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APPLICATION OF SOUTHWESTERN ELECTRIC POWER COMPANY FOR CERTIFICATE OF CONVENIENCE AND NECESSITY AUTHORIZATION AND RELATED RELIEF FOR THE ACQUISITION OF WIND GENERATION FACILITIES	§ § § § § § §	**BEFORE THE STATE OFFICE** **OF** **ADMINISTRATIVE HEARINGS**

PUBLIC UTILITY COMMISSION
FILING CLERK

SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH REQUEST FOR INFORMATION

FEBRUARY 20, 2020

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SOUTHWESTERN ELECTRIC POWER COMPANY'S RESPONSE TO TEXAS INDUSTRIAL ENERGY CONSUMERS' FIFTEENTH REQUEST FOR INFORMATION

Question No. TIEC 15-1:

To the extent not already provided, please provide all supporting workpapers and all documents cited or relied upon in the rebuttal testimonies of all SWEPCO witnesses.

Response No. TIEC 15-1:

All workpapers supporting rebuttal testimony were filed with rebuttal testimony on a flash drive provided to all the parties. Please see enclosed documents cited by witness Noah Hollis in Attachments 1 through 10.

Attachments 1 and 5 are voluminous and are provided via the PUC interchange.

Sponsored By: Shelli A. Sloan | Title: Dir Case Suppt & Special Proj

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Tax Equity Financing: An Introduction and Policy Considerations

April 17, 2019

Congressional Research Service
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R45693

CRS REPORT
Prepared for Members and
Committees of Congress

Congressional Research Service
Informing the legislative debate since 1914

SUMMARY

R45693

April 17, 2019

Tax Equity Financing: An Introduction and Policy Considerations

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This report provides an introduction to the *general* tax equity financing mechanism. The term *tax equity investment* describes transactions that pair the tax credits or other tax benefits generated by a qualifying physical investment with the capital financing associated with that investment. These transactions involve one party agreeing to assign the rights to claim the tax credits to another party in exchange for an equity investment (i.e., cash financing). The exchange is sometimes referred to as "monetizing," "selling," or "trading" the tax credits. Importantly, however, the "sale" of federal tax credits usually occurs within a partnership or contractual agreement that legally binds the two parties.

Three categories of tax credits that either currently use or have recently used this mechanism are presented in this report to help explain the structure and function of tax equity arrangements. These include the low-income housing tax credit (LIHTC); the new markets tax credit (NMTC); and two energy-related tax credits—the renewable electricity production tax credit (PTC) and energy investment tax credit (ITC). While these credits all use the tax equity financing mechanism, no two credits do so in the same manner. The economic rationale for subsidizing the activities targeted by these tax credits is not evaluated. Instead, this report focuses on explaining the structure and functioning of tax equity arrangements, analyzing the delivery of federal financial support using this mechanism, and discussing various policy options related to tax credits that rely on tax equity.

Four policy options are presented to help Congress should it consider modifications to an existing tax equity program, or create a new one. The options are with respect to the general tax equity approach and include making the credits refundable, converting the credits to grants, allowing for the direct transfer of credits, and accelerating the credit claim periods. This list of options is not exhaustive. Due to important differences in the underlying structure of various current or future credits, some options may be better suited for particular credits than others. Careful consideration on a case-by-case basis is part of evaluating the appropriateness of each option.

Consideration of various options might ask whether the use of tax equity markets is an efficient and effective means of delivering federal financial support. At first glance, it may appear that the government would get more "bang for its buck" by delivering subsidies more directly, without a role for tax equity markets. However, such a conclusion overlooks one role that tax equity investors play in some industries in addition to providing financing: they evaluate the quality of projects before investing, as well as provide continuing oversight and compliance monitoring. Effectively, the tax equity mechanism outsources a portion of the oversight and compliance monitoring to investors in exchange for a financial return. On the one hand, there may be value to the federal government in being able to rely on outside investors to provide oversight and monitoring. On the other hand, for some tax equity programs that have a government entity overseeing participant compliance, the monitor role of investors may be redundant. There also may be ways to improve the current delivery approach.

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Introduction

The federal government subsidizes a wide range of activities through the tax code. The majority of available tax incentives are claimed directly by the party engaged in the activity targeted by the subsidy. There are several tax credits, however, that often require or encourage the intended beneficiary of the subsidy to partner with a third party to use the tax incentive. This may happen because the tax credits are nonrefundable and the intended beneficiary of the tax credit has little or no tax liability (e.g., a nonprofit), or because the credits are delivered over multiple years whereas upfront funding is needed to break ground. This situation often results in a *tax equity* transaction—the intended beneficiary of the tax credit agrees to transfer the rights to claim the credits to a third party in exchange for an equity financing contribution. One estimate placed the size of the tax equity market in 2017 at $20 billion.[1]

This report provides an introduction to the *general* tax equity financing mechanism. To facilitate the presentation of the tax equity approach to subsidization, three categories of tax credits that either currently use or have recently used this mechanism are examined: the low-income housing tax credit (LIHTC); the new markets tax credit (NMTC); and two energy-related tax credits—the renewable electricity production tax credit (PTC) and energy investment tax credit (ITC).[2] This report does not evaluate the economic rationale for subsidizing the activities targeted by these tax credits, and does not analyze whether these subsidies increase net investment in these activities. Instead, this report focuses on explaining the structure and functioning of tax equity arrangements.

Tax Equity Investments

Tax equity investment is not a statutorily defined term, but rather identifies transactions that pair the tax credits or other tax benefits generated by a qualifying physical investment with the capital financing associated with that investment.[3] These transactions involve one party agreeing to assign the rights to claim the tax credits to another party in exchange for an equity investment (i.e., cash financing). The exchange is sometimes referred to as "monetizing," "selling," or "trading" the tax credits.[4] Importantly, however, the "sale" of federal tax credits occurs within a partnership or contractual agreement that legally binds the two parties to satisfy federal tax requirements that the tax credit claimant have an ownership interest in the underlying physical investment. This makes the trading of tax credits different than the trading of corporate stock, which occurs between two unrelated parties on an exchange.[5] The partnership form also allows

[1] Alex Tiller, "Insight: Tax Equity Remains an Under-Utilized Tool for Corporate Tax Strategy," *Daily Tax Report*, January 30, 2019.

[2] Another tax incentive that uses this approach, but is not discussed in this report, is the historic tax credit (HTC). Recent expansion and changes to the tax credit for carbon capture and sequestration have led some to believe that this credit may be part of tax equity transactions.

[3] Tax equity investors may also receive tax benefits that are not credits, such as accelerated or bonus depreciation or tax losses. While this report tends to refer to tax credits when describing tax equity transactions, other tax savings may be involved.

[4] Some tax provisions can be allocated or transferred between parties. For example, in the case of the §179D deduction for energy-efficient commercial building property, deductions allowed for property owned by federal, state, or local governments can be allocated to the person who designed the property (an architect, engineer, or contractor, for example). Another example is the §30D plug-in electric vehicle tax credit, where tax credits for vehicles sold to tax-exempt entities can be allocated to sellers.

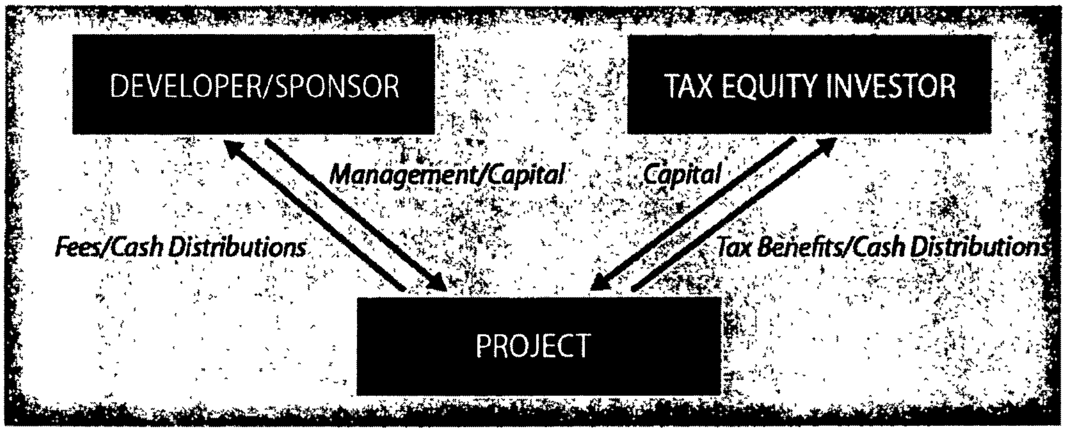
[5] This is not necessarily true with credits offered by states; some states allow particular credits to be transferred to a

for income (or losses), deductions, and other tax items to be allocated directly to the individual partners. In some cases, nonprofit entities can form a partnership with taxable investors and benefit from tax credits through this relationship.

Overview of Structure and Mechanics

While the specifics of a tax equity arrangement vary depending on the project and tax credit program involved, these deals often share some general common structural features.[6] **Figure 1** provides a graphical summary of the structure and mechanics of one kind of project that relies on tax equity investment.

Figure 1. General Tax Equity Structure



Source: CRS illustration.

The process begins with a developer, also sometimes referred to as a "sponsor," identifying a potential project eligible for federal tax credits. For projects where an application is required, the developer will apply to the entity in charge of awarding the credits.[7] At the same time, the developer will seek out potential investors willing to contribute equity capital in exchange for the tax credits expected to be awarded. A developer can partner directly with an investor, or, as is also common, partner with a tax credit "syndicator" that manages a tax credit fund for multiple investors that may not have the expertise to partner directly with a developer, or that may want to diversify their tax equity investment portfolio. The syndicator will earn a syndication fee for identifying, evaluating, and managing tax equity investments for the fund. Regardless of whether

third party without requiring the relevant parties to enter into a partnership.

[6] This report focuses on tax equity arrangements that use a partnership structure. Tax equity investors may also participate in certain energy projects using various lease structures (a sale-leaseback, for example). The role of tax equity investors in this type of arrangement, or other arrangements, is not explicitly discussed in this report.

[7] This entity can be a federal or state-level entity, depending on the program. For example, affordable housing developers will submit an application for a low-income tax credit award to the housing finance agency in their state. In contrast, a commercial property developer will submit an application for a new market tax credit to the Community Development Financial Institutions Fund (CDFI Fund), a federal entity. There is no application process associated with the energy ITC or PTC. Instead, tax credits associated with qualifying investments or production are claimed on federal income tax returns.

the partnership with investors is direct or via a syndicator, the tax equity investors are typically large corporations with predictable tax liabilities.[8]

The developer and investors will negotiate how much equity capital will be contributed in exchange for the right to claim the tax credits and other tax benefits.[9] As previously mentioned, this is commonly referred to as the "selling," "trading," or "monetizing" of tax credits. The tax equity investors will serve as the "limited" partners in the partnership, meaning they generally have a passive role and do not participate in management decisions.[10] The developer will serve as the "general" partner overseeing day-to-day operations in exchange for a fee and possibly any cash distributions the project may generate. The developer may also contribute their own capital to or arrange or coordinate other sources of capital for the project, depending on the particular tax credit program being used. While tax equity investors are not generally required to have an active management role, they have an incentive to monitor the project to ensure it complies with the program's rules, since compliance violations can result in forfeiture of tax credits.

The Tax Equity Investor's Return

A tax equity investor's return depends on the price paid per credit and associated benefits the investor secures in exchange. In the simplest case, the only benefit the investor receives from the credits is the ability to reduce their tax liability. For example, consider a project that will cost $1.5 million to complete and that will generate $1 million in federal tax credits that its owner is seeking to sell to finance the upfront cost of the project. An outside investor has agreed to contribute 90 cents in equity financing in exchange for each $1.00 of tax credit. Thus, the investor pays (contributes in capital) $900,000 in exchange for $1 million in tax credits. The net return to the investor is $100,000 (in reduced taxes), or 11.1% ($100,000 divided by $900,000).[11]

The project developer will need to make up the difference between the project's cost ($1.5 million) and tax equity investor's capital contribution ($900,000). This difference is often referred to as the "equity gap." Possible options for filling the equity gap include traditional loans or equity financing from other sources. The gap could also be filled with additional federal, state, or local subsidies. These might be grants, below-market-rate loans, or other tax incentives.

Depending on the structure of the arrangement, the tax equity investor may also secure other benefits, such as additional state and federal tax incentives, a claim to operating income and losses, a share of any capital gains when the underlying investment is sold, or goodwill with the community or regulators. With regard to regulatory-driven motives, investments in LIHTC and NMTC projects, for example, can assist financial institutions in satisfying requirements under the Community Reinvestment Act (CRA; P.L. 95-128), which is intended to encourage banks to make credit more readily available in low- and moderate-income communities. Tax equity investors in

[8] Big banks and financial institutions are major tax equity investors. Examples include Bank of America, JP Morgan, Citigroup, GE Financial Services, U.S. Bank, and Capital One. See Alex Tiller, "Insight: Tax Equity Remains an Under-Utilized Tool for Corporate Tax Strategy," *Daily Tax Report*, January 30, 2019.

[9] In the case of energy tax credits, these negotiations are constrained by guidance from the Internal Revenue Service regarding allocations of tax benefits and investment returns or losses.

[10] The designation of being a limited partner may also imply that the investor has limited legal liability.

[11] The tax equity investor may be guaranteed a certain rate of return depending on the particular tax credit program involved and the specific structure of the partnership.

renewable energy projects generally have returns that consist of both tax attributes and operating cash flow to conform to guidance provided by the Internal Revenue Service (IRS).[12]

The price investors are willing to pay for tax credits not only depends on the benefits attached to the credits, but on factors associated with the underlying project. These factors can include the risk associated with the project, how it is financed, and the time period over which benefits accrue.[13]

Due to the complexity of tax equity transactions and the size of investors' tax liabilities they desire to offset, the current federal tax equity mechanism may not, in some cases, be well suited for assisting small individual projects. When possible, tax equity investors typically seek large projects expected to generate a fairly significant amount of credits.[14]

Since tax equity investors require a financial return in exchange for providing financial capital, a portion of the subsidy is diverted away from the targeted activity. Returning to the previous example, if a tax equity investor agrees to contribute 90 cents in equity financing per $1.00 of federal tax credit, it means that for every $1.00 in government subsidy (i.e., tax credit), 10 cents is diverted away from subsidizing the underlying activity and to the investor and middlemen. Put differently, every 90 cents in federal subsidy that reaches the targeted industry actually costs the government $1.00 in lost tax revenue. This aspect of the tax equity mechanism is discussed in more detail in the "Policy Options and Considerations" section.

Subsidy Fluctuations

The use of the tax equity mechanism can create fluctuations in the amount of subsidy qualified activities receive. The subsidy flowing into a project depends on the price tax equity investors receive in exchange for their financing contributions. All else equal, higher tax credit prices imply more federal subsidization of the targeted activity per dollar loss of federal tax revenue. Therefore, factors that cause variability in tax credit prices also cause variability in the subsidization rate. This can lead to fluctuation in the subsidy delivered via the tax equity mechanism, even though there has been no direct policy change regarding the tax credit program itself. For example, during the Great Recession, falling corporate tax liabilities reduced investor demand for credits, leading to depressed credit prices. In turn, qualified investments had difficulty raising enough equity to finance projects. To bypass the tax equity mechanism, some credits were temporarily converted into direct grants.[15]

Policies enacted by Congress, but not directly related to the underlying tax credit program itself, can also lead to subsidy fluctuations. This occurred most recently with the 2017 tax revision (P.L. 115-97). Although some direct changes were made to several incentives that use the tax equity mechanism, there have also been concerns that the reduction in corporate tax rates and overall corporate tax liabilities could curb investor appetite for credits, and reduce the amount of tax equity investment being offered in the market. With less tax equity being supplied in the market, tax equity investors might demand higher rates of return, which could increase the cost of

[12] See Internal Revenue Service (IRS) Rev. Proc 2007-65.

[13] The price investors are willing to pay for the same benefits accrued over a longer time period, all else equal, would be less to account for the time value of money.

[14] For example, NMTC projects have a bias to larger project sizes, as the amount used for "fees" is limited to a percent of the project. In contrast, some states place limits on the LIHTCs a development can receive, which can limit the size bias.

[15] For background, see CRS Report R41635, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options*, by Phillip Brown and Molly F. Sherlock.

financing from the perspective of investors in targeted activities.[16] Additionally, the subsidies delivered by LIHTC and NMTC can also vary geographically due to the CRA.

Policies can also affect the demand for tax equity. For example, with renewable energy tax incentives phasing down, renewable energy investors may have fewer tax credits they are seeking to monetize. Less demand for tax equity could tend to reduce tax equity financing costs from the perspective of investors in targeted activities, reducing the overall rate of return for tax equity investors.

Select Case Studies

While several current federal tax credits use the tax equity financing mechanism, no two credits do so in the same manner. For example, affordable housing developers are awarded LIHTCs by officials in each state who review applications, decisions regarding NMTC applications are made by federal officials, and renewable energy tax credits have no similar application and review process. The rate of subsidization and time frame over which the various tax credits may be claimed are also different, as are many of the intricacies of the rules and requirements of each. This section reviews three large tax credits that employ the tax equity financing mechanism to illustrate the various ways the approach is used in practice.

Low-Income Housing Tax Credit

The LIHTC program was created by the Tax Reform Act of 1986 (P.L. 99-514) to replace various affordable housing tax incentives that were viewed as inefficient and uncoordinated at the time.[17] The tax credits are given to developers over a 10-year period in exchange for constructing affordable rental housing. Originally scheduled to expire in 1989, the program was extended several times before being made permanent in the Omnibus Budget Reconciliation Act of 1993 (P.L. 103-66). According to the Joint Committee on Taxation's (JCT's) most recent tax expenditure estimates, the LIHTC is estimated to cost the government an average of approximately $9.9 billion annually in reduced federal tax revenues.[18]

The mechanics of the program are complex. The process begins at the federal level, with each state receiving an annual LIHTC allocation based on population. In 2019, states received an LIHTC allocation of $2.75625 per person, with a minimum small-population state allocation of $3,166,875.[19] These amounts reflect a temporary increase in the amount of credits each state received as a result of the 2018 Consolidated Appropriations Act (P.L. 115-141). The increase is equal to 12.5% above what states would have received absent P.L. 115-141, and is in effect through 2021.

[16] With respect to the renewable energy industry, experts observed early in 2018 that tax equity investors were continuing to provide tax equity following the tax policy changes enacted late in 2017. See Emma Foehringer Merchant, "Renewables Tax Equity Market Fares Fine in Q1, Calming Industry Fears," *Greentech Media*, May 17, 2018, https://www.greentechmedia.com/articles/read/renewables-tax-equity-market-fares-fine-in-q1.

[17] For more information on the LIHTC program, see CRS Report RS22389, *An Introduction to the Low-Income Housing Tax Credit*, by Mark P. Keightley.

[18] Computed as the average estimated tax expenditure associated with the program between 2018 and 2022. U.S. Congress, Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2018-2022*, committee print, 116th Cong., 1st sess., October 4, 2018, JCX-81-18.

[19] The state allocation limits do not apply to the "noncompetitive" 4% LIHTCs, which are automatically packaged with tax-exempt-bond-financed projects. Tax-exempt bonds are issued subject to a private activity bond volume limit per state, which limits the amount of "noncompetitive" credits available by default. For more information, see CRS Report RL31457, *Private Activity Bonds: An Introduction*, by Steven Maguire and Joseph S. Hughes.

State or local housing finance agencies (HFAs) then award credits to developers using a competitive application process to determine which developers receive a credit award. HFAs review developer applications to ensure that proposed projects satisfy certain federally required criteria, as well as criteria established by each state. For example, some states may choose to give priority to buildings that offer specific amenities such as computer centers or that are located close to public transportation, while others may give priority to projects serving a particular demographic, such as the elderly. Delegating authority to HFAs to award credits gives each state the flexibility to address its individual housing needs, which is important given the local nature of housing markets.

Upon receipt of an LIHTC award, developers typically "sell" the tax credits to investors in exchange for an equity investment. This transaction occurs within a partnership structure and in a manner similar to the generalized example discussed in the previous section. While LIHTC prices fluctuate over time and geographic regions, they typically range from the mid-$0.80s to mid-$0.90s per $1.00 of tax credit. In addition to the tax credits, the equity investor may also receive tax benefits related to any tax losses and other deductions, as well as residual cash flow.

New Markets Tax Credit

The NMTC program was created by the Community Renewal Tax Relief Act of 2000 (P.L. 106-554) to provide an incentive to stimulate investment in low-income communities (LICs).[20] The original allocation authority eligible for the NMTC program was $15 billion from 2001 to 2007.[21] Congress subsequently increased the total allocation authority to $61 billion and extended the program through 2019.[22] The tax credits are awarded to community development entities (CDEs) to make eligible low-income community investments.[23] According to JCT's most recent tax expenditure estimates, the NMTC is estimated to cost the government an average of approximately $1.2 billion annually in reduced federal tax revenues.[24]

[20] For more information on the NMTC program, see CRS Report RL34402, *New Markets Tax Credit: An Introduction*, by Donald J. Marples and Sean Lowry.

[21] Congress provided a schedule limiting the NMTC allocation authority for calendar years 2001 through 2007. The schedule allowed for $1.0 billion in allocation authority in 2001, $1.5 billion in 2002 and 2003, $2.0 billion in 2004 and 2005, and $3.5 billion in 2006 and 2007.

[22] The Gulf Opportunity Zone Act of 2005 (P.L. 109-135) authorized an additional $1 billion of NMTC equity for qualified investments in areas affected by Hurricane Katrina, the Tax Relief and Health Care Act of 2006 (P.L. 109-432) extended the NMTC for an additional year (through 2008) with an additional $3.5 billion of NMTC allocation authority, and the Emergency Economic Stabilization Act of 2008 (P.L. 110-343) extended the NMTC for an additional year (through 2009) with an additional $3.5 billion of NMTC allocation authority. In the 111th Congress, the American Recovery and Reinvestment Tax Act of 2009 (P.L. 111-5) increased the NMTC allocation for 2008 and 2009 from $3.5 billion to $5 billion; and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (P.L. 111-312) extended the NMTC authorization through 2011 at $3.5 billion per year. In the 112th Congress the American Taxpayer Relief Act of 2012 (P.L. 112-240) extended the NMTC authorization for 2012 and 2013 at $3.5 billion per year. In the 113th Congress the Tax Increase Prevention Act of 2014 (P.L. 113-295) extended the NMTC authorization for 2014 at $3.5 billion. In the 114th Congress the Protecting Americans from Tax Hikes (PATH) Act (Division Q of P.L. 114-113) extended the NMTC authorization through 2019 at $3.5 billion per year.

[23] A CDE is a domestic corporation or partnership that is an intermediary vehicle for the provision of loans, investment funding, or financial counseling in low-income communities (LICs). To become certified as a CDE, an organization must submit an application to the CDFI that demonstrates that it meets specific criteria.

[24] Computed as the average estimated tax expenditure associated with the program between 2018 and 2022. U.S. Congress, Joint Committee on Taxation, *Estimates of Federal Tax Expenditures for Fiscal Years 2018-2022*, committee print, 116th Cong., 1st sess., October 4, 2018, JCX-81-18.

The process by which the NMTC affects eligible low-income communities involves multiple agents and steps. The multiple steps and agents are designed to ensure that the tax credit achieves its primary goal: encouraging investment in low-income communities. For example, the Department of the Treasury's Community Development Financial Institutions Fund (CDFI) reviews NMTC applicants submitted by CDEs, issues tax credit authority to those CDEs deemed most qualified, and plays a significant role in program compliance.

To receive an allocation, a CDE must submit an application to the CDFI, which asks a series of standardized questions about the CDE's track record, the amount of NMTC allocation authority being requested, and the CDE's plans for any allocation authority granted.[25] The application is reviewed and scored to identify those applicants most likely to have the greatest community development impact and ranked in descending order of aggregate score.[26] Tax credit allocations are then awarded based upon the aggregate ranking until all of the allocation authority is exhausted.[27]

Upon receipt of an NMTC award, developers often "sell" the tax credits to investors in exchange for an equity investment. This transaction typically occurs through a limited liability corporation obtaining a loan from a bank and combining the loan proceeds with the tax credit proceeds to invest in the low-income community. While NMTC prices fluctuate over time, geographic regions, and the business cycle, they typically range from the mid-$0.70s to mid-$0.80s per $1.00 of tax credit.[28] Unlike the LIHTC investor, the NMTC equity investor does not generally receive tax benefits related to any tax losses and other deductions.

Energy Tax Credits

Investment tax credits for renewable energy date back to the late 1970s.[29] The production tax credit (PTC) for renewable energy was enacted in the Energy Policy Act of 1992 (P.L. 102-486).[30] In recent years, the cost of both of these incentives has increased, as investment in renewable energy technologies has accelerated. For FY2018, the JCT estimates tax expenditures for the renewable energy investment tax credit (ITC) will be $2.8 billion.[31] Tax expenditures estimates for the PTC are $5.1 billion for FY2018. Most of the forgone revenue associated with the ITC is attributable to solar ($2.5 billion of the $2.8 billion for all eligible technologies).[32] In the case of

[25] In addition, priority points are available for addressing the statutory priorities of investing in unrelated entities and having a demonstrated track record of serving disadvantaged businesses or communities.

[26] For past examples of what the CDFI Fund has considered as "highly ranked applications" for the NMTC, see Community Development Financial Institutions Fund, *2014 NMTC Allocation Application Review Process*, Washington, DC, 2015, https://www.cdfifund.gov/Documents/2014%20NMTC%20Allocation%20Application%20Review%20Process.pdf.

[27] In each of the completed NMTC rounds, significantly more CDEs applied for allocations than were able to receive allocations.

[28] GAO-10-334 and New Markets Tax Credit Coalition, *New Markets Tax Credit Progress Report. 2018*, Washington, DC, 2018.

[29] CRS In Focus IF10479, *The Energy Credit: An Investment Tax Credit for Renewable Energy*, by Molly F. Sherlock.

[30] CRS Report R43453, *The Renewable Electricity Production Tax Credit: In Brief*, by Molly F. Sherlock.

[31] Joint Committee on Taxation, "Estimates of Federal Tax Expenditures for Fiscal Years 2018-2022," JCX-81-18, October 4, 2018.

[32] Other ITC-eligible technologies include geothermal, fuel cells, microturbines, combined heat and power, small wind. and geothermal heat pumps.

the PTC, most of the forgone revenue is associated with tax credits claimed for using wind to produce electricity ($4.7 billion of the $5.1 billion for all eligible technologies).[33]

The energy credit for solar is 30% of the amount invested in solar projects that start construction before the end of calendar year 2019. In 2020, the credit rate is reduced to 26% for property beginning construction in 2020, before being reduced again to 22% in 2021. For property that begins construction after 2021, the credit is 10%.[34] As an investment credit, the ITC is generally claimed in the year the property is placed in service.[35] The energy credit may be recaptured, meaning a taxpayer must add all or part of the tax credit to their tax liability, if a taxpayer disposes of the energy property or ceases to use the property for the purpose for which a tax credit was claimed. The recapture period is five years.[36]

The PTC is a per-kilowatt-hour (kWh) tax credit that can be claimed for the first 10 years of qualified renewable energy production. In 2018, the tax credit for wind was 2.4 cents per kWh. The amount of the credit is adjusted annually for inflation. Since 2009, taxpayers have had the option of electing to receive an ITC in lieu of the PTC.[37] Wind or solar projects that began construction in 2009, 2010, or 2011 had an option to elect to receive a one-time grant in lieu of tax credits.[38] Using tax equity financing arrangements has allowed developers to monetize the tax benefits, essentially trading future tax benefits for upfront capital.

The ITC and PTC were not designed as tax equity incentives. Rather, they were intended to subsidize investment in and production of renewable energy. Unlike the LIHTC and the NMTC, the energy tax credits were not intended to rely on taxpayer investors to deliver the subsidy.[39] In the case of the PTC, when enacted, it was anticipated that tax credits would be claimed for electricity produced at facilities owned by the taxpayer and later sold by the taxpayer.[40] Over time, however, partnerships began to form to efficiently use tax benefits.

Recognizing that tax equity transactions were being undertaken with respect to wind development, in 2007 the IRS released Revenue Procedure 2007-65, which established a safe harbor under which the allocation of tax credits in a tax equity partnership structure would not be challenged as long as certain ownership requirements were met.[41] While separate guidance has not been issued for solar projects claiming the ITC, industry practice has generally been to follow the safe harbor guidance provided to wind projects claiming the PTC.[42]

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[33] Other PTC-eligible technologies include closed-loop biomass, geothermal, qualified hydropower, small irrigation power, municipal solid waste, marine and hydrokinetic, and open-loop biomass.

[34] Credit rates and expirations vary for different technologies.

[35] It is possible for taxpayers to claim the tax credit for progress expenditures associated with the construction of property with a normal construction period of two or more years.

[36] One way to view the ITC is as a tax credit that "vests" over time. Using this perspective, the ITC vests at a rate of 20% per year. After the first year, 20% of the credit cannot be recaptured. After five years, the credit is fully vested, and cannot be recaptured.

[37] This provision is temporary but has regularly been extended along with the PTC.

[38] CRS Report R41635, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options*, by Phillip Brown and Molly F. Sherlock.

[39] Thomas W. Giegerich, "The Monetization of Business Tax Credits," *Florida Law Review*, vol. 12, no. 9 (2012), p. 760.

[40] For background and discussion, see Thomas W. Giegerich, "The Monetization of Business Tax Credits," *Florida Law Review*, vol. 12, no. 9 (2012), pp. 709-826.

[41] IRS Revenue Procedure 2007-65.

[42] Scott W. Cockerham, "Putting U.S. Solar Financing Structures in Perspective," *Tax Notes*, July 23, 2018, pp. 499-

Partnership flips are a common tax equity financing structure in renewable energy markets.[43] Under a partnership flip structure, a renewable energy developer partners with a third-party tax equity investor.[44] The tax equity investor has (or expects to have) sufficient tax liability to use the tax credits associated with the renewable energy investment or production. The tax equity investor and renewable energy developer establish a partnership, which is the project company. The tax equity investor may provide upfront cash to the project company, in exchange for production or investment tax credits, depreciation, interest deductions, and operating income.[45]

During the initial phase of the project, the tax equity investor will receive most of the tax benefits, as well as the income or loss (often the share is 99%). The developer retains a small allocation of tax benefits and income (profit or loss). Once the tax equity investor has achieved a targeted internal rate of return (IRR), the partners' interests in the project company will flip, with the developer now receiving most of the tax benefits and income (profit or loss) associated with the project (typically 95%, leaving the tax equity investor with 5%). The developer may also buy out the tax equity investor, such that the tax equity investor no longer owns any part of the project.

Tax equity generally provides a portion of a project's capital needs—somewhere from 30% to 60%, depending on the specifics of the project.[46] For renewable energy projects, tax equity is generally more expensive than other sources of debt financing. For example, tax equity investors require rates of return that are 7% to 10% higher than the return on a comparable debt product.[47] Tax equity yields (or the after-tax return required by tax equity investors) can vary widely across energy projects, but often fall in the 6% to 8% range, depending on the technology and specifics of the project.[48]

Policy Options and Considerations

There are a range of policy options to consider when it comes to using tax equity markets to monetize tax benefits. For existing programs and new tax policies that could involve tax equity transactions, consideration of various options might ask whether the use of tax equity markets is an efficient and effective means of delivering federal financial support. At first glance, it may appear that the government would get more "bang for its buck" by structuring the subsidy delivery mechanism to eliminate investors. However, such a conclusion overlooks one role that

503.

[43] Other structures include sale leasebacks and inverted leases. These structures are not discussed here, but more information can be found in Scott W. Cockerham, "Putting U.S. Solar Financing Structures in Perspective," *Tax Notes*, July 23, 2018, pp. 499-503; Keith Martin, "Solar Tax Equity Structures," *Project Finance NewsWire*, September 2015; and various chapters in *Energy and Environmental Project Finance Law and Taxation: New Investment Techniques*, eds. Andrea S. Kramer and Peter C. Fusaro (Oxford University Press, 2010).

[44] More detailed discussions of the partnership flip structure in the context of renewable energy projects can be found in Michelle D. Layser, "Improving Tax Incentives for Wind Energy Production: The Case for a Refundable Production Tax Credit," *Missouri Law Review*, vol. 81 (2016), pp. 453-517.

[45] Some tax equity structures involve a tax equity investor purchasing a share of the developer's membership interest. Tax equity investors may realize income from the sale of their equity interest.

[46] Paul Schwabe, David Feldman, Jason Fields, and Edward Settle, *Wind Energy Finance in the United States: Current Practice and Opportunities*, National Renewable Energy Laboratory, NREL/TP-6A20-68227, August 2017; and Emma Foehringer Merchant, "Renewables Tax Equity Market Fares Fine in Q1, Calming Industry Fears," *Greentech Media*, May 17, 2018, at https://www.greentechmedia.com/articles/read/renewables-tax-equity-market-fares-fine-in-q1.

[47] Paul Schwabe, David Feldman, Jason Fields, and Edward Settle, *Wind Energy Finance in the United States: Current Practice and Opportunities*, National Renewable Energy Laboratory, NREL/TP-6A20-68227, August 2017.

[48] See, for example, CohnReznick LLP / CohnReznick Capital, *U.S. Renewable Energy Brief: The Tax Equity Investment Landscape*, Summer 2017, https://www.cohnreznickcapital.com/usrenewableenergybrief_summer2017/.

tax equity investors often play in addition to providing financing: tax equity investors evaluate the quality of projects before investing, as well as provide continuing oversight and compliance monitoring. Effectively, the tax equity mechanism outsources a portion of the oversight and compliance monitoring to the investors in exchange for a financial return. There may be value to the federal government in being able to rely on outside investors to provide oversight and monitoring. It could be argued, though, that for some tax equity programs that have a government entity overseeing participant compliance, the monitor role of investors is redundant.

This section presents several policy options frequently discussed in debates regarding tax equity. The options are with respect to the general tax equity approach. Due to important differences in the underlying structure of various current or future credits, some options may be better suited for particular credits than others. Careful consideration on a case-by-case basis is part of evaluating the appropriateness of each option. The list of options presented here is by no means exhaustive.

Make the Credits Refundable

Making the tax credits refundable could, in some cases, reduce or eliminate the need for tax equity. In other cases, making the tax credits refundable could reduce the cost of such financing for those who still need to access tax equity markets.

All the tax credits currently using the tax equity approach are nonrefundable. Nonrefundable credits have value only to the extent that there is a tax liability to offset. In contrast, refundable credits have value regardless of tax liability.[49] For example, if a developer has $1,000 in refundable tax credits and no tax liability, they may claim the credits and receive a tax refund of $1,000.[50] Thus, fully refundable credits are similar to direct grants administered through the tax system.

Even if the relevant tax credits were made refundable, there could still be a role for tax equity investment. Current tax credits relying on tax equity are delivered over multiple years or when the investment in qualifying property is complete and tax returns are filed. Project developers, however, typically need upfront capital to make their investments. Thus, developers (for-profit and nonprofit) may still choose to rely on tax equity markets to monetize tax credits even if they were refundable. Alternatively, allowing tax credits to be refundable could make it easier for projects to rely on debt financing. Lenders may be more willing to lend on favorable terms to a project that expects a refundable tax benefit in the future.

Moving to refundable credits could potentially increase the amount of subsidy per dollar of federal revenue loss. That is, it could increase the efficiency of the subsidy delivery mechanism and result in more of the targeted activity taking place. As discussed previously, all else equal, higher tax credit prices imply there is more federal subsidization per dollar loss of federal tax revenue. With refundable tax credits, current tax equity investors would be expected to pay more for each tax credit because the risk of not having sufficient tax liability to use the credits would be removed. Additionally, potential investors who are currently not purchasing tax credits because of uncertainty over their ability to use nonrefundable tax credits may enter the market now that the uncertainty is gone. This would add to the competition among investors and would likely put upward pressure on tax credit prices, further enhancing the subsidy mechanism.

Transitioning to refundable business tax credits raises two potential concerns. The first is the federal cost. Refundable tax credits typically result in a large revenue loss because they may be fully utilized regardless of tax liability, whereas nonrefundable credits may be claimed only to the

[49] Unless the credits are only partially refundable.

[50] Tax-exempt entities that do not file income tax returns are generally not able to claim refundable tax credits.

extent there is a tax liability, which can result in a portion of nonrefundable credits ultimately going unused. This concern is likely less of an issue with LIHTC and NMTC, since few of these tax credits currently go unclaimed.[51] This implies that converting these to refundable credits would likely not result in a significant increase in federal revenue loss.

Making the energy credits (PTC and ITC) refundable could result in considerable federal revenue loss. ITCs and PTCs that are currently carried forward and ultimately go unused under current law could instead be claimed immediately by taxpayers. For energy tax credits, many are claimed without the involvement of tax equity investors. Tax equity investors typically require projects to be of a certain size (i.e., generate a certain amount of tax benefits) to invest. As a result, there are many PTC- and ITC-eligible projects that are not able to monetize tax benefits using tax equity investors. Making energy tax credits refundable could (1) make the tax credits more attractive to developers that are not currently participating in tax equity markets; and (2) reduce the cost of tax equity for developers that are participating. Without a cap on the amount of ITCs or PTCs that can be claimed, if policy changes were made that increased demand for credits, the cost associated with delivering those credits would increase. One option to address concerns about the potential cost associated with an unlimited tax credit would be to limit the amount of tax credits that could be claimed.[52]

There is some experience with refundable energy tax credits. The energy tax credits enacted for wind and solar in the late 1970s were refundable, although legislation was enacted to make the credits nonrefundable in 1980.[53] Also, several states offer tax credits designed to promote renewable energy that are refundable.[54]

The second concern is allowing businesses to claim a refundable tax credit generally. Refundable tax credits are a useful tool for providing income support via the tax code. For this reason, refundable tax credits have generally been reserved for households, and mostly for lower-income households. Some may take issue with allowing businesses to access an income-support tax incentive. Others assert that allowing the credits to be refundable would likely result in each dollar of federal tax revenue loss yielding more subsidy flowing into the intended activity.

Convert to Grants

The tax credits could be replaced with grants. A concern with the current tax equity mechanism is the amount of subsidy that is diverted away from the underlying activity and toward third-party investors and middlemen. Even if the tax credits were fully refundable, as discussed above, tax equity might still be used to monetize tax credits to get upfront financing. Nonprofit entities that do not file federal income tax returns would also not generally benefit directly from an incentive

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51 There is high demand for a limited annual amount of these tax credits. If a potential claimant of these credits, after making a tax equity investment, does not have enough tax liability in a given year, they are allowed to carry back their credits 1 year and carry them forward for up to 20 years. LIHTC also allows states to carry over a given year's tax credit allocation authority for one year. If a state does not allocate all credits after the second year, then the credits are returned to a national pool where they can be reallocated to states that have exhausted their allocation authority.

52 For example, the advanced energy manufacturing tax credit (IRC §48C) allocated $2.3 billion in tax credits. Investors wanting to claim tax credits were required to submit an application. Tax credits for clean coal have also been allocated (IRC §§48A and 48B).

53 The Energy Tax Act of 1978 (P.L. 95-618) introduced a temporary 10% refundable tax credit for investment in wind and solar energy property. As part of the Windfall Profit Tax Act of 1980 (P.L. 96-223), the tax credit rate was increased to 15%, but the credit was made nonrefundable.

54 Thomas W. Giegerich, "The Monetization of Business Tax Credits," *Florida Law Review*, vol. 12, no. 9 (2012), pp. 797-798.

delivered through the tax code. Another concern with the current tax equity structure that has already been mentioned is that it can potentially create a bias toward larger-scale projects because of tax credit investors' appetite for credits combined with the cost savings from evaluating and monitoring fewer projects.[55]

One way to potentially overcome or mitigate these concerns would be to provide lump-sum grants. The effective subsidy would correspond to the federal revenue loss, and there would no longer be a bias toward larger projects resulting from the way the subsidy was delivered.[56] The tradeoff, however, is that there would be no outside investors scrutinizing the long-term feasibility of potential projects or monitoring compliance after construction—though a mechanism such as that used to award NMTCs may help address this concern. Thus, there could be an increase in project failure and noncompliance, without the federal government (and in some cases, state governments) filling the role of tax credit investors. Carefully designed recapture provisions would also be needed in the case of project failure. In the end, replacing tax credits with grants would likely increase government administrative costs that could offset the increased subsidy flowing to the projects from the removal of tax credit investors.

An option for maintaining the role of investors would be to deliver a portion of the tax credits as upfront grants, and deliver the remaining tax credits over time. To maintain a feasible tax credit market and investor participation, the proportion of grant funding would have to be such that enough developers sold their remaining tax credits. It is not clear exactly what proportion would achieve the appropriate balance, although there are several options. The federal government could statutorily determine a particular split, such as 50% grants and 50% tax credits. For programs primarily administered by states, such as the LIHTC, the decision could be left to the states. Alternatively, developers could request that a specific amount of their funding be in the form of grants up to a certain percentage. In any case, if enough developers chose not to sell their credits, then the tax credit market would not function well, and project feasibility assessment and compliance monitoring responsibilities would fall on the government.

There is recent precedent for allowing grants in lieu of tax credits. During the Great Recession, falling corporate tax liabilities reduced investor demand for credits, leading to depressed credit prices.[57] In response to the general macroeconomic conditions at the time, Congress passed the American Recovery and Reinvestment Act (ARRA; P.L. 111-5) in early 2009. The act allowed a portion of LIHTCs to be converted into grants. Renewable energy tax credits also had the option of receiving a grant in exchange for forgoing future tax benefits.

In the case of the LIHTC, the grants were awarded via the competitive process used for awarding the credits. The need to intervene in tax credit markets highlights that the tax equity mechanism can create fluctuations in the subsidy qualified activities receive, as was discussed in the "Subsidy Fluctuations" section.

In addition, ARRA allowed taxpayers who otherwise would have been eligible for the PTC or ITC to elect to receive a one-time grant from the Treasury in lieu of these tax benefits.[58] Initially,

[55] As has also been mentioned, there may be particular restrictions that counteract the bias toward larger projects, as there are in the rules certain states use to make LIHTC awards.

[56] There may still be a bias toward larger projects due to features of the underlying investment. For example, urban areas typically require larger-sized housing structures than nonurban areas. It can also be more costly to build in urban areas, which influences the size of the project in dollar terms.

[57] The Great Recession began in December 2007 and ended in June 2009. See CRS In Focus IF10411, *Introduction to U.S. Economy: The Business Cycle and Growth*, by Jeffrey M. Stupak.

[58] CRS Report R41635, *ARRA Section 1603 Grants in Lieu of Tax Credits for Renewable Energy: Overview, Analysis, and Policy Options*, by Phillip Brown and Molly F. Sherlock.

the grant option was to be available for 2009 and 2010, although the policy was later extended such that projects that began construction before the end of 2011 could qualify. Since the grant was designed to be in lieu of existing tax benefits, tax benefits that could be claimed only by tax-paying entities, tax-exempt entities were not eligible.

Allow the Direct Transfer of Credits

The tax code could be modified to allow the direct transfer of tax credits without having to form a legal partnership. Currently, federal tax law requires tax equity investors to have an ownership interest in the underlying business venture in order to claim the associated tax credits. To meet this requirement, monetization of federal tax credits typically takes place within a partnership structure that legally binds the project's sponsor and investors for a period of time. In contrast, certain states permit state tax credits to be sold directly to investors without the need to establish a legal relationship.

Removing the need to form a partnership to invest in tax equity projects could broaden the pool of potential investors. In turn, this could enhance competition for tax credits, resulting in more equity finance being raised per dollar of forgone federal tax revenue. It is unclear, however, what impact the direct transfer of credits would have on deals involving other tax benefits that are often bundled with the tax credits. For example, the section titled "The Tax Equity Investor's Return" notes that investors may also secure a claim to other state and federal tax incentives, operating income and losses, capital gains when the underlying investment is sold, or goodwill with the community or regulators.

A number of issues would need to be addressed before allowing tax credits to be directly transferred. For example, allowing credits to be sold to anonymous investors with no formal ties to the underlying project potentially removes the tax equity investors' oversight incentives, which are a crucial feature of the current approach. Additionally, procedures would need to be implemented to track who has the right to claim the credits and prevent credits from being claimed (or from being recaptured) in instances of noncompliance or project failure. A decision would also need to be made about whether credits could be transferred only once, or if purchasers could resell credits. This would determine the resources needed to accurately track eligible credit claimants. Policymakers would also face the issue of who could participate in this market. Unsophisticated investors may not fully understand the risks or how to properly scrutinize these investments.[59]

Some of these issues may be resolved by the market itself if direct transfers were permitted. For example, at the state level, tax credit brokers have emerged to facilitate the exchange of transferable credits.[60] There are also a number of online tax credit exchanges where state tax credits are traded. Brokers or exchanges can provide some level of expertise and guidance on the risks of these transactions. Their services also come at a cost that reduces the subsidy directed to the targeted activity. Imposing reporting requirements on brokers or exchanges may help with the administration of a direct transfer regime.

Another option would be to allow more flexibility in transferring tax credits among various project participants. For example, tax-exempt entities engaged in a subsidized activity could be allowed to transfer their tax credit to someone else involved in the project (a designer or builder,

[59] With LIHTC, this would likely also require modification to the passive activity loss rules.

[60] Jennifer Zimmerman, "The Transferability and Monetization of State Tax Credits," *Journal of Multistate Taxation and Incentives*, vol. 25, no. 1 (March/April 2015).

or the provider of financing, for example) without entering into a formal partnership.[61] As was the case with general transferability of credits, even allowing more restricted transfer of credits could impose additional administrative and oversight burdens on both taxpayers and the government.

Accelerate the Credits

Accelerating the credits could potentially reduce the cost of tax equity. This option, however, would not eliminate the need to rely on tax equity markets altogether. Further, this option is most directly applicable to tax credits or other tax benefits that accrue and reduce tax liability over a multiyear period, as opposed to the current tax year.

A straightforward way to accelerate the credits would be to shorten the time period over which they are claimed. Alternatively, acceleration could also be achieved by leaving the claim periods unaltered, and frontloading the credits so that a greater proportion could be claimed in the earlier years. Either of these changes would likely increase the amount of equity a developer could raise from a given tax credit award because tax equity investors would be willing to pay a higher price per dollar of tax credit. This, in turn, would result in more subsidy flowing into the targeted investment, and allow for more projects to be undertaken for the same federal revenue loss.

Tax equity investors would be willing to pay more if credits were accelerated for two reasons. First, a shorter claim period means that investors would reduce the discount applied to the total stream of tax credits, since they could offset tax liabilities sooner. Second, longer claim periods result in more uncertainty (risk) over whether an investor will have sufficient tax liability to use purchased credits. Accelerating the tax credit reduces that risk, and less risk would lead to *current* investors being willing to pay higher prices for tax credits. Less risk could also bring *new* tax equity investors into the market, which would also tend to increase tax credit prices.

A concern with accelerating the tax credits is the potential for participants to lose focus on the investment after they have claimed all the credits. This concern could be addressed with a compliance period that is longer than the claim period and with credit recapture. For example, currently LIHTC is claimed over a 10-year period, but investors and developers are subject to a 15-year compliance period. Should the project fall out of compliance with the LIHTC rules in the last five years, the investors are subject to recapture of previously claimed tax credits. For purposes of this example, the claim period could be shortened to five years while leaving the 15-year compliance period in place.

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[61] This type of policy was enacted with respect to the advanced nuclear production tax credit (IRC §45J) in the Bipartisan Budget Act of 2018 (P.L. 115-123).

Disclaimer

The firm receives cash flows of $30,000 and $20,000 in the first two years, whic
up to the $50,000 original investment. This means that the firm has recovered its inve
within two years. In this case two years is the *payback period* of the investment

The payback period *rule for making investment* decisions is simple A particul
off time, say two years, is selected All investment projects that have payback peri
two years or less are accepted and all of those that pay off in more than two years
all—are rejected

Problems with the Payback Method

There are at least three problems with the payback method To illustrate the first two
lems, we consider the three projects in Table 6.1 All three projects have the same
year payback period, so they should all be equally attractive—right?

Actually, they are not equally attractive, as can be seen by a comparison of di
pairs of projects

Problem 1: Timing of Cash Flows within the Payback Period Let us compare
A with project *B* *In years 1 through 3, the cash flows of project A* rise from $20 to $50
the cash flows of project *B* fall from $50 to $20 Because the large cash flow of $50
earlier with project *B*, its net present value must be higher Nevertheless, we saw abo
the payback periods of the two projects are identical. Thus, a problem with the payb
riod is that it does not consider the timing of the cash flows within the payback perio
shows that the payback method is inferior to NPV because, as we pointed out earl
NPV approach *discounts the cash flows properly.*

Problem 2: Payments after the Payback Period Now consider projects *B* and *C*
have identical cash flows within the payback period. *However, project C is clearly* pr
because it has the cash flow of $60,000 in the fourth year Thus, another problem w
payback method *is that it ignores all cash flows occurring after the payback* perio
flaw is not present with the NPV approach because, as we pointed out earlier, the N
proach *uses all the cash flows of the project* The payback method forces managers
an artificially short-term orientation, which may lead to decisions not in the share
best interests

Problem 3: Arbitrary Standard for Payback Period We do not need to refer
6 1 when considering a third problem with the payback approach. When a *firm*
NPV approach, it can go to the capital market to get the discount rate. There is no
rable guide for choosing the payback period, *so the choice is arbitrary to some* ex

■ TABLE 6.1 **Expected Cash Flows for Projects *A* through *C* ($)**

Year	A	B
0	−100	−100
1	20	50
2	30	30
3	50	20
4	60	60
Payback period (years)	3	3

Managerial Perspective

The payback rule is often used by large and sophisticated companies when making relatively small decisions. The decision to build a small warehouse, for example, or to pay for a tune-up for a truck is the sort of decision that is often made by lower-level management. Typically a manager might reason that a tune-up would cost, say, $200, and if it saved $120 each year in reduced fuel costs, it would pay for itself in less than two years. On such a basis the decision would be made

Although the treasurer of the company might not have made the decision in the same way, the company endorses such decision making Why would upper management condone or even encourage such retrograde activity in its employees? One answer would be that it is easy to make decisions using the payback rule. Multiply the tune-up decision into 50 such decisions a month, and the appeal of this simple rule becomes clearer

Perhaps most important though, the payback rule also has some desirable features for managerial control. Just as important as the investment decision itself is the company's ability to evaluate the manager's decision-making ability Under the NPV rule, a long time may pass before one decides whether or not a decision was correct. With the payback rule we *know in two years whether the manager's assessment of the cash flows was correct.*

It has also been suggested that firms with very good investment opportunities but no available cash may justifiably use the payback method For example, the payback method could be used by small, privately held firms with good growth prospects but limited access to the capital markets. Quick cash recovery may enhance the reinvestment possibilities for such firms.

Notwithstanding all of the preceding rationale, it is not surprising to discover that as the decision grows in importance, which is to say when firms look at bigger projects, the NPV becomes the order of the day. When questions of controlling and evaluating the manager become less important than making the right investment decision, the payback period is used less frequently For the big-ticket decisions, such as whether or not to buy a machine, build a factory, or acquire a company, the payback rule is seldom used

Summary of the Payback Period Rule

To summarize, the payback period is not the same as the NPV rule and is therefore conceptually wrong. With its arbitrary cutoff date and its blindness to cash flows after that date, it can lead to some flagrantly foolish decisions if it is used too literally. Nevertheless, because it is so simple, companies often use it as a screen for making the myriad of minor investment decisions they continually face

Although this means that you should be wary of trying to change rules like the payback period when you encounter them in companies, you should probably be careful not to fall into the sloppy financial thinking they represent. After this course you would do your company a disservice if you ever used the payback period instead of the NPV when you had a choice.

QUESTIONS

- List the problems of the payback period rule
- *What are some advantages?*

THE DISCOUNTED PAYBACK PERIOD RULE

Aware of the pitfalls of the payback approach, some decision makers use a variant called the **discounted payback period rule.** Under this approach, we first discount the cash flows. Then we ask how long it takes for the discounted cash flows to equal the initial investment.

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Attachment 3

Wind Energy Finance in the United States: Current Practice and Opportunities

Paul Schwabe, David Feldman, Jason Fields, and Edward Settle
National Renewable Energy Laboratory

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Prepared under Task No. WE16.3H01

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List of Acronyms

A2e	Atmosphere to Electrons
DOE	Department of Energy
DSCR	debt service coverage ratio
FTR	financial transmission rate
GW	gigawatt
IRR	Internal Rate of Return
IRS	Internal Revenue Service
ITC	investment tax credit
kWh	kilowatt-hour
LCOE	levelized cost of energy
LLC	limited liability company
LLP	limited liability partnership
MACRS	modified accelerated cost recovery system
MW	megawatt
MWh	megawatt-hour
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PPA	power purchase agreement
PRUF	performance, risk, uncertainty, and finance
PTC	production tax credit
PV	photovoltaic
RPS	renewable portfolio standard
SPV	special purpose vehicle
SAM	system advisor model
WACC	Weighted Average Cost of Capital

Executive Summary

In the United States, investment in wind energy has averaged nearly $13.6 billion annually since 2006 with more than $140 billion invested cumulatively over that period (BNEF 2017). This sizable investment activity demonstrates the persistent appeal of wind energy and its increasing role in the U.S electricity generation portfolio. Despite its steady investment levels over the last decade, some investors still consider wind energy as a specialized asset class. Limited familiarity with the asset class both limit the pool of potential investors and drive up costs for investors.

This publication provides an overview of the wind project development process, capital sources and financing structures commonly used, and traditional and emerging procurement methods. It also provides a high-level demonstration of how financing rates impact a project's all-in cost of energy. The goal of the publication is to provide a representative and wide-ranging resource for the wind development and financing processes.

Wind energy finance generally comprises three main sources of capital: sponsor equity, tax equity, and debt. The blend and proportion of each of these capital sources in a given project is referred to as the capital structure or capital stack. Each source is discussed briefly below:

- **Sponsor equity** in a project most closely resembles a traditional equity investor and often can be provided by the original developer of the project. The sponsor equity is typically the first investor to suffer losses and the last to receive distributions of profit. Because the sponsor commonly faces the highest risk in the partnership, it will often have the highest return requirements, but is typically a small portion of the overall capital stack.
- **Tax equity** will commit upfront capital to a project in exchange for access to tax credits and tax losses from accelerated depreciation. Because this type of investment requires significant capital and tax capacity for up to ten years, tax equity investors are often large financial entities such as banks and insurance funds. Tax equity investors have several other tax-oriented investment options outside of wind to consider including solar energy as well as affordable housing.
- **Debt capital** is a contractually-arranged loan that must be repaid by the borrower and occurs when the lender has no ownership shares in the company or venture. Debt is generally a lower-risk and lower-cost funding source relative to equity—particularly as compared to sponsor equity. Debt capital providers benefit from additional financing protections such as contractually-fixed payment schedules, preferred repayment positions, access to collateral, and rights to assume control of a defaulting company if necessary. Debt capital may be invested through a variety of different financial mechanisms including a construction loan, a direct loan to the sponsor or developer of the project, or, to a lesser extent, a loan to the project itself.

One of the key factors in wind finance is the mechanism by which electricity is sold. Traditionally, power purchase agreements (PPAs) have been used as a contract between energy generators (sellers) and energy "offtakers" (buyers). Offtakers generally include utilities and other load-serving entities; increasingly, however, corporate buyers and financial companies are also serving as offtakers. Wiser and Bolinger (2016) report that around 24% of cumulative installed wind projects have been constructed on a "merchant/quasi-merchant" basis in which they are financed and built with either a partial PPA or without a PPA entirely, instead selling energy into the wholesale spot markets, typically with a pricing hedge contract. In these cases, investors may demand a higher return for the risks attendant to merchant projects, such as unforeseen shortfalls in revenue and resource risk (Wiser and Bolinger 2016). Recently, the various procurement strategies by which corporations have sought to supplement their electricity purchases with wind contracts have included offsite PPAs, virtual PPAs, and other mechanisms.

This report also provides a high-level illustrative example of how financing rates can modestly impact a project's overall cost of energy and, accordingly, its cost competitiveness with other investment alternatives. The financing rates of a wind project reflect the perceived risks by potential investors in a project. These risks can be categorized into three basic risk types. *General risks* can be attributed to macroeconomic forces and market-wide risks tolerances, which are illustrated in metrics such as benchmark interest rates. There are also *wind-industry-specific risks* derived from issues like regional market factors, national incentive structures, and industry-wide financing practices. Lastly, there are many *wind-project-specific risks* such as the turbine's performance history in the marketplace, the project developer's history of delivering projects on time and budget, the use of contractual elements to mitigate risks, and other subjective factors. All of these considerations contribute to both the ability of the developer to secure financing as well as the overall investment costs for a wind energy project.

Looking ahead, the near-term outlook for wind energy reported previously suggests a continued need for capital at levels consistent with deployment seen in 2015 and 2016 (Wiser and Bolinger 2016). The market has shown the capacity to finance projects using the current mechanisms at economically viable rates; however, increased deployment could require investment from new capital providers. Broad changes to the financial industry—such as the possibility of major corporate tax reform and, specifically, the role of the tax equity—could fundamentally reshape the predominant mechanism for wind energy investment. Financing will continue to have at least a modest impact on a project's overall economic competitiveness, and efforts to open up more capital sources and reduce financing costs will be one of a set of levers to improve the economic competitiveness of wind power and enable a larger expansion onto the power grid.

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1 Introduction

By the end of 2016, cumulative U.S. wind generation capacity stood at 82.2 gigawatts (GW), expanding by 8.7 GW from 2015 installations levels (AWEA 2017; Ray 2017). Wind energy added the most utility-scale electricity generation capacity to the U.S. grid in 2015 and the second most in 2016 (Lee and Darling 2016; Ray 2017). Project investment in wind in the United States has averaged $13.6 billion annually since 2006 with a cumulative investment total of $149 billion over this time period (BNEF 2017).[1]

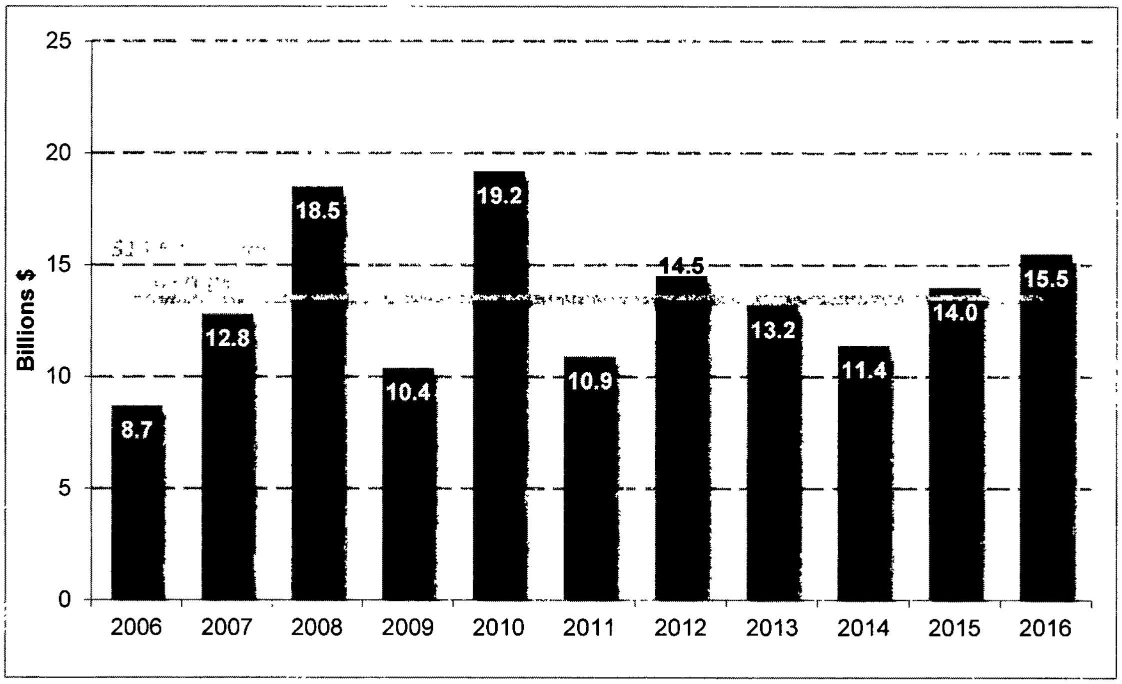

Figure 1. New U.S. investment in wind energy 2006-2016

Source: BNEF 2017

Despite its consistent investment levels over the last decade, some investors still consider wind energy as a specialized asset class. The level and depth of understanding and comfort with the technology, market, policies, and financing practices that underpin the deployment of wind energy naturally varies among financiers. Limited familiarity of the particular asset class can both limit the pool of potential investors and drive up costs for investors. And for a capital-intensive project such as a wind farm, where a 100-megawatt (MW) project can cost, on average, nearly $165 million (Wiser and Bolinger 2016), reducing the cost of capital even by just a half percentage point could result in measurable cost savings and improved competitiveness and ultimately enable greater penetration on the grid.

[1] As reported by BNEF (2017), all figures are in nominal dollars. BNEF 2017 investment estimates include public capital sources such as stock and bond markets, commercial capital from banks and insurance funds, research and development funds from corporations and governments, and other sources such as private equity or venture capital.

To this end, the National Renewable Energy Laboratory (NREL) is leading an effort called "Performance, Risk, Uncertainty, and Finance" or "PRUF" under the Atmosphere to Electrons (A2e) initiative sponsored by the U.S. Department of Energy (DOE). A2e is focused on risk mitigation, and PRUF in particular is focused on the mitigation of risk related to investment and financing of wind energy projects. Through activities such as PRUF and general industry maturation, a broad and widely understood assessment of wind energy project risk among developers, investors, and policymakers can help to expand the potential pool of industry investors and drive down the cost of capital for the wind industry. Reducing the cost of capital can lead to attendant—though modest—reductions in the levelized cost of energy (LCOE), which in turn contribute toward wind energy competitiveness in the marketplace (EERE 2017).

This publication provides an overview into the wind project development process, capital sources and financing structures commonly used, and traditional and emerging procurement methods. It also provides a high-level demonstration of how financing rates impact a project's all-in cost of energy. The goal of the publication is to provide a representative and wide-ranging resource for the wind development and financing processes. It is organized into five sections after this introduction:

- **Section 2** offers a general summary of the various risks during the development, construction, and operation phases of a wind project. Risk is a critical factor in the availability and cost at which project sponsors (owners) can access debt and equity capital as well as the rates offered.
- **Section 3** takes a chronological tour through the wind project development cycle, from screening and pre-development all the way through commissioning and project operation. It also indicates what kind of capital is typically invested at each stage.
- **Section 4** discusses three capital sources in greater depth: sponsor equity, tax equity, and debt. The subsection on tax equity also includes a brief overview of the federal tax benefits available to wind projects as of this writing. The section concludes with a discussion of the financial structuring designed to monetize these tax benefits.
- **Section 5** covers the various contractual instruments by which wind projects can earn revenue from the energy they generate with a focus on corporate purchasing.
- **Section 6** presents a high-level analysis to demonstrate the effect of variation in the cost of capital (through improved investor risk perception, robust due diligence, and other practices) on LCOE, which contributes to an energy project's competitiveness and feasibility in a particular market.

2 Risk and Uncertainty in Wind Projects

Commercial-scale wind projects are large, complex, and capital-intensive infrastructure assets. Like any other large-scale energy or infrastructure project, decisions to invest in wind projects are built on expectations about the future that are subject to some amount of uncertainty, including electricity price projections, changing market demand, technology and cost evolutions over time, and yearly weather patterns among other factors. The owners of these wind projects (referred to hereafter as "project sponsors") extensively study these uncertainties to develop a model that forecasts the project's financial performance and the returns it can pay to its investors.

In simple terms, risk is a measure of the uncertainty of future outcomes and their impact on a project. Risk is ubiquitous across financial investments, and investors can be made comfortable with accepting certain types of risk knowing that reduction mechanisms and remedies can be put into place. Higher risk generally offers the potential for a correspondingly higher return on investment. Any event that could have a negative impact on the investment is typically referred to as a "risk event" and largely consists of the scenario, the probability of occurrence, and the magnitude of impact.

One tool used to examine the effects of risks and uncertainty in a wind project's performance is through analysis with a pro forma financial model.[2] Each of the parameters underlying the pro forma financial model carries a degree of uncertainty that introduces an element of risk to the project. Project sponsors strive to identify sources of risk, quantify the potential impact of each risk, and develop strategies to minimize the potential of these risks to negatively impact project outcomes. As with all investments, some risk inevitably remains in wind energy despite best efforts to analyze and control for uncertainties.

Investors, industry analysts, and financial ratings agencies describe a few major areas of risk with land-based wind energy projects (Fitch 2016).[3] These perceived risks are summarized at high level below.

- **Project Development Risk**. This risk reflects the uncertainty of a project reaching commercial operations and the point at which it generates electricity and therefore revenue. A project developer will likely pursue the development of multiple potential projects at a time and could choose to pause or permanently halt the development activities of any one project for any number of reasons. Site control difficulties, lack of transmission access, wind resource uncertainty, and unfavorable market dynamics are among the more commonly reported issues. In general, the time and cost spent developing a wind project is considered entirely at risk because an unsuccessfully developed project has only a minimal asset value, and limited or no revenue potential.[4]

[2] The term *pro forma* is Latin for "for the sake of form" (Investopedia 2016). A pro forma financial estimate is defined as "assumed, forecasted, or informal information presented in advance of the actual or formal information" (Business Dictionary 2017).
[3] For a more comprehensive listing, the investment rating agency Fitch provides a thorough analysis in "Rating Criteria of Onshore Wind Farms Debt Instruments" (Fitch 2016). The Fitch report summarizes risk for only one type of investors—a lender—though it is broadly applicable to other types of investors (e.g., tax equity) as well.
[4] The possible exception here is where a project development company may transfer a partially-developed project to another developer.

- **Construction Risk**. Fitch (2016) classifies the construction risk of wind projects as "low in complexity" based on the industry's extensive history constructing land-based projects. The construction of a project is generally viewed as an acceptable risk after turbine pricing has been secured, and the construction is likely completed with a fixed-price contract with built-in protections for the investors. Fitch does note, however, that delays in the supply chain can have a material impact on the ability of the project to generate revenue. Delays and over-runs can be contractually mitigated through guarantees, funds set aside for contingencies, and punitive payments.
- **Regulatory Risk**. This is the risk arising from the inability to predict with complete certainty if regulatory schemes supporting wind energy development will be available for the term described at the onset of the project. For example, the use of tax incentives that are recovered over a period of 10 years and green energy attributes that also may have multi-year contracts both provide a revenue source to the project, but are only valuable if they are considered secure by the investor in the project.
- **Market or Selling Price Risk**. This risk encompasses the extent to which the project's source of revenue is subject to an unknown selling price (e.g., if the plant is "merchant" and relies on revenues from selling into an electricity market with variable pricing rather than a fixed-price PPA contract). All else being equal, a project that has a guaranteed price for its energy over its entire lifetime has less uncertainty and therefore less perceived risk compared to a project with some market price exposure. Of course, while guaranteed power prices protect project investors from the downside of market exposure, they also prevent the investor from benefitting from the potential upside of increasing market prices above the locked-in rate. Another component of the selling price risk involves the ability of the electricity purchaser to pay for the energy as contractually obligated.
- **Pre-Construction Energy Estimate Risk.** This is the risk associated with the forecast accuracy of the amount of energy a wind project is expected to generate annually and over its lifetime. Expected production is a critical input to a financial model, as it will significantly factor into determining investment viability, sizing, and profitability. It is also the key focus area of PRUF's 2016 energy estimate primer (Clifton et al. 2016). Fitch's rating criteria for wind projects notes that the ratings agency will typically reduce any pre-construction energy estimate by up to 10% based on a number of project-specific factors (Fitch 2016).
- **Technology and Energy Production Risk.** This risk category includes several different components that all manifest as reduced energy production in a given year, and consequently diminished electricity sales volume and revenue. There are many factors that contribute to production risk that can be either temporary or permanent in nature. Some of these factors include weather anomalies, technology reliability, project availability, curtailment, and unexpected operations and maintenance (O&M) events. Availability generally refers to the ability of the operator to keep the wind project working and producing electricity. Curtailment can refer to the situation where a project is technically capable of delivering power to the grid but fails to do so for either bulk

electric system reliability issues or economic reasons.[5] Similarly, O&M risk typically refers to the track record of the entity responsible for running the wind plant to service turbines in a timely manner and according to budgeted forecasts.

[5] System reliability curtailment typically refers to a situation in which a generating asset must curtail its power to protect the safety of the grid system. Economic curtailment typically refers to a situation in which the price of electricity bid into the wholesale market is not accepted. The renewable energy asset owner typically bears the risk of system reliability and emergency curtailment; however, it is up to the contract to determine whether the project owner or electricity purchaser bears the risk of economic curtailment.

3 Wind Energy Project Lifecycle

Wind project development contains multiple phases, each with its own unique set of tasks, risks, capital sources, and potential obstacles to overcome. Collectively these phases represent the lifecycle of a wind energy project, and while there is no standard definition or sequencing of the project development phases, most approaches envision a comprehensive set of actions that can be carried out in parallel or in some instances in a stage-gate manner.

During the development process, a central coordinating party (the developer or sponsor) ushers the project through a series of activities that addresses all the requirements for reducing risks and uncertainties, completing milestones, and advancing a project from conceptual to concrete. Development activities are directed to demonstrating and assembling the key criteria of a successful wind project, which include but are not limited to the following:

- Verified resource (feasible wind characteristics)
- Controlled location (a permitted site)
- Market for product (demand for energy and other grid services)
- Path to market (transmission access).

The remainder of this section briefly describes the major phases of project development.

3.1 Screening

The initial phase of a project is providing a first-order assessment of its overall feasibility within the larger energy market. Typically, a developer will first evaluate the suitability of the site through a virtual screening, followed by a more robust, dedicated wind study. For a virtual assessment, regional wind profiles allow for a quick desktop-based screening to determine estimated winds based on the local characteristics rather than the specific site.

During the initial screening, a project developer will also conduct a "fatal flaw analysis" that gauges the critical aspects across a number of different potential sites and tries to identify all mission critical barriers to development. This step is undertaken very early in the development process so as to avoid investing too much time and capital in a project that ultimately may prove unfeasible. Some common issues that developers may consider a fatal flaw include:

- Poor wind resource
- Lack of transmission access
- Limited site access
- No electricity purchaser
- Insufficient local support and buy-in
- Environmental sensitivities
- Historical or cultural sensitivities
- Permitting complications.

Investment required at this initial screening phase is relatively small and typically sourced from the developer's own funds. Outside investment is not typical at this early stage due to the high-risk nature of the activity and the uncertainty of any one project becoming fully developed and commercially operational (Springer 2013).[6] Sources of funding at this stage for a small developer may be personal funds from the principals in the development company, landowner(s), friends and family, or other willing early-stage investors. Larger developers will usually fund scouting and initial prospecting using capital available on their own balance sheet. They may also purchase promising projects from smaller developers who have conducted initial screens.

3.2 Pre-Development

If the initial screening of a site indicates a promising resource and has no apparent fatal flaws, then the developer may elect to continue with early stage development activities. At this stage, a more credible assessment of the wind resource will be conducted, requiring an onsite, structured wind-measurement program be implemented. In many cases, multiple meteorological towers will be deployed temporarily across the site to further assess the wind speed, direction, duration, and turbulence. A 12-month (or more) data collection period with a high level of data quality assurance will provide input to a power production model that will be used later for construction financing (Vestas, n.d.). Robustness of the wind data varies across developers and projects, although, generally, the more detailed and specific the data, the higher the likelihood that the developer will secure funding for construction. The quality of the meteorological monitoring program will contribute to both the availability and the cost of capital.

Another crucial aspect of the development activity is to ensure sufficient access to and certain control over the project site (Taylor and Parsons 2008). Even the best wind data is of little value without also having sufficient control over the potential site. Though the developer will typically treat the wind data as highly confidential, the developer will also need to forge relationships early with potential wind turbine hosts on the site.[7] Site control can be contracted through various mechanisms including a land lease or outright purchase. The developer will typically seek site control for an extended period to accommodate the timeline of the development and operations processes.

During the initial development phase, the developer may also have preliminary discussions with county commissioners, local government agencies, community leaders, and other key stakeholders to begin to secure the permits necessary for construction of the project. Presenting the local authority having jurisdiction with the meteorological monitoring program findings may give the commissioners an opportunity to identify whether they will likely object to all or a portion of an eventual wind farm located at the site.

At the early development stage, the developer will also prepare an economic assessment for converting the wind resource into marketable electricity at the chosen site. A simplified pro forma financial model using typical assumptions for technology, reliability, availability, degradation, transmission losses, revenue, expenses, incentives, and other inputs will indicate

[6] Risk at various levels from prospecting through development is not easily quantified without understanding success rates for the pool of wind energy developers, and developers are often hesitant to publicize such detail (Taylor and Parsons 2008). Therefore, characterization of development risk herein is illustrative.
[7] The "site" could entail multiple landowners and multiple counties.

whether a wind project at the site will deliver a satisfactory return on investment. Such a model can also help forecast whether the project will produce power at an economically attractive price. A business case is likely developed with updates as more details come to light and conditions and assumptions change, demonstrating whether or not the project appears to be economically feasible (Springer 2013).

3.3 Development

As a conceptual project begins to show more promise and risks are mitigated, development activity in the project will typically accelerate. Preliminary design and site engineering work can begin with a basic layout of the project on the site. At this stage, a utility PPA or comparable instrument will be pursued. The turbine vendor will be selected and a turbine supply agreement will be considered. The impact on the local electrical grid will also be studied through system impact and interconnection studies to help determine if any upgrades may be necessary for the wind farm to connect to the grid and the market served (Burns & McDonnell 2009). A construction contractor or multiple contractors may also be preliminarily screened and qualified.

At this stage the likelihood of the project reaching completion will have increased as will the level of investment in the project. Larger developers will usually continue to fund such development with their own internal capital, while smaller developers may look for additional support through partnerships with external funding sources, a sale of development rights, and other approaches.

As the end of the development stage approaches and construction of the wind farm appears to be reasonably likely, the projected future revenue of the project will be heavily scrutinized to secure outside commercial financing. The various agreements in the development stage, however, are typically pliable so they can be modified if necessary. The investor will typically provide term sheets that outline the specifics of the investment to ensure that the parties agree to the basic parameters before advancing to the more costly final negotiations. Outside advisors such as independent engineers and tax consultants will also be engaged to help investors understand project risks from an objective perspective (Fitch 2016).

At the end of the development stage, construction is ready to begin, pending the finalized decision(s) for investment and the financial close (the point at which the financial documents are signed and capital begins flowing to the project from the investors).

3.4 Construction

A wind farm will begin construction when the developers give the Notice to Proceed to the contractor(s). At this stage, the project has secured the necessary financing and development risk has shifted to construction-oriented risks, including unforeseen construction barriers, cost and timeline overruns, and others. Because of the large number of wind projects successfully completed, construction of land-based wind farms is generally well-understood by construction contractors, insurance providers, and equipment vendors among others (Fitch 2016).

Activities during the construction phase include the procurement of materials; the physical building of the wind farm; management of construction site, personnel, and process; reporting to investors; and community relations. The elements of the physical construction process generally include construction of support roads; concrete pumping for the turbine pad; turbine delivery; setting the tower section; lifting the nacelle; assembling the rotor; lifting and attaching the rotor; installation of a collection system of wiring to electrically connect to a substation; and construction of an O&M support building (We Energies, n.d.).

In a typical construction financing scenario, the project sponsor will be expected to contribute significant capital to the project, colloquially referred to as "skin in the game." This contribution ensures that priorities between the different parties during construction are aligned. The remainder of the investment is typically a loan from a commercial bank (aptly called a "construction loan"). In many cases the construction lender will also provide longer-term financing for the project. This commonly happens through a conversion, where the construction loan is refinanced by the same lender as a term loan, with a different interest rate, maturity, and term sheet.

During the construction phase but before the wind farm is fully completed, the project sponsor may be able to bring certain turbines online to deliver test electricity to the grid for sale. The revenue received on such electricity sales before the commercial operation date of the wind farm may be sold at separate prices from the power delivered after the project is fully operational and may be contributed as sponsor equity.

3.5 Operations

Operation of the wind farm generally commences once a substantial amount of construction has been completed. "Substantial completion" generally means that each wind turbine has been commissioned and certified, electricity will be delivered to the grid, and there is coordination with the grid operator and utility or power purchaser.[8]

During the first year of the wind farm operation, the operator (the developer/sponsor or a contracted third-party operations manager) will typically ensure that any challenges—from hardware (e.g., blades, gearboxes, etc.) to software (e.g., turbine electronics, wind farm controls)—are tracked and remedied. This is sometimes referred to as "teething." These actions can reduce the availability of the wind project and diminish the amount of energy produced by the system operating in its initial phase compared to pre-construction estimates (Fitch 2016). By the second year of operation, the wind farm is generally expected to be producing and selling electricity at a level consistent with the forecast presented in the wind plant's pro forma financial model. The level at which operational wind projects have been producing energy compared to their earlier performance forecasts, however, varies (Fitch 2014; NAW 2014; Bailey 2016).

The plant operator may be contracted to carry out both routine O&M activities as well as major maintenance measures, although the original turbine supplier may also be involved for some technically complex activities. Major maintenance is generally pre-funded through reserve accounts, which are set up during the project's financial close. As the major maintenance reserve is drawn upon to repair failures, it is usually replenished from the project's cash flow. After a few years of successful operation consistent with the original business plan, risk is generally considered to be at its lowest in the project's operating lifecycle.

[8] See IRS 2013 for guidance on placed in service conditions (IRS 2013).

3.6 End of Life

As the wind farm approaches the end of its original estimated useful life, the equipment may be decommissioned, overhauled, or repowered. These activities will depend on land lease provisions, PPAs, and the economics of different decision pathways. Typically, wind energy contracts will provide a financial mechanism such as posting a performance bond or requiring a reserve account be set aside to fund the cost of the end of life activities to restore the site to a pre-agreed-upon condition.

4 Capital Sources

Generally, wind project financing is composed of three main sources of capital: equity—including sponsor equity and tax equity, and debt. The blend and proportion of each of these capital sources in a given project is referred to as the capital structure or capital stack. At a basic level, most wind project capital structures will include a sponsor equity partner (commonly a developer), a debt provider, and many projects will use a third party tax equity partner that provides upfront capital in exchange for the tax benefits of the project.

Subsections 4.1–4.3 provide focused discussions on each of the primary capital sources, while Section 4.4 summarizes how these sources combine to form capital structures.

4.1 Equity Capital

Equity generally refers to an ownership share of an asset, which can take the form of a security (e.g., stock or share) or a direct investment in a company. Equity investors typically stand to lose some or all of their investment depending on whether the company or project is successful. Conversely, equity capital also stands to gain beyond original expectations if the company or project outperforms forecasts or if the project is sold to another party.

There are multiple ways in which an equity partner can invest in the construction and/or long-term ownership of a wind project. This report looks at the two most common forms: tax equity and sponsor equity. Before jumping into these equity options, a basic overview of the federal tax incentives available to wind technologies is warranted.

4.1.1 U.S. Federal Tax Incentives

The United States Federal Government incentivizes renewable energy projects principally through the tax code. As of this writing, wind technologies are eligible to receive either the production tax credit (PTC) or the investment tax credit (ITC) (one or the other, but not both) as well as accelerated depreciation tax offsets through the Modified Accelerated Cost Recovery System (MACRS). The tax credit incentives (the PTC and ITC) provide an after-tax credit on tax liabilities (i.e., the taxes paid) and thus are often described as dollar-for-dollar tax incentives. Accelerated depreciation, by contrast, provides a reduction in taxable income against which the tax rate is subsequently applied, and so is described as a before-tax incentive. As of this writing the PTC is currently worth $0.024 for every kWh generated over a 10-year period[9] while the ITC is structured as a one-time credit valued at 30% of eligible system costs (Novogradac 2016). For projects to claim the aforementioned full PTC or ITC values, however, the project is required to have begun construction prior to December 31, 2016.[10] Projects that begin construction in 2017 through 2019 are available for a reduced-value PTC or ITC, shown in Table 1.

Depending on the performance of the project, the net present value of the full $0.024 value of the PTC combined with the accelerated depreciation benefits have historically provided in excess of 50% of the project's initial capital costs in tax savings (Bolinger 2014).[11] The rules governing

[9] Periodically adjusted for inflation.
[10] Qualifying criteria for begun construction clarified in IRS 2016 and IRS 2017a.
[11] A diminished value of the PTC or ITC would reduce this estimate somewhat. Note that only the PTC or ITC is reduced in value while, as of this writing, the MACRS schedule is a permanent part of the tax code.

the eligibility, receipt, and other aspects of the tax credits are codified in the Internal Revenue Code, specifically Section 45 for the PTC and Section 48 for the ITC. The rules related to the accelerated depreciation of property for tax purposes are found in several places, including Section 168, Section 48, and Internal Revenue Service (IRS) Publication 946 (IRS 2017b).[12] In addition to the five-year MACRS schedule, qualifying renewable energy projects have the option to depreciate 50% of an investment operation under a so-called "bonus" depreciation scheme.[13] See Figure 2 for an illustrative example of how PTC and 5-year MACRS are received over the life of a typical wind project (Bolinger 2014).

Table 1. Tax Credits and Accelerated Depreciation

	Year	PTC Value	ITC Value	Accelerated Depreciation
Value/Basis	2016	100% PTC (2.4¢/kWh)	30%	Depreciation of *qualifying* project costs according to specified annual schedule. For wind, 100% of qualifying costs (and ~92%–98% of total project costs) can be depreciated in the first six years of commercial operation. The principal section of the U.S. Internal Revenue Code that deals with depreciation is Section 168.
	2017	80% PTC (1.8¢/kWh)	24%	
	2018	60% PTC (1.4¢/kWh)	18%	
	2019	40% PTC (0.9¢/kWh)	12%	
Expiration/Step-Down	Wind projects must be deemed to have begun construction by each year to qualify for credit value. Credit value steps down from 2017–2019 and expires completely on December 31, 2019. Qualifying criteria for "begun" construction clarified in IRS 2016 and IRS 2017a.			**5-year MACRS:** No expiration **Bonus Depreciation:** 50% depreciation allowed in year 1 of project operation until December 31, 2017; 40% until December 31, 2018; and 30% until December 31, 2019.

Source: Updated from Lowder et al. 2015 and Novogradac 2016

[12] Section 168 defines accelerated depreciation broadly, and Section 48 contains the provision for an investment tax credit for several renewable energy technologies. Publication 946 contains MACRS schedules, including the 5-year MACRS for eligible renewable energy technologies (IRS 2017b). Note that election of the ITC also requires a reduction in the eligible cost basis for MACRS equal to one-half the value of the tax credit (e.g. 15% for the 30% ITC and so forth).

[13] Bonus depreciation can generate sizable tax losses in the first year of the project and thus requires an entity with a significant tax liability to make efficient use of it. Moreover, high tax losses will decrease the tax equity partner's capital account, which can introduce complications and risks into the financial structure of the project. For this reason, tax equity investors may forgo the use of bonus depreciation in wind deals (Burton 2016).

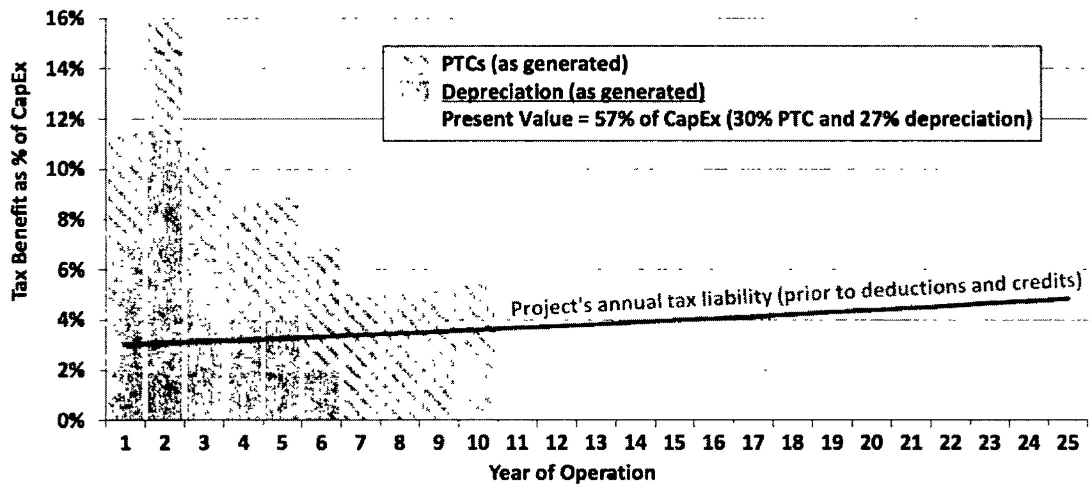

Figure 2. Timing of the federal tax benefits generated by a wind project[14]

Source: Bolinger 2014

4.2 Tax Equity

To make the most efficient use of the tax benefits—the PTC or ITC coupled with MACRS—a taxable entity must apply them to taxable income (depreciation) and tax liability (credits) in the year in which the benefits were generated. However, many sponsors or developers in the wind industry do not have enough tax capacity to do so and would otherwise have to carry the benefits forward (thus depleting their present value due to the time value of money) if it were not for the ability of outside investors to "monetize" them. These investors, known as tax equity investors, will commit capital to a project in exchange for access to the PTC or ITC and accelerated depreciation, thus providing the project with a sizable portion of its capital needs (typically 30%–50% of the total). Because this type of investment requires significant capital and tax liabilities, tax equity investors are often large financial entities such as banks and insurance funds. Several multinational corporations are also active in the tax equity market.

To access the tax benefits, investors must demonstrate ownership of the project assets for tax purposes (a determination made by the IRS). In wind projects, this ownership usually comes in the form of a partnership with the developer (unless the project is owned by a single entity that can wholly use the tax incentives themselves). The partnership is structured as a special purpose vehicle (SPV)—either a limited liability partnership (LLP) or limited liability company (LLC)—into which each of the partners (developer and tax equity) makes a capital contribution. Each partner is allocated a certain share of the project value streams—namely income (cash) and tax benefits (deductions and credits)—which change over the life of the partnership.[15]

[14] CapEx refers to the capital expenditures of a wind project.

[15] Renewable energy projects that utilize the investment tax credit (Section 48) can execute one of three tax equity financial structures: partnership flip, sale leaseback, and inverted lease/lease pass-through. However, projects that utilize the PTC are not permitted to execute lease structures as per the "owner/operator" requirement in Section 45. For this reason, the partnership flip is the dominant financial structure to monetize tax equity for wind projects.

Two criticisms of utilizing outside tax equity investments are frequently reported. First, there are relatively few active tax equity partners in the market in any given year.[16] Because the demand for this type of capital often outpaces the available supply, the tax equity investors may require a higher return than a comparable debt product, ranging generally from 7%–10% based on the particulars of the investment and the overall supply of market tax equity (Shurey 2016; Shanahan, Wisniewski, and Andiorio 2017).

The second criticism to tax equity financing is also a function of the complicated structuring. Setting up a deal entails high transaction costs—e.g., fees associated with legal services, tax opinions, consultants, financial structuring, and other services (Feldman, Lowder, and Schwabe 2016). Such transactional costs reduce the nominal value of the tax incentives and can also drive deal flow to larger project sizes (which keep the more-or-less fixed transaction costs low relative to deal size). This can have the effect of limiting the competitiveness in the wind development market place, as smaller developers may not be able to access financing as readily as larger players.

4.3 Sponsor Equity

The sponsor equity ("sponsor") in a project most closely resembles a traditional equity investor and often can be the original developer of the project. The sponsor equity is typically the ultimate financial backstop in the project, and also the last entity to receive payment in the distribution of income in the project. Because the sponsor commonly faces the highest risk in the partnership, it will often also have the highest return requirements. However, because the sponsor equity is typically either back-levered (discussed later) or is only a marginal portion of the capital stack, this highest cost equity may exert only a limited impact on the project's weighted average cost of capital (WACC)—the combined cost of capital from all the sources in the project's capital stack).

If the sponsor is also the developer, it is responsible for bringing the project from initial concept through the extensive development phase all the way to construction and commercial operations.[17] In many cases, the sponsor may ultimately manage the long-run functioning of the project, providing O&M services, fulfilling the obligations of the PPA (if there is one), or managing the dispatch of electricity into wholesale markets. In some cases, the sponsor can also be a relatively passive or non-active owner in the project and contract out the day-to-day O&M of the project. The sponsor may also receive some of the project's income distributions as well as a "development fee" that it collects upon commercial operation of the project (Bolinger 2014). This fee varies, but some report ranges from 8%–15% of the project capital costs, which can be paid from a portion of the tax equity's initial investment in the partnership, from any leftover construction debt, or from a portion of the term debt disbursal (Martin 2011; Feldman, Lowder, and Schwabe 2016). Sponsor equity largely receives its returns on a primarily cash basis rather than through distribution of the tax benefits.

[16] One of the reasons that the pool of tax equity investors is limited (which in turn can drive tax equity yields higher for the limited supply relative to demand) is the passive activity loss and at-risk rules in the U.S. Internal Revenue Code. Both rules effectively prevent certain entities from accessing the full value of the tax benefits available to investors in renewable energy projects (Eliason 2012).

[17] In some cases, more than one developer can be involved in the process of conceptualization, project development, construction, and ultimate ownership of the project. This will happen when one developer sells a project to another at the outset of any one of these phases.

The sponsor can raise funds for project development and investment via several sources, including their own balance sheet; funding from customers and suppliers; outside private investors; and others. More recently, companies have looked to the public capital markets, employing vehicles such as yieldcos once projects were fully developed (see textbox below) to raise equity funds at a lower cost than other sources. Additionally, a more mature company may "go public" and issue stock in the public markets and the proceeds can be used to fund development work.

Financing in the Capital Markets: Yieldcos

Capital markets are the transactional marketplace into which businesses, governments, individuals, and other entities sell debt and equity instruments to investors, and investors sell such instruments to one another. The most common instruments sold in the capital markets are bonds (debt) and stocks (equity) (Goldman Sachs 2014). In the last several years, renewable energy developers have turned their attention to the capital markets as a source of low-cost finance that could help to reduce project LCOE. Two means by which developers have accomplished this are through yieldcos and asset-backed securities (see textbox below for a discussion of securitization and asset-backed securities).

A yieldco is a corporate entity (a limited liability corporation, limited liability partnership, or joint venture) that aggregates a portfolio of energy assets for which ownership shares—i.e., stocks—are sold. Yieldcos are commonly subsidiaries of larger parent developers that hold and generate additional value from operating assets. As such, yieldcos often get a right-of-first-offer for projects developed by their parent companies, and this in turn can give the parent a captive means to sell completed projects and redeploy capital. Yieldcos also purchase operating projects and pipelines from other developers to grow their asset-base (Lowder et al. 2015).

Yieldcos allow project developers to potentially access lower-cost equity capital, and to source capital for growth that might otherwise be difficult to come by (either through corporate bonds, stock issuance, or other means). The principal benefit of a yieldco for investors include: limited taxation (accelerated depreciation benefits can allow yieldcos to eliminate corporate-level tax for a number of years); long-term predictable cash flows; and, until recently, the promise of dividend growth. This last benefit became difficult to achieve as yieldco sponsors found the practice of continually expanding their asset bases to be difficult to sustain. This and other factors have led to a dormancy in yieldco markets that has largely persisted since late 2015. Some of the more stable yieldcos have been able to raise some equity since that time, though others have not (owing, in some cases to financial difficulties at the corporate parent) (Lowder et al. 2015).

4.4 Debt

Debt is a contractually-arranged loan that must be repaid by the borrower and in which the lender has no ownership shares in the company or venture. Debt is generally considered a lower-risk investment and therefore a lower-cost funding source relative to equity, though in the case of tax equity financing risk may be considered comparable between the two (Shurey 2016; Shanahan, Wisniewski, and Andiorio 2017). Outside of this unique case, the reduced risk profile of a debt investment derives from several structural features, including but not limited to the following:

- Lenders are typically less exposed to the downside of project performance (i.e., if a project does not generate as much electricity in a year as was forecasted), but correspondingly do not enjoy the upside if the project outperforms forecasts. Moreover, once the loan is paid off, there are no remaining financial obligations from the borrower to the debt providers.
- Debt can be—though not always with tax equity involved— a "senior" investment, meaning that debt investors are typically repaid before other investors in the capital stack (i.e., most notably sponsor equity). This means that shortfalls in project revenues from underperformance, equipment failures, force majeure events, or others could cut payments to the equity holders to allow for the full and timely repayment of the loan. In some cases, however, tax equity providers may actually have repayment seniority over debt due to the relative scarcity of tax equity compared to debt (Chadbourne & Parke 2017; Feldman, Lowder, and Schwabe 2016).
- Lenders often have financial protections such as collateral to their investment (e.g., the project assets or partnership interests) or rights to "step-in" and take over control of the company if necessary. These are often expressed in the debt "covenants"—agreements between the lender and the borrower executed before the disbursement of the loan.

The three main forms of debt in the wind market are short-duration construction debt, longer-duration term debt, and back-leverage. Each of these financing products is described in more detail below.

4.4.1 Construction Debt

As the name implies, construction debt is used primarily to fund the engineering, design, equipment procurement, and construction of the wind project. Construction debt is typically characterized by lower-cost, shorter-tenor debt compared to the long-term debt that funds the operation of the project. Construction debt reflects the inherent risk of the project's construction processes and the associated likelihood of experiencing events that can negatively impact the ability of the project to recover its costs (Groobey et al. 2010). Examples of these risks include the project exceeding its budgeted cost or missing construction milestones, which delays the ability of the project to generate revenue. Moreover, the lender is providing construction capital against a project that is not yet generating revenue, thus the pricing is also influenced by the longer-term characteristic and credit quality of the project and its sponsor. The tenor of the construction debt (i.e., length) of the construction loan may match the construction period until the project is considered to be commercially operational.

A distinguishing feature of construction debt is the ability to access the debt financing as it is needed rather than entirely upfront (referred to as a construction drawdown schedule). For the lender this pre-negotiated scheduled helps to mitigate their lending risk by limiting the amount of capital going to the project until specific milestones have been met and excess funds are not used improperly for other purposes. For borrowers, the construction drawdown schedule allows them to reduce the amount of time for which that debt is outstanding and typically reduces the amount of overall interest costs paid.

The availability and pricing of construction debt will also vary depending on the type of construction strategy employed. For example, projects that employ a single designated party to engineer, procure, and construct the wind facility tend to be viewed as less risky than a multi-party strategy that may separate and allocate these tasks to more than one entity.

4.4.2 Term Debt

Term debt is the loan (or portfolio of loans) that refinances the construction loan at a longer maturity (construction loans typically last only a couple years while term debt loans extend to 7+ years). The interest rate on a term debt reflects the longer tenor of the term loan compared to the construction loan, as well as the risk profile of an operating asset. In some cases, capital from the term loan can be used to "take out" or, more simply, replace a portion of the sponsor equity's stake in a project, which will reduce project WACC and therefore LCOE. Accordingly, term loans are sometimes referred to as "takeout financing." Term debt can come from several sources, including commercial banks, syndicates (a group of banks operating in agreement with one another), private equity funds, insurance and pension funds, equipment manufacturers (vendor financing), and governments (in the form of concessional loans, export credit financing, and other mechanisms). Term debt can sit at either the project level or at the sponsor level, though recent trends in tax-based wind finance structures most commonly utilize debt at the sponsor level, which is described in the section on "Back-Leverage" (Chadbourne & Parke 2017).

In the current market, much of the term debt extended to wind projects is structured as "mini-perms." Mini-perms are long-term debt products (where the principal and interest are amortized over a period near the length of the contracted revenue period such as a 20-year PPA), but have shorter-dated maturities (typically 5–7 years). Due to this structuring, mini-perms will have a large balloon payment that is due when the maturity is up. This balloon payment is typically refinanced by another mini-perm loan with another principal and interest amortization schedule that extends beyond the loan's maturity (Feldman, Lowder, and Schwabe 2016).

For example, a lender might offer an 18-year loan to a wind project with a slightly longer 20-year PPA (to avoid the final contracted years of the asset), but will require that, in year 7 of project operation, all available revenue coming into the project be "swept" up to repay the entire amount of the debt service. In order to prevent this, the project sponsor will refinance the original mini-perm for another 7 years, although the principal and interest payments will continue to amortize as if the loan term were longer than 7 years.

Debt Service Coverage Ratio (DSCR)

When deciding the appropriate amount to lend to a renewable energy project, term lenders will often look at the expected production of the project in the form of exceedance probabilities. The lender will evaluate a set of probability scenarios where energy production would exceed forecasts in any given year (Fitch 2016). Typically, they will look at a 50%, 90%, and 99% exceedance probability scenario (denoted as P50, P90, and P99, respectively).

Exceedance probabilities will also determine the debt service coverage ratio (DSCR), which is the measure of a project's cash flow to its debt obligations. A DSCR of 1.25 means that the project is anticipated to generate 25% more cash flow available for debt service (revenue less operating expenses) in a period than is required for debt service. Lenders will often require certain DSCRs at certain exceedance probabilities to afford themselves sufficient cushion in case energy production and therefore the cash flow falls below a specified amount in a certain timeframe or expenses are higher than anticipated.

4.4.3 Back-Leverage

When it sits at the project level, term debt can obstruct cash flows to the equity partners, impose complications in daily operations through the various covenants, and present a risk to the tax equity investor's ability to receive its anticipated economic returns. For these reasons and others, tax equity may be unwilling to lend to a project with project-level debt or may demand a higher return on its investment than it would for a project without debt at the project level. Accordingly, sponsors in the project have adopted the practice of "back leveraging" their loans. In a back-leveraged debt arrangement, the tax equity and the sponsor equity form a partnership company that owns the project through different class ownership shares. The sponsor equity will typically own more junior Class B shares, while tax equity will own more senior Class A shares. The sponsor equity will pledge its ownership interests in the project company as collateral, and a lender will issue debt to the sponsor directly instead of to the project company. This removes the debt from the project company level and the loan is repaid by the cash flows allocated to Class B shares as defined in the partnership company agreement. In this scenario, the cost of back-leveraged debt is based on the overall credit of the sponsor rather than the wind project itself. If there is a default, the financiers (lender or tax equity) may exercise the right to step in and take on the managing interests that were previously afforded to the sponsor.

At current interest rates and terms, back-leveraged debt is typically priced slightly higher than project-level debt, as it can represent a riskier loan than term debt from the perspective of the lender, particularly because tax equity may have preferred repayment rights. Developers, however, will often back-leverage their debt on a project in order to attract the limited tax equity funding. Back-leverage lenders tend to be a more limited group than term-debt lenders, consisting largely of commercial banks (though some private equity players have reportedly issued loans in the back-leverage market).

Financing in the Capital Markets: Securitization

Securitization is the process by which financial assets (e.g., contracts such as leases and loans that stipulate cash transfers between parties) are pooled and processed into financial vehicles (securities), which are then sold to investors. These securities represent claims to the cash flows in a particular pool of assets, and in this way, the purchase of a security by an investor is treated as a collateralized loan. One of the principal goals for executing securitization transactions is to achieve a lower cost of capital on a pool of assets—essentially, to refinance at a lower rate (Lowder and Mendelsohn 2013).

In a wind project financial structure, it is possible for a developer or sponsor to "pledge" its partnership interests in the project LLC (and thus any income it receives from project revenues) to a securitization trust. From this trust a series of instruments (likely asset-backed securities) would be issued to investors. In this way, a developer/sponsor could swap out their high-cost equity for a lower-cost debt from the capital markets.

To date, securitzation has been most effectively executed by distributed solar sponsors (namely the large third-party finance providers such as Tesla [formerly SolarCity] and Sunrun). It is theoretically possible that a wind project could securitize its cash flows, though because wind projects tend to be large, utility-scale assets, securitization is not as readily applicable to the wind asset class at this time. The technique works well in the distributed solar space in part because the high number of offtaker contracts (residential and some commercial PPAs and leases) that back a securitization pool provides diversity that can protect investors. Additionally, there is standardization among these contracts, which facilitates pooling these assets together into a trust and alleviates the diligence requirements (and therefore costs) for investors.

4.4.4 Other Forms of Debt

4.4.4.1 Term Loan B

Term loan B are debt products that are underwritten by an institutional investor or other non-bank entity (such as a hedge fund or collateralized loan obligation fund), and typically issued for projects perceived as higher risk than a standard wind deal (e.g., a "merchant" project that doesn't have a PPA). Typically, term loan B debt holders will have less interaction with the project sponsor than would a bank in a term loan situation and make fewer requirements of the borrower (Dworkin and Holland 2014). Because of the risk profile, the relative relief in debt covenants, and other factors, term loans B will usually carry a higher interest rate than a loan from a commercial bank (Chadbourne & Parke 2015, 2017).

4.4.4.2 Bonds

Bonds are a form of debt security that can be backed by a corporate balance sheet, an entity's creditworthiness (as in the case of a municipal bond), a project's projected cash flows (as in the case of non-recourse finance), or other forms of collateral. In the case of a wind project financing, the sponsor can issue corporate bonds provided it has access to the bond capital markets, or bonds can be issued by the project's SPV (in which case it is project-level debt). The costs, regulations, and creditor requirements are different for bonds than they are for debt sourced through a commercial bank, though the capital is still treated as a debt on the borrower's balance sheet. The terms of the debt, specified in a document called the debenture or covenant, are spelled out to protect the interest of both parties and will differ by the type of bond and the issuer. A municipality with a high credit rating will be able to issue bonds at a lower interest rate and often with a tax exemption on the interest payments to investors. Corporate entities commonly have lower credit ratings (if they are rated at all) than municipalities and other governments, and may not be able to access debt capital for as long a term and as low an interest rate.

4.5 Financial Capital Stack

The various financing sources described above are the principal source of funds for most wind energy projects. Collectively these sources of funds are referred to as the "capital stack" of the wind project, which represents the total financing package needed to construct and build the wind project. In some projects, a particular type of funds such as the term loan may actually be provided by more than one capital provider. This is typically because the total cost of a wind project can exceed the preferred or even maximum investment size for any one partner, requiring multiple investors to collectively make up the capital stack. For loan products this is typically referred to as a syndicated loan product, which can take a number of different forms depending on the type of the arrangement between the group of lenders. Tax equity syndication is also available (US Bank 2016).

Figure 3 below depicts an illustrative representation of the relative risks and returns of each of the main sources of capital in wind energy projects as well as the typical point of investment for the type of investment product. As described above, the construction debt, term debt, and tax equity of the project are typically the lowest-risk and lowest-cost financing available for a number of reasons, including preferred payment position, collateral in the project, contractually agreed upon yields or returns, and step-in rights, among others. Term debt is typically priced higher than construction debt due to the longer tenor of the term loan compared to the construction loan, the drawdown feature of construction loans, and other contractual protections such as full engineering, procurement, and construction wraps with fixed-price structures. Depending on a project's specifics, term debt and tax equity may be considered comparable in risk for a number of reasons, such as they both can benefit from preferred payment position, collateral in the project, and step-in rights, among others. Tax equity, however, typically commands a higher return compared to term debt due to the relatively limited supply of tax equity (wind energy competes for tax equity investment with other energy technologies or alternative tax-oriented investments such as affordable housing) and return periods that extend to around ten years, typically a few years longer than current mini-perm term debt tenors. Among the equity options, tax equity typically assumes less risk than either the sponsor or developer equity (which may be one and the same) because of senior repayment structures and pre-defined yields.

Figure 3 also shows whether the investment capital typically comes into the project prior to or following commercial operations, which have different risk profiles. The main finance sources that come into the project before reaching commercial operations are the construction loan and the developer equity that fund the steps preceding even the construction phase. Note that the sponsor equity and developer equity may be one in the same.

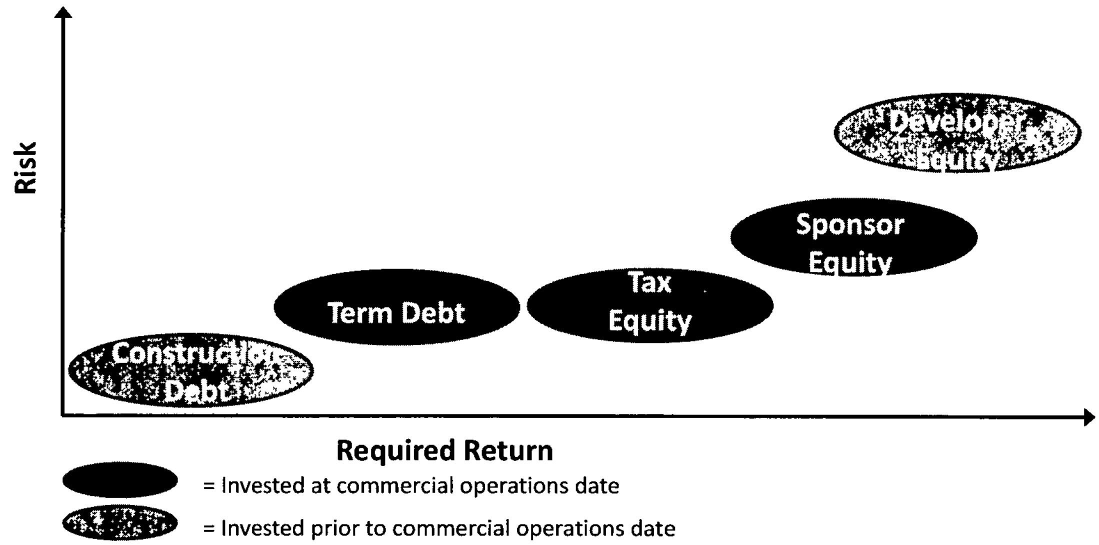

Figure 3. Comparison of the relative risks and returns for typical wind energy financing sources

Adapted from Schwabe 2010

4.6 Financial Structures

Historically there are a number of different financial structures that have been used to fund a wind project. This section briefly touches on two of the most common structures: the single-owner model and the partnership flip. The report here largely focuses on the partnership flip, as this structure demonstrates a multiple-party finance structure with separate entities for sponsor equity, tax equity, and debt.

4.6.1 Single-Owner

If the sponsor of a wind project can duly fund the project with its own capital (or source sufficient debt for a portion), *and* also make efficient use of the federal tax benefits, then single ownership is likely the most economic option. The single ownership structure employs a single entity, to develop, finance, and operate a project themselves. With only one owner in the effort, there is no requirement for third-party tax equity and comparatively smaller transaction costs for setting up a project financial structure with an outside entity. Single ownership is also the simplest financial structure available to wind project sponsors, as it keeps control of the project, its assets, and its benefit streams wholly within their control.

4.6.2 Partnership Flip

The partnership flip structure is the predominant tax equity financial structure currently available to wind projects due to an owner-operator requirement in Section 45 of the Internal Revenue Code (that the owner of the wind project must also be the operator), among other reasons. Thus, the use of the Section 45 PTC prevents a lease arrangement for any project that elects the PTCs since the lease splits the owner and operator roles. If a wind developer were to elect the ITC instead of the PTC, additional financial structures could be used including a partnership flip, sale leaseback, or inverted lease (also known as a lease pass-through).

In a partnership flip, both equity partners (i.e., the sponsor and the tax equity) contribute the upfront capital requirement to finance the wind project and, in turn, share in the project's economic distributions. The principal economic benefits include distributable cash and tax losses and credits. Distributable cash is the revenue earned primarily from selling energy and environmental attributes less operating expenses. Tax deductions stem from accelerated depreciation, while tax credits are claimed from the ITC and PTC.

Although every project is unique, in one often-employed version for wind projects, the sponsor equity and tax equity collectively fund the entirety of the project's upfront capital requirements. The sponsor equity receives some or all of the initial distributable cash during a predefined period. Concurrently, the tax equity investor would typically receive the majority of the project's tax benefits including both the PTC as well as taxable losses generated from accelerated depreciation and some portion of the distributable cash. After a predefined period or a financial return threshold is met, the project allocations will "flip" and the distributions of distributable cash and tax benefits shift to a second sharing allocation. The secondary allocations will typically remain until the tax equity investor achieves their pre-determined internal rate of return (IRR), which is typically modeled to occur around the expiration of the principal tax benefits (i.e., around year 10 for the PTC). After the tax equity investors achieve their IRR, the project might "flip" for a second time, after which a majority of the project's remaining benefits flow to the sponsor. Figure 4 displays a schematic of a hypothetical partnership flip structure described above.

In executing a partnership flip, the sponsor and the tax equity will jointly invest in a SPV (the "partnership"), which will be the project operations entity (i.e., it will hold and manage the assets), which is also shown in Figure 4. Typically, the tax equity partner will contribute up to 50%–60% of the project's cost as an investment in the partnership, with the sponsor contributing the balance (Chadbourne & Parke 2016b). The sponsor may also use back leveraged debt to finance the sponsor's capital contribution which is shown in Figure 4.

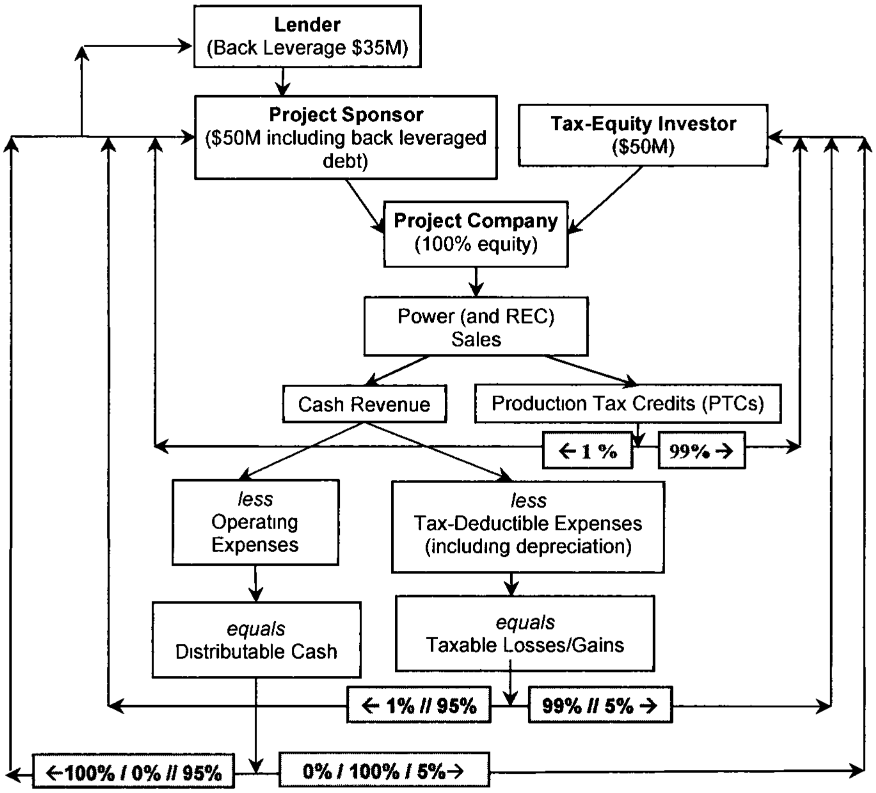

Figure 4. Hypothetical partnership flip structure for a $100 million wind project

/= first flip point in transaction where distributions ratios are initially altered
//= second flip point in transaction where distribution ratios are again altered
Source: Adapted from Feldman, Lowder, and Schwabe 2016

5 Corporate Purchasing and Procurement[18]

PPAs are energy transaction contracts—usually long-term (20 years is common)—between electricity generation owners (sellers) and energy offtakers (buyers). A PPA stipulates the commercial terms at which energy sales will be transacted from the buyer of electricity to the seller, principally the price at which the offtaker will purchase the energy (usually expressed in kilowatt-hour [kWh] or megawatt-hour [MWh]) and the length of time during which it will make such purchases (the term).[19]

One of the principal benefits of a PPA is that it provides electricity generation owners with long-term, contractually-obligated energy sales mechanisms in which they earn revenue and investment returns. Financiers of wind projects will typically require that the sponsor has successfully negotiated a PPA from a creditworthy buyer before providing capital for the project. There are, however, cases in which wind farms have been constructed on a "merchant" basis (i.e., they are financed and built with a partial PPA or entirely without a PPA and must sell energy into the wholesale markets), and in these cases investors will typically demand a higher return for the risks associated with merchant projects (Wiser and Bolinger 2016).

Utilities have traditionally been the primary offtakers/buyers for electricity from wind PPAs, largely because of renewable portfolio standards (RPS) at the state level. The contribution of RPS purchasing to renewable energy growth, however, has declined in recent years, falling from 71% of builds in 2013 to 46% in 2015 (Barbose 2016).[20] While compliance-oriented purchasing of renewables from utilities has been decreasing in recent years, purchases of renewable energy by corporations has been on the rise. For example, the Rocky Mountain Institute reports that all corporate renewable deals rose from 50 MW in 2012 to a recent high of 3.25 GW in 2015, which fell to 1.48 GW in 2016. Nearly 1.17 GW of corporate purchases were completed in the first six months of 2017 (see Figure 5).[21]

[18] Unless specifically noted otherwise, this section was constructed from a variety of industry sources including the 2016 Corporate Renewables Conference, with discussion from Chester et al. (2016), Martin et al. (2016), Porter, Craft, and Jackson (2016), and Quan (2016).
[19] Other common PPA terms may include an energy price escalation rate, insurance requirements, in-term purchase options, stipulations for system repair and maintenance, and removal, among other terms.
[20] Compliance purchasing is still likely to play an important role in wind procurement, particularly as states increase their renewable portfolio standards requirements.
[21] Note that this figure includes some corporate procurement strategies not included here such as green power purchases and green tariffs. For more information on these sources see the forthcoming Heeter et al. report.

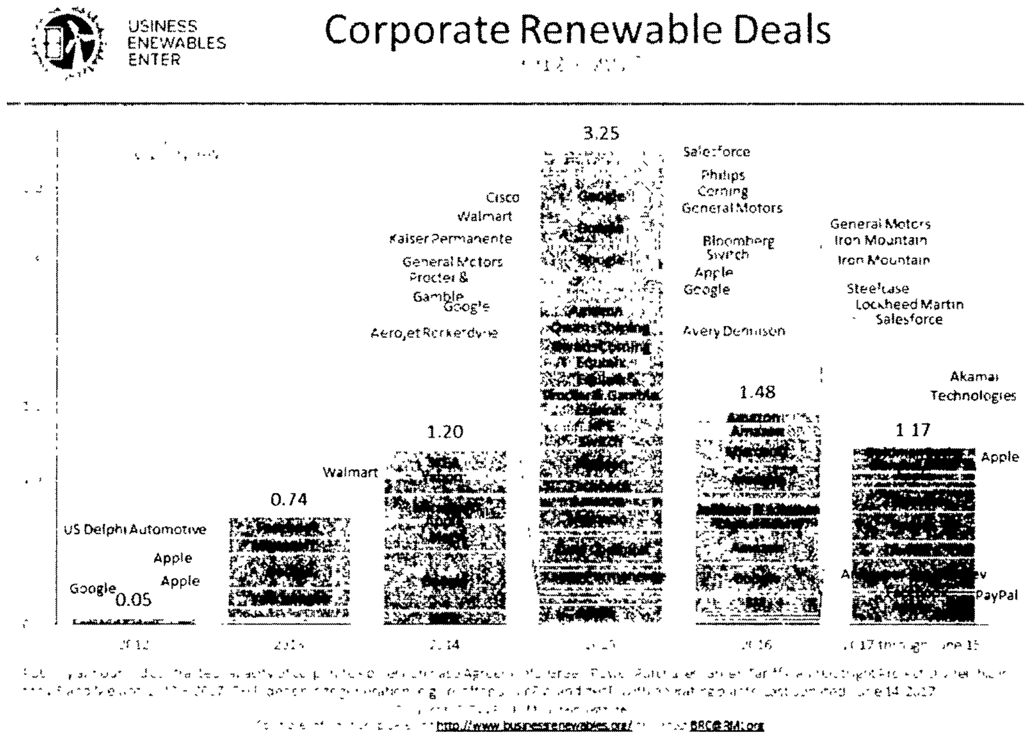

Figure 5. Corporate renewable deals: 2012-2017

Source: Rocky Mountain Institute 2017

The rise of corporate purchasing has allowed businesses to hedge their exposure to electricity price increases and meet sustainability goals while providing the wind industry with the critical revenue contracts that drive project financing. Corporate procurement has also offered additional opportunities for wind developers to attract new customers beyond just utilities. The following subsections, discuss the various contractual mechanisms by which corporations have sought to supplement their electricity purchases, primarily focused on those pertaining to wind-energy based procurement.

5.1 Corporate Onsite Procurement

Onsite procurement of energy may be an option for many commercial entities to meet their sustainability goals, limit exposure to energy price variability, benefit from federal tax incentives, and potentially return a profit. The majority of onsite renewable energy corporate procurement to date has used photovoltaic (PV) technology, with 13.8 GW of non-residential distributed PV installed at the end of 2015 (SEIA and GTM Research 2016).[22] Large companies have contributed significantly to this deployment.

However, corporations have installed other renewable technologies as well, including wind. Commercial and industrial projects represented 57% of the 28 MW of distributed wind capacity installed in 2015 (Orrell and Foster 2016).

There are several advantages to procuring onsite renewable energy over offsite procurement. Companies have the potential to leverage underutilized assets, such as unused land or roofs for economic gain. Energy produced onsite is also potentially more valuable than energy procured offsite, as it is closer to energy load and does not necessarily need the use of transmission and distribution infrastructure. Onsite generation also provides a better hedge against rising electricity prices by simply reducing electricity consumption, rather than an imperfect hedge offered by a virtual PPA (discussed in the next section). Companies can also more directly incorporate these generating assets into their existing energy use to optimize performance.

However, the ability for companies to use onsite renewable energy is highly dependent on resource availability, available land, local interconnection policies, and other utility and government regulations. For large energy users such as datacenters, it is unlikely that companies will be able to source all of their energy from onsite generation, making it more difficult to meet aggressive sustainability targets. Additionally, some commercial customers may not have the ability to diversify their onsite renewable energy procurement options, potentially making them limited in their technology choices (Wrathall, Kramer, and Gerard 2016).

5.2 Corporate Offsite Procurement

Another way that corporations have secured renewable energy is by purchasing energy from a project that is located offsite or away from the corporate entity, utilizing variants of the PPA mechanism, and other procurement options.

Offsite procurement of renewable energy can mitigate many site-specific limitations that a company's physical land and building facilities may face in installing renewable energy systems. For example, a corporation may be located in an area with a comparatively poor wind resource quality or may have insufficient land, rooftops, or regulatory permission to build a renewable energy asset large enough to meet its energy needs (particularly if the corporation has aggressive energy goals). Additionally, a corporation with multiple facilities can pool its total energy needs and enjoy efficiencies from contracting with one or more offsite facilities. Offsite procurement can also allow corporations the ability to diversify their renewable energy procurement, potentially sourcing energy that is complementary to its needs. As an example, a corporation may contract with a wind facility to offset more of its nighttime and winter energy needs (when wind resources are typically the highest) and a solar facility to offset more of its daytime and summer energy needs.

Offsite corporate procurement can benefit renewable energy project developers because it can expand their potential customer base from utilities and onsite procurement. This is particularly

[22] The non-residential market includes mostly commercial and industrial customers, but also includes the government and nonprofit sectors.

helpful in areas where utilities have already fulfilled their renewable energy procurement requirements or are not procuring more due to uncertainty surrounding future energy scenarios. Companies, in turn, benefit because they may be able make arrangements with developers on more favorable terms (Maloney 2016).

Because electricity generated by offsite facilities is not necessarily delivered to corporations' facilities, there are several different contracts employed that allow corporations the ability to benefit from the energy or other values produced by the systems. These include direct PPAs through virtual net metering; virtual PPAs (also known as contracts for differences); and contracting renewable energy through a company's electric service provider.[23] Each procurement type will be discussed in detail below.

5.2.1 Direct PPAs through Virtual Net Metering

Under virtual net metering utility ratepayers can receive bill credits for some or all of the electricity generated by a qualifying offsite renewable energy project that is not directly interconnected to their electricity meter. A virtual-net-metered system may have many potential consumers and/or buyers of its energy including a corporate purchaser; likewise, consumers may have many virtual-net-metered systems from which to choose. However, virtual net metering is only available in select areas that have adopted legislation and/or regulation allowing its use; where available it is typically offered by the local regulated electric utility. As of October 2015, virtual net metering for wind projects was available to some corporations in six states and the District of Columbia (Farrell 2015).[24]

5.2.2 Virtual PPAs

Virtual PPAs (also known as "financial PPAs," "synthetic PPAs," "contracts for differences," or "fixed for floating swaps") do not involve the direct purchase of energy as do onsite PPA contracts or Direct PPAs with virtual net metering. Virtual PPAs, by contrast, require the ability to sell electricity into a wholesale electricity market.[25] As of this writing, virtual PPAs are among the most preferred form of offsite corporate renewable energy procurement in the United States (Heeter et al., forthcoming).

In a virtual PPA the developer or sponsor does not actually deliver the power to the customer (i.e., the corporate purchaser). Instead, the corporation and developer agree to exchange the difference between the price at which the renewable energy is sold into the wholesale electricity market from the developer and the set contract price (or the virtual PPA rate) between the developer and corporate purchaser. If the renewable energy is sold into the wholesale market at a rate higher than the set contract price, the developer pays the corporate purchaser the difference in value; if on the other hand, the renewable energy is sold in the wholesale market at a lower price, the corporate purchaser pays the developer the difference in value. At the same time, the

[23] As noted previously, examples of other procurement options include green power programs offered by electricity suppliers and purchases of renewable energy certificates. For more information on these types of corporate procurement approaches see Heeter et al. (forthcoming).
[24] These states include Maine, Massachusetts, New Hampshire, Pennsylvania, Vermont, and Illinois (in which utilities can choose to offer virtual net metering). An additional four states offer virtual net metering to state and local governments, multi-tenant properties, or agricultural customers.
[25] Wholesale markets are responsible for serving two-thirds of the United States' electricity load (FERC 2017).

corporation likely continues to purchase energy from its local utility (or utilities), ideally in the same power market. Figure 6 below summarizes these various transactions.

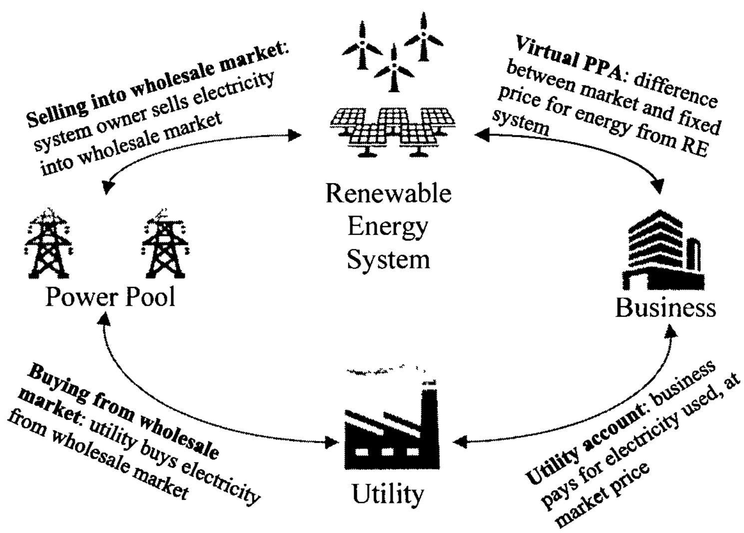

Figure 6. Summary of virtual PPA transactions

In executing a virtual PPA, both the developer and the corporate purchaser can be hedged to some extent against electricity market pricing. The developer of the renewable energy project will net the agreed-upon fixed price for energy through the contract of differences regardless of the price at which electricity was sold in the wholesale market. The corporate purchaser can also have some degree of a pricing hedge because the electricity it purchases from its service provider should be inversely correlated to the funds it either owes or receives from the developer through the contract for differences (assuming that the service provider rates are closely tied to wholesale market rates, as discussed below).

5.2.2.1 Managing Location Risk in a Virtual PPA (Busbar vs. Hub)

The ability for a business to use a virtual PPA as a hedge against its own electricity price depends on how correlated its electricity rates are to the rate at which the energy project sells its electricity.[26] The price at which electricity is bought and sold in a wholesale market can depend on one's location within the market or electricity grid. In a contract for differences, the settling price of the contract can either be designated at the hub (regional location) or at the busbar (point of interconnection). If the busbar node (i.e., point of interconnection to the electricity grid) of the renewable energy project is different from that of the business then there is a potential difference in price that imposes a risk on the transaction, making the hedge less than fully protective.[27] However, electricity can also be bought and sold at a power market's trading hub at a price which is calculated as the average price across all nodes within that area. Because these hubs

[26] When these prices are relatively correlated it is referred to as a "clean hedge;" the less correlated they are the "dirtier" the hedge.
[27] The difference between the location at which a project sells power and the location at which the contract price is set under the virtual PPA is called the "basis risk."

cover several nodes they can be less volatile and more liquid (as more trading occurs at a hub than a specific node). Buying and selling at a hub incurs more costs because the electricity has to be delivered, or "wheeled," to the hub through contracts called financial transmission rates (FTRs). FTRs are another type of hedge, representing the difference between the price at the hub and the price at the node. FTRs are offered by many financial entities and utilities.

Corporations often prefer the settling price to be at the hub because there is less "basis risk"—risk that some corporations think is better mitigated and managed by a developer. Developers, however, usually prefer the contract to be settled at the busbar because there are fewer costs and less complexity.[28] Further, some developers think that settling the price at the busbar provides companies the opportunity to make more money because they do not have to incur wheeling costs. In the end it comes down to the preference of the corporation between financial upside and risk as well as its experience with these types of contracting mechanisms. In some instances, corporations have signed virtual PPAs for projects in regions in which they have no facilities; in these transactions there is greater basis risk (though likely some level of energy price hedge), but the project may offer a better return and a larger offset of a corporation's electricity use (Chadbourne & Parke 2016a).

Bundling electricity load or renewable energy projects across a wider area can also diversify individual nodal electricity risk and create opportunities for corporations that do not own real estate and therefore are not as strongly tied to a particular location.

5.2.3 Sleeved PPAs

In some regulated states corporations may not have access to a wholesale market that prevents the use of a Virtual PPA. Additionally, some corporations may be reluctant to take on any sort of basis risk as described previously in the Virtual PPA model. Projects and developers have addressed these issues by contracting in a three-way deal with a customer's electricity provider, in what's known as a "utility green tariff," "sleeved PPA," or "back-to-back PPA."

In a sleeved PPA transaction the electricity service provider agrees to purchase the electricity from a renewable energy project through a PPA between the developer and electricity service provider, and the corporation in turn agrees to purchase that electricity from the utility through a matching PPA between the utility and corporate purchaser. Sleeved PPAs can offer benefits for all parties, as shown in the following examples: electricity service providers lock in energy and load from customers (avoiding stranded assets and declining customer usage); developers often have an easier time financing the project with the typically strong credit profile of a utility instead of corporation; and corporations lock in an electricity price hedge without the basis risk from their existing electric utility with which they have a long-standing relationship.

Sleeved PPAs are not without their drawbacks. Having multiple parties involved in back-to-back contracts—particularly if one of them is a regulated entity—means significant time, energy, and money is spent setting up transactions. Additionally, sleeved PPAs typically require state public utility commission approval and the regulated utility will usually charge fees on top of the PPA.

[28] In addition to the cost of arranging and executing the FTR, developers may have to set aside a cash reserve to satisfy contract terms. These additional requirements make it more difficult for the developer to finance the project.

6 Cost-of-Capital Impacts

The cost of capital can influence a wind project's overall cost of energy and accordingly its cost competitiveness. It is therefore critical for developers to have a comprehensive understanding about not only the availability of capital, but also about how variations in possible financing rates will impact their projects' economic cost profile. Developers often won't have fully-secured financing rates until near the financial close of the project, which is among the latter milestones of the development process. Thus developers will use best estimates and forecasts to estimate possible financing costs and the corresponding impact on their projects' overall economics. The developer will typically identify the point at which the financing rates are low enough to enable the project to be economically viable and the high-cost threshold where the project may no longer be competitive.

This section demonstrates how low- and high-cost financing scenarios can impact the cost of a wind energy project using a simplified LCOE analysis.[29] LCOE is an economic measure that is calculated by summing the entirety of the project's lifetime costs (including upfront capital costs, ongoing O&M expenditures, and financing rates among others expenses), discounting to present value terms, and then dividing by the expected lifetime energy production of the wind plant. The output of this calculation is a cost per unit of energy, typically expressed either in cents per kWh or dollars per MWh. LCOE can be used in comparison to the price that a developer expects to receive for the energy generated by the system, which could be the market price, the negotiated PPA price, the applicable green tariff rate, or another revenue source. A calculated LCOE at or below the comparative energy price would indicate the project is competitive economically, while an LCOE at or above the comparative price would likely require additional actions to lower the LCOE of the project through decreasing costs or increasing energy production.

To illustrate the effects of financing rates on the LCOE, the authors ran an analysis in NREL's System Advisor Model (SAM), a performance and financial model that allows users to provide a number of project-specific input parameters to estimate the LCOE along with several other outputs (NREL 2017). The authors employed a simplistic methodology that minimizes the number of non-financial parameters required, including capital costs (equipment), capacity factor (i.e., energy production), annual O&M expenses, and annual inflation assumptions.[30] The specific values of these variables were based on NREL's comprehensive wind cost analysis report "2015 Cost of Energy Review" (Moné et al. 2017).

In this analysis, two financing scenarios are assumed representing a high- and low-cost financing case while the non-financial parameters are held constant. The input values for the financial parameters are shown in Table 2. In the Higher-Cost Financing Scenario, sponsor equity and tax

[29] Other recent wind energy LCOE analyses include Cory and Schwabe (2009), which present multiple-variable sensitivity analyses, and the International Energy Agency (IEA) Wind Working Group Task 26, which looks at international variations in the cost of wind energy (Cory and Schwabe 2016, IEA 2016). The investment bank Lazard also produces an annual report that compares LCOE across multiple energy generation technologies as well as various cost sensitivities (Lazard 2016).

[30] The following values were used for the non-financial parameters representing the "Base-Case" project in the cost of energy review: $1,690/kW capital costs, a net capacity factor of 39.9% based on a P50 estimates, annual O&M costs at $51/kW-yr, 2% inflation and escalation rates, and a 20-year project, assuming the use of the $23/MWh PTC for the first ten years of a project's operation (equating to the PTC value in 2016 for a project that began construction in 2016 to qualify for the full value PTC).

equity IRR are valued at 12% and 8%, respectively; the interest rate on debt is offered at 5% with a 15-year repayment term, and debt comprises 35% of the project's capital.[31] In the Lower-Cost Financing Scenario, sponsor equity and tax equity IRR are 10% and 7%, respectively; interest rate on debt is 4.5% with an 18-year repayment term, and debt comprises 40% of the project's total capital. The use of the PTC is also assumed in both cases.

These financing cost scenarios illustrate only two of any number of possible financing permutations. In general, however, the Higher- and Lower-Cost Financing Scenarios represent plausible variations in both the cost and structure of the project. The Lower-Cost financing scenarios generally reflect historic lows in pricing, particularly for the tax equity rates (Chadbourne & Parke 2007; Harper, Karcher, and Bolinger 2007), while the Higher-Cost Financing Scenario is closer to project pricing in 2016 (Shurey 2016; Chadbourne & Parke 2015).

As shown in Table 2, the SAM model yields an LCOE of $51 per MWh for the Higher-Cost Financing Scenario. Under the Lower-Cost Financing Scenario, the SAM model yields a lower LCOE of $42 per MWh. This analysis reveals an LCOE premium of approximately $9/MWh for the Higher-Cost Financing Scenario relative to the Lower-Cost Financing Scenario.[32]

Table 2. LCOE Comparison of a Higher Cost and Lower Cost Financing Scenario

SAM Financial Model Inputs	Higher-Cost Financing Scenario	Lower-Cost Financing Scenario
Sponsor Equity IRR	12%	10%
Tax Equity IRR	8%	7%
Debt Interest Rate	5%	4.5%
Loan Term (years)	15	18
Debt Percentage	35%	40%
Resulting Nominal LCOE ($/MWh)	**$ 51**	**$ 42**

From the perspective of the project developer, these calculated LCOEs of $51/MWh and $42/MWh would then be compared to the expected energy price of the project, whether that be an executed PPA price, a wholesale energy price, a green tariff rate, or other revenue metric. If the project's developer had secured an energy price that exceeds the LCOE from either the Higher- or Lower-Cost Financing Scenarios, then the project will likely generate sufficient revenue to meet its ongoing maintenance, debt payments, reserve accounts, and investor returns. This case is illustrated by the black gradient bar shown in Figure 7. The more the energy price exceeds the LCOE, the larger the potential revenue surplus and thus the more profit the project may earn.

[31] SAM's financial calculations model debt that is secured at the project level. The debt term assumes that a constant amortization period is utilized rather than the mini-perm structure described previously, which requires a balloon payment before the end of the term.
[32] Importantly, this LCOE range includes the effect of both economy-wide conditions, such as the overall supply of debt and equity and investor's appetite for risk, as well as project-specific risk factors. A project developer may be able to address the project-specific risk factors but usually not those attributable to market-wide forces, such as overall investor sentiment and benchmark financing rates. As an example, Bolinger (2017) finds a comparatively smaller LCOE reduction opportunity of around $2/MWh to $2.5/MWh when analyzing risks specifically associated with energy production uncertainty (Bolinger 2017).

Conversely, if a developer has secured an energy price that is below the Lower-Cost Financing Scenario's LCOE, then the project will not likely generate sufficient revenue to both meet its ongoing cost obligations (i.e., debt payments, O&M, reserve accounts, etc.) as well as provide the modeled return to the investor. This case is depicted with the red gradient bar in Figure 7. In this case, the sponsor or investor may willingly accept a lower return, seek cost reductions elsewhere (e.g., through lower-cost equipment), or delay project financing until market conditions improve (e.g., if benchmark interest rates fall). An energy price that falls between the two financing costs scenarios ($51/MWh versus $42/MWh—showed in the dashed area in Figure 7) can likely proceed if the developer is able to secure financing at the rates used in the Lower-Cost Scenario. However, if rates lie at the Higher-Cost Financing Scenario, the developer may seek similar measures to close the revenue gap.

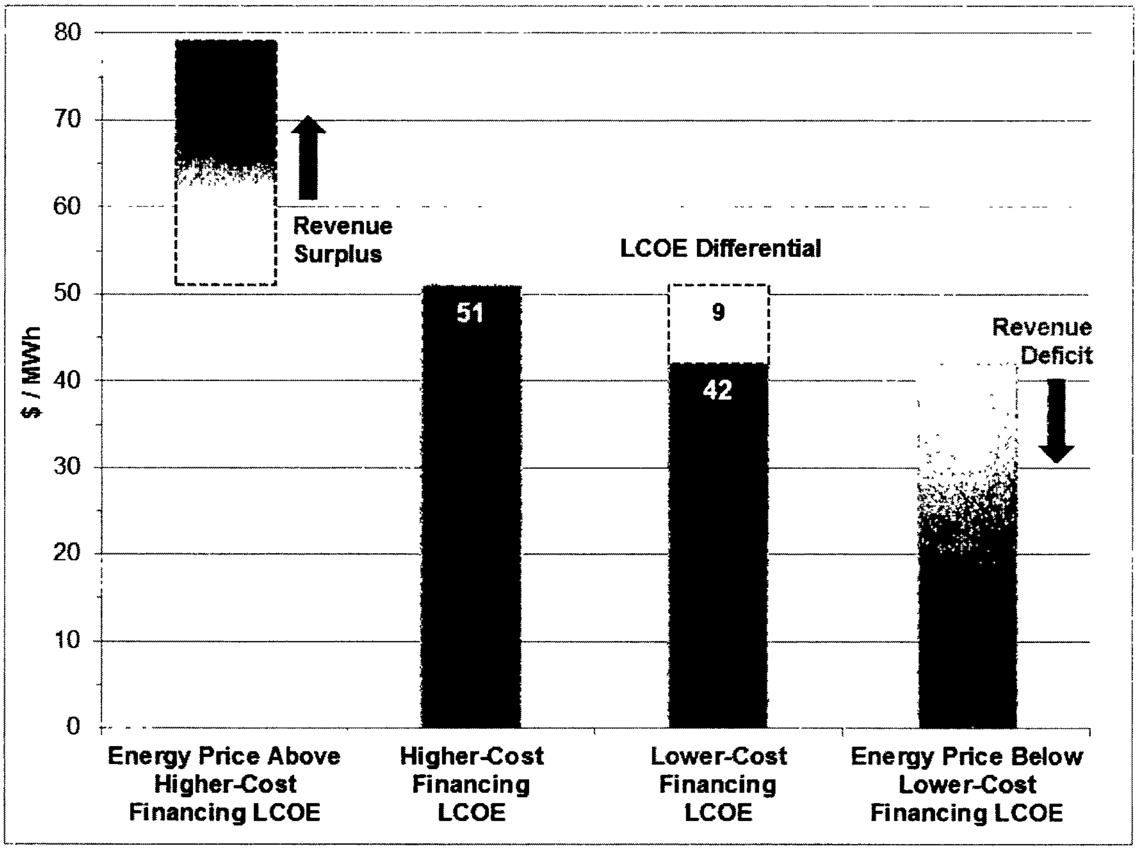

Figure 7. Comparison of financing scenarios to energy prices

There are several reasons why the financing costs for a wind project can vary from one project to the next, as well as over time. First, some financing cost variations are attributable to macroeconomic forces and reflect the changing benchmark interest rates or the market's risk tolerance. Second, financing rates are also driven by the unique characteristics of the project itself. For example investors will look at unique project-specific factors such as the type of the specific turbine technology utilized, its performance history in the marketplace, the commercial experience of the project developer to deliver projects on time and budget, and the specific elements within the deal to mitigate and control for risks and uncertainty. Some investors will simply be more comfortable with accepting certain types of project risks while others investors will not. Finally, other hard to quantify or subjective factors also contribute towards the overall financing costs of a project. As an example of this, the history and relationship between the firms is also an important consideration: commercial lending can be a "relationship-based" business and firms may be willing to offer preferred pricing to partners who have a long, profitable, or strategic banking partnership. In reality, many if not all of these factors contributes in varying degrees to the overall investment costs for a project.

7 Conclusion

As discussed in this report, investment in wind energy in the United States has averaged nearly $13.6 billion on annual basis since 2006 with more than $140 billion invested cumulatively over that period (BNEF 2017). The investment activity demonstrates the persistent appeal of wind energy and its significant role in the overall market for electricity generation in the United States. The development and financing of wind projects, however, remains a complex and expensive process that, because of the capital requirements of wind energy, can influence the economic competitiveness of wind energy compared to other generation sources that are less capital intensive.

Looking ahead, the near-term outlook for wind energy reported previously suggests a continued need for capital availability at levels consistent with deployment seen in 2015 and 2016 (Wiser and Bolinger 2016). The market has shown the capacity to finance projects at this level using current mechanisms at economically viable rates; however, increased deployment could necessitate new sources of capital. Broad changes to the financial industry—such as the possibility of major corporate tax reform, the currently scheduled phase out of the PTC and ITC for wind, and, specifically, a change in the role of tax equity—could fundamentally reshape the predominant mechanism for wind energy investment. It is possible that financing practices may need to evolve, while the growing body of wind energy deployment and operational experiences could help to attract new market participants. Whatever the future holds, it is likely that financing will continue to impact a project's overall economic competitiveness, and that efforts to open up more capital sources and reduce financing costs will continue.

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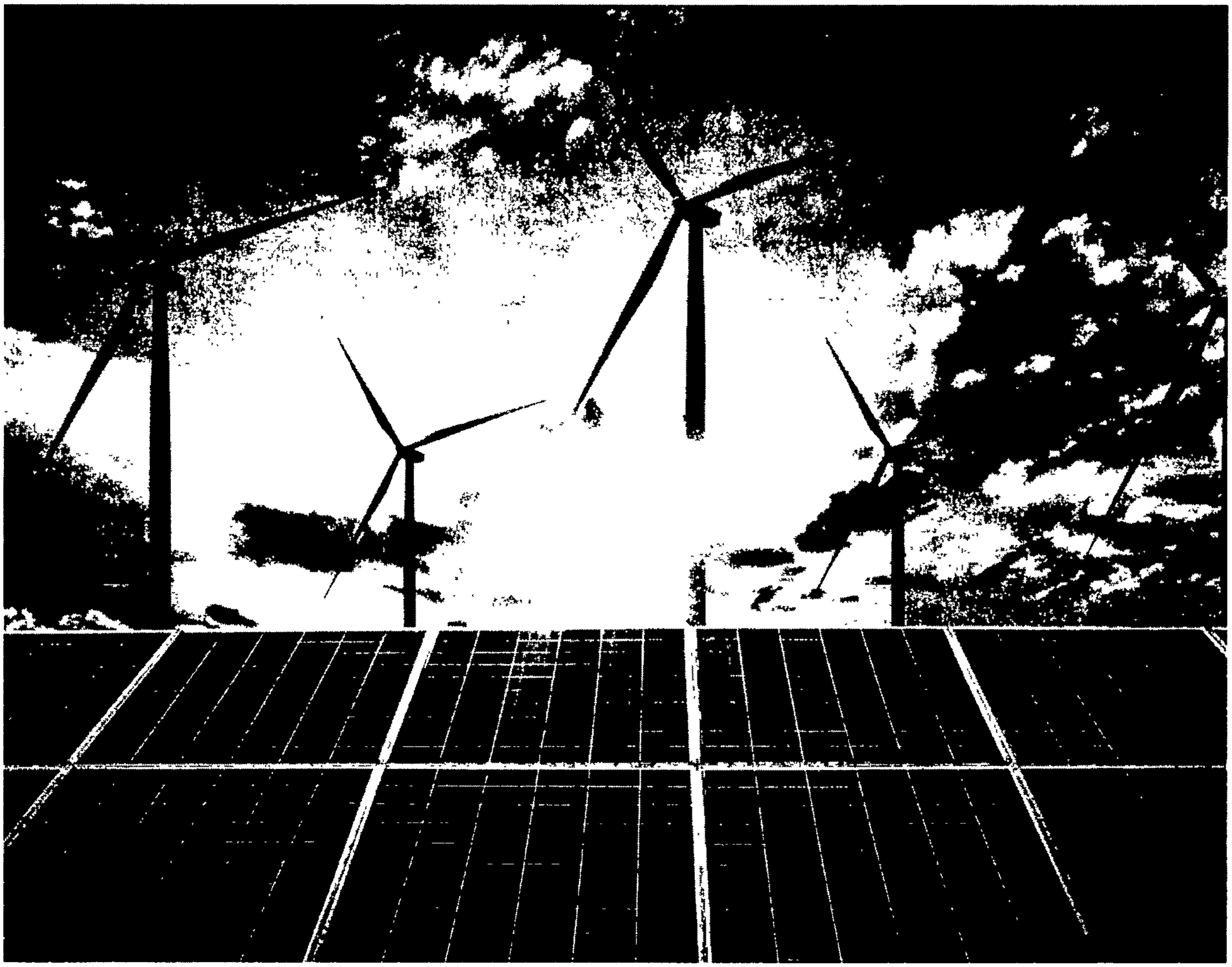

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NOTE FROM THE EDITOR

Tax equity investments, based on the production and investment tax credits, have underpinned billions of dollars of wind and solar projects in the U.S., and although the end of these incentives may now be in sight, the market has not stopped evolving.

That's why *Power Finance & Risk* and **Mayer Brown** brought together a panel of experts on tax equity in September to review the latest developments and innovations in this fascinating area of renewable energy finance, as well as the outlook for the coming years.

The received wisdom, since the supply of tax equity capital is limited, is that tax-oriented investors have their pick of the best projects, while developers are constantly hunting around for new sources of funds.

The true picture, however, is more nuanced, as you will see in this report.

Although fiscal reform slashed tax bills for major corporations last year, there are probably, on balance, more investors than there were before.

Well-established wind and solar project developers with large, solid balance sheets behind them can raise more than enough tax equity to meet their needs.

But for mid-market developers, the market dynamics look very different, prompting concerns about a "bifurcation" of the market.

Meanwhile, emerging technologies like offshore wind and battery storage present new questions for market participants.

With a few years left before the tax credit well runs dry, the renewables tax equity story is far from over. And that's before we even think about another extension...

Richard Metcalf
Editor
Power Finance & Risk

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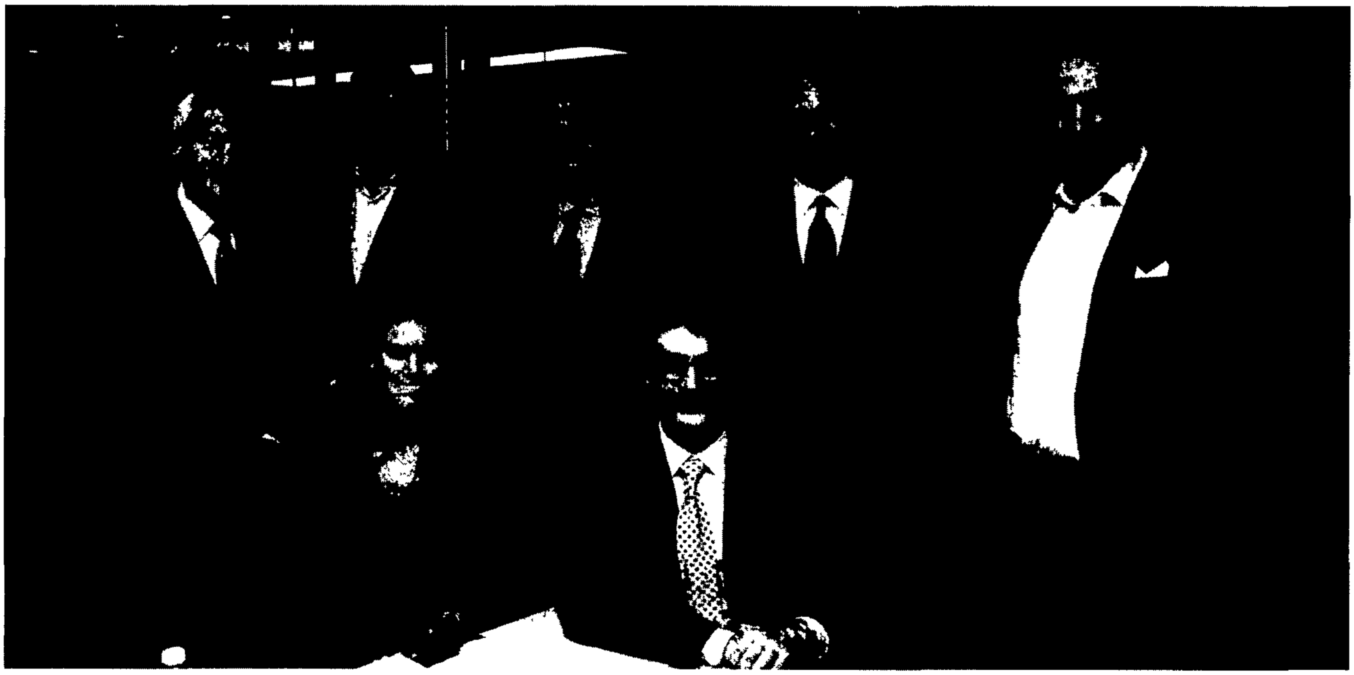
Tax Equity Roundtable 2018



SPEAKERS:

David Burton, partner, **Mayer Brown**
Jeffrey Davis, partner, **Mayer Brown**
Pedro Almeida, director of finance, **EDP Renewables North America**
Rich Dovere, managing member, **C2 Energy**
Kathryn Rasmussen, principal, **Capital Dynamics Clean Energy and Infrastructure**
Marshal Salant, head of alternative energy finance, **Citi**
Richard Metcalf, editor, *Power Finance & Risk* (moderator)

PFR: A major theme this year has been the impact of tax reform and the repercussions of that, in terms of investors perhaps leaving the market or having less appetite. What impact has tax reform had?

David Burton, Mayer Brown: I think the two largest effects of tax reform have been, first, that each tax equity investor, on a high level, has 40% less tax appetite than they did before. The second thing—which correlates to that—is that the depreciation benefit is worth less, so instead of a deprecation benefit being multiplied by 35%, it's only multiplied by 21%, which means that sponsors are able to raise less tax equity than they were before for the depreciation benefit. Tax reform did not impact the tax credits themselves, other than the fact that investors have less tax appetite to offset with credits.

Jeffrey Davis, Mayer Brown: Because of 100% expensing—the so-called "bonus depreciation"—the tax benefits are potentially more front-loaded for any particular deal. So, when you have a taxpayer with lower tax capacity, it has to be a little more careful about either allocating its resources to different deals, or, alternatively, requiring that sponsors elect out of the 100% expensing bonus.

Kathryn Rasmussen, Capital Dynamics: I wouldn't say that we've experienced *huge* shifts as far as how we're viewing tax equity. There is, absolutely, less tax equity that we're

"We spent, as well as other people a massive amount of time during the uncertainty before the [tax] bill was finalized literally hundreds of hours analyzing scenarios—looking at what could happen"

Marshal Salant, Citi

getting in our deals—that is partially offset by the fact that we can raise a little bit more debt.

However, we also have a bit of a benefit just from the fact that, post-tax, we have the lower tax rate as well. So it absolutely has decreased the amount of tax equity that we can raise, but not to a point that has significantly moved our view on the projects and the assets that we're investing in.

Pedro Almeida, EDP Renewables North America: I think that outside of the factual implications on the amount of depreciation benefit, what we're seeing is that the dynamics of whether investors want to allocate capital more on an ITC [investment tax credit] basis or if they want to invest in PTCs [production tax credits] and 100% expensing are changing. Because their tax capacity has shrunk, they're more selective in allocating capital to the different alternatives in the market.

That being said, we always felt that there were different types of tax equity markets. We don't feel that EDPR is affected and we don't feel that the market has less depth. We just feel that the financial institutions and the typical investors are more selective. So, I think tax reform has mainly changed the dynamics in the market and how investors allocate capital between ITC and PTC and, as a consequence, then between wind and solar.

PFR: So yes, it is having an impact, but it might depend on the kind of sponsor or on the sponsor, to some extent?

Almeida, EDPR: Correct. I think there are projects that will always get the capital that they need, and that capital will be able to be raised very competitively.

PFR: Marshal, you were nodding there. What has been Citi's response, or how has your activity adapted to tax reform?

Marshal Salant, Citi: It's a very interesting question. We spent, as well as other people, a massive amount of time during the uncertainty before the bill was finalized, and particularly working with **ACORE** and other industry groups—literally hundreds of hours analysing scenarios—looking at what could happen.

And we agree with the conclusion David Burton reached. Where has that 40% number come from? If you were a hypothetical corporation and you made $10 billion of income, you used to pay $3.5 billion in tax to the federal government. Now you're paying $2.1 billion to the federal government. And it's that difference—when you pay $3.5 billion versus $2.1 billion, you've decreased your tax bill by $1.4 billion. That is exactly 40% of what you were paying.

That, theoretically, should impact the overall tax capacity in the market. There were also massive amounts of time spent by various parties in tax equity and a whole lot of other parts of the financial world and the legal and tax world on the so-called BEAT, base erosion anti-abuse tax. And in the end, I would say that it's still not really clear what the impact is.

After all the analysis was done and we could think about all the theoretical impact that should occur, the reality is that for big developers with well-structured projects, I don't think it's really had much impact at all, which is maybe counterintuitive.

There's a couple of banks that have maybe decreased what they're doing. There's others that have said it has no impact. There's maybe one or two that look to have significantly pulled back. But overall, the amount of time spent talking about and analysing it seems so far to be far greater than the actual impact we've seen.

PFR: I've certainly heard people say that some tax equity investors, obviously not Citi, may have withdrawn entirely from the market as a result of tax reform, whether directly or because they just decided that it was too complicated and it wasn't worth trying to figure out.

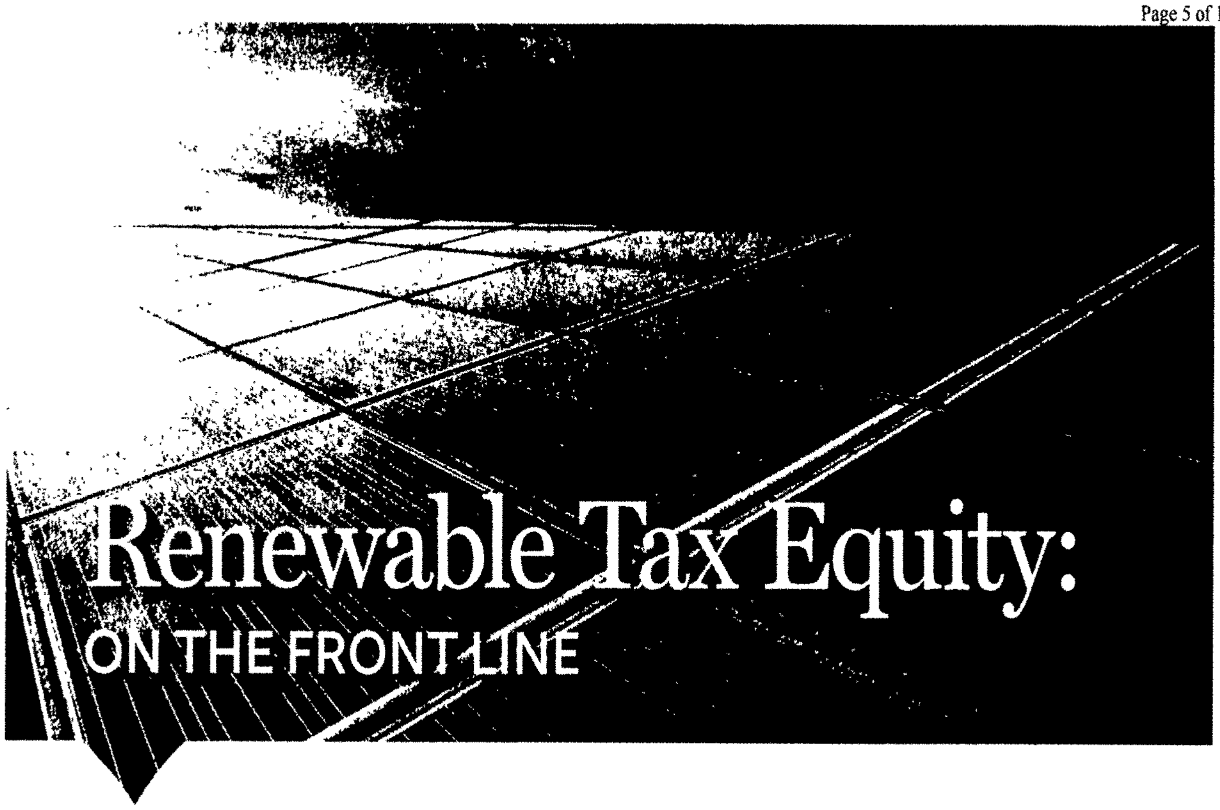
Rich Dovere, C2 Energy: We haven't seen investors withdraw entirely. It almost seems like a negotiating stance. Where we sit in the market is different, in terms of project size, but if investor takes the position: "I'm leaving tax equity. I can't do any tax equity," to a certain extent, I think the response is: "But what if it were this much per credit? Or what if we did this yield, would it make it that compelling?"

Burton, Mayer Brown: I think a handful of multinationals have exited the tax equity market, reportedly due to BEAT, but that's been made up by, generally, smaller players entering the market. They're realizing that the after-tax returns are compelling compared to what they could earn on other types of investment, or for ESG [environmental, social and governance criteria] reasons.

Rasmussen, CapDyn: We're seeing a lot more first-time, second-time tax equity investors who may be sitting behind a seasoned tax equity investor who is selling down their position on the back end or post-closing or syndicating a piece of it upfront.

Salant, Citi: Anecdotally, we believe there are one or two players that have essentially pulled out. But when you ask them, they typically say, "Oh, that's not true. For our best clients and the right project, we might still be able to do it." So it's very hard to pin people down on this.

It's certainly not good for the supply/demand imbalance in the market, but it didn't have the overwhelming impact that people thought it was going to have.



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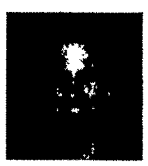
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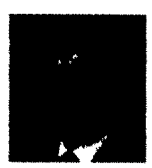
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Almeida, EDPR: I tend to agree with Marshal. I feel that, at least in our investor community, the people we talk to, we haven't heard anyone say they're out of the market.

PFR: I think might also be worth pointing out that the major impact, if any, on an institution's ability or willingness to invest tax equity will be much greater on those that are either foreign or have a lot of overseas business. So it may not have affected U.S. regional banks as much. Is that fair?

"Either they will come in after a tax equity investor that's more seasoned has signed a commitment . or there are some cases where the first investor puts a tax equity partnership on top of the tax equity partnership"

Jeffrey Davis, Mayer Brown

Burton, Mayer Brown: That's fair. It would be relatively surprising that it impacted U.S. regional banks. But foreign-owned banks or U.S.-owned banks with big foreign operations, in some circumstances, can have an issue with BEAT. BEAT, also, is going to get more challenging in future years. Currently most of the tax credits are permitted under the BEAT calculation, but that's going to change down the road.

Davis, Mayer Brown: Another interesting aspect of the BEAT is it's calculated year-by-year, and therefore, for any given year, a bank or an investor must project what its taxable income, deductions, earnings strippings, payments and so on might be, so it can determine whether it's going to be in the BEAT and figure out if it can benefit from the tax credits.

It has already set up a difference between PTCs and ITCs, where the ITC, because it's upfront and determined based on tax basis, is more predictable and an investor can look at its income and expenditures and determine whether it thinks it will be subject to the BEAT in the year the ITC arises. Whereas with the PTC, because you've got the ten-year stream based on production, it's a little more challenging. It's hard for anyone to predict what their income is going to be next year let alone ten years out.

PFR: Going back to something that Kathryn mentioned, which is syndication and smaller investors coming in behind a seasoned investor, is that something that you've seen more of recently?

Davis, Mayer Brown: I've seen more new investors taking that very approach. Either they will come in after a tax equity investor that's more seasoned has signed a commitment, and they'll take a piece of that prior to funding—and that's failry common in an ITC deal—or there are some cases where the first investor puts a tax equity partnership on top of the tax equity partnership and sells an interest in that. That's oftentimes accompanied by risk mitigation features and other things that might make it more attractive to an investor that's not as familiar with the underlying assets and the risks that are inherent in renewable energy projects.

PFR: Marshal, does Citi sell down tax equity in this way?

Salant, Citi: We act as principal, we also act as agents. The answer is: yes, we do both.

The good news is that if you're a sponsor looking for tax equity, there are some new participants, there is a little bit more liquidity, we are seeing more almost like secondary trading in PTCs.

The bad news is that the tax complexity has not changed. On the ITC, it's a very narrow window and you can't sell down after the deal closes. It's impractical for that to really work. Whereas with PTCs, you could hold it for a year and then sell off the back nine years. You can't do that with the ITC, but you do have that window between commitment and funding, or between first funding and second funding. And we've been a big player in that market, to the extent it makes sense.

Every large tax equity investor I know has spent the last couple of years, if not five years, trying to develop new investors, with mixed successes. There were a couple of highly successful cases, but in the past there's been a lot more talk than actual action. Lately, we've seen a little bit more pick-up, and that's been great for the market.

The reality is, for the really big players, who need a couple hundred million of tax equity, getting new entrants or regional banks in who are writing checks for $7 million, $10 million, $15 million, $20 million doesn't really work for them, because it's too unwieldy to have ten different $20 million pieces club together trying to do a $200 million deal. So for that market, they're still dependent on the big players.

There's a handful—people debate the numbers, but probably between 15 and 20—of large tax equity investors who can lead and negotiate deals, which is good for the tax equity, but it's also good for the sponsors, because they know what they're getting. And then there may be another 10 or 20 who come in behind those people, because if you're a first-time investor, it's helpful to tell your superiors or your board: "Look, we're behind Citi," or behind somebody else who's been doing this for many, many years. "They know what they're doing, so they're going to make sure that the transaction has no surprises."

That is a logical way to increase the volume, and I think that's been mostly what's happening. There are some new entrants that want to deal directly on their own and, hopefully, that will develop over time also.

Rasmussen, CapDyn: I definitely agree—more investors is definitely a good thing, especially on the sponsor side. But there is some hesitancy on our side to deal with first-time investors, so unless there's a very compelling case, we much prefer having a situation where we have a seasoned provider.

Almeida, EDPR: I agree. Let me start by

"If you do a deal with EDPR you pretty much know what the PPA's going to look like all that stuff You do a residential solar deal, right, its all pre-baked But DG is in the middle"

David Burton, Mayer Brown,

saying that we embrace new investors. For the last five years, there has not been a year in which we haven't brought one or two new investors into our portfolio. We're also fortunate enough that most of our investors, as a rule, like to hold their investments until they've flipped, the exception being if we see any syndication pre-funding, which is rare, in any event.

From a sponsor perspective, we need to have certainty on execution. We have our capital commitments and delivery obligations in terms of CODs [commercial operation dates], in terms of megawatts that we want to put in the ground. Last year, for instance, we made a deal, $440 million, with a single investor. Not a lot of investors can do that.

But I understand that syndication makes sense more and more now, because if you have this mix of uncertainty around what is your tax capacity and you pair that with the uncertainty of when will the assets be placed in service, especially if you're investing ITC—is it this year? is it next year?—that can have a big impact now with the lower tax bills.

Salant, Citi: It's also important that we remember that when we talk about the tax equity market, that's difficult to view as one homogeneous market. We've been saying this, as have others, probably for at least a year or two now: we've seen massive bifurcation in this market.

There are certain big, giant developers who have great relationships with banks—we've done deals with Capital Dynamics, we hope to do deals with EDPR—they're big, well-established players. And when an EDPR, a **NextEra Energy**, with an investment grade balance sheet, comes to you, there's one way to deal with transactions like that. They can raise all the tax equity they want. They can get a couple hundred million, they can deal with the big players, they'll even get oversubscribed if they want to.

The disconnect in the market is, you can go to a conference and hear people like them talking about how they're oversubscribed, what's the problem? The fact is tax equity investors are trying to get into their deals that can't. But then you hear that for every big, giant developer there may be five to ten little developers who are running around going: "I can't raise a dollar. What's wrong with this?" And it's because as of the last year or two, or maybe even three, the tax equity market isn't one market any more.

Burton, Mayer Brown: I think there's definitely bifurcation as you describe it, and there's also bifurcation around structure. There's the older, more experienced tax equity investors who maybe started in wind, and they tend to use an IRR [internal rate of return]-based flip structure and to structure even their solar deals more like a wind deal. And then there's, typically, smaller investors in solar, newer investors in solar, who don't have the wind experience and don't necessarily have all this sophistication, and they prefer investing based on a time-based flip, where you don't have to calculate the IRR and worry about getting that just right. That's much easier for a smaller, newer investor who doesn't have the sophistication of a Citibank to deal with than the kind of PTC, after-tax, IRR-style structure.

Dovere, C2: C2 definitely falls more into the middle-market developer bucket. The difference being that we started four years ago, with a balance sheet growing organically, but quickly. We view ourselves in another subsection of the tax equity market where there's the guys running around who can't raise a dollar and there's firms like us with $150 million balance sheets who can raise the tax equity that we need.

We were typically doing it deal-by-deal, because it was harder to attract institutional attention without a very large fund or an investment grade balance sheet. And so we have actually been in what I think is a very positive position, where we are able to pick up the smaller opportunities from the guys who can't raise tax equity and function in an effective aggregation role as well as have our own development assets and balance sheet, and to be able to work with tax equity to a point where we can start to garner more institutional attention.

As relates to David's comment about the time-based flip, the structures tend to be modelled off of a **U.S. Bank** structure. And I think that, actually, if they were to stipulate an IRR-based flip, it would be such an egregious number to even put on a document to make it equivalent to a six-year flip that it's just easier and more polite for them to do it as a time-based flip, because the IRRs that they're getting are already so high. It looks like a polite way of no one actually having to acknowledge what that cost of capital is.

"It's not as outrageous as it was some years ago I think everyone is working to make the market more liquid, to bring the supply and demand closer together"

Pedro Almeida, EDPR

But I would put us in that middle tier of the market where we can get the tax equity that we need. It's a lot harder and a lot more time and brain damage, especially for the individuals on the team that have to do the tax equity structuring. So that's, hopefully, what we're aspiring to move out of, but that's where we have also created a business opportunity in the market, because if you're a developer and you've got 3 MW to 5 MW, you're not getting that thing tax equity-financed unless you've got a high net worth contact. We've seen deals trade away from us that we would otherwise buy in that size range because there's a local high net worth individual and they are going to do the tax equity. That's not a market—that's a one-off situation.

Salant, Citi: Yes, and to clarify, I overstated when I said they can't raise a dollar. That's the extreme case. What I literally mean is there are many smaller developers or new developers for whom it's just very, very difficult. Hopefully, they get there eventually, but it's not like an EPDR who can put out an RFP [request for proposals] and say, "Here's our portfolio," and send it to the 20 big players who are investors and have 10 of them say they want to be in it. It's not even close to that. It's the guys who can spend weeks and months knocking on doors, trying to raise the money that they need. Much harder.

Almeida, EDPR: Yes, I totally agree with Richard. And I think that aggregation trend that you guys are seeing on the lower tier of the market, I think we, to a certain extent, can also play a role in consolidating some of the opportunities in the middle market.

There comes a point in which I think any developer will, more so in the current environment, given the new rules of the tax equity market, ask themselves whether it makes more sense for them to continue developing the project or think about consolidation and maybe bring it to us at a level where we still can have a meaningful say in how the project is structured.

Because I think we don't raise competitive tax equity only, or probably not at all because we are big. We raise competitive tax equity because we develop our projects and build them to certain standards, and we look at revenues that have a certain pedigree. And for us to be able to package that and bring it to the tax equity market, we need to be involved at an earlier stage.

We foster these relationships with middle market developers that have assets, but why would they continue developing them and feel that they would be squeezed on the tax equity market if they can work early on with sponsors that have the size and the capability to shape the product in a way that it's more sellable on the tax equity market?

Burton, Mayer Brown: The other thing about smaller deals, D.G. [distributed generation] deals, is that they each have their own contracts. So if you do a deal with EDPR, as you just said, you pretty much know what the PPA [power purchase agreement]'s going to look like, you know what the O&M [operations and maintenance] agreement's going to look like, the land rights, all that stuff. You do a residential solar deal, right, it's all pre-baked, it's "take it or leave it". Mr. Jones is not negotiating his PPA with the resi solar provider.

But D.G. is in the middle, and most D.G. customers are big enough to have a general counsel who's like, "I need this to be under Oklahoma law," or whatever his or her view is, and so they're negotiated. And they're different, and that makes the diligence very expensive and time consuming, and then it's a smaller transaction on top of it. So you have many factors stacked against these D.G. transactions. They are getting done, they are profitable, but it takes a lot of elbow grease on both sides of the table to get it done.

Davis, Mayer Brown: I want to go back to David and Rich's point about the two different structures that we're seeing in the market. The suggestion was that the investors that are doing the time-based flips may be less sophisticated. I think it's also in part a product of their view of commercial risk versus tax risk. Those investors that are doing the time-based flips are oftentimes more willing to take a little more tax risk to minimize their commercial risk.

And I think it's in part because a lot of those investors may have had a history in either the low-income housing space or the historic tax credit space, and similar structures have neem frequently used there.

PFR: Let's talk about pricing. If anyone would like to say a figure, they're absolutely welcome to, but what I've been hearing is, this year, around the 6% to 7% range for tax equity. We've been talking a lot about the bifurcation into two different markets. Does pricing also come into that?

Dovere, C2: Yes.

Burton, Mayer Brown: Absolutely. But the 6% to 7% range, that's a quote for a PTC deal or somebody doing a solar deal using an IRR yield-based flip. If you're doing a time-based flip, there is no IRR, so that 6% to 7% doesn't really mean anything. They tend to quote in terms of dollar-per-credit instead.

PFR: And can you put any figures on that?

Dovere, C2: It's a function of how much cash you're taking. At the highest end, we've seen $1.38 a credit, which is not really fair comparison because it's a different dynamic. And the lowest we've seen... You know, at the beginning of the year we were getting $1.05, and that same investor's now at $1.15, $1.14, and it's just a function of how much of a preferred return they're taking. These are all modelled after the U.S. Bank structure, which, I think, prior to tax reform was $1.20 to $1.25 a credit, with a 2% pref.

Almeida, EDPR: Rich, any time I'm asked about pricing, I always say that it's too high for the risk profile of the investment.

Dovere, C2: I forgot to say that too!

Almeida, EDPR: If you look at, let's say, a long-term bank project finance or—more traditional in the U.S.—a back-leveraged deal, that can be in the 4% range. If you look at an equity investment where someone comes in, takes equity risk, the unlevered returns are going to be in the 5% to 6% range, if the asset is a quality asset. So if tax equity prices between 6% and 7%, and you're talking about a preferred return investment, senior to both back-leverage and equity, that can only be explained by the dynamics of the market and the balance between supply and demand.

It's not as outrageous as it was some years ago. I think everyone is working to make the market more liquid, to bring the supply and demand closer together. But still there is a spread.

PFR: So, still too expensive, in summary. And the figure that I've heard is, on a return basis, 100 basis points lower than at some point last year.

Salant, Citi: The discussion of pricing has always been an annoyingly difficult conversation in the tax equity market. Those of us who have been to various industry conferences for ten years, lawyers will ask questions of a panel, and not one person will admit a number, which is crazy. But they're all private, bespoke, negotiated transactions, so nobody ever wants to quote a number. Once or twice I threw out numbers, and people yelled at me: "Why are you throwing out a number?"

Clearly, for ten years, sponsors have felt tax equity was too expensive, and I can understand why they felt that way. When you look at it from the outside, it's just the financing cost that looks high, and it is, because of all the complexities. It's because of the need to use your own tax capacity for the partnership structures, the internal accounting, the GAAP accounting, below the line, above the line, not helpful to earnings... The structure, from day one, does everything it can to make it unattractive for the reporting company to be a tax equity investor, yet we have to provide a tax equity and we have to put massive amounts of capital against it.

So it'll never be something that people think is appropriately priced, because all the internal machinations banks and others have to go through to be able to do the transactions are very painful.

What you can say is that in the last year, yes, levels have gotten lower. And if 6% to 7% is the right level, where it used to 7% to 8% or even 8% or higher, what is interesting is that just about every debt rate you can think of let's say, in the last six months, 12 months, they've tended to go up a little bit, and spreads have widened. To the extent people felt it was way too expensive, maybe it's less expensive today, because it doesn't look quite as bad relative to other things.

Burton, Mayer Brown: The other thing is that within the institution, within the bank, the tax equity does compete with other desks for the tax appetite. So, for instance, if you do low-income housing tax credits, you get Community Reinvestment Act. If those deals are paying, let's say, 5%, tax equity's going to have to pay something materially higher than 5% in order to persuade the bank not to just do all the low-income housing tax credit deals.

Dovere, C2: Or, like us, you have solar deals that serve low-income housing. Our tax equity partners were very excited about that.

PFR: I've heard quite a bit this year about regulated utilities looking to own more renewable energy assets directly rather than contracting them through PPAs. I'm curious about how that affects tax equity, whether utilities use third-party tax equity to finance projects, or their own tax base, and when you're developing a project and if you're going to sell it to a utility company, how that affects the dynamics there.

Burton, Mayer Brown: The first thing is that ITC is subject to normalization, which is a complicated tax issue for regulated utilities, but, basically, it makes ITC relatively unattractive to regulated utilities. The PTC is not subject to normalization, so you have a first fork in the road between ITC and PTC.

If it's an ITC deal, the regulated utility is probably going to want to do it as a PPA and not own it itself. If it's a PTC deal, they may very well want to own it themselves and rate-base it. And that can be very attractive to them to both get the PTCs and to be able to rate-base it.

They have to have tax appetite to be able to use the PTC, of course, and a lot of the utilities for a while didn't have tax appetite because the regulators were typically making them claim bonus depreciation, which would wipe out or exceed their tax appetite.

One of the things tax reform did is that it instituted an interest limitation rule of, basically, 30% of EBITDA, as the limit on your

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ability to deduct interest. But that rule is not applied to regulated utilities. However, a trade-off for that was that regulated utilities agreed to not be able to take bonus depreciation. So the regulated utilities no longer have their regulator saying, "You have to take bonus and pass through that benefit to the consumer," so now they have more tax appetite. So them owning wind PTC deals themselves and claiming PTCs themselves is potentially an attractive proposition.

"Or, like us, you have solar deals that serve low-income housing. Our tax equity partners were very excited about that."

Rich Dovere, C2

Salant, Citi: Again, it's part of the supply/demand imbalance. You had all the backlog of transactions, what I call the normal-way business that people already try and do. Add to that the repowerings that people now want to do, which throws a whole new chunk of transactions out there that probably will want tax equity. Coupled with the fact that there are people who have had their tax positions change, or some publicly disclosed situations where people are in the market selling portfolios of tax equity, so you've got secondary sales of tax equity that has to find buyers. And we are aware of a couple of utilities that, for the first time, are looking for tax equity investors for their big portfolios, because they may have capacity, but they don't want to use it all for this and they actually would like to monetize some of it. And then add to that, hopefully, just off the horizon, the offshore wind market finally developing in the U.S.

So the problem is, when you take all the regular-way business and you add repowerings and secondaries and big utilities and offshore, you could have a very significant increase in the need for tax equity. And the question is: are these positives on the investor side going to be enough to absorb all of that new product that may need a home very shortly?

PFR: I'm glad you mentioned offshore wind. A lot of states, especially on the East Coast, are looking at offshore wind. New Jersey just made an announcement on that topic this week (PFR, 9/18). These projects are very large and expensive. What challenges do they present when looking to take advantage of tax credits?

Davis, Mayer Brown: The size and the cost of the projects presents a challenge by itself, because the sponsor has to be able to arrange enough tax equity financing to finance the project. And given the cost of the project and the fact that the wind projects that are offshore typically claim the ITC because of those high costs, there's a large credit upfront—a big hit in one year. So you need either an investor or, more likely, a number of investors who are able to absorb all of those tax benefits in the first year. That's why, as Marshal knows, Citi and **General Electric** were co-investors in the Block Island transaction.

Another complexity that that introduces is with respect to negotiations with the sponsor. The sponsor now has to deal with multiple investors, each of whom is typically a large institutional investor that has very strongly-held positions on certain issues, and they may not be the same issues from one investor to the next, so the developer has to figure out how to address each of those investors' issues to keep them at the table. So that, obviously, presents a lot of challenges for the sponsor in trying to round up the club of investors for offshore wind.

Rasmussen, CapDyn: I think there's no doubt that it's going to be a major part of the North American market. It has been lagging compared to Europe, where it is an established industry, so I think it's also a new market for tax equity. We do think that offshore is something that we'll be looking at, and how it's going to fit into our portfolio, but one of the struggles that we anticipate having is just the fact that it is a new market and you're dealing with other construction issues, other cost issues, even just tax equity players coming into that market for the first time. So I do think we have some of those hurdles that we would expect to see.

"Offshore is something that we'll be looking at but one of the struggles that we anticipate having is just the fact that it is a new market and you're dealing with other construction issues, other cost issues."

Kathryn Rasmussen, CapDyn

Davis, Mayer Brown: An additional challenge has to do with the development timeline. Because the IRS has basically given you the four-year window from when you start, which could be as much as five years if you start early in year one. And given the permitting and approvals and various hoops that developers have to jump through, they may find that they're butting up against the end of that four-year period. And tax equity, typically, doesn't want to invest in deals that aren't in the four-year safe harbour, notwithstanding the delays may have been because of various things that are permitted in the IRS guidance. So that's a real challenge.

Almeida, EDPR: EDPR has offshore experience in Europe, and the reality is that offshore projects make sense when they're big. And so, if we have a capital constraint because of what you are saying, because people don't want to have ten investors in one deal, they just make the projects smaller than they should be. And that is, from my perspective, hindering the competitiveness of offshore, and there should be a solution for this.

But, interestingly enough, even though the tax equity ticket is large, just because the project is big, the percentage of the tax equity for an offshore project is smaller than for a typical onshore wind project. That is interesting for us, because we can bring more debt into the mix, but it creates different dynamics, because the tax equity investors, the tax equity investors also need to deviate from some of the traditional dos and don'ts of the structure and be able to come up with structures that accommodate a much larger debt component than your traditional onshore wind.

Burton, Mayer Brown: One thing that is hopeful on the tax side for offshore wind is that most of the RFP responses for offshore wind are including storage.

PFR: Battery storage?

Burton, Mayer Brown: Battery storage. And that's a nice fit with offshore wind, because offshore wind could qualify for the PTC or the ITC, but because of the high cost, the conventional wisdom is the ITC is more attractive because the 30% ITC exceeds the present value of the PTC.

And then if you have an ITC project that charges a battery, you can claim ITC on the battery as well. And conventional wisdom has been that if you had a PTC project charging a battery, it may not qualify. So the fact that offshore wind, for commercial reasons, is going with battery storage, and the tax law conveniently facilitates the pairing of offshore wind and battery storage, is helpful for the projects.

Davis, Mayer Brown: The statute requires that in order for equipment to be eligible for the ITC, it has to be electric generation equipment. The batteries by themselves aren't generation equipment, but the IRS has some old regulations that say that storage equipment can be eligible—and that has been found to include batteries under private letter rulings—presumably under the notion that they're part of, or integral to, some generating facility.

"Absolutely, we're thinking about the phase out But right now, for all intents and purposes, as a practical matter, it's a bit early I wont say too early, but a bit early"

Marshal Salant, Citi

However, it may be difficult to get around the literal language of the statute, and for that reason there's a strongly-held view that you can't claim the ITC on batteries that are part of a PTC wind farm. In my view, that's an area where the industry should be pushing the IRS for additional guidance, because the stakes are high enough, and as David points out, with all the RFPs that are looking to include batteries, it's an issue that we're going to see repeatedly. Although the IRS guidance project for what equipment qualifies for the ITC has been dropped from the IRS's priority guidance plan, I understand from an IRS official that it is still open but guidance won't be coming out until 2019.

Salant, Citi: We'd like to think at Citi that we have good experience here. We did the Block Island deal, the **Deepwater Wind** deal, as was mentioned. We've done a lot of deals in Europe. For example, we did the Walney Extension off the coast of England, which is the largest offshore wind farm. So because of that expertise, we get asked to talk to clients and potential clients about this.

There are all these technical challenges on the tax side. What does continuous work really mean when you're out in the ocean? And you're not going to be able to show that you did a lot of work onsite...

PFR: ...building roads and things.

Salant, Citi: Yes, there's a lot of language about roads. Well, that's not going to apply for the thing you're building in the ocean. And the numbers are big, and we have to convince everybody about the risks.

I think it's fair to say, in Europe there's not a big premium between financing, offshore versus onshore, because they have the history, they've proven that they can do it. In the U.S. we've only got this one little project that's very successful, but it's small compared to the ones that are coming. And when you go to do multi-billion projects, it's going to require a lot of people participating, with a lot of capital, and we're going to spend a lot of time talking about the best way to do it.

PFR: So onshore wind-plus-battery-storage, in particular, has this mismatch between the PTC and the ITC. But there's been solar with battery storage integrated into it, and I guess that's a slightly simpler proposition from a tax equity point of view. Has a lot of financing been done on that basis so far?

Burton, Mayer Brown: It depends on what a lot is. There have been a number of projects that have combined solar and storage, but it's not every project, it's not half the projects, but it has happened.

And even that has tax questions about. An early IRS ruling said, "You just have to charge it with the solar, you're fine." And then the most recent ruling, which is still a couple of years old, said, "Well, if you charge it less than 75% with solar in the first five years, you fall off a cliff and you have to pay back the ITC." The IRS analysis in the rulings has evolved to reach that determination.

Davis, Mayer Brown: The easy case is the battery is built at the same time as the solar project. It's co-located, it's under the same ownership, and the battery is charged 100% from the solar—there's nothing coming from the grid. It becomes a little more complex where, as David talks about, you get into the dual-use property rules, because the battery is now charged by the grid for some portion of time.

Other facts that make it a little more complicated might be the batteries aren't co-located. They're not right there with the solar project, they may be located somewhere else, or they may be owned by a different party. And these are things that the IRS has not yet addressed and that the industry's struggling with, underscoring the need for additional guidance.

Almeida, EDPR: Let me give another example where the current status quo might be hindering innovation. We are looking at hybrid projects, wind and solar, in our other geographies, and potentially those could have storage as well. You would be able to put together an energy product that is shaped more appropriately. You might be able to use the infrastructure that's just sitting there, and so wind could use it part of the day, solar could use it at another part of the day. How do we deal with that under current tax guidance?

Davis, Mayer Brown: Pedro raises a great point, because the diurnal nature of wind versus solar, you're going to get solar just during the day, but you get your best wind at night. The so-called hybrid project would allow you to potentially use some pieces of equipment for both solar and wind and therefore cut the cost of having a certain megawatt capacity of wind and a certain megawatt capacity of solar.

In fact, I submitted on behalf of a client a comment letter to the IRS requesting guidance on that very point. There are really compelling arguments that you ought to be able to use that type of hybrid equipment and claim the PTC for the wind production and the ITC for the solar equipment, but we'll have to wait to see whether the IRS agrees.

Dovere, C2: I would love for that to be the case. But as far as the storage goes, it's actually something that we think is very exciting on the D.G. side. We're going to retrofit our projects with storage. We're only talking about building a couple megawatts of *new* projects that will have it, but we basically just negotiated that if there's anything that tax equity has a problem with, we'll just take the tax credit ourselves, so just allocate 95% to us. There's obviously a functional limit to that, but it's still a couple million dollars a year worth of batteries.

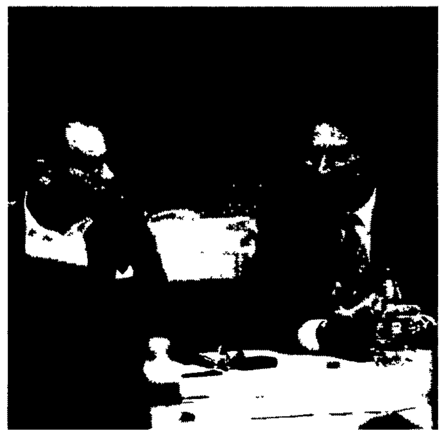
PFR: It strikes me that a lot of these difficulties with integrating different technologies will be resolved when the PTCs go away entirely, because there will be no compatibility issue any more. Are people thinking already about the phaseout and how that will affect financing, or is it too early?

Salant, Citi: Absolutely, we're thinking about it. But right now, for all intents and purposes, as a practical matter, it's a bit early. I won't say too early, but a bit early.

Rasmussen, CapDyn: It's never too early to start thinking about the future and what our future funds are going to look like, where we're going to allocate our investment dollars in the future. However, if it's qualified for the safe harbour, you have four years to do it. That's another five years, essentially, a little over five years from today. And a lot can change in five years. We've seen costs dramatically go down. How much more they can go down... We'll see. But we do expect there will be improvements in production, whether it's more efficient turbines or more efficient solar panels. A number of things are going to feed into what the landscape looks like in 2023.

Burton, Mayer Brown: In terms of the extension, that's really a political judgement, and I know my political crystal ball has been not working too well since 2016, but I think there's a possibility of an extension given the right president and the right Congress. But we'll have to wait and see.

PFR: And under the existing schedule, there would still be a 10% ITC for solar projects, that there is no existing plan to get rid of that, right?



Salant, Citi: That is correct, yes.

PFR: And, also, there'll be depreciation, so there may still be a role for this kind of structure beyond the planned phaseout?

Burton, Mayer Brown: Right, I believe so. Ten percent ITCs are much smaller than the current 30%, but it's still a material number that I think people would want to monetize. The 100% expensing ratchets down over time, but you still have five-year MACRS [Modified Accelerated Cost Recovery System] depreciation, which is still relatively accelerated. And there were always and are tax-oriented deals done on equipment and things that don't qualify for tax credits. So I think there's always going to be some structuring and tax planning and tax motivation as long as there's some level of tax credit and accelerated depreciation available. ■

S&P Global
Ratings

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American Electric Power Co. Inc.

Business Risk: EXCELLENT

Vulnerable — Excellent

Financial Risk: SIGNIFICANT

Highly leveraged — Minimal

Anchor	Modifiers	Group/Gov't
a-	a-	a-

Issuer Credit Rating

A-/Stable/A-2

Credit Highlights

Overview	
Key Strengths	**Key Risks**
Mostly lower-risk electric utility holding company.	Elevated capital spending program requires ongoing balanced funding and timely cost recovery.
Large scale of operations with a customer base of about 5.4 million combined with solid geographic diversity with operations in 11 U.S. states.	Significant coal-fired generation remains.
Generally credit-supportive and constructive regulatory frameworks.	Higher operational risk arising from the ownership of the Cook Nuclear Plant.
Coal-fired generation being scaled back through retirements as the company expands transmission assets.	Financial measures at the lower end of the benchmark range for the financial risk profile, resulting in limited cushion.

Proposed North Central Wind rate-based generation investment in Oklahoma is a scalable strategy. American Electric Power Co. Inc.'s (AEP's) proposal is credit supportive in that regulators can approve the construction of individual wind farms without approving the entire plan. S&P Global Ratings expects AEP to fund these investments in a credit-supportive manner. In addition, these wind farms will help AEP lower its overall carbon dioxide emissions and the proportion of coal-based generation.

Large multistate operations that have constructive regulatory frameworks bolster overall credit quality. AEP is one of the largest electric utilities in the U.S., delivering electricity to about 5.4 million customers across 11 states. This diversity helps mitigate the impact of adverse regulatory decisions or regional economic challenges. The jurisdictions generally have a constructive regulatory framework that provides for the timely recovery of approved capital expenditures, as well as pass-through fuel cost mechanisms and recovery of various operating expenses.

Federal Energy Regulatory Commission (FERC)-regulated transmission investments are credit-enhancing. AEP's latest capital spending plan calls for higher spending on transmission infrastructure and projects. This should further increase its transmission rate base, providing stable and predictable cash flows through formula-based rates.

Outlook: Stable

The stable outlook on AEP and its subsidiaries reflects the company's improving business risk profile consisting almost entirely of solid regulated utility operations. We expect AEP to generate funds from operations (FFO) to debt of 15%-16% through 2021 after factoring in the impact of U.S. tax reform.

Downside scenario

We could lower the ratings on AEP and its subsidiaries if the company's financial performance weakens such that FFO to debt is consistently below 14%, or if its business risk increases as a result of ineffective management of regulatory risk or the pursuit of risky unregulated investments.

Upside scenario

While not likely, we could raise the ratings on AEP and its subsidiaries if the company's financial performance improves, with FFO to debt consistently above 20% while business risk is unchanged.

Our Base-Case Scenario

Assumptions

- Economic conditions in the company's service territories continue to improve modestly, supporting a gradual increase in load growth.
- Operating cash flow expected to strengthen from rate recovery of additional capital and operating costs.
- Capital spending is elevated at $5.8 billion-$7.8 billion per year.
- Common stock dividends total about $1.3 billion annually.
- Negative discretionary cash flow indicates external funding needs.
- Company refinances all debt maturities.

Key Metrics

	2019e	2020f	2021f
Adjusted FFO to debt (%)	13.3-14	14-16	15-17
Adjusted debt to EBITDA (x)	5.2-5.7	4.8-5.3	4.5-5
Adjusted FFO cash interest coverage (x)	4-4.5	4.2-4.7	4.5-5

e--Expected. F--Forecasted. FFO--Funds from operations.

Base-case projections

- Gross margin benefits from rate recovery mechanisms and transmission formula rates, partially offset by the impact of U.S. tax reform.
- Annual debt to EBITDA averaging about 5x.

- Company uses debt to partly fund negative discretionary cash flow.
- Adjusted FFO to debt in the 14%-16% range, with the outer years strengthening following incremental recovery of costs through rates.

Company Description

Columbus, Ohio-based AEP is a holding company of electric utilities that serve about 5.4 million customers in 11 states.

Business Risk: Excellent

We base our assessment of AEP's business risk profile on the very low risk of the regulated utility industry and the company's mostly lower-risk, rate-regulated operations that provide electricity, an essential service. Although in 11 states, the company's operations in Ohio, Texas, Virginia, and West Virginia represent the majority of consolidated revenues. AEP has reached largely constructive regulatory outcomes in the jurisdictions where it operates, ensuring some cash flow stability over the next few years. AEP is investing in transmission projects, a trend that is likely to continue, providing support to credit quality through cash flow diversity and further regulatory diversification.

Quality of the service territories varies, but many are in stable and diverse economies. They collectively benefit from broad diversity that mitigates the effect of weather and local economic conditions. AEP also benefits from a diverse set of customers, which provides stability in the case of lower usage by any particular class, generating the bulk of revenues from residential, commercial, and wholesale customers with lower contribution from the more volatile industrial class.

AEP's generation fleet benefits from low-cost and efficient operations leading to competitive customer rates. Also, AEP has been lowering its historically high reliance on coal-fired generation through plant retirements and sales, bringing the company's coal-fired capacity at year-end 2019 down to 13,200 megawatts (MW), about one-half the level of 2010. In addition to lowering air emissions from generation assets, the company is avoiding the need for large environmental compliance spending to comply with existing air emissions rules. Increasing investments in transmission assets helps diversify the regulated rate base and potentially facilitate compliance with evolving environmental standards by bringing in power from other regions. These upsides are somewhat offset by the company's exposure to nuclear generation, which has higher operational risk. The company owns and operates the 2,200 MW Cook Nuclear Plant in Michigan.

Peer comparison

We consider AEP similar to peers Berkshire Hathaway Energy Co., Duke Energy Corp., WEC Energy Group Inc. (WEC), and Xcel Energy Inc. They all have excellent business risk profiles and significant financial risk profiles. They operate across numerous states, have many customers, and electric generation, including coal-fired plants. Like AEP, all peers except WEC have nuclear generation. Regulated electric transmission plays a part in each company's strategy. The three-year average of AEP's financial measures after factoring in U.S. tax reform has resulted in the company declining to the middle of peers. The utilities of these companies all operate under generally supportive regulatory environments with various rate and cost-recovery mechanisms.

Table 1

American Electric Power Co. Inc.--Peer Comparison

Industry Sector: Electric

	American Electric Power Co. Inc.	Berkshire Hathaway Energy Company	Duke Energy Corp.	WEC Energy Group Inc.	Xcel Energy Inc.
Ratings as of Jan. 29, 2020	A-/Stable/A-2	A/Stable/A-1	A-/Stable/A-2	A-/Stable/A-2	A-/Stable/A-2
	--Fiscal year ended Dec. 31, 2018--				
(Mil. $)					
Revenue	15,848.0	19,787.0	24,437.3	7,679.5	11,537.0
EBITDA	5,252.2	7,349.1	10,481.1	2,544.1	3,988.4
FFO	4,210.1	6,219.6	8,427.7	2,054.5	3,268.8
EBIT	3,124.7	4,500.6	5,815.1	1,711.3	2,226.6
Interest expense	1,241.6	2,011 6	2,761.8	506.1	791.6
Cash interest paid	1,066.8	1,909.6	2,319.4	473.3	746.6
Cash flow from operations	5,047.3	6,824.6	7,215.9	2,501.3	3,142.8
Capital expenditure	6,321.0	6,198.9	9,717.5	2,155.4	3,962.6
FOCF	(1,273.7)	625.7	(2,501.6)	345.9	(819.8)
Dividends paid	1,255.5	0.0	2,497.9	708.8	730.0
DCF	(2,529.2)	518.7	(4,999.5)	(435.4)	(1,550.8)
Cash and short-term investments	393.2	671.0	442.0	84.5	147.0
Gross available cash	393.2	671.0	442.0	84.5	147.0
Debt	26,216.3	41,367.7	56,558.1	12,183.2	19,194.7
Preferred stock	0.0	0.0	500.0	265.2	0.0
Equity	19,128.8	29,723.0	44,334.0	10,077.5	12,222.0
Debt and equity	45,345.1	71,090.7	100,892.1	22,260.7	31,416.7
Adjusted ratios					
EBITDA margin (%)	33.1	37.1	42.9	33.1	34.6
EBIT margin (%)	19.7	22.7	23.8	22.3	19.3
Return on capital (%)	7.2	6.4	5.9	7.8	7.3
EBITDA interest coverage (x)	4.2	3.7	3.8	5.0	5.0
EBITDA cash interest coverage (x)	4.9	3.8	4.5	5.4	5.3
FFO cash interest coverage (x)	4.9	4.3	4.6	5.3	5.4
Debt/EBITDA (x)	5.0	5.6	5.4	4.8	4.8
FFO/debt (%)	16.1	15.0	14.9	16.9	17.0
Cash flow from operations/debt (%)	19.3	16.5	12.8	20.5	16.4
FOCF/debt (%)	(4.9)	1.5	(4.4)	2.8	(4.3)
DCF/debt (%)	(9.6)	1.3	(8.8)	(3.6)	(8.1)
Debt/debt and equity (%)	57.8	58.2	56.1	54.7	61.1

Table 1

American Electric Power Co. Inc.--Peer Comparison (cont.)					
Industry Sector: Electric					
	American Electric Power Co. Inc.	**Berkshire Hathaway Energy Company**	**Duke Energy Corp.**	**WEC Energy Group Inc.**	**Xcel Energy Inc.**
Return on common equity (%)	9.2	8.3	5.3	10.8	9.3
Common dividend payout ratio, unadjusted (%)	65.3	0.0	97.4	65.9	61.9

FFO--Funds from operations. FOCF--Free operating cash flow. DCF--Discretionary cash flow.

Financial Risk: Significant

Under our base-case scenario, we anticipate AEP's adjusted FFO to debt will be in the 15%-16% range over the next few years as the company benefits from recovery mechanisms like the investment cost rider, formulaic transmission rates, and forward test years for rate cases. Various rate mechanisms allow for the timely recovery of costs and support more stable operating cash flow. We expect the company will continue to fund its investments in a manner that preserves credit quality.

Over the next several years, AEP will have elevated capital spending that will average about $6 billion per year. About 10% will be allocated to generation including renewables and the balance to wires-based operations, including over 50% of total capital spending allocated to FERC-regulated transmission investments. These benefit from a constructive regulatory framework that provides for timely investment recovery. The elevated capital spending along with dividends results in significantly negative discretionary cash flow, indicating external funding needs and likely limiting material deleveraging. We expect adjusted debt to EBITDA in the 4.8x-5.5x range for 2020 and 2021. We assess AEP's financial risk profile using our medial volatility financial benchmarks that reflect lower-risk regulated utility operations and effective management of regulatory risk. These benchmarks are more relaxed than those used for a typical corporate issuer.

Financial summary

Table 2

American Electric Power Co. Inc.--Financial Summary					
Industry Sector: Electric					
	--Fiscal year ended Dec. 31--				
	2018	**2017**	**2016**	**2015**	**2014**
(Mil. $)					
Revenue	15,848.0	15,080.3	15,988.9	16,033.4	16,623.7
EBITDA	5,252.2	5,538.7	5,493.8	5,420.2	5,347.6
FFO	4,210.1	4,612.1	4,555.6	4,367.2	4,333.1
EBIT	3,124.7	3,667.1	3,714.5	3,598.2	3,543.5
Interest expense	1,241.6	1,088.0	1,060.7	1,082.7	1,069.7
Cash interest paid	1,066.8	927.8	908.8	932.8	897.5
Working capital changes	516.7	(162.2)	27.0	222.5	128.0

Table 2

American Electric Power Co. Inc.--Financial Summary (cont.)

Industry Sector: Electric

	--Fiscal year ended Dec. 31--				
	2018	**2017**	**2016**	**2015**	**2014**
Cash flow from operations	5,047.3	4,098.4	4,309.0	4,519.4	4,447.7
Capital expenditure	6,321.0	5,750.7	4,857.9	4,538.7	4,271.0
FOCF	(1,273.7)	(1,652.3)	(548.9)	(19.3)	176.7
Dividends paid	1,255.5	1,191.9	1,121.0	1,059.0	994.0
DCF	(2,529.2)	(2,844.2)	(1,669.9)	(1,078.3)	(817.3)
Cash and short-term investments	393.2	376.3	330.5	292.2	269.0
Gross available cash	393.2	376.3	542.2	563.2	269.0
Debt	26,216.3	23,278.4	22,002.8	20,314.8	20,327.9
Equity	19,128.8	18,313.6	17,420.1	17,904.9	16,824.0
Debt and equity	45,345.1	41,592.0	39,422.9	38,219.7	37,151.9
Adjusted ratios					
Annual revenue growth (%)	5.1	(5.7)	(0.3)	(3.6)	10.7
EBITDA margin (%)	33.1	36.7	34.4	33.8	32.2
EBIT margin (%)	19.7	24.3	23.2	22.4	21.3
Return on capital (%)	7.2	9.1	9.6	9.5	9.7
EBITDA interest coverage (x)	4.2	5.1	5.2	5.0	5.0
EBITDA cash interest coverage (x)	4.9	6.0	6.0	5.8	6.0
FFO cash interest coverage (x)	4.9	6.0	6.0	5.7	5.8
Debt/EBITDA (x)	5.0	4.2	4.0	3.7	3.8
FFO/debt (%)	16.1	19.8	20.7	21.5	21.3
Cash flow from operations/debt (%)	19.3	17.6	19.6	22.2	21.9
FOCF/debt (%)	(4.9)	(7.1)	(2.5)	(0.1)	0.9
DCF/debt (%)	(9.6)	(12.2)	(7.6)	(5.3)	(4.0)
Debt/debt and equity (%)	57.8	56.0	55.8	53.2	54.7

FFO--Funds from operations. FOCF--Free operating cash flow. DCF--Discretionary cash flow.

Liquidity: Adequate

We assess AEP's liquidity as adequate because we believe its sources are likely to cover uses by more than 1.1x over the next 12 months and meet cash outflows even with a 10% decline in EBITDA. The assessment also reflects the company's generally prudent risk management, sound relationships with banks, and a generally satisfactory standing in credit markets.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash and liquid investments of about $210 million.	• Capital spending of $4.6 billion.

- Estimated cash FFO of about $4.8 billion.
- Credit facility availability of about $4 billion.
- Debt maturities, including outstanding commercial paper, of about $2.3 billion.
- Dividends of about $1.3 billion.

Debt maturities

- 2020: $1.02 billion
- 2021: $1.91 billion
- 2022: $2.79 billion
- 2023: $491 million
- 2024: $271 million

Covenant Analysis

As of June 30, 2019, AEP had adequate cushion as per the financial covenant of consolidated total debt to total capital of no more than 67.5%.

Compliance expectations	Requirements
• The company was in compliance as of June 30, 2019. • Single-digit percentage EBITDA growth and elevated capital spending should still permit a cushion. • Although we believe the company will remain in compliance, covenant headroom could decrease without adequate cost recovery of capital investments or if, while making these investments, debt rises rapidly without adequate growth in equity.	• Current: no more than 67.5% • As of year-end 2020: no more than 67.5% • As of year-end 2021: no more than 67.5%

Environmental, Social, And Governance

We consider environmental factors in our rating analysis. AEP's social and governance factors are generally comparable with those of its peers. As both a vertically integrated and wires-only electric utility with a total generation fleet capacity of about 31,000 MW, of which 73% is based on fossil fuels (about 45% coal; 28% natural gas), AEP's environmental risks are greater than those of vertically integrated peers. The company's reliance on coal-fired generation exposes it to heightened risks, including the ongoing cost of operating older units in the face of disruptive technology advances and the potential for increasing environmental regulations that require significant capital investments. AEP began reducing its reliance on coal through plant retirements and renewable investments such as hydro, wind, solar, and energy efficiency. However, this upside is partly offset by AEP's exposure to nuclear generation (7% of the generation fleet), which introduces higher operational risks and plant retirement responsibilities. AEP's management is taking active steps to reduce its fleet's environmental footprint, committing to an 80% reduction of carbon dioxide emissions by 2050 from 2000 levels.

From a social perspective, AEP's internal safety and health management systems processes enable it to effectively serve one of the largest service territory footprints in North America. AEP's cost-reduction efforts enabled the company to stabilize operations and maintenance costs in an inflationary economic environment, facilitating competitive customer rates. This is important because all transmission and distribution companies are moving proactively to deploy capital to upgrade, modernize, and harden assets in the wake of recent weather events and for technological reasons. AEP's governance practices are consistent with other publicly traded utilities.

Group Influence

Under the group rating methodology, we assess AEP as the parent of the group that includes all of the company's operating subsidiaries. AEP's group credit profile is 'a-', leading to an issuer credit rating of 'A-'.

Issue Ratings - Subordination Risk Analysis

- The short-term rating is 'A-2', based on our issuer credit rating.
- We rate AEP's mandatory convertible equity units two notches below the issuer credit rating. This reflects that the units consist of a remarketable junior subordinated note due 2024 and a purchase contract that obligates the owners of the units to purchase AEP's common stock in three years.

Capital structure	Analytical conclusions
AEP's capital structure consists of about $28 billion of debt, of which about $22 billion is priority debt.	We rate AEP's unsecured debt one notch below the issuer credit rating because priority debt exceeds 50% of the company's consolidated debt, after which point AEP's debt is considered structurally subordinated.

Reconciliation

Table 3

Reconciliation Of American Electric Power Co. Inc. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $)

	--Fiscal year ended Dec. 31, 2018--								
American Electric Power Co. Inc. reported amounts									
	Debt	**Shareholders' equity**	**Revenue**	**EBITDA**	**Operating income**	**Interest expense**	**S&P Global Ratings' adjusted EBITDA**	**Cash flow from operations**	**Capital expenditure**
	25,545.7	19,028.4	16,195.7	5,039.9	2,682.7	984.4	5,252.2	5,223.2	6,371.6
S&P Global Ratings' adjustments									
Cash taxes paid	--	--	--	--	--	--	24.7	--	--
Cash taxes paid: Other	--	--	--	--	--	--	--	--	--
Cash interest paid	--	--	--	--	--	--	(939.3)	--	--
Operating leases	971.4	--	--	252.8	71.2	71.2	(71.2)	181.6	--
Accessible cash and liquid investments	(393.2)	--	--	--	--	--	--	--	--
Capitalized interest	--	--	--	--	--	73.6	(73.6)	(73.6)	(73.6)
Share-based compensation expense	--	--	--	53.2	--	--	--	--	--
Securitized stranded costs	(1,117.0)	--	(347.7)	(347.7)	(40.8)	(40.8)	40.8	(306.9)	--
Power purchase agreements	336.0	--	--	46.5	23.5	23.5	(23.5)	23.0	23.0
Asset retirement obligations	549.4	--	--	93.7	93.7	93.7	--	--	--
Nonoperating income (expense)	--	--	--	--	223.8	--	--	--	--
Noncontrolling interest/minority interest	--	100.4	--	--	--	--	--	--	--
Debt: Other	324.0	--	--	--	--	--	--	--	--
EBITDA: Other income/(expense)	--	--	--	113.8	113.8	--	--	--	--
Depreciation and amortization: Impairment charges/(reversals)	--	--	--	--	70.6	--	--	--	--
Depreciation and amortization: Other	--	--	--	--	(113.8)	--	--	--	--
Interest expense: Other	--	--	--	--	--	36.0	--	--	--
Total adjustments	670.6	100.4	(347.7)	212.3	442.0	257.2	(1,042.1)	(175.9)	(50.6)

Table 3

Reconciliation Of American Electric Power Co. Inc. Reported Amounts With S&P Global Ratings' Adjusted Amounts (Mil. $) (cont.)

S&P Global Ratings' adjusted amounts

	Debt	Equity	Revenue	EBITDA	EBIT	Interest expense	Funds from operations	Cash flow from operations	Capital expenditure
	26,216.3	19,128.8	15,848.0	5,252.2	3,124.7	1,241.6	4,210.1	5,047.3	6,321.0

Ratings Score Snapshot

Issuer Credit Rating

A-/Stable/A-2

Business risk: Excellent

- **Country risk:** Very low
- **Industry risk:** Very low
- **Competitive position:** Strong

Financial risk: Significant

- **Cash flow/leverage:** Significant

Anchor: a-

Modifiers

- **Diversification/portfolio effect:** Neutral (no impact)
- **Capital structure:** Neutral (no impact)
- **Financial policy:** Neutral (no impact)
- **Liquidity:** Adequate (no impact)
- **Management and governance:** Satisfactory (no impact)
- **Comparable rating analysis:** Neutral (no impact)

Stand-alone credit profile : a-

- **Group credit profile:** a-

Related Criteria

- Criteria - Corporates - General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013

- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- General Criteria: Group Rating Methodology, Nov. 19, 2013
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria - Corporates - Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012
- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- Criteria - Insurance - General: Hybrid Capital Handbook: September 2008 Edition, Sept. 15, 2008

Business And Financial Risk Matrix

	Financial Risk Profile					
Business Risk Profile	Minimal	Modest	Intermediate	**Significant**	Aggressive	Highly leveraged
Excellent	aaa/aa+	aa	a+/a	**a-**	bbb	bbb-/bb+
Strong	aa/aa-	a+/a	a-/bbb+	bbb	bb+	bb
Satisfactory	a/a-	bbb+	bbb/bbb-	bbb-/bb+	bb	b+
Fair	bbb/bbb-	bbb-	bb+	bb	bb-	b
Weak	bb+	bb+	bb	bb-	b+	b/b-
Vulnerable	bb-	bb-	bb-/b+	b+	b	b-

Ratings Detail (As Of January 31, 2020)*

American Electric Power Co. Inc.	
Issuer Credit Rating	A-/Stable/A-2
Commercial Paper	
Local Currency	A-2
Junior Subordinated	BBB
Senior Unsecured	BBB+
Issuer Credit Ratings History	
02-Feb-2017	A-/Stable/A-2
16-Sep-2016	BBB+/Watch Pos/A-2
29-Sep-2014	BBB/Positive/A-2

*Unless otherwise noted, all ratings in this report are global scale ratings. S&P Global Ratings' credit ratings on the global scale are comparable across countries. S&P Global Ratings' credit ratings on a national scale are relative to obligors or obligations within that specific country. Issue and debt ratings could include debt guaranteed by another entity, and rated debt that an entity guarantees.

S&P Global
Ratings

(/en_US/web/guest/home)

General Criteria: Group Rating Methodology

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OVERVIEW AND SCOPE

1. This article describes S&P Global Ratings' methodology for rating entities that are part of corporate, financial institutions, insurance, and international public finance groups, as well as U.S. public finance obligated groups. For the related guidance article, see "Guidance: General Criteria: Group Rating Methodology (/en_US/web/guest/article/-/view/sourceld/11001497)."

2. These criteria articulate the steps in determining an issuer credit rating (ICR) on group members and their holding companies. This involves assessing the group credit profile (GCP; i.e. the group's overall creditworthiness), the stand-alone credit profiles (SACP) of group members, and the status of an entity relative to other group entities.

3. The criteria also describe how we assess the potential for support (or negative intervention) from group entities, or from other external sources such as a government.

4. These criteria apply to corporate, financial institution, insurance, and international public finance entities that we consider part of a group and U.S. public finance entities that we consider part of an obligated group For these entities, we believe that their ownership, control, influence, or support by or to another entity could have a material bearing on their credit quality. Examples of entities that are outside the scope of these criteria include project finance and corporate securitizations.

5 These criteria may complement other criteria that address sector-specific support considerations.

6. This methodology follows our request for comment, "Request for Comment: Group Rating Methodology (/en_US/web/guest/article/-/view/sourceld/10764521)," published Dec. 12, 2018.

Key Publication Dates

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