input assumption, while its 10-year IRR is derived. Unlike in the other structures, the developer in the Corporate structure receives all of the benefits throughout the 20-year period.

- The template project's 20-year LCOE under the seven structures ranges from $48/MWh to $63/MWh, suggesting that choice of financing structure can have a significant impact on a wind project's LCOE.

Although the modeling results are intended to be illustrative of current market conditions, they are, of course, a function of the modeling assumptions. These assumptions are merely indicative and do not reflect a specific project. Using a different set of input parameters will generate different results.[45] Finally, the model does not undertake detailed tax-oriented analysis with respect to partnership accounting issues, as introduced in Appendix C. Accordingly, the returns should not be assumed as likely for specific projects using the various financing structures. Instead, the comparative nature of the analysis means that these LCOE results are best

[44] However, the depreciable basis for these structures is not as high as the capital cost might suggest, because the debt service reserve account is non-depreciable.
[45] For example, this analysis assumes a 36% net capacity factor for the template wind project. Capacity factor, a measure of energy production, greatly affects the profitability of a wind project, as it drives both revenue and PTC generation. Reducing the capacity factor assumption to 32% forces the projected LCOEs to rise. While the percentage increase varies from 13% to 20%, the relative differences between the LCOEs for the financing structures do not change.

considered relative to one another – i.e., to illustrate the relative impact of financing structures – rather than individually or on an absolute basis.

Table 2. Project Costs, Investor Returns, and LCOE by Financing Structure

	Cash & PTC Leveraged	Cash Leveraged	Institutional Investor Flip	Back Leveraged	PAYGO	Strategic Investor Flip	Corporate
Assumed Installed Project Costs							
Hard Cost ($/kW)	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Soft Cost ($/kW)	229	215	183	183	183	183	125
Total Cost ($/kW)	1,829	1,815	1,783	1,783	1,783	1,783	1,725
Tax Investor After-Tax Return (The 10-year target IRR is a model input, while the 20-year IRR is a model output)							
10-Year Target IRR	9.25%	9.00%	6.50%	6.50%	6.50%	6.50%	N/A
20-Year IRR	9.67%	9.29%	7.12%	7.12%	7.02%	7.02%	N/A
Assumed Loan Terms (For those structures using leverage; Table B3 has details)							
All-in Interest Rate	6.70%	6.70%	N/A	6.70%	N/A	N/A	N/A
Tenor (maturity)	15 years	15 years	N/A	calculated	N/A	N/A	N/A
Developer After-Tax Return (Except for the Corporate 20-year IRR, the developer returns are all model outputs)							
10-Year IRR	9.25%	9.00%	0.00%	-10.08%	5.75%	6.50%	6.64%
20-Year IRR	33.15%	30.58%	10.44%	11.91%	11.52%	37.44%	10.00%
20-Year NPV *($000 @ 10%)*	7,208	7,540	1,578	4,673	7,811	20,745	0
20-Year Levelized Cost of Energy (LCOE)							
Nominal $/MWh	48	50	53	53	59	61	63

The Tax Investor's 10-year IRR targets for each of the six structures accessing Tax Equity are key differentiators of the resulting LCOE. Since there is no public registry of the Tax Investor 10-year IRR agreed upon between the developer and the Tax Investor for individual projects, the target returns assumed here, as well as the relative relationships of these assumptions among structures, are based on anecdotal industry information. Nonetheless, some discussion of these assumptions relative to each other is of use, if only to distinguish the results of this report from actual projects.

The prominence of the Institutional Investor Flip structure in recent years makes its associated 10-year Tax Investor IRR assumption a benchmark for comparison with other structures. The 6.50% rate is in the range of projects closing financing in the last year, with some especially strong projects securing a slightly lower rate and other, less-strong projects needing to offer a higher rate. This hurdle rate of 6.50% is used as the benchmark for the other all-equity structures utilizing Tax Investors.

The Tax Investor's 10-year IRR targets for the Cash Leveraged and Cash & PTC Leveraged structures are assumed to be 250 and 275 basis points, respectively, above the Tax Investor return for the Institutional Investor Flip structure. The target returns are set higher to reflect both the incremental risk[46] and the mechanical impact of debt on equity returns.[47] The study sets the 10-year Tax Investor IRR target for the PAYGO structure at the 6.50% industry benchmark. Arguments that the rate should be reduced to reflect the fact that Tax Investors only pay for the PTC benefits if and as they are generated are counter-balanced by the view that the Tax Investor needs to reserve just as much tax capacity for PAYGO structures as it does for other structures. Also, some Tax Investors say that the greater complexity of PAYGO structures and, in some cases, the high initial investment, justify the same, if not a higher, rate of return.

The 6.50% IRR for the Tax Investor under the Strategic Investor Flip is the most difficult to assess, as there have been few deals using this structure in recent years. One Tax Investor currently active in the market argues that the assumed 6.50% rate should be higher since the required investment amount is little different from that required for the Corporate structure. This investor also argues that it should be higher than the required Tax Investor return under the Institutional Investor Flip structure, since that structure requires less up-front capital to be contributed by the Tax Investor. On the other hand, unlike the Corporate structure, the Strategic Investor Flip structure protects the Tax Investor from the development and construction risks of the project, and does not require the Tax Investor to assume active project management. Moreover, compared with the Institutional Investor Flip structure, the Tax Investor under the Strategic Investor Flip structure receives both cash *and* Tax Benefits from the outset of project operations and forces the developer to wait for a decade or more to start receiving the bulk of its return. In practice, rates negotiated for specific projects will balance the relative strengths and needs of the Tax Investor and the developer.

The developer's 10%, 20-year IRR target assumed for the Corporate structure is based on anecdotal industry information of returns sought by entities directly able to use the Tax Benefits and interested in long-term ownership of wind projects. There is little data available on the IRR requirements of developers using this structure, though FPL Energy has provided some indications of its internal valuation metrics to stock analysts.[48] The Corporate structure return target figure does not reflect the risk and reward calculations of either Tax Investor or pure developers unable or unwilling to invest in long-term ownership, but rather it is a hybrid of the two. While the 10%, 20-year IRR assumption and the calculated 6.64% ten-year IRR can be compared to the developer returns under the other structures, such comparisons may not be germane, as comparison implies a choice. More typically, the reason a developer seeks Tax Investor capital is based less on relative returns than simply the need to make efficient use of the Tax Benefits, combined with an inability to do so directly.

---

[46] The incremental risk comes from the lender having a first call on all project cash flows to meet debt service obligations and a priority lien on the project assets in the event of a loan default; thus, poor operating performance will magnify the impact on the equity investor.

[47] Some of this basis point premium is to reflect the mechanics of leverage. If debt costs less than equity, then the use of debt to partially finance a project results in a higher equity return than if no debt were used – regardless of risk considerations – since the incremental operating cash flow after servicing the cheaper debt (relative to the cost of equity) flows to the equity investors.

[48] FPL Energy has advised that it seeks wind projects yielding an IRR of 10% or better (http://seekingalpha.com/article/34007-fpl-group-q1-2007-earnings-call-transcript) and that it factors in a 50/50 debt-equity ratio when assessing the accretive impact of new wind projects on its corporate results (http://seekingalpha.com/article/42882-fpl-group-q2-2007-earnings-call-transcript).

Each individual structure's modeling results are discussed in more detail below.

As shown in Table 2, the financing structure with the lowest LCOE is Cash & PTC Leveraged, which has a 20-year LCOE of $48/MWh. In other words, given the assumptions used in the analysis, the template project – when financed using this structure – requires a flat $48/MWh for the first twenty years of operation to cover its capital and operating costs, and to meet the return requirements of the Tax Investor as well as the financing terms of the debt provider. The next-lowest LCOE is found with the Cash Leveraged structure, at $50/MWh (with the slightly higher LCOE reflecting slightly less leverage, due to the absence of PTC-backed debt).

The fact that the two structures with the lowest LCOEs have project debt is not unexpected. Debt has a cheaper cost of capital than does equity, so the more debt a project can secure, the lower the LCOE (assuming no other changes). This is true despite the fact that, as reflected in Table 2, required equity returns are higher when leverage is involved, to account for the extra risk imposed on equity providers when debt is used. Moreover, the investors still receive the full amount of the Tax Benefits as if the project had been financed with all equity and no debt. Additionally, debt interest payments are tax-deductible, so they increase the tax loss in the early years of the project (a potentially counter-intuitive characteristic unique to tax-based investments is that greater tax losses *enhance* the returns to Tax Investors).

If the developer's goal is to create the lowest LCOE, then the LCOE results reported here indicate that some form of leverage at the project level would be widely used. However, this has not been the case in recent years. Indeed, it is estimated that only 20% of the deals in the market in 2006 included project level debt.[49] In a perfect market, economic theory suggests that no one structure would generate higher returns than another, in which case there should not be such disparities in usage levels. Chapters 2 and 3, however, have described several reasons why developers and Tax Investors have preferred not to use debt, including concerns about up-front transaction costs, increased default risk, and additional time to close. As discussed, up-front fees, reserve accounts, and transactional expenses will reduce the net IRR gain from using debt. Many Tax Investors prefer not to have a bank holding a first claim on the project assets, in the event the project underperforms materially. While the indicative cost assumptions used for the model are meant to reflect current market conditions, they may nonetheless not be incorporating all perceived market costs or risks when developers and investors structure financing for actual projects.

The effect of leverage and the increased risks associated with debt from a Tax Investor's standpoint are reflected in their equity return requirements. In this analysis, the Tax Investor's 10-year after-tax target returns are 9.00% and 9.25% for the Cash Leveraged and Cash & PTC Leveraged structures, respectively. These targets are 250-275 basis points higher than the comparable Tax Investor returns in the all-equity structures. The developer's IRR projected for the leveraged structures, as well as for the Strategic Investor Flip structure (the underlying structure for the leveraged cases), are also among the highest of all those examined. Indeed, the developer's projected after-tax returns for the two leveraged structures are about 9% (for the 10-year return) and over 30% (for the 20-year return). This is because in these scenarios the developer contributes very little initial capital, yet receives almost all of the project allocations

[49] See Chadbourne & Parke, LLP, op. cit.

after the Flip Point. However, the increased cost and risks associated with leverage makes these projected returns more uncertain. Lower-than-projected wind production will disproportionately reduce or delay cash flow distributions to the developer, since the annual debt service requirements do not change. This significant volatility, i.e., the risk that the developer's return will prove substantially lower, is not captured in the single-point forecast of the model.

The Institutional Investor Flip and Back Leveraged structures have the next lowest LCOE at $53/MWh. As noted earlier, these all-equity structures are identical with the exception of the developer's company-level debt in the Back Leveraged structure. Because this debt is not at the project level, the Back-Leveraged structure uses the same 6.50% IRR assumption and these two structures show the same project returns, Tax Investor 20-year returns, and required LCOEs. The only variation is in the developer's returns. For the Institutional Investor Flip structure, the developer has no 10-year return on its capital due to the allocation of cash and Tax Benefits under the structure. In the Back Leveraged structure, the developer has a negative 10-year IRR (reflecting repayment of the company-level debt), but has a 20-year IRR (11.9%) that is about 150 basis points higher than the developer's 20-year IRR (10.4%) using the Institutional Investor Flip structure. The developer's higher 20-year IRR reflects the lower cash investment enabled by the use of debt in the Back Leveraged structure.

The PAYGO structure – where the Tax Investor pays the developer an annual amount equal to a fixed percentage of the PTCs generated – is found to be next cheapest, with a LCOE of $59/MWh. This structure allows the developer to make a significant capital contribution (45% in this analysis) and secure a cash-based return in the form of cash distributions from the project and Tax Investor PTC payments. The model assumes that the Tax Investor receives a 10-year target return of 6.5%, inclusive of the PTC monetization payments; in turn, this yields a projected 20-year IRR to the Tax Investor that is roughly 50 basis points higher, at 7.02%. The developer's return in the PAYGO structure is among the lowest of the structures involving Tax Investor equity, with a 20-year after-tax IRR of 11.5%. This return is a function of the amount of capital contributed up-front (the most of any structure, at 45% of total equity) and the receipt of a majority of the return, via the PTC payments, over time.

The LCOE and developer return for the PAYGO structure are affected greatly by the PTC payment percentage. This analysis assumes the Tax Investor pays the developer 85 cents for each dollar of PTCs produced. If that amount decreases to 80 cents the LCOE decreases from $59 to $56, and the developer return decreases to 10.5%. In practice, the developer and the Tax Investor negotiate a PTC payment rate at a level that will achieve their respective return requirements.

The Strategic Investor Flip structure has the second-highest LCOE, at $61/MWh. The developer's 20-year return in this structure is projected to be the highest of all the structures. This is because (i) the developer contributes just 1% of the up-front capital and receives a pro-rata share of the cash and Tax Benefits prior to the Flip Point and (ii) after the Flip Point it receives 90% of all allocations. Therefore, it contributes virtually no capital up-front yet receives almost all of the allocations after year ten. The LCOE of this structure is highly dependent on the Tax Investor's target return requirement. As the Tax Investor does not take development-stage risks, and only contributes funds when the project is operational, the 10-year return requirement is assumed to be lower than required for a Corporate structure investment.

In this analysis, the Tax Investor's (whether Strategic or Institutional) 10-year target return for the all-equity partnership structures is uniformly set at 6.5%. As a result, one might expect that the Strategic Investor Flip and Institutional Investor Flip structures would generate the same LCOE. However, the calculated LCOE in the former is $8/MWh greater than in the latter. The difference is due to the developer's capital contribution and return profile. In the Strategic Investor Flip structure, the developer contributes almost no cash, but nevertheless receives a pro rata return on its investment for the first ten years prior to the Flip Point, yielding a positive return at the end of year ten. In contrast, the developer in the Institutional Investor Flip structure invests a larger amount of capital but receives only a return *of* capital in the first ten years (0% IRR). In other words, under the Institutional Investor flip structure, the developer recovers its capital in the first four to six years of operation (six years in this analysis), but receives nothing from that point through year ten. Because the developer is not receiving a return in the first ten years of operation, the project is essentially using a large percentage of zero-cost capital, which allows the Tax Investor to reach its 10-year return target through a lower cost of energy.

The highest LCOE resulting from our analysis is associated with the Corporate structure, and is largely a function of the fact that the model sets the 20-year target return for the developer/Corporate entity at 10%. A developer's return requirement is used, as there is no involvement by a separate Tax Investor. Although this is technically an all-equity structure, the structure differs from the other structures in that a single owner bears all of the project risks, i.e., there is no separation of the risks (and returns) between two equity parties, with one party having lower risks and, hence, lower returns, than the other. In other words, the target return might be thought of as a blended equity hurdle rate, reflecting a melding of the returns to the Tax Investor and the developer in other all-equity structures. Alternatively, it could be considered the blended rate of a higher equity return requirement, averaged with cheaper debt financing obtained at a corporate level above the project. In either case, this higher return requirement and the lack of leverage yields a comparatively high LCOE. If developers using this structure have a lower weighted-average cost of capital than assumed for this study, then the LCOE would be reduced. For example, if the 20-year 10% return assumption is reduced to a 9% blended return, then the calculated LCOE would decrease to $58/MWh.

In sum, variations in the LCOE across financial structures (assuming the same underlying template project) reflect the different assumptions made about the equity returns and debt financing costs required by Tax Investors and lenders in the marketplace. Investors and lenders require higher returns to invest in wind projects that use structures deemed more risky, e.g., those that defer returns until later in the life of the project, or that use leverage. Thus, assuming all other cost and operating parameters are held equal,[50] the LCOE for a given financing structure is a proxy for the relative cost of equity and, if used, debt financing for the project. As with other maturing sectors, the cost of financing becomes a competitive differentiator among project developers. Those with access to cheaper money will be able to offer lower-cost power to their customers.

[50] This assumption is important: variations in assumptions about the underlying template project itself – including turbine and balance-of-plant costs, capacity factors, and operating costs – will also impact the resulting LCOE.

In the economists' perfect world, no one financing structure should generate higher returns than another, LCOEs would not differ substantially among structures, and there should be little difference in the degree of usage of these structures. This analysis suggests that the economists' perfect world does not exist in the wind financing marketplace. Additionally, the divergence of the presumed attractiveness of each structure (as measured by LCOE) from actual market practice suggests that developers considering financing structures take multiple factors into account in addition to the projected LCOE. Most obviously, their financial analyses consider project-specific costs and revenues, and not simply generic assumptions. Non-monetary considerations also play an important role. Information flows, access to equity and debt capital, and experience levels are not uniform across the sector. Given these realities, developers and investors likely will continue to find value in optimizing the financing structure for their wind projects.

5. Conclusions – Observations & Future Trends

The U.S. wind power sector has grown significantly in the last decade. The pace of sector development has outstripped the ability of most developers to fund project capital costs and to make efficient use of the Federal Tax Benefits. In response, the sector has been successful in creating novel project financing structures to attract both Institutional Investors and Strategic Investors wanting to enter the sector. Different financing structures have evolved to meet specific developer and investor needs, and this evolution will continue so long as the sector attracts new investment capital. This chapter concludes this report by making some observations about the potential direction of this evolution and the potential impact on the cost of wind energy.

Specific financing structures will change in popularity from year to year. As an example, the use of leveraged structures increased in 2006 and may do so again in 2007, compared with less frequent use earlier in the decade. A key driver for this increased use is the rise in turbine costs in the last two years. Commensurate increases in power prices have not occurred, which has put pressure on developer and investor returns and spurred efforts to boost returns through the use of leveraged financing structures. The extension of the PTC through the end of 2008 also has afforded developers more time to craft leveraged financing structures. Finally, lenders are devising loan forbearance terms to accommodate Tax Investor needs in potential default situations, such that some Tax Investors are becoming less worried about the participation of lenders in wind financings. On the other hand, debt financings may become less attractive if lenders tighten credit standards and loan terms as a reaction to the recent difficulties in the sub-prime mortgage financing market.

Rising turbine and other capital costs in the last few years have additional implications. Prior to 2004, the average cost of wind projects was declining.[51] This enabled developers to offer lower power prices to their utility customers. The lower prices, along with several other factors, accelerated utility acceptance of wind as a viable power source. Since then, project costs have been rising, and developers have offset a significant amount of the cost increase with the financial gains from reductions in third-party equity and debt return requirements, such that prices offered to utilities do not appear to have climbed as much as might otherwise be expected.[52] Some Tax Investors are accepting Flip Point dates later than ten years, which provides more time for projects to reach the investors' targeted returns. However, further material reductions in return requirements are unlikely. Separately, a rise in interest rates or more cautious views by capital sources about wind resource assessments could push direct financing costs higher. Absent finding savings elsewhere, developers may be obliged to pass on such increases by charging more for the power from new projects.

The significant developer consolidation in the last three years also will affect the choice of financing structures for future projects. Larger, well-capitalized developers have more financing options than do small developers. Such companies have the opportunity to use their financial strength to absorb perceived project risks and to structure and schedule financings to take

[51] Wiser and Bolinger (2007), op. cit.
[52] Diane Bailey, "Cheaper Finance Helps Offset Rising Turbine Costs," Windpower Monthly, May 2007, pp. 58-62.

advantage of market conditions. By de-linking financings from project deadlines and by providing more corporate support in the financings, larger developers will foster new or differentiated financing structures and also put pressure on capital providers to improve their financing terms and conditions. At the same time, the entry of foreign utilities into the U.S. wind market via purchases of mid-sized and smaller U.S. developers suggests a continued, if not expanded, need for domestic institutional equity sources able to use the Tax Benefits.

Financial sector comfort with wind power technology and markets is enabling some transactions to be able to handle risks previously considered unfinanceable, i.e., risks that lenders and Tax Investors historically required project developers to absorb. Earlier in the decade, lenders and Tax Investors only financed wind projects with long-term PPAs with stipulated prices in place. This was based on the belief that variances in both production (to be expected in wind projects) and prices created too much uncertainty in the level of cash flow available to service the debt. Additionally, many banks had suffered huge losses in having financed conventional power projects without such contracts (known as merchant plants), and had become increasingly more stringent with their underwriting requirements. In the last two years, however, several wind projects in Texas and earlier this year, a large transaction in New York, have closed on financing arrangements using shorter-term PPAs followed by financial hedge contracts to reduce market-price risk in the later years. Some lenders and Tax Investors have become comfortable with the ability of hedge contracts to provide sufficient (if not perfectly comparable) price risk reduction compared with a traditional PPA during the term of the hedge contracts. The addition of hedge counterparties as credit providers to wind project financings is obliging lenders and Tax Investors to craft intercreditor arrangements with the hedge providers. More such transactions are likely to close in Texas and New York in the next year; developers and bankers also are exploring if such hedge contracts are feasible in financing wind projects in other states.

Separately, lenders and Tax Investors are becoming more willing to finance projects using new wind turbine technology from companies such as Suzlon Energy Limited and Clipper Windpower. Their willingness stems in part from the increased supply of lenders and Tax Investors relative to available wind financing opportunities. Potential capital providers are competing by assuming greater risks and by easing terms and costs.. That said, until the new turbines accumulate a significant operating history, their comfort likely will come with tighter investment terms and conditions, including highly-negotiated incremental support offered by the developer and the turbine manufacturer to mitigate perceived incremental risks.

Investor-owned utilities also are showing renewed interest in acquiring wind projects outright to add to their internal generating portfolio. This differs from unregulated developer subsidiaries of utilities (such as FPL Energy) buying projects where the power is sold to other utilities. Such direct acquisitions to a utility’s internal generation portfolio can provide benefits to the utility compared with entering into long-term power purchase agreements with stand-alone project-specific entities. The Tax Benefits of ownership of wind projects are attractive to utilities enjoying profitability, and therefore with enough tax liability to benefit from the Tax Benefits of wind projects. The effective price of power may also be somewhat lower, to the extent that the utilities are able to fund project costs with lower-cost corporate funds than can be accessed by independent project-specific entities selling power on a contract basis. For utilities directly purchasing projects, the use of more-expensive and elaborate project-specific financing structures will be unnecessary. Direct ownership also obviates increasing pressure by credit rating agencies to treat long-term power purchase agreements as forms of contingent indebtedness, and provides utilities a direct return on their rate base.

At the same time, expanding interest in direct ownership by publicly owned (e.g., municipal and cooperative) utilities is fostering development of different financing structures. For example, four cooperatives and public utility districts in Washington State desired to develop and own a wind project, but were unable to use the Tax Benefits because of their tax-exempt status. They devised a financing structure that involves pre-paying some of their projected power purchases.[53] The prepayments will be used, along with Tax Investor equity and debt financing, to finance initial construction costs. The financial closing of the White Creek project, as it is named, was announced in January 2007. To date, this project is the only one to close financing using this structure. Whether this structure becomes more widely employed will depend on the relative interest of other credit-worthy publicly-owned utilities and other entities becoming increasingly comfortable with wind power technology to be willing to make such pre-payments.

Publicly owned utilities and cooperatives separately are beginning to tap a new tax credit bond financing program known as Clean Renewable Energy Bonds ("CREBs"). CREBs were established by the Energy Policy Act of 2005 to encourage public sector entities and cooperatives that are unable to use Tax Benefits to invest in renewable power projects. The program is just beginning, however, and the first CREBs are likely to be issued this year. Currently, wind project financing structures incorporating CREBs are still being devised, and their utility for large projects currently is limited. The IRS, which administers the program, currently allocates CREBs mostly to small projects. Congress is considering changes in the program that would expand the amount of CREBs and make them more available for larger projects.

The continuing use of the PTC as a key Federal incentive for wind power projects also has implications on future financing structures. As the sector expands, so does the impact of the PTC on Federal tax receipts. Lengthening the period of the next extension to provide more stability to the sector and thereby spur a higher rate of new capacity additions will increase the expected budgetary impact still further. Nonetheless, a longer-term PTC extension may lead Tax Investors not currently participating in the wind sector due to the temporary nature of the PTC to commence financing projects. Separately, some investment bankers are attempting to devise financing structures that incorporate contingent insurance or bank letters of credit to mobilize hitherto reluctant Tax Investors by fine-tuning their projected exposure to project downside risks. While such structures may be commercially feasible allocations of project risks, they are being hampered by IRS requirements that Tax Investors be exposed to equity risks if they are to be allocated the Tax Benefits.

On the other hand, if the PTC framework is not renewed or is changed substantively to limit its cost to the Treasury, wind power financing structures designed to attract Tax Investors may no longer be attractive absent changes in the structures and/or terms. Such a change would be a

---

[53] See Brian Skeehan, "Cowlitz PUD's Post 2011 Power Supply and the White Creek Wind Project," presentation at Northwest Public Power Association Power Supply Workshop, April 11, 2006. www.nwppa.org/web/presentations/Skeehan_presentation.ppt.

paradigm shift in the U.S. industry, as the current structures developed to attract and utilize tax-based equity investment would become obsolete. The market would ultimately adapt, but there would be a transition period as new structures are developed or existing ones are modified.

Portfolio financings are increasing in usage and are being considered by both project developers and financial institutions. Such portfolio financings are being stimulated by the increasing pace of development. Several investment banking firms have established or are developing pools or funds of institutional investor capital to invest in projects. Funds being set up by financial institutions vary in targeting new projects, refinancing existing projects, or some combination of the two. The funds variously amass capital from multiple smaller Tax Investors or else target Cash Investors. Babcock & Brown Wind Partners is one such fund that has a global focus.[54] Two wind developers already have raised debt or tax equity to refinance portions of their existing portfolios. The entry of the large foreign developers able to fund capital costs, but lacking the requisite tax appetite, likely will spur additional future portfolio refinancings. Such refinancings and poolings of projects may increase the use of the PAYGO financing structure or lead to modified versions of other financing structures.

Each of these various trends and influences will affect how future wind power projects are financed in the United States. It will be useful for the DOE to monitor these developments, and their actual impacts on wind financing structures, as part of its ongoing review of the cost of energy from wind power.

[54] See http://www.bbwindpartners.com/.

References

American Wind Energy Association (AWEA). 2007a. “U.S. Wind Industry to Install Over 3,000 MegaWatts of Wind Power in 2007: First Quarter Market Report.” AWEA press release, May 10, 2007. Available at www.awea.org/newsroom/releases/AWEA_First_Quarter_Market_Report_2007.html

______. 2007b. “Wind Power Capacity in U.S. Increased 27% in 2006 and is Expected to Grow an Additional 26% in 2007.” AWEA press release, January 23, 2007. Available at www.awea.org/newsroom/releases/Wind_Power_Capacity_012307.html.

______. 2006. “Energy Department, Wind Industry Join to Create Action Plan to Realize National Vision of 20% Electricity From Wind.” AWEA press release, June 5, 2006. Available at www.awea.org/newsroom/releases/Energy_Dept_Wind_Industry_Action_Plan_060506.html

______. 2000. “After Blowout Year in 1999, Wind Energy Looks to Even Brighter Future in U.S. Market.” AWEA press release, April 30, 2000. Available at http://www.awea.org/news/news000430w2k.html.

Babcock & Brown Wind Partners. 2007. “BBW Investor Pack 2007.” Available at www.bbwindpartners.com.

Bailey, Diane. 2007. “Cheaper Finance Helps Offset Rising Turbine Costs. *Windpower Monthly*, May 2007, pp. 58-62.

Bolinger, Mark, Ryan Wiser, Tom Wind, Dan Juhl, Robert Grace. 2004. *A Comparative Analysis of Community Wind Development Options in Oregon*. Energy Trust of Oregon. Available at http://www.energytrust.org/RR/wind/OR_Community_Wind_Report.pdf.

Chadbourne & Parke, LLP. 2007. “The Tax Equity Market” in the April 2007 edition of *Project Finance Newswire*. Chadbourne & Parke, LLP, April 2007, pp. 1-12.

Chester, Jeff. 2007. “Wind Power Market Overview 2006.” Kaye Scholer, LLP, presentation at Infocast’s *Wind Power Finance & Investment Summit 2007*, La Jolla, CA, February 7-9, 2007.

Eber, John. 2006. “Windpower Tax Monetizations Transactions.” JPMorgan Capital Corporation, presentation at AWEA Wind Project Finance & Investment Workshop, April 2006.

Energy Information Administration. 2007. *Annual Energy Outlook 2007 with Projections to 2030*. DOE/EIA-0383(2007). Available at www.eia.doe.gov/oiaf/aeo/excel/aeotab_19.xls.

Energy Northwest. 2007. Nine Canyon Wind Project webpage. Available at http://www.energy-northwest.com/generation/nine_canyon.php.

Feo, Ed. 2004. "The Equity Market for Wind Projects." Presentation at AWEA's Wind Power Finance & Investment Workshop, September 28-29, 2004.

Fitch Ratings. 2005. Press release, "Fitch Expects to Rate FPL National Wind Opco 'BBB' and Holdco 'BB'", February 9, 2005. Available at http://findarticles.com/p/articles/mi_m0EIN/is_2005_Feb_9/ai_n9509206.

FPL Group, Inc. 2006. Form 8-K filing to the U.S. Securities & Exchange Commission, June 26, 2006. Available at http://www.psc.state.fl.us/library/filings/06/05916-06/05916-06.pdf.

_____, 2005. Press release, February 23, 2005. Available at http://www.fplenergy.com/news/contents/05020.shtml.

Kubert, Charles. 2004. *Community Wind Financing: A Handbook by the Environmental Law & Policy Center*. Environmental Law & Policy Center. Available at http://www.elpc.org/documents/WindHandbook2004.pdf.

Meridian Clean Fuels, *Comparing Alternative Structures for Tax Equity Investments in Wind Projects*, June 2006 presentation at AWEA's Wind Power 2006 conference in Pittsburgh, Pennsylvania.

Murphy, James. 2005. "Invenergy Wind Finance Company Portfolio Financing Transaction." Invenergy, LLC, presentation at Renewable Energy Finance Forum, June 23-24, 2005, organized by Euromoney and American Council on Renewable Energy.

Renewable Energy Access. 2007. "EDP Enters U.S. Market with Acquisition of Horizon Wind Energy." March 27, 2007. Available at www.renewableenergyaccess.com/rea/news/story?id=47894.

Skeehan, Brian. 2006. "Cowlitz PUD's Post 2011 Power Supply and the White Creek Wind Project." Presentation at Northwest Public Power Association Power Supply Workshop, April 11, 2006. Available at www.nwppa.org/web/presentations/Skeehan_presentation.ppt.

Wiser, Ryan, and Mark Bolinger. 2007. *Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2006*. DOE/GO-102007-2433. Washington, DC: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy.

Appendix A: Glossary

AWEA:	American Wind Energy Association
Cash Investor:	An investor in a wind project that prefers a cash-based return as opposed to one comprised primarily of Tax Benefits.
COD:	Commercial Operations Date – The date on which the project first achieves full commercial operations. This often is the same date as the "placed-in-service date", which is when a project's turbines first are deemed eligible to earn the PTC.
Developer:	Sometimes referred to as the project sponsor, this is the entity that initiates and develops the wind project, and may wish to participate in the ongoing ownership of the project through one of the financing structures described in this report.
DOE:	United States Department of Energy
DSCR:	Debt Service Coverage Ratio – The safety margin required by lenders to ensure that a project will generate sufficient cash flows to service its debt, i.e., to meet principal and interest payments. In this report, a DSCR of 1.45 was used, which means that each project is expected to generate operating cash flows equal to 1.45 times the debt service in each period, for cash-based debt. In this way, the DSCR limits the amount of debt a project can support.
Flip Point:	The point at which the Tax Investor has received a negotiated after-tax IRR on its investment. The Flip Point is typically structured to occur at the tenth anniversary of the COD, after which no further PTCs are generated and the majority of the depreciation charges have been taken.
Institutional Investor:	An entity that invests in a wind project for the Tax Benefits principally as a financial investment. The entity seeks returns on excess capital relative to other passive investing opportunities and wants to offset its large tax obligations from its primary business activities. Examples include large banks and insurance companies.
IRR:	Internal Rate of Return – In technical terms, the IRR is the discount rate that sets the net present value of an investment equal to zero. Wind project financings are often structured to enable investors to reach a target IRR at a set point in time (i.e., at the Flip Point).

LCOE: Levelized Cost of Energy – The minimum required nominal 20-year power purchase price (with no escalation) that enables a project to cover its operating costs while also satisfying the requirements of lenders (if any) and equity providers.

LIBOR: London Interbank Offer Rate – A floating short-term (e.g., 3-6 month) interest rate that represents what banks charge each other for funds. LIBOR is a benchmark for a commercial bank lender's cost of capital. Wind projects seeking debt financing from commercial banks are typically charged a basis point spread over the current LIBOR rate. In most cases, prior to closing, the LIBOR rate is swapped out to a fixed rate over the term of the loan.

LLC: Limited Liability Company – A form of business entity that is the most popular for wind project companies.

MACRS: Modified Accelerated Cost Recovery System – The method by which most wind power assets are depreciated for tax purposes under the U.S. tax code. As a general rule of thumb, roughly 90-95% of a wind project's installed cost can be depreciated using a 5-year MACRS schedule. This accelerated tax depreciation (relative to the project's expected 20- to 30-year life) creates tax losses in the early years of a project, which Tax Investors use to offset taxable income from other business operations.

MW: MegaWatt – One thousand kilowatts, or one million Watts. In this context, a MW is a measure of electrical generation capacity.

MWh: MegaWatt Hour – The energy production of one MW for one hour. For example, 10 MW of capacity producing electricity for two hour yields 20 MWh.

PAYGO: The pay-as-you-go financing structure (described in detail in Section 3.4)

PTC: Production Tax Credit – This Federal incentive, contained in Section 45 of the U.S. tax code, currently provides an inflation-adjusted 10-year tax credit for each MWh of qualified renewable generation produced and sold. For 2007, the inflation-adjusted value of the PTC is $20/MWh.

RPS: Renewable Portfolio Standard – A legislative or regulatory requirement that certain load-serving entities must source a minimum percentage of their generation portfolio from eligible renewable resources. Half of all states have instituted RPS

	requirements. Currently, there is no Federal RPS, although Congress has considered one on several occasions.
REC:	Renewable Energy Credit – A REC represents the attributes associated with one MWh of renewable power generation, and can be sold separately from the generation itself. RECs are often used as a tool to evidence compliance with RPS policies.
Sponsor:	The developer that initiates and develops the wind project, and may wish to participate in the ongoing ownership of the completed project through one of the financing structures described in this report.
Strategic Investor:	An entity that invests in a wind project not only for the Tax Benefits but also because the investment is in line with the entity's primary business activities. An example is an electric utility that invests in a range of power generation assets.
Tax Benefits:	Collective term including the Federal Production Tax Credit and the income tax shield provided to investors from accelerated tax depreciation (i.e., 5-year MACRS depreciation) of the assets of the wind project.
Tax Equity:	The equity invested in a wind project by Tax Investors.
Tax Investor:	An entity that invests in a wind project principally for the Tax Benefits; includes both Strategic and Institutional Investors**.**

Appendix B: Description of Pro Forma Financial Model and Assumptions

Overview

To facilitate comparisons of the mechanics of each of the seven structures analyzed in this study and the impact of these structures on the cost of energy, the authors developed a simplified Excel-based pro forma financial model. The intent of the model is to create a template of an indicative wind project as the basis for illustrating the effects of each financing structure. To this end, the authors developed a set of key assumptions to define the template project.

It is important to recognize that the purpose of the model is to understand the principal differences across the financing structures. It is not derived from an actual wind project financial model. Nor does it attempt to portray a specific project or projects in a particular region of the country. Instead, it simply provides an underlying platform from which the structures can be compared relative to each other. Actual wind project financial models typically feature a spreadsheet listing key assumptions and multiple separate spreadsheets that focus on different aspects of the project, such as: capital costs, operations, depreciation, equity returns for the project developer and for third-party investors, aggregate and partnership allocations of project cash and Tax Benefits, debt financing (if any is used), and sensitivity analyses, graphs, or charts. Financial models used in financing negotiations often calculate project flows on a quarterly or monthly basis so as to capture more precisely the changes that occur in such time periods. Some models may add a summary spreadsheet to show key results for ready analysis.

By contrast, the assumptions used for this report summarize many capital and operating costs for which developers of actual wind projects generate substantially more-detailed assumptions. The model purposely does not include the levels of detail typically included either in models used by developers considering whether to undertake a potential wind project or in the still-more-richly detailed models that form the basis for negotiating equity and debt financing from Tax Investors and lenders. Specifically, the model does not attempt to portray detailed tax partnership allocations derived from capital accounts (Appendix C provides a brief overview of key tax partnership matters). Though such detail is germane for enabling specific return projections in actual negotiations, the simplified model assumptions used in this report suffice to illustrate the main flows for each financing structure. While the authors believe that the assumptions are within the ranges seen in recent market transactions, no attempt was made to ensure that the inputs are precisely correct, as such precision is not the primary purpose of the model.

Market Assumptions

In setting the values used for the model's common and structure-specific assumptions, the report makes certain guiding assumptions about the market in which the template wind project operates. These broad assumptions are intended to reflect the market conditions experienced by almost all utility-scale wind projects developed and financed in the last several years. These market assumptions are likely to remain the predominant paradigm for the majority of wind projects in the near future. As some of these market conditions are changing for very recent projects, however, it will be important to acknowledge any divergences from such market assumptions as a prelude to comparing financing structures, financial returns, and the cost of energy for future projects.

Several market assumptions relate to the terms for selling the project output. The most important is that the report's template wind project is assumed to generate electricity for sale on a wholesale basis to a utility. The project's energy sales are assumed to be on a long-term basis, i.e., for the 20-year time horizon of the model, under a power purchase agreement with a utility. All of the output of the project is assumed to be sold under this arrangement. Put another way, the price for the electricity, as well as the financing hurdle rates, assume that the project will not have any exposure to subsequent fluctuations in either price or demand for its output. Chapter 5 notes that a few wind projects currently being financed have relaxed this assumption, as evidence of how financing structures are evolving.

The model similarly reflects an assumption that all of the RECs generated by the project are sold under a long-term off-take agreement – perhaps the same agreement that governs power sales. The model allows for separate prices and revenue calculations for electricity and REC sales. This reflects the market in some states where the existence and nature of a RPS has led to an "unbundled" REC market, separate from power markets. In states that do not have an RPS, the value of a project's RECs is not as clear. In such instances, developers of wind projects often have elected to sell both energy and RECs under a single contract by which all attributes of a project are sold to a single buyer using a consolidated price. Thus, the important legal points of who owns the RECs (the project owner or the buyer of the electricity) and who holds the risk of determining current and future values are established contractually. Developers of wind power projects have often been content not to force negotiation of a distinct REC price, provided that the single bundled price generates sufficient revenues to make the project commercially viable to develop. In practice, the model allows for alternative scenarios to be considered by changing these assumptions.

The off-take agreement(s) for energy and/or RECs are further assumed to be with a creditworthy entity, i.e., one that the providers of the equity and debt capital for the project believe is likely to be able to honor the purchase obligations for the full term of the agreement. As such, the model assumptions for off-take prices and required financial hurdle rates do not factor in default risk. In practice, investors and lenders typically require that the off-taker has an investment-grade credit rating from one or more of the national credit agencies such as Standard & Poor's or Moody's. If the off-taker does not have such credit strength, then financing parties will look for a parent company or other entity that does have such credit quality to guarantee the off-taker obligations.

The model's base-case assumptions do not assume any inflation in the prices under the off-take agreement(s). The establishment of a fixed, non-inflating price for such sales for the full term of the off-take agreement(s) is common, as it represents a key advantage enjoyed by wind power producers relative to fossil fuel power plants subject to ongoing fuel price fluctuations. However, the model allows for separate inflation factors to be used for the sales of electricity and RECs, so as to enable alternative pricing scenarios to be considered in future analysis.

A separate, but important, market assumption is that the template wind project is employing known wind turbine technology and experienced contractors for the construction and operation of the project. An important factor for many financial institutions in the wind sector is a belief that technology risks are modest and properly and effectively allocated to parties willing and able to handle such risks. In exchange, more capital providers are willing to provide capital on a long-term basis and to reduce their required hurdle rates. This bargain is an attribute of a maturing market. Chapter 5 notes how a few wind projects currently being financed feature new turbine technology and the implications for their financing.

Another market assumption for the template wind project is the availability of the Federal PTC in its current form. For utility-scale wind projects with market-based pricing, the PTC typically represents a substantial part of the total value of the project to investors. Absent this benefit, the power and/or REC prices would need to rise, i.e., the effective cost of energy would increase in order to attain the equity capital hurdle rates. This would be true irrespective of the financing structure, since all of them assume the ability to make efficient use of the PTC. The PTC currently is available for projects entering operation prior to January 1, 2009. For purposes of this report, the model assumes that the template wind project enters operation during calendar year 2008, and that the PTC benefits are therefore available to the owners.

The template project also assumes that the investors in the project can make full, i.e., efficient, use of the Tax Benefits in the years in which they are generated. This is a simple assumption but one that is very important given the value of the Tax Benefits. While it is possible for an owner to carry-forward unutilized portions of the PTC and depreciation deductions (in the form of net operating losses) for up to 20 years, the time value of money effects of such delays progressively erode the value to the investors. In theory, a developer could offset this erosion by seeking higher prices for power and RECs and a third-party investor could require a higher nominal equity hurdle rate as a condition of investing in a given project. From a competitive standpoint, however, developers taking this course handicap themselves relative to other developers competing for the right to sell power and RECs to the same off-taker. Similarly, more-expensive investor capital will lose out in seeking investment opportunities to less-expensive investment capital able to make efficient use of the Tax Benefits.

For purposes of the model, Federal and state income tax rates are assumed to be consistent across all the structures. State taxes were included in this analysis, but with losses being carried forward until they could be used by the wind project itself. The underlying assumption is that the Tax Investor does not have other state tax liabilities (beyond those generated by the template wind project) with which to offset operating losses from the template wind project. Tax rates are used to generate an estimated after-tax return to project investors. Measuring investor returns on an after-tax basis is standard in the industry given the tax-based nature of the equity investment.

Finally, this analysis does not take into account certain partnership accounting and allocation issues associated with wind projects. For example, the model does not show stop-loss reallocations, minimum gain charge-backs, or capital account deficit restoration obligations that can arise in certain financing structures. With tax-based investing, it is very important to monitor the allocations of cash and Tax Benefits to each partner relative to their respective capital accounts. Transactions involving a flip structure and disproportionate allocations of cash and Tax Benefits may trigger income reallocations that, while mandated by IRS Code requirements, may be nonetheless out of proportion with the allocation percentages agreed between the partners. Such reallocations can materially affect the economic return to the project owners. The authors did not incorporate partnership accounting or allocation issues into the model, as these factors are highly project-specific and require a level of detail beyond the scope of this report. Appendix C provides a qualitative summary of these matters.

Common Assumptions Across All Structures

The model consists of a single Excel workbook, with the common assumptions used by all of the structures aggregated on a single worksheet. To facilitate comparison of the financing structures, the worksheet aggregates in separate columns the distinct financing-related assumptions for each structure. The model also includes dedicated worksheets to compute the cost of energy for the template wind project using each of the seven financing structures. To the extent possible, each calculation worksheet follows the same format and draws from the common assumptions. Using the various assumptions, the model then calculates the requisite 20-year cost of energy for each financing structure. For each structure involving third-party capital, the model solves for the cost of energy that yields the specified required Tax Investor IRR at the end of ten years. A ten-year time frame is used because project developers and Tax Investors typically use it as a basis for negotiating the IRR for a specific project. PTC generation expires on the tenth anniversary of the start of commercial operations and most of the tax depreciation benefits have been utilized by that time. Note that the model is simplified in that it does not model the exercise of a post-flip purchase option by the developer. In other words, the analyses assume that the Tax Investor remains involved with the project over the full twenty-year life of the project. The model is also simplified by including a fixed initial development fee and by excluding an ongoing management fee in the returns to the developer. For the Corporate structure, the model solves for the cost of energy that yields the specified required developer IRR at the end of twenty years. The use of a 20-year target return is consistent with the developer in this structure being the sole investor, with a longer-term time horizon.

Table B1 lists the various input assumptions for the template wind project that are common to all of the financing structures. For each assumption, the value used in the model is given and background notes are listed on the basis for the value.

Table B1. Input Assumptions Common to All Structures

ASSUMPTION	VALUE	NOTES
PROJECT INFORMATION		
Year of Initial Commercial Operation	2008	The project becomes operational at the beginning of 2008.
Project Capacity	100 MW	Representative project size in 2008.
Annual Net Capacity Factor	36.00%	Average 2006 cap. factor for recent projects (Wiser and Bolinger 2007).
Inflation Rate	2.00%	Close to GDP price deflator projection in *Annual Energy Outlook 2007.*
Interest on Reserves	2.00%	Set to be consistent with assumed inflation rate.
CAPITAL COSTS ($000)		
Hard Costs		
Development Costs	5,000	Roughly consistent with the range of recent project costs presented in Wiser and Bolinger (2007)
Wind Turbines	120,000	
Balance of Plant	25,000	
Interconnection	10,000	
Soft Costs		
Interest During Construction (IDC)		
Interest Rate	6.70%	Consistent with the rates for cash and PTC-based debt (see Table B3).
Construction Period	12 months	Estimate includes turbine delivery and actual project construction.
Construction Debt Closing Fee (% of debt amount)	1.25%	Estimate based on industry review.
Soft Cost Totals ($000)		
Interest During Construction (IDC)	Calculation	Assumes 100% of costs outstanding for half the construction period.
Equity Closing Costs	400	Based on industry review (legal fees & consultants; no finder's fee).
Developer Fee	3,500	Residual value assumption. Actual fee amounts vary by project, depending on relative project value and financing terms.
Working Capital	1,000	Estimate based on industry review.
Contingency (5% of Hard Costs)	8,000	5% figure based on industry review; the $ amount is calculated.
ANNUAL OPERATING EXPENSES		
Operations & Maintenance (O&M) Costs		
Fixed O&M ($/kW-yr)	11.50	Aggregate fixed and variable O&M costs are consistent with those used in DOE/AWEA's *20% Wind Vision Analysis.*
Variable O&M ($/MWh)	6.00	
PPA Letter of Credit (LOC)		
LOC Amount ($000)	5,000	Based on industry experience (this figure can vary widely)
Annual LOC Rate	1.50%	The annual cost of the 20-year LOC, based on industry experience.
PTC		
PTC Base Year ($/MWh)	15.00	Energy Policy Act of 1992
2007 Inflation Adjustment Factor	1.3433	Page 14862 of the 2007 Federal Register (volume 72)
2008 Inflation Adjustment Factor	1.3702	2007 inflation adjustment factor inflated by 2% assumed inflation
2008 PTC Rate ($/MWh)	21.00	$15/MWh multiplied by 1.3702 and rounded to the nearest integer
Years Available	10	Qualifying projects can currently claim the PTC for 10 years.
TAXES		
State	6.0%	Representative state tax rate.
Federal	35.0%	Standard industry assumption for Federal corporate tax rate.
DEPRECIATION ALLOCATION		
Hard Costs		Estimates are based on industry experience. Items labeled as "Indirect" are depreciated using the same schedules in the same proportions used for directly depreciable assets in aggregate. For example, if 90% of all directly depreciable costs or assets are depreciated using 5-year MACRS, then 90% of all "Indirect" costs will also be depreciated using 5-year MACRS. These high-level allocations are meant to be representative; actual allocations are highly cost-item dependent. Specific advice from tax counsel and accounting firms is highly recommended.
Development Costs	Indirect	
Wind Turbines	Direct 5-yr MACRS	
Balance of Plant		
Interconnection	Direct 20-yr SL	
Soft Costs		
Interest During Construction (IDC)	Indirect	
Debt Closing Costs (when debt is used)	Direct 15-yr SL	
Debt Closing Fee (when debt is used)	Indirect	
Debt Service Reserve	Non-Depreciable	
Equity Closing Costs		
Working Capital		
Developer Fee	Indirect	
Contingency (5% of Hard Costs)	Indirect	

In several instances, the model draws upon basic project assumptions used in the *20% Wind Vision Analysis* project being conducted jointly by the DOE and AWEA.[59] Since the *Wind Vision* assumptions have already been vetted within the wind industry, this report has used them where appropriate rather than creating different assumptions. Although some of the *Wind Vision* assumptions are simplified (e.g., O&M costs are aggregated rather than broken out into individual cost items), the fact that this report's focus is on comparing differences in the financing structures rather than crafting a model of a potential real project allows for such simplification. Notwithstanding this, the model is set up to accept more-detailed assumptions as may be deemed appropriate by future users.

General project assumptions such as the project's annual net capacity factor (a measure of energy production), capacity, and inflation rates are shown in Table B1. The 100 MW project size is meant to be representative of the utility-scale wind projects currently being developed. The 36% capacity factor reflects the capacity-weighted average 2006 capacity factor of a sample of utility-scale projects built in 2004 or 2005.[60] The capacity factor is particularly important for projects as it determines both the amount of energy produced for sale and the amount of PTCs generated. The table lists a two percent (2.0%) annual inflation rate. This is in line with the inflation rate assumed in the Energy Information Administration's most recent *Annual Energy Outlook*.[61] The model has the option of escalating power prices by inflation over time or leaving them flat. As noted earlier, the authors have assumed that revenues are not inflated, i.e., that the power price is fixed at the outset under a long-term purchase arrangement. Thus, the inflation rate is only used to increase operating expenses.

The aggregate "hard" – i.e. not including financing costs – capital cost estimate of $160 million (or $1600/kW) is roughly consistent with data on recent installed project costs.[62] As seen in Table B1, a large portion of the hard costs are comprised of the wind turbines. The soft costs, i.e. the financing costs, are specific to each financing scenario and consequently vary across the structures (soft costs relating to debt are shown in Table B3). The hard and soft costs add together to generate a total project cost. The treatment of project costs for tax depreciation purposes is important to the investor returns. As a general rule, roughly 90-95% of the project costs can be depreciated over the first five years of project life using the 5-year Modified Accelerated Cost Recovery System (5-year MACRS). Depreciating such a large amount over five years generates large depreciation charges in the early years that tax-based investors can use to offset income from other operations. Most of the remaining total cost of wind power projects is either depreciated using several other schedules (including 15-year MACRS and 15- and 20-year straight-line schedules), is indirectly allocated, or is non-depreciable. The cost of items that are indirect allocations for tax purposes is allocated proportionally to the other categories, in keeping with tax convention. Please note, the depreciation allocation figures used in this study are simplified for illustrative purposes and are not meant to be used for specific projects.

The fixed and variable O&M cost assumptions in the model are taken from the DOE/AWEA *20% Wind Vision Analysis*. These numbers are meant to be inclusive of all operating costs,

[59] See www.awea.org/newsroom/releases/Energy_Dept_Wind_Industry_Action_Plan_060506.html
[60] As presented in Wiser and Bolinger (2007), op. cit.
[61] See the GDP chain-type price index found at www.eia.doe.gov/oiaf/aeo/excel/aeotab_19.xls.
[62] As presented in Wiser and Bolinger (2007), op. cit.

including items such as land lease payments, property taxes, insurance, management fees, etc. The model does have line items for each of these detailed cost items in the event that a future user desires to break out individual components.

Structure-Specific Assumptions

In addition to the common assumptions described in the previous section, the calculation of the cost of energy for each scenario relies on certain financing assumptions specific to each particular structure. These relate to two aspects: (i) the cost of financing provided under each structure, and (ii) where applicable, the allocations of the project's cash and Tax Benefits between the different types of equity investing in the project.

The costs of debt and equity financing are expressed in different ways. The cost of financing from Tax Investors typically is negotiated in terms of the IRR required by the investor. In cases where the Tax Investor's or developer's IRR is magnified due to a low initial contribution, developers and investors sometimes also look at the net present value of their investment, or other metrics. Tax Investors typically also consider the developer's return to ensure that the developer has sufficient exposure to be motivated to perform its obligations. Tax Investors set their required IRR to account for the relative risk associated with the project. In general, the higher the perceived risk of the project, the higher the required IRR, and vice-versa. Currently, wind project developers solicit equity capital from multiple sources and, assuming all other factors are held equal, will favor investors requiring the lowest minimum IRR. It is important, however, to put the use of the IRR into context. Project-specific factors influence the IRR requirements negotiated between the developers and Tax Investors. Tax Investors will adjust their requisite IRR based on the perceived risks of a given project. They will seek a higher IRR to compensate for the added risk of debt at the project level. In addition to the calculable financial returns, investors will adjust their requisite IRR to reflect qualitative risks across projects or in the timing of the financial returns. For example, a wind project with only short-term or even no power or REC purchase agreements in place is typically considered to be more risky than a project with a long-term off-take contract. Similarly, a wind project with most benefits occurring later in the project life is considered more risky than one that relies more on returns generated early in the project life, even if each project shows the same IRR. Project developers can meet a Tax Investor's IRR target by adjusting the relative allocations of cash and Tax Benefits as well as the level and timing of certain fees paid to the developer. The power sales price is another potential lever that can be adjusted, if not already fixed in a power purchase agreement.

IRR levels in the wind sector are also affected by the relative supply of equity capital predisposed to invest in these projects. Since 1999, as the market has matured and the structures have become better defined, the number of Tax Investors willing and able to make efficient use of the Tax Benefits has gradually expanded. Developers of solid wind projects currently are able to solicit third-party equity capital from multiple sources. With the supply of capital currently greater than the supply of solid projects, competition has been fostered among capital sources and, along with other factors, this has contributed to a broad decline in Tax Investor IRR levels for wind projects in recent years. Other contributing factors are noted in Chapter 2.

A key facet of several of the financing structures is a differential allocation of the cash and Tax Benefits to the project developer and the Tax Investors. It is important to note that the cash and Tax Benefits can be allocated in varying proportions between each partner. For example, for a period of time all of the cash could go to the developer while all of the Tax Benefits could go to the Tax Investor. Chapter 3 of the report provides details about the varying cash and Tax Benefit allocations specific to each structure.

These allocations can vary both in terms of percentage amounts and over time. The rationale for these allocations, as well as their impact on the respective IRRs for the developer and the other investor(s), vary by the financing structure. Chapter 3 describes these influences and impacts for each of the financing structures. For actual wind project investments, the developer and prospective Tax Investor will negotiate the level of the IRR required by the latter. Therefore, to facilitate comparison of the effective cost of energy across the various financing structures, the report assumes an IRR target value and target date for the cost of Tax Investor capital for each structure. The cost of energy is the price that yields the required Tax Investor return.

Due to the differential allocations in amounts and timing mentioned above, the IRR for an overall project will vary from the respective IRRs for the project developer and the Tax Investor. While it would be possible to develop a single weighted-average of the IRRs for the different investors, the report does not use this approach for the structures accessing third-party capital, as such averages are not used in actual practice and thus are not readily comparable to market conditions. Instead, the authors assume an IRR required by a Tax Investor and percentage allocations of cash and Tax Benefits under each financing structure. The model determines the required price of power to achieve the stipulated 10-year IRR for the Tax Investor, and then calculates the resulting IRR for the project and the project developer. For the Corporate structure, the model determines the required price of power to achieve the stipulated 20-year IRR for the developer, which in this case is the Corporate investor.

Table B2 summarizes the equity-related financing assumptions that are specific to each structure. For those structures involving more than one investor (i.e., with equity capital from a Tax Investor as well as the project developer), the table shows the percentage allocations of the initial equity contributions, cash returns, and Tax Benefits to the project developer and to the Tax Investor. For those financing structures where the allocations change over time, the allocations prior to and after the Flip Point are listed. The flip occurs when the returns to the Tax Investor have reached the agreed upon IRR target (also shown in Table B2).[63] All of these percentage contributions and allocations should be considered merely indicative; actual percentages will vary by project according to relative project value.

[63] If project performance does not meet initial expectations, then the Tax Investor likely will not reach its IRR target on schedule (at the end of 10 years), in which case the Flip Point will simply be delayed until the target is met. In this way, Tax Investors are somewhat shielded from performance risk.

Table B2. Structure-Specific Equity Financing Assumptions

ASSUMPTION	VALUE		NOTES
	Developer	Tax Investor	
PARTNERSHIP ALLOCATIONS			
Equity Contributions			
Corporate	100%	N/A	Constructed on the balance sheet of a single entity with tax appetite.
Strategic Investor Flip Cash Leveraged Cash & PTC Leveraged	1%	99%	Because these structures are used by developers with limited capital, developer equity will be a low number. Developer equity can vary slightly, but this is a standard industry assumption.
Institutional Investor Flip Back Leveraged	40%	60%	Though project-specific, developer equity typically ranges from 20% to 40% of total capital.
Pay-As-You-Go	45%	55%	Developer equity typically ranges from 40% to 60% of total capital.
Cash Allocations			
Pre-Flip Cash			
Corporate	100%	N/A	This structure involves only one investor, so no flip.
Strategic Investor Flip Cash Leveraged Cash & PTC Leveraged	1%	99%	Pre-flip sharing ratios are pro rata with equity interests in these structures.
Institutional Investor Flip Back Leveraged	0%	100%	The developer gets 100% of the cash until it earns a return *of* its capital, *after which* the pre-flip allocations reflect those shown here.
Pay-As-You-Go	30%	70%	Developer receives substantial cash to reflect its high equity investment.
Post-Flip Cash			
Corporate	100%	N/A	This structure involves only one investor, so no flip.
Strategic Investor Flip Cash Leveraged Cash & PTC Leveraged Institutional Investor Flip Back Leveraged	90%	10%	Estimates based on industry experience. The post-flip sharing ratio is transaction-specific. As a general rule the Tax Investor share will not go below 5% for tax opinion reasons. The figures here were sized to obtain an industry estimate of the 20-year Tax Investor return being 50-70 basis points higher than the 10-year return.
Pay-As-You-Go	95%	5%	
Tax Benefit Allocations			
Pre-Flip Tax			
Corporate	100%	N/A	This structure involves only one investor, so no flip.
Strategic Investor Flip Cash Leveraged Cash & PTC Leveraged	1%	99%	Estimates based on industry experience. In all cases virtually all of the pre-flip Tax Benefits (i.e., PTC and depreciation losses) are allocated to the Tax Investor – i.e., the partner that can efficiently use them.
Institutional Investor Flip Back Leveraged Pay-As-You-Go	0%	100%	
Post-Flip Tax			
Corporate	100%	N/A	This structure involves only one investor, so no flip.
Strategic Investor Flip Cash Leveraged Cash & PTC Leveraged Institutional Investor Flip Back Leveraged	90%	10%	Estimates based on industry experience. The post-flip sharing ratio is transaction-specific. As a general rule the Tax Investor share will not go below 5% for tax opinion reasons. The figures here were sized to obtain an industry estimate of the 20-year Tax Investor return being 50-70 basis points higher than the 10-year return.
Pay-As-You-Go	95%	5%	
IRR TARGET (10-year Tax Investor target, except for the Corporate structure, which is a 20-year developer target)			
Corporate	10.00% (20-yr target)	N/A	This is the developer's 20-year target, since it invests in the project for its lifetime and does not seek any outside capital. 10% is a proxy for the internal cost of funds likely paid by unregulated utility subsidiaries and other large entities that use the Corporate structure.
Strategic Investor Flip	N/A	6.50%	This 10-year target is at a slight discount to the developer's 10-year IRR computed for the Corporate structure. The discount reflects the Tax Investor's avoidance of development/construction risks and receipt of most project flows until achieving its target IRR. Very few projects have used this structure in recent years, making this estimate uncertain.
Institutional Investor Flip Pay-As-You-Go Back Leveraged	N/A	6.50%	The estimates for these all-equity structures are based on industry experience for an average-quality wind project. Since the Back Leveraged structure involves debt only at the developer (not project) level, from the Tax Investor's perspective, this structure is unlevered.
Cash Leveraged	N/A	9.00%	The premium over all-equity structures reflects the greater default risk born by the Tax Investor. The 25 basis-point incremental premium for Cash & PTC Leveraged is due to the added PTC tranche of debt.
Cash & PTC Leveraged	N/A	9.25%	

Table B2 illustrates the differences in the assumed allocation percentages and the target equity IRR rates across the various financing structures. The rationales for the allocation differences are discussed in Chapter 3. The values themselves are indicative of recent market levels, as discussed in Chapter 4.

Two of the financing structures have project-level debt, while one has debt at the developer company level. Three loan parameters have the most effect in determining the size and cost of the loan for a wind project: the interest rate, the loan term, and the DSCR. Commercial banks in the wind sector typically quote interest rates as a spread over LIBOR. Institutional lenders such as insurance companies may instead quote spreads over U.S. Treasuries, but most debt discussions are LIBOR-based. Lenders typically require borrowers to hedge the interest rate risk, which usually means swapping the floating interest rate for one that is fixed for the duration of the loan. Hedging costs to fix the interest rate are added at the time of closing.[64]

The DSCR is a measure of the projected operating cash flow available to meet interest and principal payments on the loan. A DSCR of 1.45:1 means that the project is obliged to generate operating cash flow in a given time period, e.g., one year, equal to 145% of the scheduled debt service obligations, principal and interest, during such time period. Lenders will set these terms based on their perception of a project's risks. Lenders use these tools and projected revenue levels (which may vary with seasonal wind patterns) to customize a loan amount and repayment schedule for a given wind project. Such schedules typically allow wind projects to support more debt than would mortgage-style or fixed-principal amortization schedules. The loans are provided on a limited recourse basis, where the lenders look principally to the project-related cash flows and assets for repayment and security for the loan (the PTC loan also typically includes a limited guarantee from the Tax Investor).

Table B3 outlines the specific debt financing assumptions used by the model for those structures incorporating debt. As with the assumptions outlined previously, the values assumed here are intended to illustrate recent market conditions. However, these assumptions are not derived from any specific existing project or projects, nor are they appropriate to utilize for prospective projects, absent adjustment to incorporate the risk profile of the specific project. These assumptions can be modified as deemed appropriate by future users of the model.

[64] The Federal Reserve Bank updates on a daily basis Form H.15, which provides indicative costs of swapping a floating 3-month LIBOR rate to fixed rates of various terms (e.g., see the "Interest Rate Swaps" section of http://www.federalreserve.gov/releases/h15/update/).

Table B3. Structure-Specific Debt Financing Assumptions

ASSUMPTION	VALUE	NOTES
TERM DEBT (project-level debt backed by cash flows or a pledge of PTCs)		
Cash Flow Debt		
Debt Tenor (Years)	15	Standard term given a 20-year PPA with a creditworthy counterparty.
All-In Annual Interest Rate	6.70%	10-year (estimated average life of the loan) swap rate of 5.20% plus a constant spread of 150 basis points. The constant spread is a simplification from common industry practice of lower rates in the early years, followed by rising rates in later years.
Debt Service Coverage Ratio	1.45	Standard industry practice.
PTC Debt		
Debt Tenor (Years)	10	Standard term coinciding with duration of PTCs.
All-In Annual Interest Rate	6.70%	Same assumption as term debt.
Debt Service Coverage Ratio	1.45	Standard industry practice.
Both "Cash Leveraged" and "Cash & PTC Leveraged" Structures		
Debt Closing Costs	400	Based on industry experience (legal fees, technical consultants).
Total Debt Closing Fee	Calculation	Assumes a fee equal to 1.25% of the loan amount, based on standard industry practice. Specific dollar amount is calculated by the model.
Debt Service Reserve	Calculation	Assumes an amount equal to 6 months of debt service obligations, based on standard industry practice. Specific $ amount calculated by the model.
Annual Debt Agency Fee ($000 flat)	25 & 40	The lower estimate is for the Cash Leveraged structure and the higher estimate is for the Cash & PTC Leveraged structure (the added tranche of debt in the latter yields a higher cost per year).
BACK LEVERAGE DEBT (debt secured by the developer, rather than by the project itself)		
Debt Tenor (Years)	Calculation (5.5 years in base case)	Though there are different structures in the market, it is common for the amortization to be based on a nominal 15-year tenor. However, cash sweep provisions reduce the actual tenor to well under ten years. For simplicity, the template model ties the term to the period of time needed for the developer to recoup its initial investment (on grounds that the lender will not want to have the loan outstanding for longer than the developer's own exposure).
All-In Annual Interest Rate	6.70%	Same assumption as term debt.
Debt Service Coverage Ratio	1.45	Standard industry assumption.

The table lists two forms of debt financing used at the project-level. While both are limited recourse financings, they vary in the sources of cash to repay the loans. Cash Flow Debt refers to debt financing extended on the basis of the cash flow generated from the sale of the electricity and RECs from the project. These cash flows are the source of funds to repay the loan. PTC Debt refers to a loan facility supported by the guarantee of incremental periodic equity contributions provided by the Tax Investor receiving the PTCs generated by the project. As the PTCs are a non-cash item to the project, the bank requires a commitment from the Tax Investor to contribute, if necessary, any amounts required to make the scheduled PTC Debt principal and interest payments. The commitment to make such additional contributions effectively creates a second source of cash flow against which the lender is willing to extend a second loan facility; in effect, the equity investor receiving the PTCs monetizes the future PTC benefits in order to reduce its initial investment. The relative projected amount of the future PTC benefits, along with the terms above, determines the principal amount of the PTC Debt. The ten-year term of the PTC Debt is tied to the ten-year period during which the PTC benefits are generated. In practice, some lenders to wind projects provide a single loan facility with a customized loan amortization that consolidates Cash Flow and PTC debt. For transparency and clarity in this report, the model portrays them as separate loan facilities.

The other type of debt listed above is leverage at the developer company level, one step above the project-level. A developer's use of debt to finance its equity investment in the project is known as "back leveraging." This report uses the Institutional Investor Flip structure, in which the developer contributes a significant amount of up-front capital and receives 100% of cash distributions until it has recovered its investment, as the basis for the Back Leveraged structure. However, in the analysis there is no difference in the LCOE between the Back Leveraged and Institutional Flip structure as the debt in the former is at the developer level and therefore has no impact on the project.

Appendix C: Overview of Partnership Tax Accounting Issues

Virtually all utility-scale wind projects involving multiple investors use a special purpose limited liability company ("LLC") to hold the assets of the project. An LLC with more than one member is usually treated as a partnership for U.S. federal income tax purposes. A key feature of partnerships is that they are generally not directly subject to U.S. federal income tax on their income. Instead, the partnership's taxable income or losses flow through to the owners of the partnership and are reported on the owners' separate tax returns.

Allocations of partnership income or losses for tax purposes can differ from distributions of cash to partners. Partnership tax rules generally allow items of partnership income and deductions to be allocated to each partner in any manner that is agreed upon by the partners, provided that the agreed-upon allocations have "substantial economic effect" as required under the IRS Tax Code. To meet the "substantial economic effect" requirement, the partnership must maintain capital accounts and must make liquidating distributions in accordance with positive capital account balances. In addition, the partnership agreement must contain either (i) a deficit capital account restoration obligation or (ii) a number of regulatory allocation provisions, such as "minimum gain chargeback" and "qualified income offset" provisions. These regulatory allocation provisions are generally designed to prohibit partners from having deficit capital account balances when the partnership is liquidated. These "substantial economic effect" requirements and regulatory allocation provisions may have a significant impact on partnership allocations throughout the life of the partnership. As a result, the financial model for a specific project should track changes in each partner's capital account and adjusted tax basis in the partnership, as well as the impact of the regulatory partnership allocations on partnership operations.[65]

The complexity arises in reconciling these tax allocation and accounting rules with the desires of project developers and investors to direct project cash and Tax Benefits to the parties best able to make use of them. Agreeing to disproportionate cash distributions and tax allocations can violate these rules, absent special reallocations pursuant to the regulatory allocation provisions or compliance with certain exceptions.[66] The exceptions themselves can create contingent financial obligations on the partners such as deficit capital account restoration obligations requiring a partner to inject capital back into the entity in the event of a liquidation of the partnership or regulatory tax allocations that require allocations of taxable income to eliminate a partner's capital account deficit prior to liquidation.

Non-recourse debt financing at the project level also adds to the complexity in allocating tax losses. In certain circumstances, gross income may be specially allocated to a partner to reflect a reduction in the potential taxable gain that would be recognized should the loan ever go into default and the lender foreclose on the assets (such an allocation is known as a "minimum gain chargeback"). This gain represents, in essence, that partner's savings from avoiding the repayment obligation of the loan. These requirements interact with the partnership allocation

[65] Since this report does not model a specific wind project, the finer nuances of these partnership issues are not included in the analysis.

[66] For example, one partner with a negative capital account cannot be allocated additional losses (i.e., a capital account reduction) until the other partner has a capital account of at least zero. This rule, simply stated, is that a partner's capital account cannot go "more negative" if the other partner's capital account is positive.

rules to further complicate the accounting. Other tax requirements also affect the financial modeling of partnership-based wind projects.

Allocation of the PTCs is also subject to potential adjustments. Pursuant to the partnership tax allocation regulations, PTCs must be allocated in the same manner as gross income from electricity sales ("GIFES"). To the extent there is a reallocation of GIFES due to partnership accounting issues discussed above, the PTCs may also have to be reallocated to the partners in percentages that are inconsistent with the original and negotiated agreement.

Partnership accounting rules are highly complex and can affect the economic return to both partners. Moreover, not all tax attorneys agree on the specific manner in which PTCs can be specially allocated. Developers and investors should therefore consult their legal counsel and accountants for guidance.