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The return – and returns – of tax equity for US renewable projects

Tax credits are likely to again become the most important subsidies supporting renewable project development in the US, as the Treasury cash grant is on the verge of expiring. This report, commissioned by Reznick Group and undertaken by Bloomberg New Energy Finance, depicts the outlook for US renewable financing in 2012 and delves into the economics of tax equity, focusing on the applications and comparative advantages of the various tax equity structures.

- *Growth in the US renewable sector has been largely driven by the availability of tax equity or its temporary substitute in the aftermath of the financial crisis, the cash grant.* Since 1999, the production tax credit has been allowed to lapse by Congress on three occasions, with each lapse resulting in a precipitous drop in new wind installations. The introduction of the Treasury cash grant programme in 2009 saved the industry from another drop, but that programme is due to expire at the end of 2011.

- *Alternative sources of tax equity may need to emerge to meet market demand for project finance.* Bloomberg New Energy Finance estimates that the US wind industry alone will require about $2.4bn of third-party tax equity financing in 2012 to achieve our projected wind build targets in the coming years. Incorporating other renewable generation sectors, the total tax equity financing need could be more than $7bn. That requirement exceeds the investment appetite of the established tax equity providers, according to a clean energy trade group. Yet there is a vast pool of potential incremental tax equity supply: the 500 largest public companies in the US alone paid $137bn in taxes over the past year. The participation of even a small number of these firms could narrow the gap between demand and supply.

- *There is life after the cash grant.* Despite tax equity's complexity and valid concerns about the depth of the market, tax equity economics can deliver meaningful returns to developers and investors, and there remains political support for this policy.

- *The three primary tax equity structures offer distinct advantages to developers and tax equity investors.* With the 'partnership flip' structure, the investor receives most of the project benefits until a change in ownership event – a flip – occurs. Under the second structure, sale leaseback, the developer 'leases' the asset from the investor, and the structure thus requires no investment upfront from the developer. Finally, in an inverted lease, the investor leases the project from the developer and enjoys the benefits associated with a 'pass-through' tax credit.

- *The economics of these structures can be attractive.* For relatively good but not necessarily exceptional renewable projects, the internal rates of return (IRR) and net present values (NPV) for most of these structures can meet hurdle rates for both developers and investors. Our base-case analysis shows developers achieving returns of 6-19% and investors achieving 10-49% for wind projects, depending on the structure. IRRs for investors reach the higher end of their ranges in the case of upfront receipt of tax benefits.

- *The choice of investment versus production tax credits (ITC vs. PTC) comes down to the three 'P's: performance, perspective and priorities.* Very high performing projects tend to favour the PTC. The perspective – tax equity investor vs. developer – also governs the decision; for example, investors almost always prefer the ITC on an IRR basis and the PTC on an NPV basis, whereas for the developer, this choice depends on the structure and the project quality. For both investors and developers, priorities – whether NPV matters more or less than IRR, or whether other strategic considerations matter more than these financial measures – may drive the choice.

- *The optimal tax equity structure depends on the project characteristics... but perfect optimisation may be a pipedream.* 'Optimisation maps' show the ideal tax equity structure from the developer's or tax equity investor's perspectives for a given scenario. For example, for less high-performing projects (ie, those with high capex and low capacity factors), the ideal structure may be a sale leaseback for a developer and a 5-year partnership flip for an investor. The fact that the two parties' preferred tax equity structure usually differs highlights the trade-off in value: one party benefits at the expense of the other. Ultimately, selection of the final structure – as well as fixing the terms of variables such as 'syndication rates' and 'early buyout price' – depends on relative negotiating power.

1. INTRODUCTION

For the past three years, the US renewable sector has enjoyed the benefits of the Treasury cash grant, an incentive that entitles project developers to receive 30% of a project's capital cost in the form of cash. This incentive is on the verge of expiring. When it does, tax equity – an incentive that drove much of the sector's growth over the past decade – will re-emerge as the dominant form of federal support for development of wind, solar, geothermal, and biomass projects.

Tax equity is complex. It is more complex than other renewable-promoting policies such as the feed-in tariff incentives that are popular throughout Europe and the clean energy tenders available in some developing world countries. It usually involves multiple parties (developers, sponsors, investors, and sometimes lenders), switches of ownership midway through project lifetimes, legal arrangements to facilitate these instances of shared or swapped ownership, and a sophisticated understanding of the US tax code.

However, despite this complexity, the system works. Annual US wind installations grew by more than 300% year-over-year the last two times that the tax equity incentive mechanism was extended by Congress, and developers and investors have both realised attractive returns in the past for projects funded partially through tax equity (provided the projects' capital costs and power purchase agreement, or PPA, terms were reasonable).

This report delves into the economics of tax equity, focusing on the applications and comparative advantages of the various tax equity structures. It was undertaken by Bloomberg New Energy Finance and commissioned by Reznick Group – a national accounting, tax, and business advisory firm.

2. BACKGROUND

2.1. History of production and investment tax credits

Established by the 1992 Energy Policy Act, the production tax credit (PTC) gives tax credits pegged directly to production to owners of renewable energy projects. For each MWh of electricity a qualifying project generates, the owner receives a tax credit that can be applied directly to its tax bill. Today that credit is roughly $22/MWh. The incentive is production-based – the more hours a project produces power and the more MWh it produces, the more credits it generates. The credit applies only to the first 10 years of the project's life, and the benefit, indexed to inflation, could rise over time.

The investment tax credit (ITC), like the PTC, is a tax credit a project owner can apply directly towards its tax bill. Unlike the PTC, it is equal to a percentage of the project's qualified capital expenditure, and is not linked to production. As part of the Energy Improvement and Extension Act of 2008, the ITC, which previously existed for solar power, fuel cells and microturbines, expanded to include small wind, geothermal heat pumps, and combined heat and power (CHP) systems. In 2009, as part of the American Recovery and Reinvestment Act, the ITC was further expanded to include wind – though, as will be explained below, use of the ITC for wind projects has been rare. For wind and solar, the credit is set at 30% of qualified capex. To make use of the ITC, projects have to be placed in service by 1 January 2013 for wind, 1 January 2014 for biomass, and 1 January 2017 for the remaining energy systems.

Third-party tax equity providers, typically financial firms, have historically filled the 'tax equity' gap for developers without tax exposure.

Historically, most developers could not easily use tax credits due to their small size, lack of profitability, and, thus, lack of tax exposure. Third-party 'tax equity providers' emerged to fill this gap. These providers – which generally had experience of investing in low-income housing to capture similar tax benefits – invested in clean energy projects and took their payouts in the form of the tax credit, rather than cash. In the years up to 2008, a small, specialised pool of tax equity investors, led by JP Morgan and GE Capital, played a critical role in US renewable financing by providing capital in exchange for tax credits as well as separate tax benefits associated with accelerated depreciation: the Modified Accelerated Cost Recovery System (MACRS).

2.2. Modified Accelerated Cost Recovery System

MACRS allows tangible property to be depreciated on an accelerated basis according to a detailed schedule specified by the Internal Revenue Service (IRS). Wind, solar and geothermal projects, for example, are classified as five-year property and depreciated at a set rate over the course of six years (biomass is classified as a seven-year property and depreciated over the course of eight years) (Table 1).

Table 1: MACRS depreciation schedule for wind, solar and geothermal projects (%)

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
MACRS	20.00	32.00	19.20	11.52	11.52	5.76
MACRS + 50% bonus depreciation	60.00	16.00	9.60	5.76	5.76	2.88

Source: Internal Revenue Service

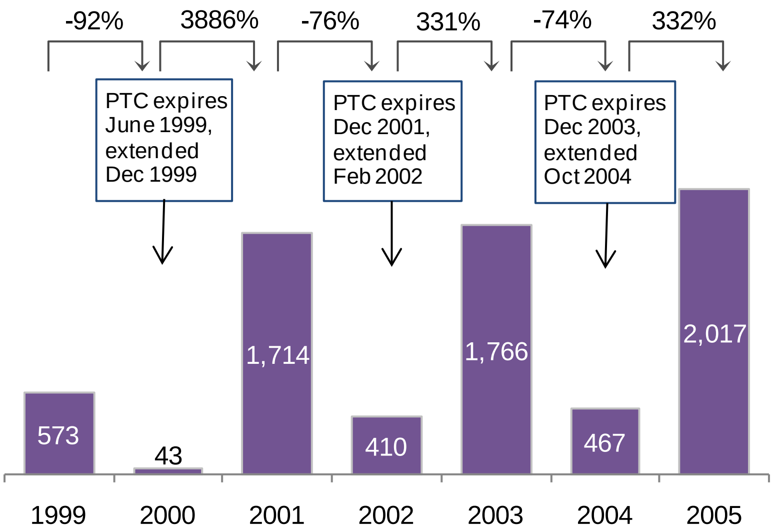
In recent years, Congressional legislation has amplified the tax benefits related to accelerated depreciation. The Economic Stimulus Act of 2008 included a 50% first-year 'bonus depreciation' provision for qualified renewable energy systems placed into service in 2008. This was extended for 2009 and 2010, and in December 2010, increased to 100% first-year bonus depreciation for qualified renewable energy projects placed in service after 8 September 2010 and before 1 January 2012. Bonus depreciation is still available in 2012, but reverts from 100% to 50% of the eligible basis. The bonus depreciation incentive is currently set to expire at the end of 2012.

2.3. Boom-bust cycle

Annual wind build in the US in the first half of the past decade was linked to lapses and extensions of the PTC.

Like many federal incentives, the PTC has had a short shelf life, relying on acts of Congress to repeatedly extend it for 2-3 years beyond its set expiry date. Since 1999, the PTC has been allowed to lapse by Congress on three occasions without being immediately extended. Each lapse resulted in a precipitous drop in new installations, as visible in US wind installations in 1999-2005 (Figure 1).

Figure 1: US wind project installations, 1999-2005 (MW)



Source: Bloomberg New Energy Finance, AWEA

Financial crisis

In 2008, another problem beset the tax equity market: the global financial crisis. With the sudden downturn in the housing market, financial institutions found themselves strapped for cash, posting enormous losses, and with scant need for tax credits. With future profitability in question, banks had little interest in an investment that would only pay out if they had significant tax liabilities for the next 10 years. Tax equity capital became scarce, and the 'tax equity yields' (returns on investment expected by providers) jumped from 6-6.5% to 9% or higher. The number of players providing capital shrank dramatically as well. As the financial crisis deepened through the fall of 2008, tax equity capital dried up almost entirely.

Evaporation of tax equity capital during the financial crisis prompted the introduction of the Treasury cash grant.

As new construction of renewable projects in the US ground to a halt, industry advocates petitioned Washington to 'fix the PTC'. In February 2009, President Obama established the clean energy grant programme through the American Recovery and Reinvestment Act (ARRA). The programme allows a project owner to receive a cash grant from the Treasury Department equal to 30% of the project's qualified capex in lieu of the PTC or ITC.

The cash grant is applicable for all projects placed in service in 2009-11, as well as those that begin construction or qualify for the 5% 'safe harbour' requirement in 2011.[1] Due to the lead time required for wind project financing, most wind projects which applied for the cash grant in early 2009 were already under construction. These projects were generally developed by the handful of large developers which could afford to finance projects with their own balance sheets and monetise the tax credits themselves, without securing tax equity financing from a third party. In at least one other case, a project was developed by a smaller player who otherwise would have sought third-party tax equity. Any developer which completed a project in calendar year 2009 could elect to receive the grant in lieu of tax credits. This included projects completed during January 2009, prior to ARRA being signed into law in February of that year.

As part of the same act that established the cash grant, the ITC was further expanded to include wind. However, the ITC has only been used rarely for such projects. This is because the ITC expansion was enacted within the same bill as the cash grant, which project owners usually prefer

1 An applicant may qualify for the cash grant if more than 5% of the total project cost has been paid or incurred. Wind projects financed in 2011 for 2012 installation can qualify for the cash grant through a down payment on a turbine order, for example.

over the tax credit option (the former is simpler, its benefits more certain, and tax equity financing comes with a cost if done through a third party).

2.4. Other developments: new players to date

New types of players – notably Google and utilities – have already ventured into tax equity.

Historically, financial institutions have served as tax equity providers. There are no legal restrictions, however, to prevent the participation of non-financial corporations,[2] and the tax equity model has attracted some alternative entrants. For example, in recent years, utilities in California, as well as Google, have undertaken tax equity investments. San Diego Gas & Electric (SDG&E) is investing $250m of tax equity in a Montana-based wind farm; Pacific Gas & Electric (PG&E) has dedicated a $60m investment in tax equity for SolarCity's rooftop PV portfolio; and tax equity has accounted for the majority of the $850m that Google has invested in clean energy – including a $100m investment in the 845MW Shepherds Flat wind farm in Oregon and a $280m investment in SolarCity's portfolio.

To date, other corporates (ie, non-financial companies) have been reluctant to take on tax equity. Renewable energy is not core business for most of these companies, and the majority do not have a dedicated in-house team to grapple with the complexities of tax equity or to assess project risks of renewable assets. In addition, the returns on tax equity investments may not be sufficient for companies such as technology pure-plays or oil majors, and particularly for companies without leverage. Finally, in the case of the PTC, engaging in a tax equity investment calls for confidence in the company's ongoing profitability over a long-term (eg, 10-year) horizon – profitability ensures the existence of tax liabilities, which makes tax equity useful. Companies that are not be able to count on that certainty would likely be unwilling to take on a PTC deal.

3. QUANTIFYING USE AND SIZE OF TAX EQUITY MARKET

At its peak in 2007, tax equity financing represented a $6bn market. At other times, tax equity availability has been insufficient to support robust growth of the renewable energy sector, and alternative financing – namely, the cash grant – has been required to fill the breach. This section examines (i) the *mix of financing* employed to fund recent build (specifically wind), (ii) the *demand* for tax equity financing specific to *wind*, based on analysis from Bloomberg New Energy Finance, (iii) the *demand and supply* of tax equity financing *across all renewable sectors*, based on analysis from US Partnership for Renewable Energy Finance, where the *supply is derived from existing providers*, and lastly, (iv) *potential supply from alternative sources* of tax equity financing.

3.1. Mix of financing types (wind-specific)

Methodology for analysing financing mix

Third-party tax equity was a necessary form of financing for most wind projects built prior to 2009 (with the exceptions primarily being those built by developers which had the balance sheet to provide financing and monetise the credits themselves). We therefore broke down the annual MW installations of wind by type of developer and excluded projects with developers that could use the tax credits themselves. This group included utilities, oil and gas companies, and some large developers such as NextEra and Iberdrola.

We analysed projects by year of commissioning and assumed that all projects were financed in the year before the date of commissioning, regardless of the size of the project or month of commissioning. For example, we assumed that projects constructed in 2009 had been financed in 2008, regardless if their commercial operation date (COD) was in January or December 2009.

2 There are restrictions that prevent certain types of entities, such as those who do not pay corporate income taxes, from participating in tax equity. Examples include real estate investment trusts (REITs) and municipal or cooperative utilities – all of which could be interested in undertaking renewable investments but which cannot make use of tax incentives.

The cash grant was enacted in February 2009 and is applicable for all projects placed in service in 2009-11, as well as projects that begin construction or qualify for the 5% safe harbour in 2011. Projects commissioned in 2009 (ie, financed in 2008) are a special case: this is because projects commissioned in a given year generally finalised their tax equity financing agreements in the preceding year and little tax equity was available in 2008. We assumed that for projects commissioned in 2009 and that applied for a cash grant in that year, the developer did not have a tax equity agreement in place – ie, they could afford to build without one.

Most projects installed in 2010-12 (financed in 2009-11) opted for the cash grant, declining the PTC/ITC option. If a developer was considering the PTC versus the cash grant, it is likely to have opted for the latter rather than taking the production risk on the PTC. The exception would be projects with especially high capacity factors where the tax credits generated would safely outweigh the cash grant. (An example of this exception is Horizon's 99MW Blue Canyon Wind Farm III, which has a capacity factor north of 35%.) At least one leading tax equity provider has noted that 2011 has seen an increased tendency towards the use of PTCs rather than the cash grant, but for this approximate analysis, we assume that these cases remain the exception.

Therefore, for projects installed over this 'cash grant period', the use of tax equity is typically confined to take advantage of the MACRS incentive. In other words, tax equity providers that invested capital did so to exploit benefits associated with the accelerated depreciation of turbines.

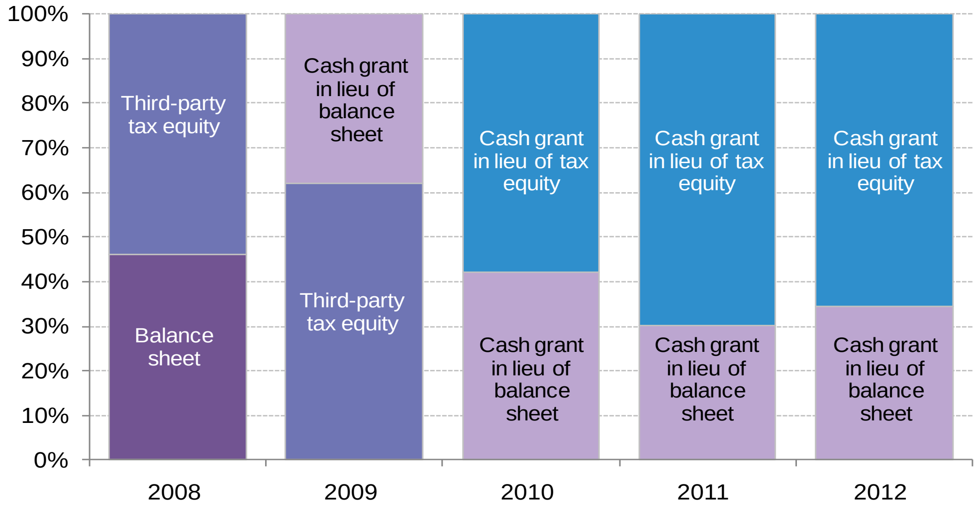
Results of financing mix analysis

Figure 1 presents the results of this analysis, displaying the estimated mix of financing type (cash grant vs. tax equity vs. balance sheet) for US wind projects. The percentage is in terms of financed capacity, and the columns correspond to the year of commissioning.

For projects commissioned between 2009-12, the cash grant has provided financial support for projects that would have otherwise used either third-party tax equity or their own company's balance sheet.

The chart shows that heavy reliance on the cash grant for projects commissioned 2010-12 (financed 2009-11). Some projects used the grant where they would have otherwise used the developers' balance sheet (if the grant had not existed), whereas others used the cash grant where they would have otherwise required a third-party tax equity provider. The 2008 and 2010 mixes present an interesting contrast – ie, 2010's mix is a 'cash-grantified' version of 2008.

Figure 2: Approximate mix of financing type for US wind projects, based on year of commissioning



Source: Bloomberg New Energy Finance Notes: (1) 'Cash grant in lieu of tax equity' includes cases of cash grant in combination with tax equity. (2) Chart shows percent of capacity financed with each kind of mechanism; it does not show financing mix of an individual project. (3) Assumes 50% of capacity developed by Tier 1 developers, and 100% of capacity developed by major corporates (eg, oil and gas majors, utilities), was done on balance sheet. (4) Analysis is an estimate: there were exceptional cases of projects commissioned between 2009-11 which chose PTC over cash grant; these cases are not accounted for here.

3.2. Demand (wind-specific, Bloomberg New Energy Finance estimates)

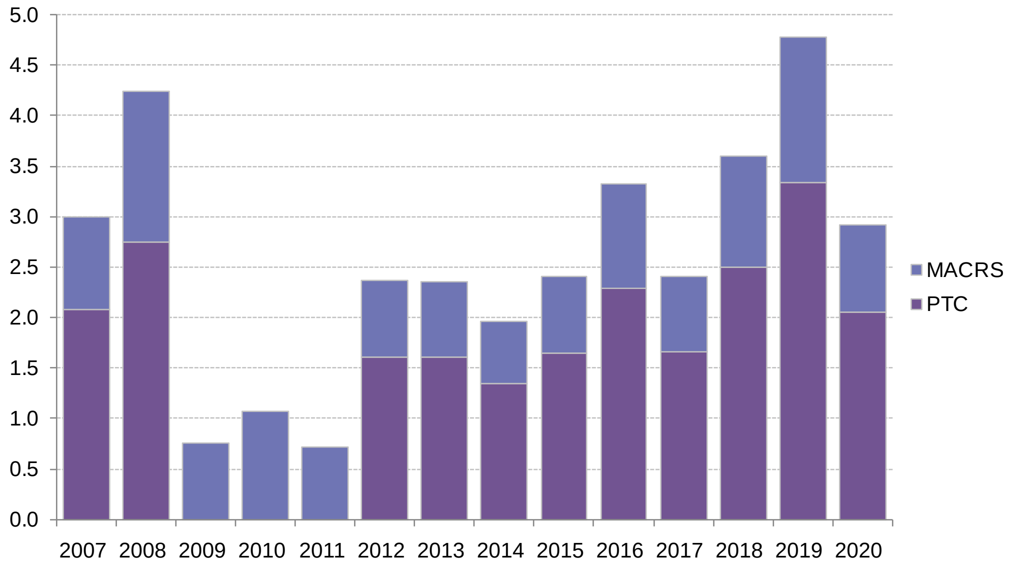
Bloomberg New Energy Finance has estimated the demand for tax equity specific to wind. Figure 3 shows the historical and projected need for third-party tax equity financing for US wind projects by year of financing. As above, we assume that all projects commissioned in a given year secure financing in the year prior to commissioning.

We exclude ITC financing from our estimates as the ITC came into existence for wind energy in the same Congressional act that created the cash grant. Since there is a cost to tax equity financing, we assume that nearly all projects by developers not able to use tax credits themselves would elect the cash grant in place of the ITC. Similarly, for projects financed in 2009-11, we assume most developers would prefer the cash grant over the PTC. For those years, as explained earlier, the use of tax equity is principally confined to take advantage of MACRS.

We assume an average 30% capacity factor for all projects. For 2008 to present, we calculate the tax equity investments in financed projects by discounting the stream of tax credits associated with those projects; the discounting is based on Bloomberg New Energy Finance's historical data on average tax equity financing yields. For future years, we assume a 9% discount rate. Capex estimates for the MACRS portion of tax equity financing also rely on our historical capex data, including the Wind Turbine Price Index. Projections assume turbine prices of \$1.2m/MW, balance of plant at \$0.5m/MW, and development costs at \$25,000/MW.

We assume that financing based on ITC or cash grant is not an option for projects placed in service after 2012, requiring projects commissioned in 2013-2021 (ie, financed in 2012-2020) to seek tax equity financing on a PTC basis (assuming extension of the PTC). Projections for wind installs come from Bloomberg New Energy Finance's US wind forecast for 2011-20. We use the historical averages of financing mix (eg, the mix corresponding to the 2008 column in Figure 2) to estimate the percentage of projects under development in need of third-party tax equity financing (the remainder are assumed to use balance sheet financing).

Figure 3: Historical and projected need for third-party tax equity financing for US wind projects (\$bn)



Source: Bloomberg New Energy Finance Notes: Wind build growth projections based on Bloomberg New Energy Finance modelling. Assumes that cash grant and ITC are not extended beyond 2011 and 2012, respectively, and that ratio of third-party tax equity financing versus balance sheet financing for the years 2012-20 is the same as the corresponding ratio that existed in 2007-08. Assumes 9% yield on tax equity financing. Analysis is an approximation: there were exceptional cases of projects commissioned between 2009-11 which chose the PTC over the cash grant; these cases are not accounted for here.

Over 2012-20, the US wind industry will require an average of $2.9bn per year of third-party tax equity.

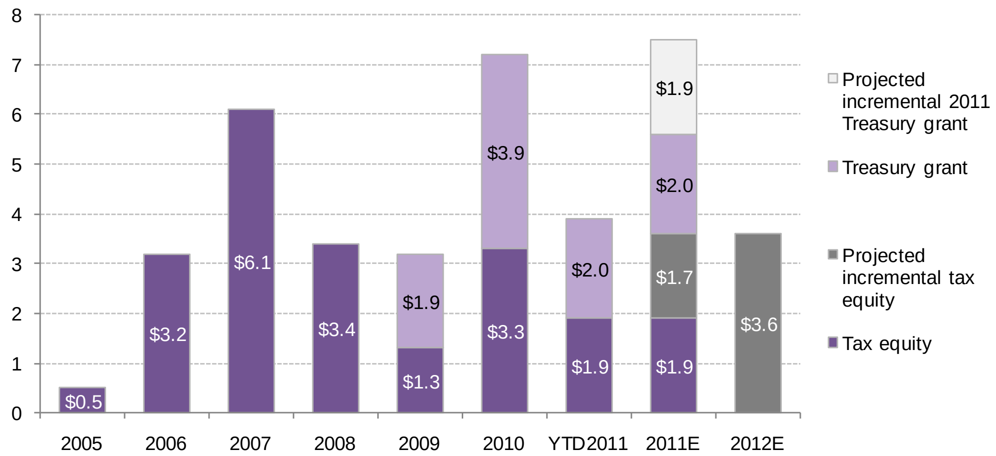
The chart shows the dramatic reduction in need for PTC-based tax equity financing during the years of cash grant availability. It shows also the ramp-up in tax equity needed in the years approaching 2020. This is tied to our forecasts for wind demand, which are based on both 'mandated' wind build (projects built to meet state renewable standards, hence the escalation in 2019 in preparation for 2020 targets) as well as 'economic' wind build (projects built in excess of mandates, for reasons such as utilities seeking to hedge against gas price volatility). Over 2012-20, the US wind industry will require an average of $2.9bn per year of third-party tax equity, including $2.4bn in 2012, with a peak of $4.8bn in 2019. The majority (75%) of that tax equity will be applied towards the PTC, with the remainder making use of MACRS.

3.3. Demand and supply (all sectors, US PREF estimates)

The US Partnership for Renewable Energy Finance (US PREF), a programme of the American Council on Renewable Energy (ACORE), conducted its own study on the historical and projected size of the US tax equity market.[3] The study spanned all sectors and included estimates of both demand (need for tax equity) and supply (availability of tax equity).

Demand for financing in 2012 will far outstrip supply of tax equity, according to this study. Based on forecasts of about 8-10GW of annual renewable build (comprised primarily of wind and about 2GW of PV), the study estimates a financing need of about $7.5-9bn. (This estimate is across all sectors, whereas the values in Figure 3 are for wind only.) For supply, the study took a bottom-up approach, summing the inputs of projected tax equity availability from the 15 major players in the US tax equity market. This 'survey' yielded an optimistic estimate of US tax equity availability in 2012 of about $3.6bn (Figure 4).

Figure 4: Historical and projected financing from tax equity and Treasury grant ($bn)



Source: US PREF "Prospective 2011-12 tax equity market observations" Note: The values in this figure (Figure 4) may not match values in Figure 3 since this analysis is across all sectors (whereas Figure 3 is for wind only) and because the two analyses likely use different assumptions about timing (ie, assumed gap between tax equity financing date and project commissioning date) and about percentage of projects historically financed on balance sheet.

3.4. Alternative sources of supply

The analysis above suggests that there may be a potential shortage of tax equity from the established providers. Yet other sources of tax equity supply could emerge. Figure 5 below shows the cash paid in taxes for the 500 largest US publicly quoted companies by sector; together, these companies paid $137bn in taxes over their trailing 12-month period. The measure of taxes paid, in combination with the effective tax rate, could serve as a high-level gauge for a company's

3 US PREF "Prospective 2011-12 tax equity market observations"

appetite for reducing these tax liabilities (ie, higher the effective tax rate, the greater the benefits achieved via tax equity investing).

Strategy, sustainability, or economics may prompt a small number of US companies to explore potential tax equity arrangements.

Several of these sectors (eg, energy, industrial) have some 'adjacency' to the renewable energy industry that could justify their involvement in renewable investments on a strategic basis. Other sectors (eg, financial, technology / telecom) have a history of participating in renewable procurement as part of their corporate sustainability initiatives.[4] On either of these grounds – strategy or sustainability – or simply on the basis of wishing to reduce their tax liabilities and valuing the returns of a renewable investment, it is conceivable to imagine several US corporations entering the space of tax equity.

Figure 5: Cash paid for taxes (trailing 12 months) for 500 largest US public companies by sector ($bn)

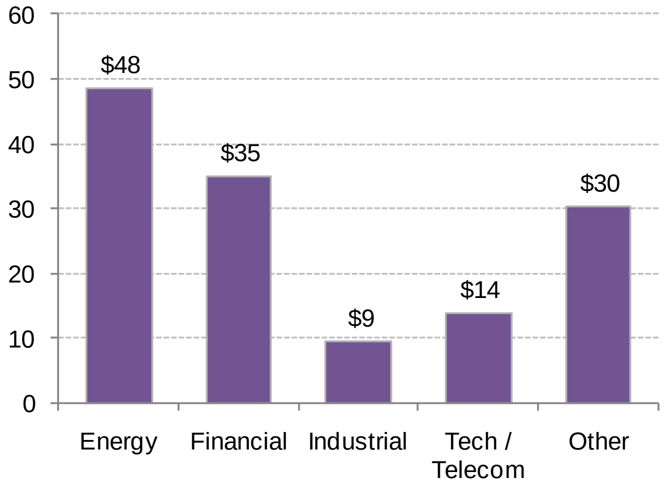
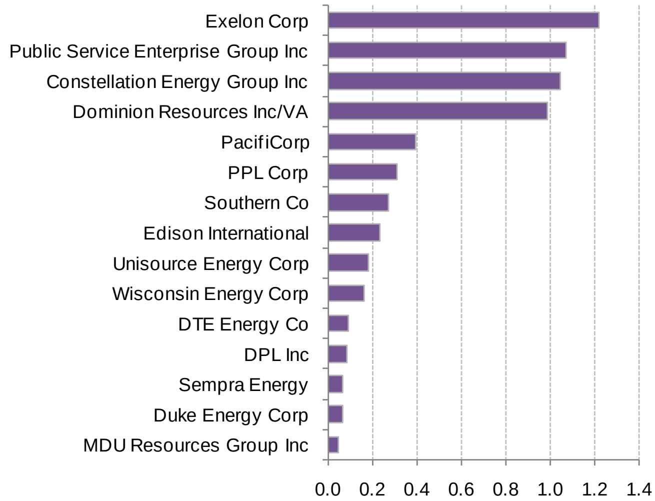


Figure 6: Cash paid for taxes (trailing 12 months) for 15 major investor-owned utilities in US ($bn)



Source: Bloomberg New Energy Finance, Bloomberg terminal data

Similarly, Figure 6 shows the taxes paid by 15 major investor-owned utilities in the US. Many of these utilities have (i) subsidiaries which face significant mandates for renewable procurement as part of state Renewable Portfolio Standards (eg, Edison), (ii) groups within the holding company which are dedicated to project development, operation, and ownership (eg, Duke), and (iii) a history of taking equity stakes in renewable assets (eg, PacifiCorp). The tax obligations of these utilities are on the order of hundreds of millions of dollars. These types of characteristics could make a utility inclined to consider tax equity renewable investments.

There are further reasons to believe that the tax equity supply may be more ample. Tax credits' legacy in the US predates their presence in the renewable sector. For example, the Research & Experimentation Tax Credit has been around since 1981, while the Low-Income Housing Tax Credit (LIHTC) was created in 1986 and – as with the renewable tax equity programme – converted temporarily into a grant as part of ARRA in 2009. A report from the President's Economic Recovery Advisory Board has estimated that usage of the R&E and LIH tax credits will total $194bn between 2008-17, or about $19bn per year.[5] The redirection of a small portion of this tax credit usage from either of these two applications to the renewable sector could meaningfully

4 Bloomberg New Energy Finance, *Global Corporate Renewable Energy Index (CREX) 2011*, June 2011. This report quantifies the voluntary renewable energy procurement over 2010-11 of over 100 of the world's largest companies. Figure 2 in the report identifies the various models for corporate investment in renewable energy, and Figure 3 shows voluntary renewable energy procurement (as a % of total electricity) by sector; the 'Financial' and 'Technology' sectors topped the list. It should be noted that tax equity investments would not qualify as voluntary renewable procurement unless the tax equity investor retained and retired the environmental attributes (eg, RECs) associated with the project.

5 President's Economic Recovery Advisory Board, *The report on tax reform options: simplification, compliance, and corporate taxation*, August 2010

lift tax equity supply. (This is not to suggest that this redirection is likely, but rather to highlight the vast pool from which tax equity for renewable energy may draw.)

3.5. Assessment: will supply meet demand?

US PREF's analysis suggests that the availability of third-party tax equity financing may be a constraint for the US renewable sector in the coming years. The $3.6bn that the group anticipates may be available next year from the traditional tax equity providers could be sufficient to support the projected need for financing if wind was the only technology requiring tax equity (compare the 2012 values in Figure 3 and Figure 4). But it would not be enough to maintain constant growth for the sector overall, as noted by the drop-off between 2011 and 2012 in Figure 4.

Yet this supply-demand imbalance may be resolved if alternative sources of tax equity emerge. We have noted above that companies which have not previously been involved in renewable investments may tend to shy away from undertaking tax equity deals. Yet there are reasons – strategy, sustainability, economics, a history of other forms of involvement in the renewable sector – to suggest that some of these non-traditional players may yet step forward. The entry of even a small number of large players could dramatically alter the tax equity availability situation and narrow the gap between demand and supply.

4. STRUCTURES

4.1. Overview of tax equity structures

The US renewable industry has produced a variety of tax equity structures to accommodate the accounting rules applicable to tax equity and the distinct preferences of investors versus developers. Broadly, the important parameters that distinguish the different types of structure are:

The various tax equity structures are distinguished by factors such as the identity of the project owner and the nature of the transition of project benefits from one party to another.

- *ITC vs. PTC*: most structures allow the participating parties (developer, investor) to elect either the ITC or PTC. One structure ('inverted lease') actually only allows the former because of the way the accounting treatment works for credits that are 'passed through'. The project's technology may also limit this choice: the ITC is only available to wind projects through 2012, and the PTC is not applicable for solar.
- *Primary project owner:* part of the complexity behind tax equity structures is the dual presence of the developer and the tax equity investor. Often, these are distinct parties. The reason that most tax equity structures involve these two types of party is that many developers cannot make use of the full incentives behind tax credits (because their tax liabilities are not substantial enough). Furthermore, tax rules generally stipulate that a party meet certain ownership credentials to qualify for the tax credit incentive. Some structures, such as the 'partnership flip', feature the investor as the owner, at least in the initial years of the project; other structures, such as the 'inverted lease', feature the developer as the owner. In the case of the 'sale leaseback', the developer initially owns the project but sells the ownership to the investor at the project's inception.
- *Nature of benefits 'switch'*: in many of these structures, the investor receives the bulk of the project benefits (eg, cash flows, tax credits) until midway through the project lifetime, at which point the benefits revert to the developer. In the case of the 5-year 'partnership flip' and the 'inverted lease', the benefits switch at the flip date or at the call date (sale date), respectively. In the case of the 'sale leaseback', the switch may occur when the 'early buyout' option is exercised.
- *Leverage*: the performance of tax equity projects can often be enhanced with debt. Debt can come in the form of lending to the project vehicle itself, or, in the case of 'back leverage', to the developer involved in the project.

Although these are the major parameters, there exist multitudes of variations to these structures – for example, the timing of the partnership flip can be contingent on a target IRR rather than on a specific time period; or debt can be tied to cash flows or tax credits.

The section below dives into the three primary structures employed in the industry, and the Appendix gives a high-level view of three other structures. Most of these structures could be deployed with either the ITC or PTC.

4.2. Three primary structures

The three primary structures for tax equity investment are the partnership flip, sale leaseback, and inverted lease (or 'lease pass-through').

Partnership flip

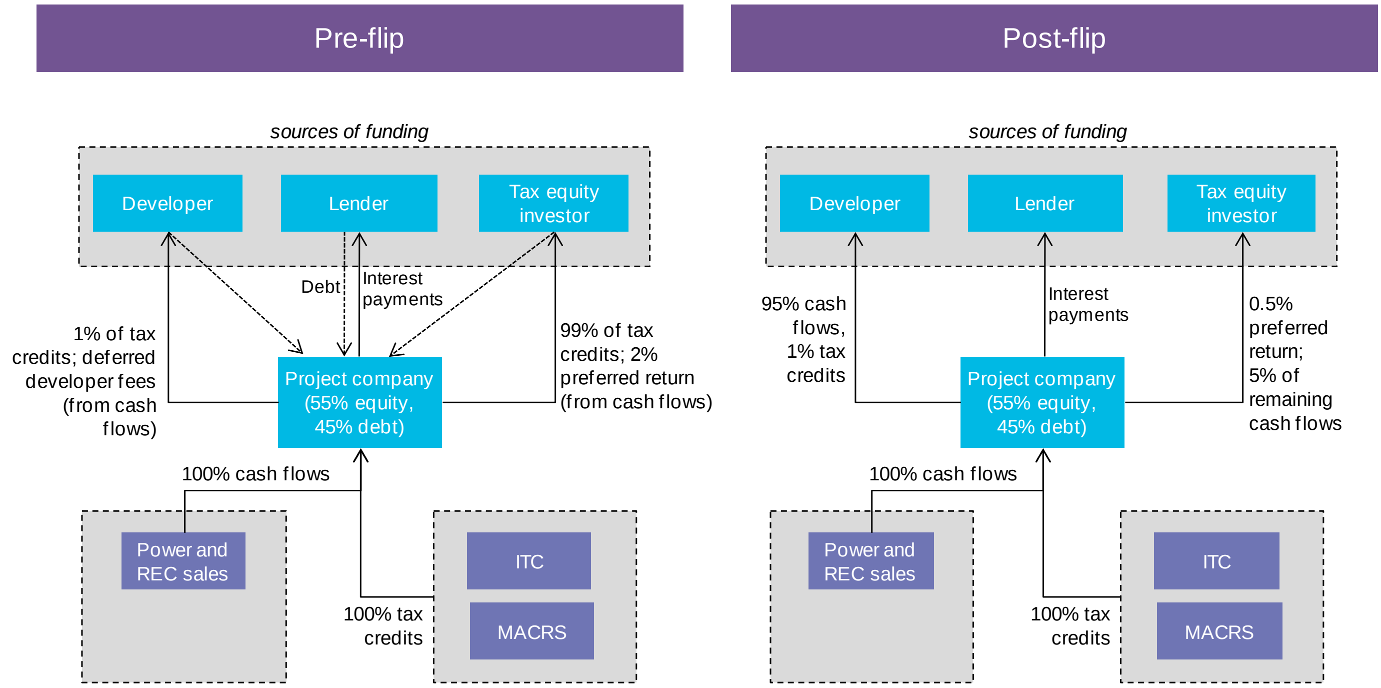
Figure 7 (5-year time-contingent) and Figure 8 (10-year yield-contingent) show the mechanics of two versions of the partnership flip structure. There are two phases to this structure. In the first phase, the tax equity investor is the primary project owner, retaining nearly all (99%) the project tax credit incentives. Then, after the flip, the primary ownership reverts back to the developer who receives most of the project cash flows.

Important features behind the economics of the partnership flip are the following:

In a time-contingent partnership flip, cash flow allocation abruptly swaps from the investor to the developer at the 5- or 10-year mark.

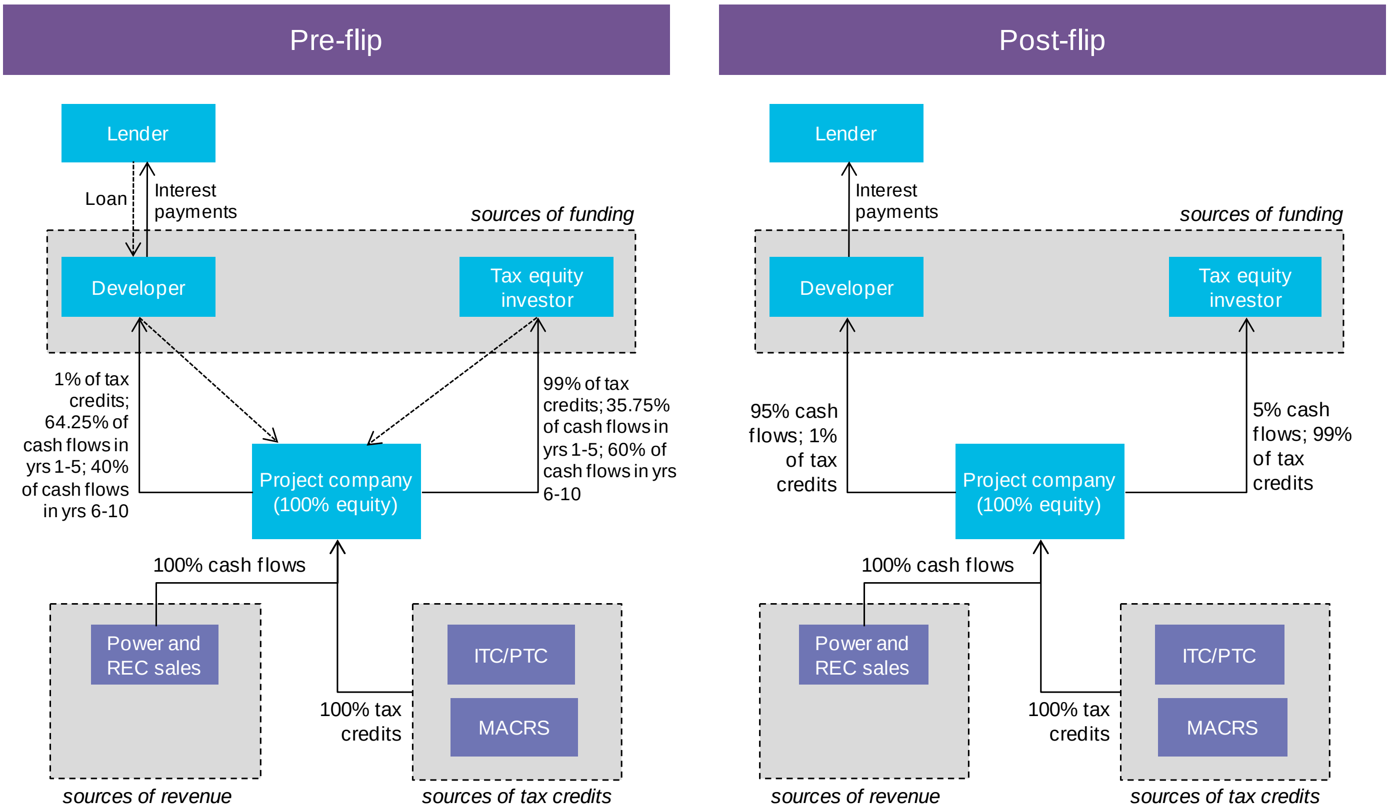
- *Flip timing*: under a 5-year (or time-contingent) partnership flip – employed by providers such as US Bank – the flip occurs at the end of year 5; under a 10-year or 'yield-contingent flip' – popularised by JP Morgan – the flip is not fixed on a given year; rather, the flip occurs when the tax equity investor has achieved a predetermined target IRR, typically on the order of 8%-9%. The 10-year time period in the yield-contingent partnership flip is used to determine the investor's equity contribution; the equity amount is set such that the present value of cash flows will yield an IRR of 8%-9% over 10 years.
- *Discrepancy between equity injection and cash flow split*: in a typical partnership flip model employed in the industry, the tax equity investor invests 45-65% of the initial equity, but this contribution does not match the cash flow distribution: the investor retains a 2% 'preferred yield' in the case of the 5-year flip and 35.75% of the initial stream of cash flows for years 1-5 in the case of the 10-year flip. ('Preferred yield' is the yield on the upfront investment which the investor receives each year, drawn from the initial stream of cash flows.) In fact, this kind of discrepancy arises in other structures as well: equity contribution does not necessarily align with cash-flow allocation. This discrepancy is partially justified by the fact that cash flows do not tell the entire story (ie, ITC/PTCs, MACRS incentives, and loss allocations are also part of the benefits) and that cash-flow allocations often switch midway through the project lifetime.
- *Equity contribution and syndication rate* – in some ITC-based structures, the tax equity investor's equity contribution is a multiple (known as the 'syndication rate') of their tax credit size. In the case of the 5-year partnership flip with ITC, we have assumed that the tax equity investor injects an equity contribution that is 1.3x the value of the ITC. For a $150m project, the investor's equity contribution is thus $59m ($150m x 30% for the ITC x 1.3 for the syndication rate). For the 10-year partnership flip with ITC or PTC, the investor's equity contribution is not based on syndication rate. Rather, for this structure, as explained earlier, the equity contribution is based on the present value of cash flows over 10 years that will equate to an after-tax IRR of 8%-9%.
- *Debt:* 5-year partnership flips are typically leveraged at the project level while 10-year partnership flips are typically back-leveraged. For our modelling, we assume 45%/55% debt-to-equity split for the project (under the 5-year flip) and 65% back-leverage for the developer (under the 10-year flip).

Figure 7: Tax equity structure – leveraged partnership flip model – time-contingent or 5-year flip model



Source: Bloomberg New Energy Finance

Figure 8: Tax equity structure – back-leveraged partnership flip model – yield-contingent or 10-year flip model

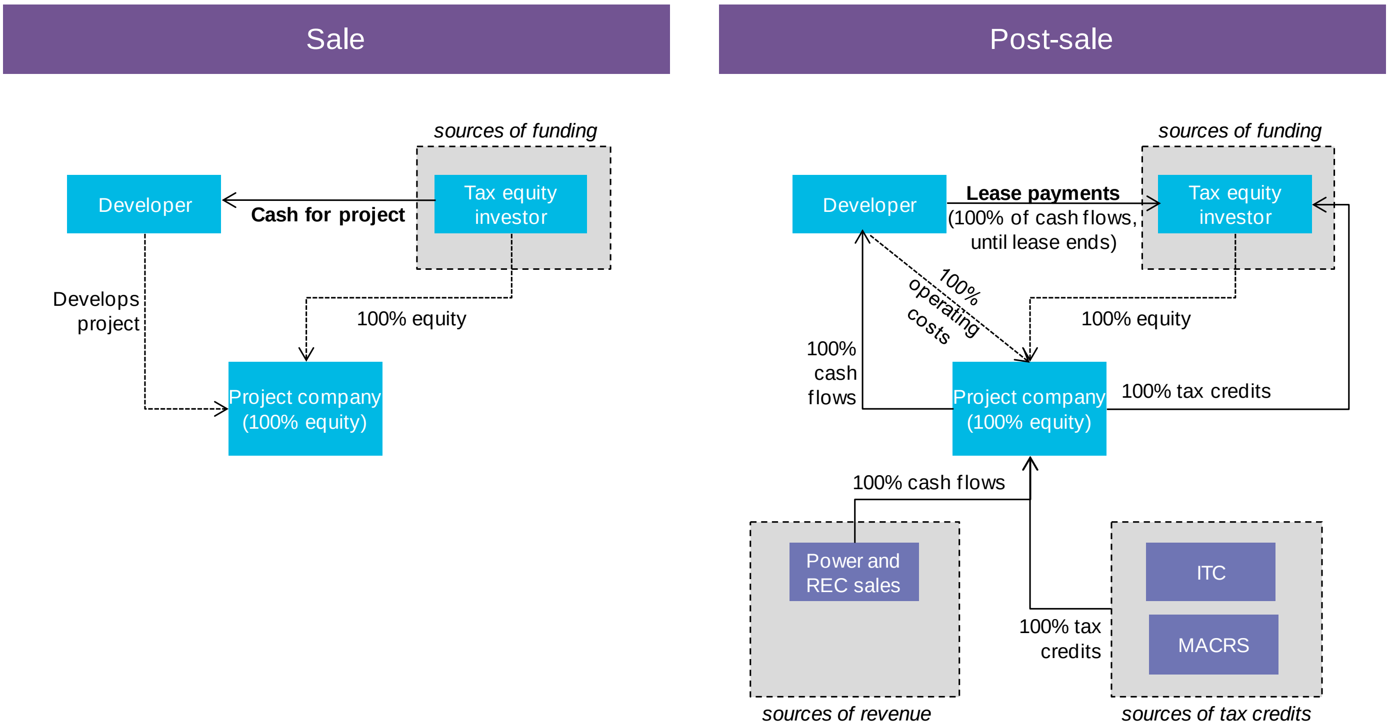


Source: Bloomberg New Energy Finance

Sale leaseback

Figure 9 shows how the sale leaseback works. In this structure, there is an initial sale of the asset by the developer, after which the tax equity investor becomes the project owner. The developer then leases the project from the investor; as the lessee, the developer is charged with operating the project (and thus bears the operating expenses). At some point, usually 10 years, the lease officially terminates; asset ownership can revert to the developer at this stage or at the 'early buy-out' date (explained below).

Figure 9: Tax equity structure – sale leaseback model



Source: Bloomberg New Energy Finance

The sale leaseback model has the developer leasing the asset from the owner, with lease payments linked to project cash flows.

For the sale leaseback, important features that influence the project economics are:

- *Varying lease payments*: one wrinkle, in contrast to most leases, is that the lease payments under this structure are not fixed: rather, they represent 100% of the project cash flows (less operating costs). At the same time, the lessor (tax equity investor) is also obtaining the tax credits associated with the project.
- *Early buyout option*: in most instances of the sale leaseback, the agreement between the developer and investor includes a provision entitling the former to an 'early buyout' option. In this case, the developer can re-acquire the asset, usually between years 7-12 of the project, at a predetermined price, usually around 30%-35% of project cost. It would choose to exercise this option if it is 'in the money' – ie, if the predetermined price is attractive compared to the project valuation at the time of acquisition. The predetermined price of the buyout turns out to be a decisive factor in resulting project economics for both the developer and investor.

Inverted lease

Lastly, Figure 10 illustrates the operations behind the inverted lease. Sometimes referred to as the 'lease pass-through', this structure is the opposite (though not the exact opposite) of the sale leaseback in that the tax equity investor directs lease payments to the developer. There is a seeming impasse behind the inverted lease: the lessor/project owner is principally the developer; yet developers in tax equity structures typically do not have sufficient tax liabilities to make use of the tax credits – which typically flow to the project owner. This impasse is resolved through the 'pass-through' component: the ITC is passed through from the lessor to the lessee.[6]

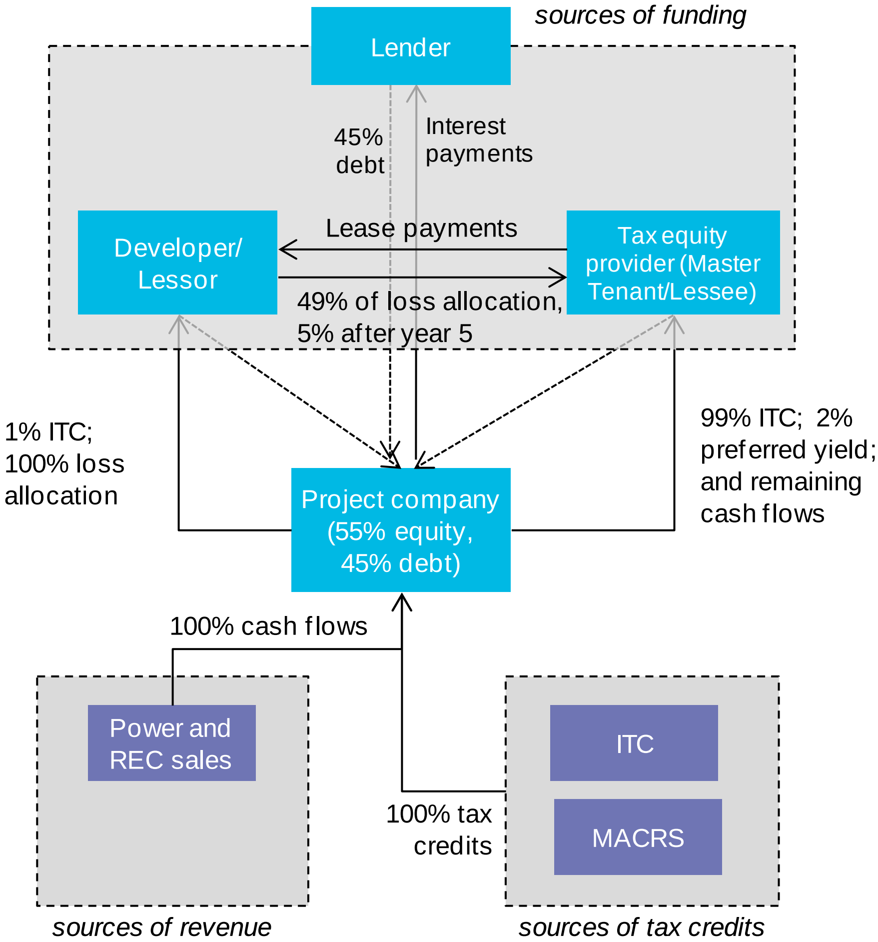
For the inverted lease, the following features are important for modelling project economics:

In the inverted lease, the investor leases the project and receives the ITC as a 'pass-through,' as well as a share of the tax benefits associated with the project's losses.

- *Varying lease payments*: as with the sale leaseback, the payments are not fixed, but instead depend on cash flows linked to project output. A typical structure has the lessee (investor) retaining a 2% preferred yield and 5% of the project's cash flows. The developer receives the deferred developer fee and the remaining project cash flows.
- *Loss allocation:* an important element of some tax equity structures is the beneficial allocation of losses: a tax equity investor sitting on sizable profits from businesses outside of the renewable energy project can make use of the losses from the project, as these reduce its tax liabilities. In the case of the inverted lease, the lessee (investor, in simplified modelling) may own up to 49% of the lessor and thus receive up to 49% of the loss allocation. This loss allocation means that it may be *in the investor's interest for a project to be as poor as possible* – ie, 'very bad' projects are better than 'bad' projects – to maximise the benefits derived from the losses.
- *Equity contribution and syndication rate:* following typical inverted lease arrangements, we have modelled the investor's equity contribution to represent a multiple of the ITC. Thus, as with the ITC-based 5-year partnership flip, for a $150m project, the investor's equity contribution is $59m ($150m x 30% x 1.3).
- *Debt:* we have modelled the inverted lease with project debt of 45%.
- *Developer equity:* the investor puts in equity as a multiple of the ITC. It therefore is up to the developer to fill the remaining equity portion, net of the investor's equity and the project debt. In our hypothetical example of a $150m project, where the investor has contributed $59m and where project debt represents 45% of the cost ($68m), the developer must still put in $23m.
- *Discrepancy of allocations*: note the variation in allocations for the different project elements: 99%/1% (investor/developer) split for the ITC benefit; 49%/51% split for the loss allocation, and roughly 45%/55% split on upfront investment (the developer's 55% includes the debt funding). These terms are generally open to negotiation, and these multiple levers underscore the complexity of this structure.

6 The actual mechanics of inverted leases are still more complex than this. Typically, in an inverted lease, the tenant (ie, the lessee, which we have simplified here to consist solely of the tax equity investor) itself invests in the project owner (ie, the lessor, which we have simplified here to consist solely of the developer).

Figure 10: Tax equity structure – Leveraged inverted lease ('lease pass-through') model



Source: Bloomberg New Energy Finance

The three structures have unique advantages and disadvantages having to do with factors such as upfront requirements, structure complexity, cash flow timing, and project risk.

4.3. Comparative advantages

Table 2 below qualitatively compares these structures from the perspective of the developer and the tax equity investor.

Table 2: Comparison of tax equity structures

Struc-ture	Description	Developer's perspective		Tax equity investor's perspective	
		Pros	Cons	Pros	Cons
Partnership flip	Tax equity investor provides most of the equity and receives most of the benefits until a flip occurs at a predetermined time or when a pre-negotiated rate of return is achieved	• Less costly for developer to acquire asset than in sale leaseback structure: In sale leaseback, price of acquisition is roughly equal to project's residual value, whereas partnership flip usually allows develop to gain ownership after the flip by buying out the investor's remaining interest which is usually 5%	• Requires upfront equity contribution from developer • Can potentially limit participation in project upside until flip occurs • Partnership structure typically more complex than sale leaseback for tax treatment	• Less upfront equity contribution from investor, and reduced liabilities on investor balance sheet, compared to sale leaseback • Provides investor with short-term ownership benefits, without the risk of holding on to asset (other than 5% interest) in long-term	• Construction risk: transaction must be closed before project is placed in service for ITC deals • Accounting issues sometimes complicate transfer of tax benefits • Indemnification offered by developer usually more limited than in sale leaseback
Sale leaseback	Developer sells the project to the tax equity investor and then leases back the project until the termination of the lease term or early buyout option is exercised	• No upfront equity contribution required from developer • Developer receives upfront cash flows in the form of asset sale, which he can use to undertake new projects • Ideal structure for underperforming projects – developer receives upfront proceeds of sale, passes poor cash flows to investor, and can choose not to exercise early buyout option	• More costly than partnership flip for developer to buy back project, as developer must pay full residual value (vs. 5% in partnership flip) • Limited participation in project upside until early buyout option arises • Compared to partnership flip, developer may need to offer broader indemnity to investor against loss of tax benefits	• Familiar structure for banks, many of which have historically engaged in leasing arrangements to capture tax benefits which operator cannot fully utilise • New funding sources: some companies are comfortable investing in leases but are unwilling to enter into partnerships • Passive role for lessor / owner, since lessee / developer manages operating costs, PPAs, etc • Tax benefits are fully transferable, avoiding accounting issues that complicate transfer of tax benefits under partnership flips • Reduced construction risk: transaction may be closed up to 90 days after project is placed in service	• Most significant equity contribution required from investor, compared to other structures • Expectation that structure involves early buyout option limits investor upside for high-performing projects • Structure must satisfy strict IRS rules regarding lease definitions (eg, expected value of asset must be >20% of asset's original capitalised cost at the end of lease term)
Inverted lease	Developer leases the project to the tax equity investor and 'passes through' the ITC	• No purchase required from developer to investor to retain project ownership • Delivers cash flow distributions to developer from the beginning, allowing developer to maintain cash yield (especially useful if developer funds come from pension-type investments) • Meaningful participation in project upside from beginning of project • Capture of depreciation-driven losses may be useful to shield distributions to developers' financial backers	• Requires significant upfront equity from developer (specifically in the case of no project debt) • If there is back-leverage instead of project debt, the developer has to bear the interest costs	• Non-ownership provides easy exit for investor, without 'residual risk' (ie, this risk may arise if the developer chooses to not exercise buyout under sale leaseback); however, the investor can choose to own up to 49% of the lessor in order to get loss allocation • Preferable accounting treatment of investment on earnings as investor is not the project owner • Capture of losses may be useful to shield investor's earnings elsewhere • Ideal structure for underperforming projects, as loss allocation is enhanced • Structure well-known in real estate industry ('master-tenant')	• Returns to investors decline as the project outperforms • Construction risk: transaction must be closed before project is placed in service

Source: Bloomberg New Energy Finance, Reznick Group, Chadbourne & Parke

4.4. Nine cases

Based on the three primary structures, we have created nine 'cases' – a combination of a structure (partnership flip, sale leaseback, or inverted lease), a technology type (wind or solar), and an incentive election (ITC or PTC). For each case, we have prepared a financial model, the results of which are explored in Section 5.

Table 3: Cases whose financials are evaluated in Section 5

ITC vs. PTC election	Wind	Solar
ITC	Partnership flip (5 years)	
	Partnership flip (10 years)	
	Sale leaseback	
	Inverted lease	
PTC	Partnership flip (10 years)	–

Source: Bloomberg New Energy Finance

Some omissions from the list of cases above are notable. We have not modelled any solar cases with the PTC, as this incentive is only available to wind. Additionally, since the duration of the PTC incentive is 10 years, the 5-year flip only makes sense for the ITC. In the case of the sale leaseback structure, PTC monetisation is typically not viable due to the requirement that the owner of the facility must also be the operator of the facility (the developer, rather than the tax equity investor, is typically responsible for operating the project in a sale leaseback structure). Lastly, the inverted lease is only examined under the ITC, as the PTC may only be 'passed through' for biomass.

5. FINANCIAL MODELLING

This section presents results of financial modelling of the nine cases (spread across three primary structures). The results include:

- Comparisons of financials for our base-case scenarios for each of the structures
- Comparisons of ITC vs. PTC-based structures under a range of scenarios
- 'Optimisation' maps that pick out the ideal tax equity structure from each party's perspective under a range of scenarios
- Sensitivity analyses for key variables impacting financial performance

Our financial models are relatively simplified approximations of the mechanics of these structures. We have incorporated significant details such as equity injections, project cash-flow receipts, debt terms and loan repayments, flip events, developer fees (deferred or not), lease payments, lease terminations, accelerated depreciation effects, and loss allocation benefits. Yet we have omitted some of the more intricate elements of these structures, such as gains on sale from the developer's purchase of the asset midway through the project in the sale leaseback and the lessee's (ie, tax equity investor) stake in the lessor (ie, the developer) in the inverted lease.

We have modelled 'typical' instances of each of these tax equity structures. However, the literature on tax equity and our discussions with participants in that market reveal a great deal of variety within each of the structures, as some of the chief elements in structural designs are open to negotiation.

This analysis, therefore, is not meant to serve as a definitive assessment of actual project pro-formas. Instead, it highlights the comparative economics of the different tax equity structures under these 'typical' circumstances. Readers looking for customised advice on the financials of their particular project are encouraged to turn to tax and business advisory specialists.

None of the analysis presented here should be construed or relied upon as advice on investments.

5.1. Key assumptions

For our modelling exercise, we have constructed 'typical' wind and solar projects. For wind, we assume a 100MW project with a capex of $1.73m/MW, a capacity factor of 30%, and revenues that consist of a $50/MWh PPA supplemented with RECs at $10/MWh for the first 15 years of the project (these revenues are consistent with projects receiving PPAs in the MISO region in the first half of 2011[7]). The fixed and variable operating costs are $30,000/MW and $6/MWh, respectively.

It is difficult to attract the interest of a tax equity investor for projects below some threshold, usually on the order of $30-50m. Therefore, for solar, our modelled project reflects a 'portfolio' of smaller projects, totalling 25MW in capacity. The capex is $3.03m/MW, the capacity factor is 15%, the PPA price is $80/MWh (comparable to rates for commercial-scale projects in PJM), and the REC price is $150/MWh (a conservative estimate compared to current prices of SREC strips in New Jersey today; despite the volatility in SREC prices and the lack of availability of longer-term strips, we assume this SREC price carries forward for 15 years for our modelling).

For both the wind and the solar project, we assume a 20-year project lifetime, 3% inflation, and 7% discount rate.

The list of assumptions behind these financial models is provided in the Appendix.

5.2. Base-case results

The figures below show the base-case IRR and NPV values for the aforementioned nine cases. For the figures showing the *investor's perspective*, the columns reflect and are sorted by *IRR*, whereas for the figures showing the *developer's perspective*, the columns reflect and are sorted by *NPV*. This emphasises the different priorities (returns versus project value) of investors and developers. (This is not meant to imply that developers are indifferent to IRR, or investors to NPV, but rather to highlight the fact that the two parties often have disparate concerns.)

From the investor's perspective (Figure 11 and Figure 12), the sale leaseback structure offers a lower IRR due to the large initial equity contribution amounting to the total project cost. However, this structure also offers a decent NPV as the investor receives 100% of the tax benefits and cash flows until the early buyout option (EBO) is exercised. For our modelling we assume that the EBO option is exercised at year 7 to ensure that the investor utilises all the tax benefits. The investor achieves the highest IRR in a 5-year partnership flip structure using ITC followed by the inverted lease structure using ITC. In both these structures, the investor contributes 1.3 (syndication rate) times the value of the ITC and receives a 2% preferred yield. However, in the 5-year flip structure, the investor receives 99% of MACRS and ITC credits, while in the case of the inverted lease structure, the investor receives 49% of *loss benefits* and an additional 5% of cash flows in addition to the 2% preferred yield.

For our wind deal base case, investors would prefer the PTC on an NPV basis and the ITC on an IRR basis.

The investor receives a higher NPV but lower IRR in the 10-year partnership flip structure using PTC than in the structure using ITC due to the combination of the four key factors below:

1. NPV of tax credits: the NPV of the PTC is slightly higher than that of the ITC
2. MACRS benefits: the MACRS benefit is higher in a PTC compared to an ITC structure since the depreciable basis is reduced by 15% (or 85% discount) in the case of the ITC
3. Equity investments: these are lower (less negative impact on equity cash flows) under the PTC structure ($122m) than in the ITC structure ($123m). (In terms of IRR, on the other hand, the immediate capture of ITC benefits compared to PTC benefits captured over a period of 10 years inflates the IRR on the ITC structure.)
4. Project revenues (PPA and RECs): these are the same under both structures

7 Bloomberg New Energy Finance, *US PPA Market Outlook Q3 2011*, 11 August 2011

Overall, factors (1) – (3) result in higher NPV for PTC.

Figure 11: Base-case project economics under various tax equity structures – wind projects, investor's perspective

IRR (%) NPV ($m)

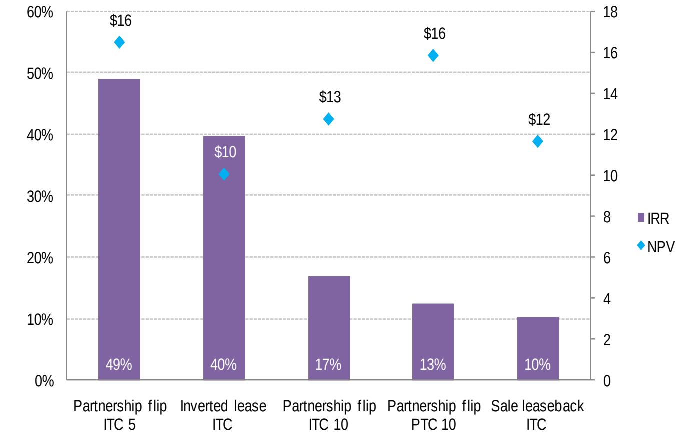
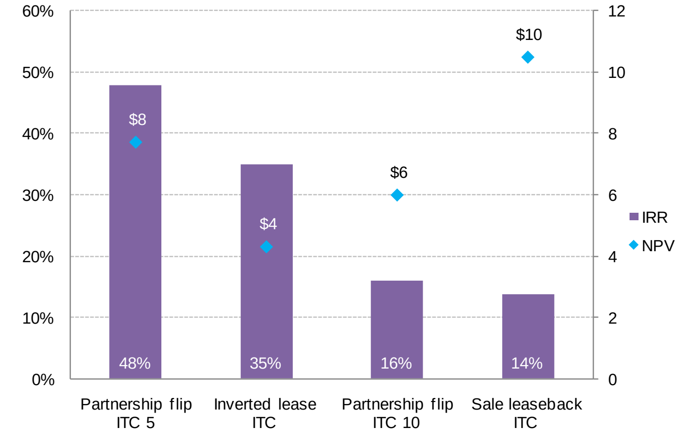


Figure 12: Base-case project economics under various tax equity structures – solar projects, investor's perspective

IRR (%) NPV ($m)



Source: Bloomberg New Energy Finance Note: Chart is sorted based on IRR. 10-year partnership flip IRRs are greater than the target 9% IRR as this analysis reflects more than 10 years worth of cash flows when calculating IRR.

From the developer's perspective (Figure 13 and Figure 14), the sale leaseback structure offers a relatively high IRR and NPV compared with the other structures as the tax equity investor provides 100% of the capital needed for the project under this structure. The developer achieves the highest IRR in the 5-year partnership flip structure using ITC. We assume that the investor sells its portion of the project back to the developer at the end of 5 years (or flip date) which enables the developer to receive all project cash flows starting in year 6 – also contributing to a high NPV compared to other structures. In both the 5-year partnership flip and inverted lease structures, there is project level debt (45%) and the developer only contributes ~10% of total project costs leading to high IRRs. The 10-year partnership flip structures (for wind) yield negative NPVs for the developer. Several factors – some of which hinge on the parties' relative negotiating power (eg, sale of asset back to the developer during project lifetime, investor's target yield) – could easily sway the NPV into positive territory.

Figure 13: Base-case project economics under various tax equity structures – wind projects, developer's perspective

IRR (%) NPV ($m)

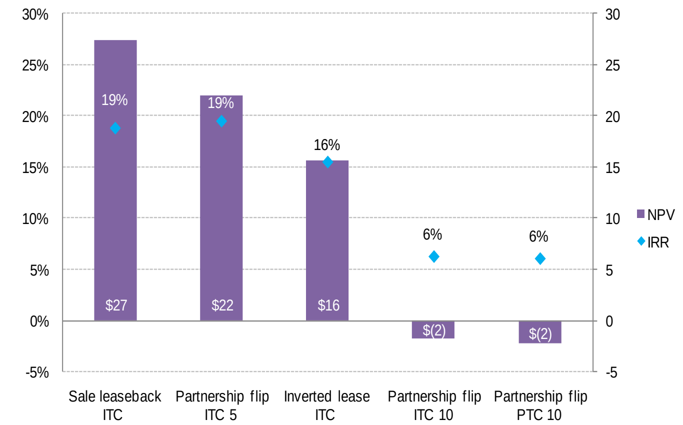
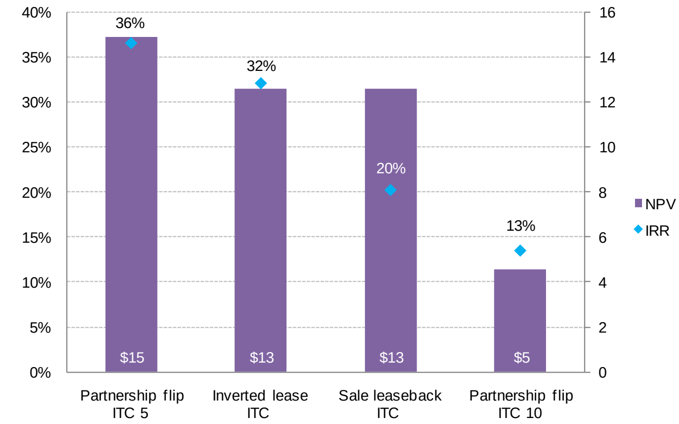


Figure 14: Base-case project economics under various tax equity structures – solar projects, developer's perspective

IRR (%) NPV ($m)



Source: Bloomberg New Energy Finance Note: Chart is sorted based on NPV

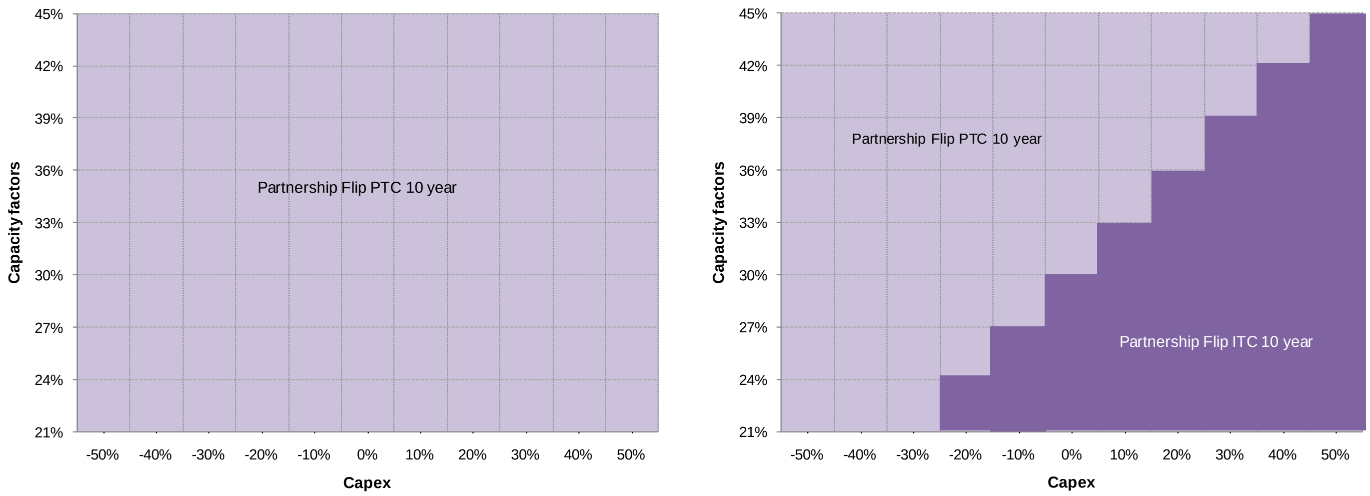
5.3. ITC vs. PTC optimisation

The 'optimisation maps' in this section and the next identify the 'optimal' structure for a given scenario. These maps hold all variables constant except for two, defined by the x- and y-axis. Section 5.3 considers only two cases – the 10-year partnership flip with the PTC and with the ITC – as they apply to wind. The purpose of only including two structures in this analysis is to *isolate the effect of the ITC vs. PTC*. Section 5.4 performs similar optimisation analysis but considers all five structures that pertain to wind.

Figure 15 shows maps where optimisation is based on NPV comparisons. The chart on the left considers the investor's perspective; on the right the developer's. Again, these optimisation maps consider only two structures: the 10-year partnership flip with ITC and with PTC.

Figure 15: Optimisation map (ITC vs. PTC) under 10-year partnership flip: wind projects, for combinations of capex and capacity factor assumptions (optimisation is based on NPV)

Investor's perspective **Developer's perspective**



Source: Bloomberg New Energy Finance Note: x-axis corresponds to % change from base-case capex assumption ie 10% = 1.1 x base-case capex, -10% = 0.9 x base-case capex

We noted in the previous section that investors usually prefer the 10-year partnership flip structure using PTC than ITC from an NPV perspective. From an IRR perspective (chart not shown here), investors prefer the 10-year partnership flip using ITC due to the immediate capture of benefits. Although the IRRs converge in very high capacity factors and very low capex scenarios, the structure using ITC still has a slightly higher IRR than the structure using PTC.

From the developer's point of view, in the base case, the 10-year partnership flip using ITC achieves a higher IRR and higher NPV to the one using PTC as the counterparty (the investor) contributes more equity in the ITC structure than in the PTC structure. This becomes more pronounced in high capex or low capacity factor scenarios, as high capex delivers high value for the ITC, and the structure's allocation of cash flows to the developer in the initial years (64.25%) is of less value for poorly performing projects.

5.4. Overall structure optimisation

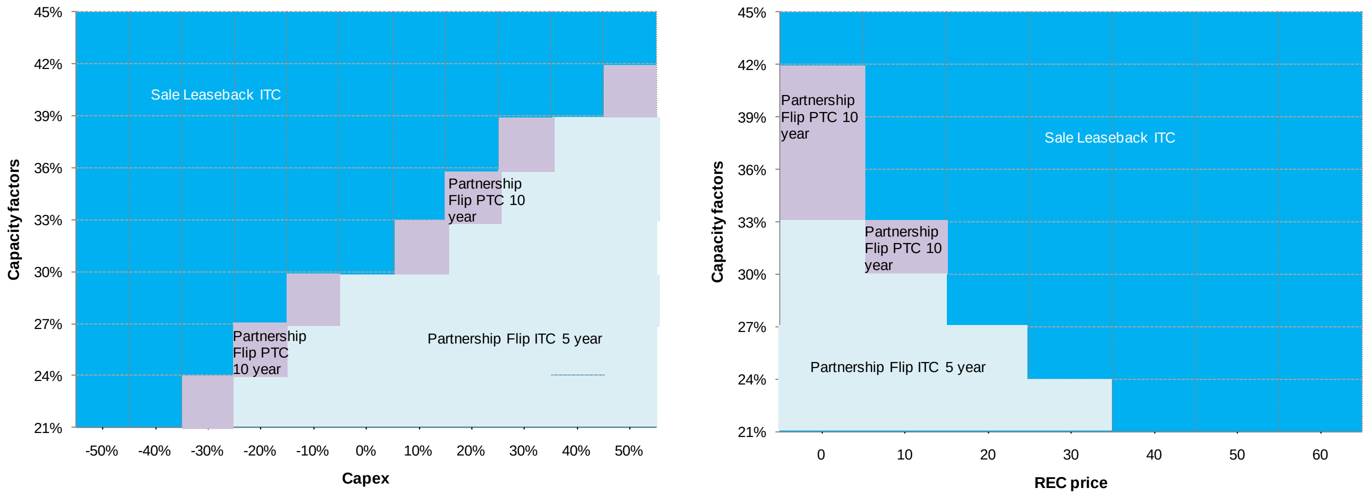
This section shows the optimal structure based on NPV for wind projects considering the five different wind-specific tax equity structures. We have run scenarios pairing capacity factor and capex (as above), as well as capacity factor and REC price.

The figures below map the optimisation from an investor's perspective (Figure 16). Although the sale leaseback structure using the ITC yields the highest NPV in most scenarios (as the investor receives all cash flows until EBO date), the 5-year partnership flip structure using the ITC yields a higher NPV under a scenario with high capex and below-average capacity factors. From an IRR standpoint (maps not shown), the investor almost always prefers a 5-year partnership flip structure using ITC.

Figure 16: Optimisation map (all structures considered): wind projects – investor's perspective

Combinations of capex and capacity factor assumptions (optimisation is based on NPV)

Combinations of REC price and capacity factor assumptions (optimisation is based on NPV)

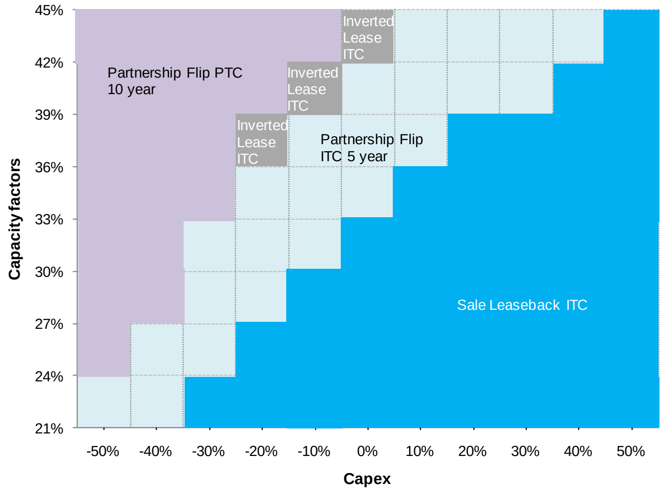


Source: Bloomberg New Energy Finance Note: x-axis on left-hand chart corresponds to % change from base-case capex assumption ie 10% = 1.1 x base-case capex, -10% = 0.9 x base-case capex; REC price is in $/MWh

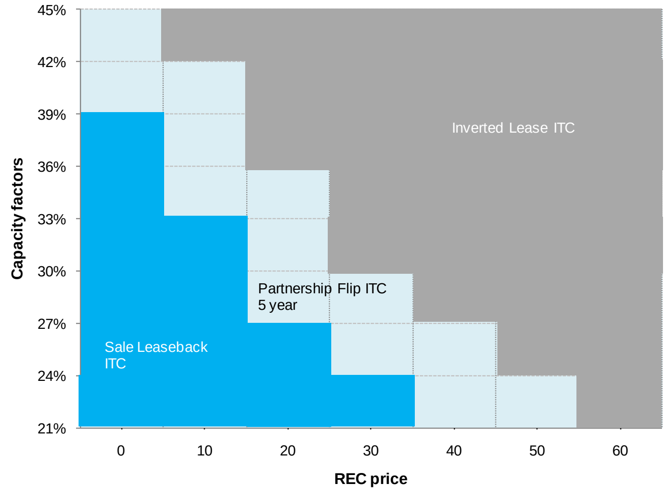
From the developer's perspective, the 5-year partnership flip structure using the ITC produces the highest IRR in the base case and the sale leaseback structure using ITC produces the higher NPV. In high capex circumstances, the developer's NPV continues to be maximised under a sale leaseback ITC (Figure 17). This is a case of the 'least worst' option – ie, in these high capex situations, all other structures call on significant equity contributions from the developer to fund these costly projects. In high-quality projects (high capacity factors, low capex, high REC prices), the developer prefers either the 10-year partnership flip or the inverted lease structure. In both these structures, the developer receives a majority of the cash flows in the initial years (in contrast to other structures where a majority of cash flows come in the later years of the project) and can therefore reap the benefits of these attractive projects.

Figure 17: Optimisation map (all structures considered): wind projects – developer's perspective

Combinations of capex and capacity factor assumptions (optimisation is based on NPV)



Combinations of REC price and capacity factor assumptions (optimisation is based on NPV)



Source: Bloomberg New Energy Finance Note: x-axis on left-hand chart corresponds to % change from base-case capex assumption ie 10% = 1.1 x base-case capex, -10% = 0.9 x base-case capex; REC price is in $/MWh

5.5. Sensitivities

Decreasing capacity factors and increasing capex leads to higher IRRs in the inverted lease structure due to loss allocations.

All else equal, a project's return will increase with higher capacity factors and lower capex. Tax equity structures – and in particular the allocation of losses to the investor (ie, loss credits) – create a unique IRR profile as projects become worse (more expensive, lower performance). The figures below (Figure 18 and Figure 19) show IRRs generally declining as capacity factors decrease and capex increases for the sale leaseback and 5-year partnership flip structures. But in the case of the inverted lease and the 10-year partnership flip structures, the IRRs in fact increase with lower capacity factors and higher capex. The decline in IRRs for the inverted lease structure is more pronounced compared to other structures due to its loss allocation feature.

Note that for our modelling of the 10-year partnership flip, we assume that the investor has perfect knowledge of the project's capacity factor – ie, we adjust the equity contribution to exactly deliver an after-tax 9% IRR; a reduction in the capacity factor assumption leads to a reduction in the investor's equity contribution.

Figure 18: Project economics sensitivity to capacity factor – wind projects, investor's perspective (IRR %)

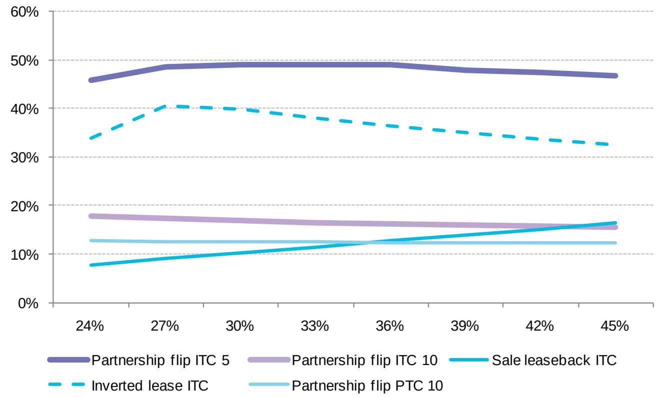
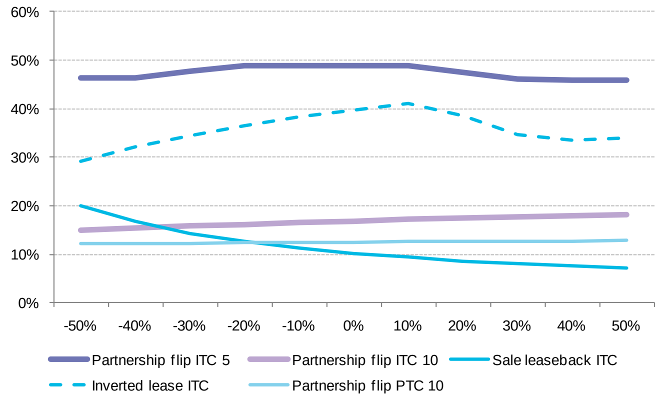


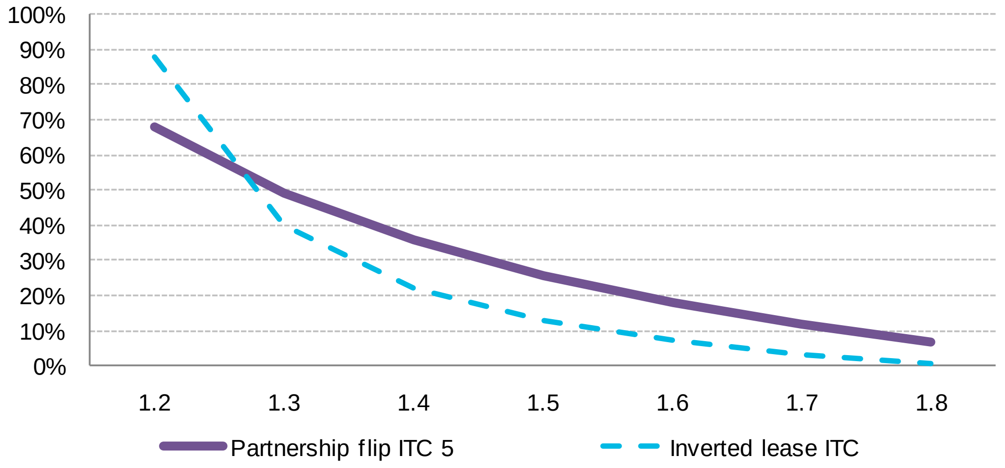
Figure 19: Project economics sensitivity to capex – wind projects, investor's perspective (IRR %)



Source: Bloomberg New Energy Finance Note: x-axis on right-hand chart corresponds to % change from base-case capex assumption ie 10% = 1.1 x base-case capex, -10% = 0.9 x base-case capex

Another important sensitivity for most of these cases concerns the syndication rate. The syndication rate paid by the tax equity investor increases the upfront equity contribution to the project. Hence, the higher the syndication rate, the lower the IRR to the investor (Figure 20). The syndication rate is typically 1.3x but is a negotiable feature of tax equity structures using the ITC.

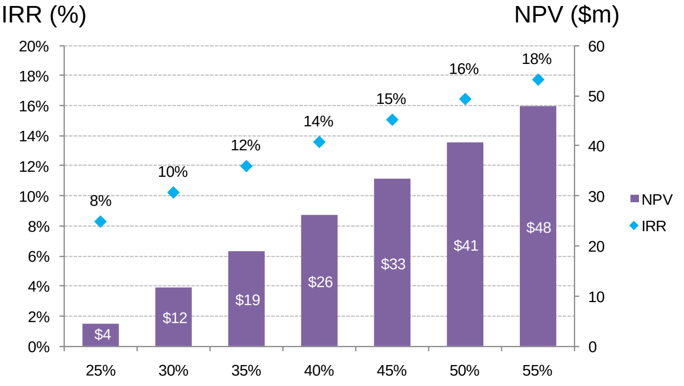
Figure 20: Project economics sensitivity to syndication rate (partnership flip and inverted lease structures) – wind projects, investor's perspective (IRR %)

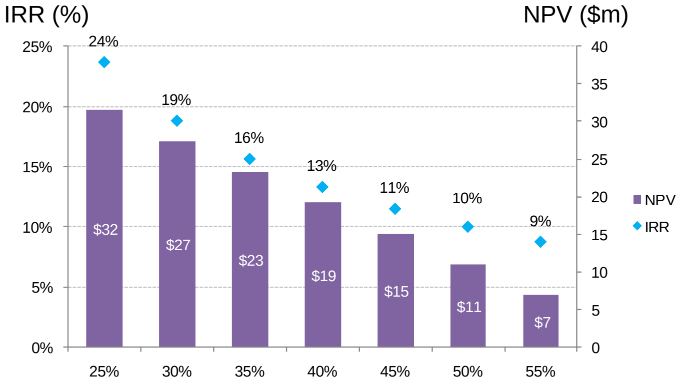


Source: Bloomberg New Energy Finance Note: X-axis shows syndication rate

For the sale leaseback structure, the early buyout (EBO) price is a negotiated parameter that can impact project economics. This price is usually determined at the beginning of the deal and is typically based on the project's 'fair market value'. However, this value is subjective and can involve appraisals from both parties. For the sake of simplicity, we have assumed an EBO price of 30% (of capex) for the base-case scenario. The higher the EBO price (or the price that the developer pays to the investor to buy back the project), the higher the return to the investor – and vice versa for the developer.

Figure 21: Project economics sensitivity to EBO (sale leaseback ITC structure only): wind projects

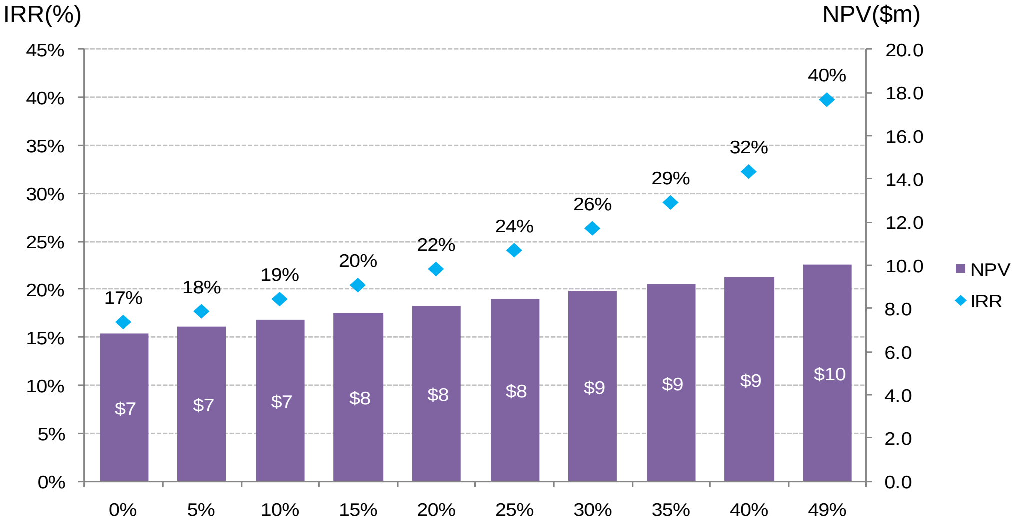




Source: Bloomberg New Energy Finance Note: X-axis shows EBO price expressed as % of capex

In an inverted lease structure, the investor benefits or receives a credit for a portion of losses incurred by the project. This portion can vary between 0% and 49%, as per the legal requirements for a lessee. Figure 22 shows the increases in IRR and NPV as the portion of loss allocation to the investor varies. The trend is reversed for the developer as it receives a smaller portion of the tax credits for losses when the investor's allocation increases.

Figure 22: Project economics sensitivity to investor's portion of allocated losses (inverted lease ITC structure only): wind projects



Source: Bloomberg New Energy Finance Note: X-axis shows % of losses allocated to investor

6. DISCUSSION OF RESULTS

The set of analyses about the various tax equity structures presented above yields insights that can serve as guidelines for potential tax equity project participants – developers and investors alike:

- *Tax equity works*. For relatively good projects (eg, 30% capacity factor and $1.73m/MW capex for wind, 15% capacity factor and $3.03m/MW capex for solar), returns from tax equity projects can be attractive for both developers and investors.
- *Size matters.* An important concern about tax equity is its limitations for small projects (eg, solar assets under 5MW). The fixed costs of employing tax equity are relatively large (compared to structures such as cash grant or feed-in tariff models) and require economies of scale; many banks usually do not even consider applying tax equity below some threshold on the order of $30m. However, there have been some developments in the US financing arena that may fill this gap – for example, the bundling of small projects to create a sizable enough 'portfolio' to attract investor interest.
- *Investor and developer return profiles differ*. Our base-case analysis shows developers achieving returns of 6-19% for wind and 13-36% for solar depending on the structure, whereas IRRs for investors can be as high as nearly 50% for wind and solar. Far from suggesting that developers do poorly and investors profit extravagantly, these results instead highlight the very different cash-flow profiles of the two parties – investors often put in significant equity but can very quickly recoup the investment under some structures (ie, in the form of the ITC), while developers, under most structures, earn their returns over the long haul. These results also suggest that IRR is not the only metric worth evaluating.
- *NPV and IRR analyses yield different answers to the optimisation question*. This is especially true for tax equity investors. For wind projects, for example, the 10-year partnership flip *with the ITC* has a 17% IRR and an NPV of $12.7m while the 10-year partnership flip structure *with the PTC* has a higher NPV ($15.8m) while yielding only 13% in IRR. Again, this discrepancy arises from the variability in the stream of cash flows delivered under the different types of structure.

- *The choice of ITC versus PTC comes down to three 'P's: performance, perspective, and priorities*.
  - *Performance*: all else equal, the higher the capacity factor, the more advantageous the PTC option becomes, as this credit is linked to production. (By the same token, projects with low production but high capex are ideal for ITC election.)
  - *Perspective:* investors almost always prefer the ITC on an IRR basis and the PTC on an NPV basis. For developers, on the other hand, this choice depends on the structure and the project quality (Figure 11, Figure 13, and Figure 15).
  - *Priority*: for investors and developers, the choice of ITC versus PTC is often contingent on which financial metric is prized more, project value or project returns. For instance, on an IRR basis, investors would prefer the ITC while on an NPV basis, they would prefer the PTC due to reasons discussed in Section 5.2.
- *Structures outside of the partnership flip accommodate other preferences.* The flip is probably the most well-known tax equity structure, but the other two primary structures studied have unique advantages. For example, the sale leaseback structure is ideal for developers with limited cash on hand or with costly projects, as it calls for minimal upfront investment. In contrast the inverted lease structure is suitable for investors which are sceptical about project performance as it spares them from primary project ownership and, paradoxically, allows them to benefit if significant losses are incurred.
- *Structure selection may evolve into a tug of war...* There is a degree of anti-symmetry to the charts that compare investor versus developer preferences. For example, the left-hand maps (capacity factors vs. capex) in Figure 16 and Figure 17 are relative opposites: one shows the investor choosing the 5-year partnership flip with ITC for an especially poor project (high capex, low capacity factor) while the developer would choose a sale leaseback with ITC for that same project. Similar results are true for the base case: the optimal structure on an NPV basis is a sale leaseback with ITC for the developer ($27.4m) and the 5-year partnership flip with ITC for the investor ($16.5m). These examples highlight the trade-off in value between the two parties: one party takes a larger slice of the pie at the expense of the other. Final structure selection may have much to do with relative bargaining power.
- *...and the war is far from done even once the structure has been chosen.* Even with structure selection, there are points of contention that would drive value from one party to another. The analyses in Section 5.5 show that project returns and profitability are highly sensitive to negotiated parameters such as: syndication rates on the partnership flip and inverted lease, terms of the early buyout price on the sale leaseback, and investor portion of loss allocation on the inverted lease. For example, a reduction in the syndication rate from 1.3x to 1.2x increases IRRs from 49% to 68% for the partnership flip structure.
- *Numbers don't tell the entire story.* Our optimisation maps in Section 5 are based purely on quantitative comparisons: the structure with the highest IRR or NPV for a given scenario was awarded the place of privilege on the map. Yet there are reasons why companies may choose one structure over another, independent of financials. For example: a tax equity investor may especially prize the value of MACRS and tax losses; the investor may wish to avoid the PTC if there is insufficient certainty about the company's long-term tax liabilities; or the investor may wish to avoid the ITC if it comes in too large a chunk to be useful (ie, the size of the ITC in a given year for a large project swallows up all of the investor's tax equity appetite in that year). Developers or investors may not be inclined to tackle structures that are relatively more complex (eg, inverted lease) than others (eg, sale leaseback). Other examples of 'non-quantitative' considerations abound. Perhaps the most telling one has to do with the 'tug of war' conclusion above: the final structure selection may not be the ideal structure from the perspective of either the developer or the investor, but *it is the structure that gets the deal done* – the compromise, in other words.

- *There's life after the cash grant.* Tax equity is more complex than cash grant-based financing, and it requires all but a handful of developers to seek third-party participation to absorb the tax equity incentives. Additionally, there are valid concerns that the supply of tax equity financing from established providers will not be sufficient to sustain year-on-year growth for the renewable sector in the US.

  Nevertheless, this analysis has shown that tax equity economics can work for the right projects. Returns for investors and developers can be meaningful. The ITC for solar looks to be securely in place through 2016, and the PTC for wind through the end of 2012 – with a decent chance of being extended. Google has been among the rare 'corporates' to have entered the tax equity field; while other non-financial companies have been reluctant to participate, the entrance of even a few big players could substantially and quickly amplify tax equity supply. Financing for the US renewable sector will look quite different in 2012 compared to the past three years, but different does not mean dead.

Appendices

Appendix A: Modelling assumptions

Table 4: Project components – assumptions about 'typical' wind and solar projects used in financial modelling for this report

	Wind	Solar
Capex ($m/MW)	1.73	3.03(1)
Opex – fixed ($/MW)	30,000	24,300
Opex – variable ($/MWh)	6	-
Capacity factor (%)	30	15
Capacity (MW)	100	25(1)
PPA price ($/MWh)	50	80(1)
REC price ($/MWh)	10	150(1)
REC term (Yrs)	15	15
Price escalation rate (%)	3	3

Source: Bloomberg New Energy Finance Notes: (1) This combination of inputs – $3.03m/MW system sized at 25MW receiving a PPA of $80/MWh and REC stream of $150/MWh – may seem unusual. (Single projects that are 25MW in size may be even cheaper and may receive lower 'all-in' revenues, PPA plus REC). This modelling scenario, however, reflects a portfolio of commercial-scale projects, each receiving these PPA and REC terms, and collectively amounting to 25MW in size.

Table 5: Structural design – assumptions about 'typical' design of tax equity structures used in financial modelling for this report

	Key assumptions about design
5-year partnership flip with ITC	• 45% project debt • Investor's equity contribution = 1.3x ITC • Developer's equity contribution = project cost – investor's contribution – project debt • Investor receives a 2% preferred return + 99% of tax credits + 99% of *remaining* cash flows (post deferred developer fee payment) before flip • Investor receives a 0.5% preferred return + 5% of remaining cash flows and tax credits after flip • For this and all other structures below, ITC benefits are received in year 1 of project operations • Investor sells asset at the end of 5 years (usually with a loss on sale)
10-year partnership flip with ITC or PTC	• 0% project debt • 65% back-levered debt (15-year term and 7% interest rate) • Investor's contribution = amount of equity where after tax IRR is equal to 9% in year 10 • Developer's contribution = project cost – investor's contribution – back-levered debt • Investor receives 99% of tax credits and developer receives 1% • Investor receives 35.75% of cash flows in years 1-5, 60% in years 6-10, and 5% thereafter
Sale leaseback with ITC	• 0% project debt • Investor's equity contribution = 100% of project cost • EBO date = 7 years from start of operation • EBO price = 30% of capex in year 7
Inverted lease with ITC	• 45% project debt • Investor's equity contribution = 1.3x ITC • Developer's equity contribution = project cost – investor's contribution – project debt • Investor has ownership stake in developer, which enables him to take up to 49% of loss allocation • Investor receives a 2% preferred return + 99% of ITC tax credits + 5% of cash flows for years 1-10 • Investor receives 49% of loss allocation for years 1-5 and 5% thereafter • Developer receives deferred developer fee and majority of project cash flows as 'lease payments' • Asset is called at the end of 5 years (usually a gain on sale for the investor)

Source: Bloomberg New Energy Finance, based on conversations with Reznick Group and project developers

Table 6: Macroeconomic assumptions

	Assumption
Discount rate (%)	7
Inflation rate (%)	3
Tax rate (%)	35

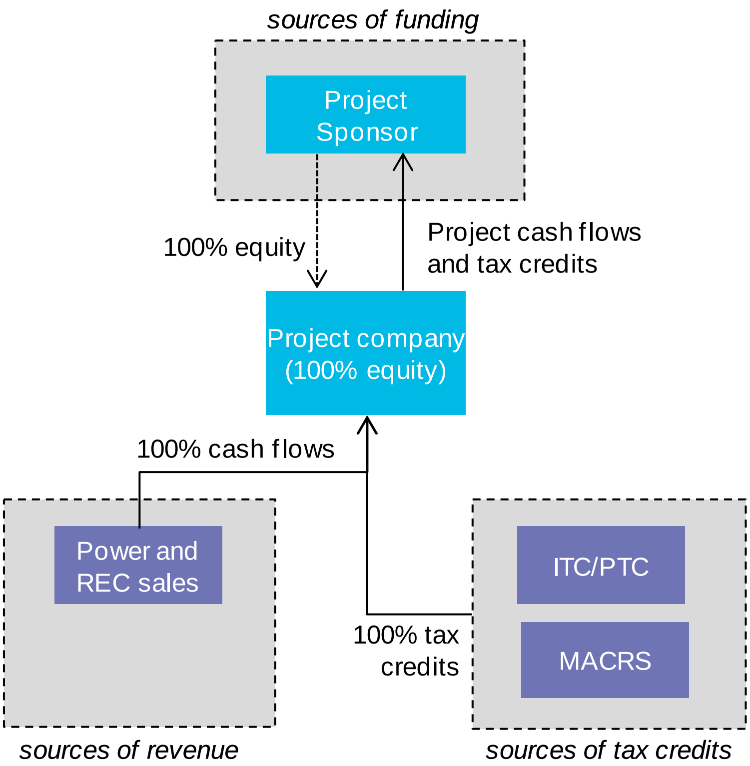
Source: Bloomberg New Energy Finance, based on conversations with Reznick Group

Appendix B: Other tax equity structures

While Section 4.2 introduced the three primary tax equity structures, more exist, and there are variations within these three. The following three figures show some of these variations.

Figure 23 below shows the simplest structure, featuring one project owner which contributes 100% equity and receives 100% of cash flows and tax benefits.

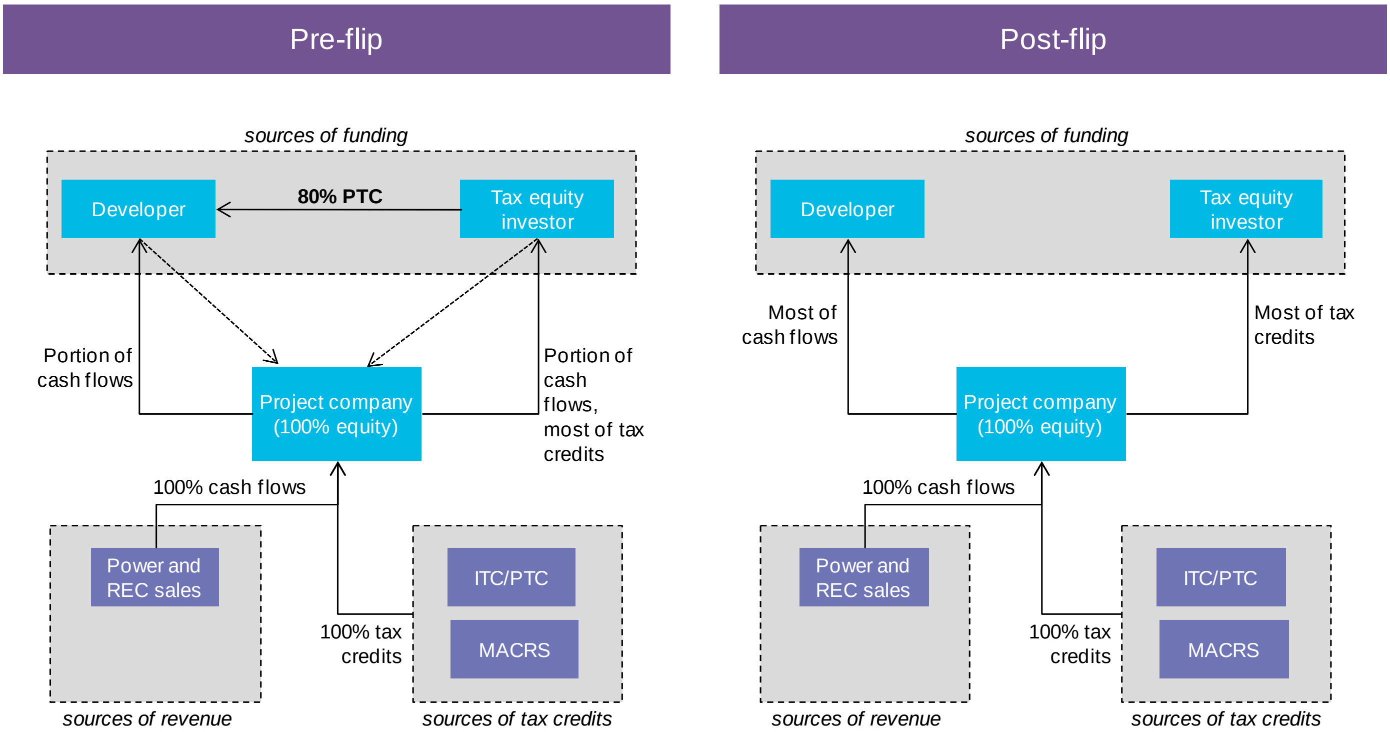
Figure 23: Tax equity structure – 'corporate' model (ie, tax equity investor is the developer)



Source: Bloomberg New Energy Finance

The next structure (Figure 24) is a partnership flip: a partnership arrangement between the developer and the tax equity investor, whereby the investor provides most of the equity and receives most of the tax benefits and project cash flows until the 'flip.' The difference between the partnership flip presented in the main body of the report versus the framework shown here is that, in this case, the tax equity investor's initial contribution is reduced, as it passes on cash flows to the developer in an amount equal to a certain percentage of the tax credits it receives.

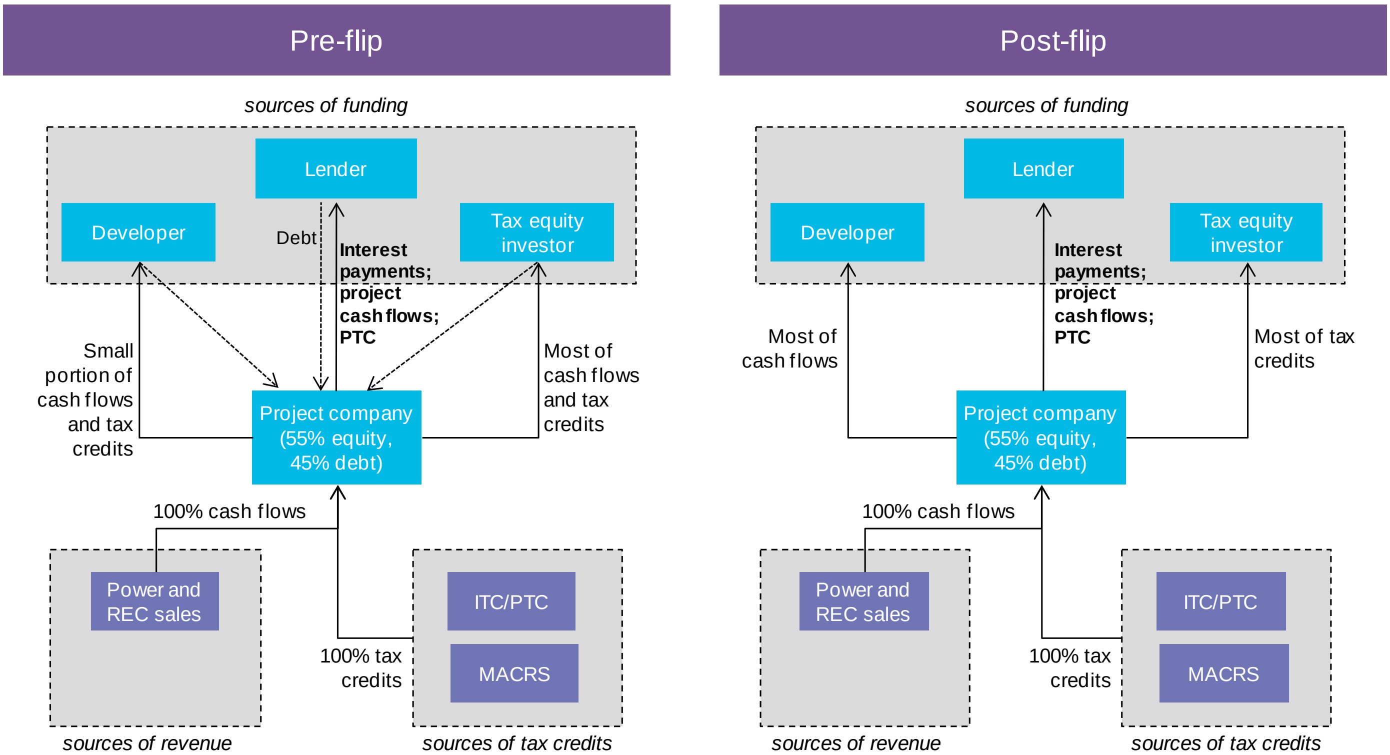
Figure 24: Tax equity structure – unleveraged partnership flip with deferred equity ('pay-as-you-go') model



Source: Bloomberg New Energy Finance

Figure 25 is a more intricate leveraged partnership flip structure: the tax equity investor provides the majority of the equity and the lender provides a loan based on cash or PTCs generated from project.

Figure 25: Tax equity structure – cash-leveraged (or cash & PTC-leveraged) model



Source: Bloomberg New Energy Finance

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