

A Review of Feasible Financing Structures for Community Wind Projects in Pennsylvania

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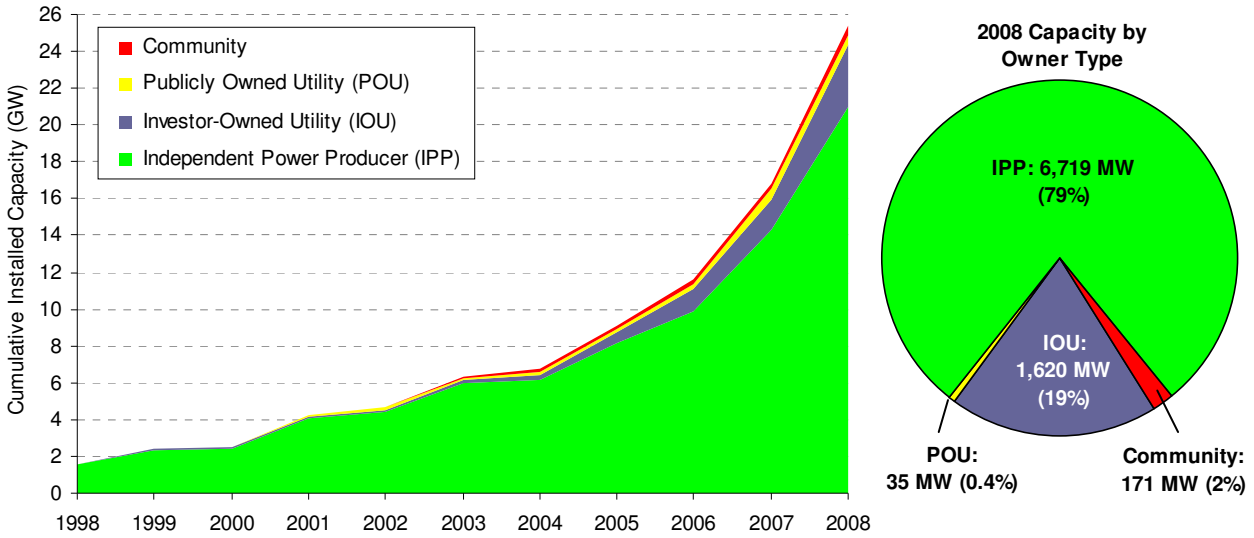
1. Introduction and Purpose

Broadly used to describe the harnessing of the wind to generate electricity, the term “wind power” encompasses several different applications and development models. At the most basic level, there is both “small wind” (e.g., wind power involving “small” wind turbines of 50 kiloWatts (“kW”) or less that are used to power single homes or businesses) and “large wind” or “utility-scale wind” (e.g., wind turbines ranging from 100 kW up to 3+ megaWatts (“MW”) that are typically – but not always – used to supply power to the electrical grid). Within the large or utility-scale segment of the industry, two primary development models have emerged: (1) commercial wind, where projects are developed by professional wind developers and owned by commercial or institutional entities; and (2) community wind, where a project is developed in large part by one or more landowners or members of the surrounding community (perhaps with the assistance of a professional developer or consultant), who also own some or all of the project.¹

In comparison to its long and storied history in Europe, where it helped to foster the development of the modern wind power industry in Denmark and Germany (Bolinger, 2001), the community wind power development model has only begun to catch on in the United States relatively recently. It was not until the late 1990s and the first part of this decade that the first few community wind projects in the United States were built in Southwestern Minnesota, along the Buffalo Ridge. The farmers that invested in those first U.S. projects recognized wind’s promise not only as a relatively cost-competitive and clean power source, but also as another cash crop that might allow their families to retain their working farms and stem the rural exodus that has afflicted so many Midwestern communities.

Despite its auspicious beginnings, which literally launched a grass-roots movement concentrated initially in the Midwest but spreading rapidly throughout the United States, community wind remains a very small segment of the U.S. market today. Wisner and Bolinger (2009) estimate that at the end of 2008, there were only 479 MW of community wind power projects – defined in this case as projects using turbines over 50 kW in size and completely or partly owned by towns, schools, commercial customers, or farmers, but excluding publicly owned utilities – located throughout the United States. This 479 MW made up just 2% of the 25,369 MW of wind installed in the U.S. at the close of 2008 (community wind also made up about 2% of the amount of wind installed in 2008 alone). Figure 1 shows that Independent Power Producers (“IPPs”) own the vast majority of wind projects in the U.S., with utilities – and in particular investor-owned utilities – starting to gain some ground. The community wind sector has found it difficult to make much headway in the last few years, in part due to the difficulty of securing smaller wind turbine orders amidst the rapid U.S. wind market expansion.

¹ Historically, another distinction between commercial and community wind projects has related to project size, with commercial wind projects often significantly larger than community wind projects.



Source: *Wiser and Bolinger, 2009*

Figure 1. Cumulative and 2008 Wind Power Capacity Categorized by Type of Owner

The recent finance-induced slowdown in the overall U.S. wind power market, however, coupled with federal stimulus legislation that could benefit community wind disproportionately, may help boost the community wind numbers in future years. This opportunity comes at the same time that a number of states – including Pennsylvania – have begun to recognize community wind’s promise as a “friendlier” form of wind development. Particularly in the Northeast, where large-scale wind development is geographically constrained and concerns over siting are high, community wind power development may offer a useful alternative to the more-common commercial model (Bolinger, 2006a).

Because of its promise, community wind power development has been a major focus area of Saint Francis University’s Renewable Energy Center (“the Center”), which commissioned this study. For several years, the Center has been working to educate Pennsylvania landowners and other stakeholders about the benefits of wind power in general, and community wind power in particular. Through its anemometer loan program, the Center has helped numerous landowners to measure the quality of their wind resource, with the goal of identifying sites that have the potential to host a community wind project.

To its credit, the Center has recognized that project viability depends on more than just the quality of the wind resource. In particular, how a project will be financed, owned, and operated can be just as critical to success. Equally important, the Center has also recognized that wind project finance in the United States is complicated, and even more so for community than for commercial wind projects, due in large part to the vagaries of Federal policy (discussed later). As a result, the Center has commissioned this study to examine financing and ownership structures that can be used for community wind projects in Pennsylvania. This study includes not only this written report, but also the creation and delivery of an Excel-based financial model that can be used by the Center to assess the mechanics and economics of various community wind ownership structures in Pennsylvania.

The purpose of this written report is to provide a general framework for thinking about community wind power project finance in Pennsylvania, and to accompany and describe the Excel-based financial pro forma model (delivered separately). To this end, the report begins in Section 2 by briefly reviewing federal and state policies and incentives that are applicable to community wind power development in Pennsylvania, and that may impact the choice of financing structures employed. Grounded in this review, Section 3 proceeds to describe the various community wind applications and financial structures that are potentially viable in Pennsylvania. Section 4 provides a high-level overview of the Excel-based financial model, including a review of inputs and assumptions, as well as illustrative modeling results for a generic community wind project in Pennsylvania. Section 5 concludes.

2. Incentives and Policies that Impact Community Wind Power Development in Pennsylvania

Wind power projects are subject to and impacted by policies and incentives enacted at each level of government – i.e., the federal, state, and local levels. In most cases, policies and incentives that impact project financing – the topic of this report – are concentrated at the federal and state levels (i.e., relevant policies enacted at the local level tend to deal primarily with siting and permitting). For this reason, as well as the difficulties in comprehensively covering local government policies throughout Pennsylvania, this chapter concentrates solely on federal and state policies and incentives.

2.1 Federal Level

For the most part, the federal policies and incentives that are of potential benefit to community wind are the same that are available to large-scale commercial wind development. That is, with a few exceptions, the federal government does not distinguish between commercial and community wind power development. While one might think that this would simplify community wind project finance, on the contrary this uniform policy treatment is at the root of what makes community wind project finance so difficult – i.e., the incentives are largely uniform, but the recipients of those incentives are far from uniform in their ability to make efficient use of the incentives.

2.1.1 The PTC and Accelerated Depreciation

Historically, the federal government has used the tax code to stimulate wind power development, in the form of a 10-year production tax credit (“PTC”) as well as accelerated tax depreciation deductions. Enacted as part of the Energy Policy Act of 1992, the PTC is a 10-year tax credit that was initially valued at \$15 per megaWatt hour (“MWh”), but that has been adjusted for inflation over time (in 2009, the inflation-adjusted value of the PTC is \$21/MWh). Assuming an installed project cost of \$2,000/kW (approximately the nationwide average in 2008, according to Wisner and Bolinger (2009)) and a capacity factor of 30%, the value of the PTC on a present

value basis comes to roughly 18.5% of installed project costs. As such, the PTC is a significant incentive for wind power development.

Under the federal tax code, wind projects are also permitted to write off or depreciate (for income tax purposes) the vast majority (i.e., typically 90+%) of the project's installed cost using a 5-year schedule under the Modified Accelerated Cost Recovery System ("MACRS").² Depreciating such a large percentage of the project using an accelerated depreciation schedule creates a taxable loss for the project in its early years, which can be used by investors to offset income from other business activities. Compared to a 20-year straight-line depreciation schedule that might otherwise be used (since the equipment is expected to last at least 20 years), this 5-year MACRS schedule provides a present value benefit equal to roughly 13% of total installed project costs. Thus, in combination, the PTC and 5-year accelerated depreciation (together, and also including the investment tax credit discussed later, referred to from here on out as the project's "Tax Benefits") amount to nearly one-third of the cost of a typical wind project – i.e., a significant benefit.

Somewhat perversely, however, most wind project developers are unable to make full and efficient use of these Tax Benefits, due to limited tax liability and the many rules and regulations that govern and restrict their use. For example, to qualify for the PTC, the owners of the wind project must also operate the project (which rules out operating leases as a viable financing structure) and the power must be sold to an unrelated party (which rules out basic self-generation applications). Furthermore, except during the project's first four years (which are exempt), the PTC cannot reduce the amount of income tax owed below the alternative minimum tax ("AMT"). Particularly relevant to community wind projects, which often require and seek other forms of government aid, the amount of the PTC is reduced in certain circumstances if a project accepts other forms of government aid, such as government grants or subsidized financing (this "PTC haircut" or "anti-double-dipping" penalty is intended to discourage projects from relying too heavily on government funding).

More broadly, the "passive credit and loss" rules require that individual taxpayers (but not corporations) who are passive investors in a wind project only use the PTC and accelerated depreciation to offset passive forms of income. Since the project will most likely generate net losses during the first few years of operations (due to the accelerated depreciation schedule), the project owners must typically have other forms of passive income (which does not include most wage or investment portfolio income) outside of the project in order to fully and efficiently use the Tax Benefits. Finally, the "at risk" rules limit depreciation deductions to the amount that an individual investor has placed at risk in the project; non-recourse loans and loans from a relative (for example) are not considered to be at risk, and therefore will limit the depreciation benefits. Though only briefly summarized here, the restrictions placed on the federal Tax Benefits provided to wind projects, and the implications for community wind projects, have been discussed extensively in other publications, including Bolinger et al. (2004).

At least on the surface, these restrictions on the use of federal Tax Benefits for wind power impact both commercial and community wind projects alike. Commercial wind project

² Projects that commence commercial operations by the end of 2009 are also entitled to first-year 50% bonus depreciation.

developers, however, have been better able to adapt to these restrictions by having projects (or portfolios of projects, or even pipelines of projects under development) that are large enough to attract the interest of third-party “tax equity” investors who are *not* subject to some of these restrictions and who *are*, therefore, able to make efficient use of the Tax Benefits. Some community wind projects have also been able to employ these third-party structures (described later), but for the most part, “tax equity” investors in wind projects have been interested in larger projects undertaken by professional developers with whom they can establish long-term relationships.

2.1.2 Changes Under the American Recovery and Reinvestment Act of 2009

For many years, analysts and community wind proponents alike have highlighted the relative difficulty that community wind projects have in utilizing federal Tax Benefits for wind power. For the most part, these revelations have fallen on deaf ears, as policymakers have always heretofore been able to point to the strong growth in commercial wind projects – which face many of the same issues – as evidence that federal incentives toward wind power are not overly burdensome. With the onset of the global financial crisis in the fall of 2008, however, the shortcomings of using the federal tax code to stimulate any type of wind project development became abundantly clear, as the supply of tax equity dried up and wind project finance ground to a halt. For the first time in many years, the interests of commercial and community wind came into sharp alignment, enabling passage of important, though only temporary, changes in wind power incentives as part of stimulus legislation passed in February 2009.

Specifically, the *American Recovery and Reinvestment Act of 2009* (“ARRA 2009”) made three important changes to federal policy towards wind power. First, it extended the “in-service” deadline for the PTC through the end of 2012, which is the longest extension in the history of that credit. Second, during that same time period it gave qualifying wind projects the option to elect a 30% investment tax credit (“ITC”) in lieu of the PTC. Third, and perhaps most significantly for community wind projects, ARRA 2009 allows qualifying wind projects to exchange the 30% ITC for a cash grant of equal value. However, this cash grant option is only temporary. To qualify, eligible projects must either be placed in service in 2009 or 2010, or else construction must have started prior to 2011, with the project placed in service by the end of 2012.

As demonstrated by a number of analysts (Bolinger et al., 2009; Karcher, 2009), the option to elect the 30% ITC in lieu of the PTC will favor those projects with above-average installed costs and below-average expected energy production, since the ITC is based on the size of the investment rather than on the amount of energy generated. Since many community wind projects may fall into this category – i.e., relatively high-cost due to small size and inability to capitalize on wind’s economies of scale, and relatively low-production due to possible site limitations – the option to elect the ITC is undoubtedly a positive development for community wind. Perhaps even more important, though, is the option to convert that 30% ITC into a cash grant of equivalent value. By receiving the incentive in cash rather than as a tax credit, the project is less-dependent on third-party tax equity investors, and can rely more heavily on conventional forms of finance that are more readily available to community wind power investors.

In addition, the 30% ITC and equivalent cash grant provide a number of other potential benefits over the PTC, many of which could be important for community wind projects:

- Whereas the PTC is only exempt from the alternative minimum tax during the project's first four years, the ITC and equivalent cash grant enjoy full AMT exemption.
- Whereas wind power must be sold to an unrelated party in order to qualify for the PTC, the ITC and equivalent cash grant face no such restriction, making them more suitable for self-generation or "behind the meter" wind projects.
- Whereas the project owner must also operate the project in order to be eligible for the PTC – a restriction that prohibits the use of leasing as a financing option – the ITC and equivalent cash grant impose no such requirement, thereby enabling the possibility of leasing.
- Whereas the use of "subsidized energy financing" (e.g., low-interest government loans) will trigger a "PTC haircut," no such "anti-double-dipping penalty" exists under the ITC.
- Whereas the PTC is subject to performance risk (e.g., if the project does not perform as well as expected, it will not earn as many PTCs as expected), the ITC and equivalent cash grant are immune from such risk.
- And finally, although no formal determinations have yet been made, some tax lawyers hold the opinion that the 30% cash grant is not subject to the "passive loss" and "at risk" rules (described earlier) that do apply to the PTC.

In aggregate, these differences between the PTC and ITC make the ability to choose the ITC or equivalent cash grant an important development for community wind projects. As a result, ARRA 2009 has the potential to spark a flurry of community wind activity, though it is important to keep in mind that these advantageous policy changes are only temporary in nature, with a very short window of opportunity. Furthermore, the policy changes discussed above only impact tax-paying entities (i.e., those that would have otherwise been eligible, at least theoretically, to claim the PTC); governmental and other tax-exempt entities cannot directly benefit from the 30% ITC or equivalent cash grant.

2.1.3 Other Federal Incentives

Although the PTC (or, for a limited time only, the 30% ITC or equivalent cash grant) and accelerated depreciation are the two major federal incentives for wind power, there are several smaller federal incentives targeted at specific types of wind project owners. Two of these that are relevant to community wind projects are United State Department of Agriculture ("USDA") grants and Clean Renewable Energy Bonds ("CREBs").

2.1.3.1 USDA Grants

Section 9006 of Title IX of *The Farm Security and Rural Investment Act of 2002* established the *Renewable Energy Systems and Energy Efficiency Improvements Program* (the "Section 9006 program"). Administered by the USDA, the Section 9006 program provided grants and loan guarantees to farmers, ranchers, and rural small businesses for assistance with purchasing renewable energy systems and making energy efficiency improvements.

In May 2008, the Section 9006 program was converted to the *Rural Energy for America Program* (the “REAP”) by *The Food, Conservation, and Energy Act of 2008*. The REAP is little changed from the Section 9006 program – i.e., the REAP still targets agricultural producers and rural small businesses with grants and loan guarantees to encourage the installation of renewable energy systems and energy efficient upgrades. Grants are limited to the lesser of 25% of the project’s cost or \$500,000, while loan guarantees may not exceed \$25 million (the combined amount of a grant and loan guarantee may not exceed 75% of a project’s cost).

Although USDA grants were popular with community wind projects under the first three rounds (2003-2005) of the Section 9006 program, interest among the “large wind” category waned considerably under the 2006 solicitation and thereafter. This sharp drop has been attributed, in part, to a growing realization in the market at that time that USDA grants negatively interact with the PTC. Through what are known as “anti-double-dipping” or, more colloquially, “haircut” provisions, the size of the PTC is reduced if a project receives certain other forms of governmental support.

The magnitude of the haircut can be significant: according to a 2006 Berkeley Lab report (Bolinger, 2006b), Section 9006 grants lose between 11% and 46% of their face value (depending on the wind project’s capital cost and capacity factor) to PTC haircuts. And because Section 9006 grants are most likely considered taxable income, an additional 20%-37% (depending on tax bracket) is lost to income tax payments on the grant. In combination, depending on the specific combination of tax bracket, capital cost, and capacity factor that pertain to a given wind project, the percentage of a Section 9006 grant lost to both income tax payments and the PTC haircut can range from 31% to 83% of the dollar value of the grant. The USDA is aware of this “problem,” but chose not to alter the program during the 2008 transition from the Section 9006 program to the REAP.

While the REAP program interacts negatively with the PTC, no such anti-double-dipping penalty exists for the 30% ITC or the equivalent cash grant that are now available for a limited time, courtesy of ARRA 2009. Recipients of REAP grants will still likely need to pay income tax on the grant, but will not have to reduce the basis on which the 30% ITC or equivalent cash grant is calculated. As noted above, this is one reason why the choice of ITC or cash grant appears to be favorable to community wind projects in particular.

2.1.3.2 Clean Renewable Energy Bonds

The Energy Policy Act of 2005 (“EPAAct 2005”) created CREBs, a financing tool for tax-exempt entities unable to directly use the federal Tax Benefits provided to wind and other renewable energy projects. CREBs are “tax credit bonds,” which means that the bond purchaser receives a federal income tax credit in lieu of interest payments. From the borrower’s perspective, CREBs are therefore essentially the equivalent of a zero-interest loan (though, in practice, CREBs issuers have often had to issue the bonds with a small supplemental interest payment – in addition to the federal income tax credit – in order to entice buyers).

CREBs were created to “level the playing field” for non-taxable entities that cannot directly use a project’s Tax Benefits. Without access to an incentive comparable to the PTC, state, local and

tribal governments, as well as public power entities and electric co-ops, face a competitive disadvantage in renewable electric generation (despite the general ability to issue tax-exempt bonds). Such entities have historically been eligible to receive the Renewable Energy Production Incentive (“REPI”), which offers a 10-year cash payment equal in face value to the PTC, but annual appropriations and insufficient funding have limited the effectiveness of the REPI.

EPAct 2005 authorized \$800 million of CREB funding, which were allocated through a smallest-to-largest solicitation/auction process in early 2006. Another \$400 million was authorized in late 2006, and allocated in February 2008. Collectively, these \$1.2 billion in allocations are now referred to as “old CREBs”, to distinguish them from the \$2.4 billion in “new CREBs” authorizations contained in the late 2008 and early 2009 federal stimulus bills. This old/new distinction is pertinent because “new CREBs” must follow a slightly different set of rules than existed under the “old CREBs” program (more on this later).

2.2 State Level

Although federal policy incentives for wind power tend to be larger in magnitude than those available at the state level, state-level policy incentives are nevertheless important in that they can be (and have been) tailored to support certain wind power applications, such as community wind power. Minnesota, for example, would not have seen as much community wind development as it has were it not for a state-level cash incentive of \$15/MWh provided over a 10-year period to qualifying wind projects of 2 MW or less. Other states such as Massachusetts, Iowa, and Oregon have also implemented policies targeting the development of community wind.

While Pennsylvania does not have any state-level policies that *specifically* target community wind power development, it does have a number of policies and incentives in place that help to create a climate that is amenable to community wind power development. These include an aggressive net metering policy, several different grant and/or loan programs, a state-level investment tax credit for renewable energy projects, and the existence of regional public benefits funds that support renewables in general.

Each of these state-level programs is described in detail within the Database of State Incentives for Renewable Energy (“DSIRE”) web site (www.dsireusa.org), which also provides useful web links to additional information. As such, the descriptions provided in this section are limited to high-level discussions of only that information that is relevant to community wind financing. Readers interested in more detail are strongly encouraged to visit the DSIRE web site.

2.2.1 Net Metering Policy

Pennsylvania has implemented one of the more-aggressive net metering policies in the nation. Non-residential systems as large as 3 MW in nameplate capacity (or 5 MW in nameplate capacity if installed as part of a microgrid, or if made available to the grid during an emergency) can be net metered, though residential systems are limited to 50 kW. System size is not limited by a customer’s load, and any monthly net excess generation is rolled forward and credited to the

next month's bill. At the end of a 12-month period (ending in May of each year), any net excess generation that remains is compensated at the utility's "price to compare," which includes generation and transmission costs, but not distribution costs.³ Same-owner meter aggregation (both virtual and actual) is allowed for meters located within two miles of the customer's property (this primarily benefits farmers who have multiple electric meters on barns and other outbuildings that they own). Any customer that reduces its annual load by more than 10% through net metering must pay for its share of the stranded costs of serving that customer.

Pennsylvania's large net metering system size limit – i.e., 3 MW for most applications – is amenable to the installation of on-site, behind-the-meter utility-scale wind turbines. Pennsylvania also has moderate-to-high retail electricity rates, which enhances the value of net-metered on-site generation. Even the "price to compare" at which annual net excess generation is compensated appears to be somewhat-favorable (to the generator) relative to spot wholesale power prices. As such, behind-the-meter community wind applications are worth examining in more detail.

2.2.2 State-Level Grant Programs

Over the years Pennsylvania has implemented a number of different grant programs that could be relevant to community wind projects. This section covers the three programs that appear to be most relevant to community wind projects at this time. For more information on any of these programs, see the Department of Environmental Protection's ("DEP's") web page at <http://www.depweb.state.pa.us/energy>, or the DSIRE web site at www.dsireusa.org.

2.2.2.1 Energy Harvest Grant Program

Established in 2003, the Energy Harvest program provides grants to projects that "promote awareness and build markets for cleaner or renewable energy technologies" (Pennsylvania DEP web site). Although the program was initially open to all types of applicants, for-profit entities were prohibited from participating in the 2008 round of funding (due to the availability of Pennsylvania Economic Development Authority grants for such entities, as described next). Funds are awarded through an annual solicitation process, and grant size is limited to \$500,000.

It is likely that Energy Harvest grants are considered taxable income to the recipient, which means that they will not reduce the basis on which the 30% federal ITC or equivalent cash grant (or depreciation) is calculated. As governmental grants used to offset the capital cost of a project, however, Energy Harvest grants will likely trigger a PTC haircut. If, however, the program continues to exclude for-profit entities going forward, neither of these distinctions is relevant.

³ As of August 2009, the "price to compare" for basic residential service in Pennsylvania varied substantially by utility, with a low of around \$60/MWh (for Allegheny Power, Penelec, and PPL) to a high in excess of \$110/MWh (for Penn Power and UGI). The non-residential "price to compare" was not published, but is presumably lower than the residential price to compare (since non-residential rates are typically lower than residential rates).

2.2.2.2 PEDA Grant Program

Although the Pennsylvania Energy Development Authority (“PEDA”) has existed since the 1980s, the current PEDA grant program for renewable energy has only been in place for a few years. Both taxable and tax-exempt entities can apply for PEDA grants, which are limited in size to \$1.5 million each, with some cost-sharing required. Annual requests for proposals will typically occur in the spring of each year. It is likely that PEDA grants are considered taxable income to the recipient, which means that they will not reduce the basis on which the 30% federal ITC or equivalent cash grant (or depreciation) is calculated. As governmental grants used to offset the capital cost of a project, however, PEDA grants will likely trigger a PTC haircut.

2.2.2.3 DCED Wind and Geothermal Incentives Program

Enacted in 2008 as part of broad alternative energy legislation, this program is jointly administered by the DEP and the Department of Community and Economic Development (“DCED”) under the direction of the Commonwealth Finance Authority (“CFA”). The program provides grants, loans, and loan guarantees to qualifying wind and geothermal projects sponsored by businesses (including non-profits), economic development organizations, and local governments and other political subdivisions (e.g., schools).

Grants for energy production facilities are limited to \$1 million per project, and smaller grants for planning and feasibility studies are also available. Loans of up to \$5 million are available to energy production facilities, at a fixed interest rate of 5% (as of August 2009) for a period of up to 10 years. Matching funds are generally required.

As with the other two state-level grant programs described above, it is likely that DCED grants are considered taxable income to the recipient, which means that they will not reduce the basis on which the 30% federal ITC or equivalent cash grant (or depreciation) is calculated. As governmental grants used to offset the capital cost of a project, however, DCED grants will likely trigger a PTC haircut.

2.2.3 Alternative Energy Production Tax Credit

The same 2008 energy legislation that created the DCED program described in the previous section also created a state-level “alternative energy production tax credit” (which is somewhat of a misnomer since the credit is actually a 15% *investment* tax credit). The credit is calculated based on the net cost of system, after deducting all state and federal grants and other investment tax credits, and is limited to the lesser of 15% of that net cost or \$1 million. Statewide dollar caps starting at \$5 million and increasing to \$10 million by 2014 and 2015 may limit the size of the credit that each eligible project receives: if the aggregate amount of credits requested in any given year exceeds the statewide dollar cap for that year, then all credit recipients will receive a credit that has been reduced on a pro rata basis. Any unused credit can be rolled forward for five years. Alternatively, any portion of a credit that has not been used in the first year can be sold to a third party that is able to use the credit immediately.

2.2.4 Regional Public Benefits Funds

In addition to the statewide programs identified above, Pennsylvania is home to a number of regional public benefits funds that support the development of renewable energy through the distribution of funds collected from ratepayers. In the past, several of these public benefits funds have supported utility-scale wind energy projects, some of which fall into the category of community wind. For example, the Sustainable Development Fund in PECO's service territory has provided funding to a behind-the-meter wind project to be built at Hazleton's wastewater treatment plant.

The type and amount of financial support provided by these public benefits funds has varied both over time and across funds. As such, it is difficult to provide any more-detailed information on potential funding opportunities. Instead, community wind projects are encouraged to check with their regional public benefits funds to see what (if any) type of financial support might be available.

3. Financial Structures that Are Feasible for Community Wind in Pennsylvania

Given the range of federal and state policies and incentives described in Section 2, a number of different financing structures could make sense for community wind in Pennsylvania. This section of the report describes, at a high level, each of these structures, broken down along the lines of those available to private and public sector projects. Any of these structures could work for either grid-supply or behind-the-meter wind applications (though public sector grid-supply projects need to consider the rules concerning private activity bonds, discussed later).

Before proceeding, it is important to understand that the focus on these particular structures is driven by a fundamental underlying assumption – borne out by the reality of wind project economics – that the federal Tax Benefits available to a wind project (i.e., the PTC, ITC, or equivalent cash grant, coupled with accelerated depreciation) must be captured in order for the project to be financially viable. Without this underlying constraint, almost any type of financial structure could be used (though not necessarily with success); but within the confines of this constraint, the number of viable structures shrinks considerably.

3.1 Private Sector Structures

This section describes, at a high level, four financial structures that the model deliverable will be able to assess: a "Cooperative LLC" structure, a "Strategic Investor Flip" structure, an "Institutional Investor Flip" structure, and a "Sale/Leaseback" structure. The first three were developed under legacy tax policy (i.e., when the PTC was the only choice of federal incentive available), while the Sale/Leaseback has only become possible since ARRA 2009 became law on

February 17, 2009 (and may also only be temporarily available, unless certain provisions in ARRA 2009 are extended).

3.1.1 Cooperative LLC

Although a business set up as a cooperative may have difficulty making efficient use of a wind project's Tax Benefits, a limited liability company ("LLC") set up to operate according to cooperative principles can retain many of the benefits of a cooperative, while also making use of the project's Tax Benefits. This is the model employed by the Minwind projects in Minnesota, a series of nine wind projects (Minwind I-IX, though developed and constructed as two larger projects – Minwind I & II and Minwind III-IX) owned by a group of local farmers.⁴ This structure involves a number of local cash investors pooling their equity capital, utilizing any federal or state grants that are available, and borrowing the remainder of installed costs from local banks or other lenders. The local equity investors try to absorb as much of the project's Tax Benefits as they possibly can (even if they've elected the federal cash grant rather than the PTC or ITC, depreciation deductions will still be available), and may even base the size of their individual equity investment on the amount of Tax Benefits that they can absorb.

Although this is a relatively straightforward model from a financial perspective, care must be taken to comply with all pertinent Securities and Exchange Commission ("SEC") regulations when soliciting equity contributions from the general public. Such regulations can add significant additional legal expense to this structure, although the Minwind projects were able to minimize such expense by restricting the number of "non-accredited" investors in each project to fewer than the SEC threshold that triggers greater regulation.

Finally, it is perhaps worth noting that this structure was developed when the PTC was the only available federal incentive. With the option, at least temporarily, to elect a cash grant instead of the PTC, this particular structure has become even more straightforward. Specifically, such a project would need to elect the 30% cash grant,⁵ raise at least another 20% of installed costs through some combination of cash equity

Pre-Selling RECs to Close the Finance Gap

With the option to elect a 30% cash grant in lieu of the ITC or PTC in place through 2012 (but only if the project began construction prior to 2011), community wind projects that can also access term debt for 50-60% of installed costs are perhaps just 10-20% away from having their project completely financed. One potential way to close at least a portion of this 10-20% gap is to pre-sell the project's renewable energy certificates ("RECs") in exchange for up-front cash. There are a number of REC marketers that might be willing to broker such a deal. For example, NativeEnergy – a Vermont-based firm with a presence in Pennsylvania – might structure such a deal under the right conditions, which include (beyond the obvious need for competitive pricing) the project having a good "story" from a societal perspective, offsetting as much carbon as possible, and demonstrating that the up-front capital will make a significant difference to the project. Under these conditions, a firm such as NativeEnergy may be willing to structure a 10-year forward REC purchase contract at a price that is in line with current spot market prices. Although locking in current REC prices for 10 years limits the project's upside potential, it also limits the downside potential while also providing much-needed capital. In exchange for a lump-sum payment made once the project achieves commercial operations, NativeEnergy will take whatever percentage of a project's RECs are required to "pay off the loan" over a 10-year period.

⁴ For background information on the Minwind projects, see <http://www.windustry.org/minwind-iii-ix-luverne-mn-community-wind-project>.

⁵ It is important to note that the cash grant, if elected, would not be received until after the project has been constructed and commenced commercial operations. Therefore, this 30% will need to be temporarily financed until the grant is received.

contributions, federal or state grants, and/or a pre-sale of renewable energy certificates (see the text box on the previous page), and then borrow the remainder (historically limited to about 50% of installed costs) from banks or other lenders. Such a project may not be able to fully absorb (in the year they are generated) the tax losses generated by allowable depreciation deductions resulting from wind's 5-year MACRS schedule, but could roll forward any unused losses until they can be absorbed by future project income.

3.1.2 Strategic Investor Flip

The Strategic Investor Flip structure was one of the first structures used in the wind industry to attract third-party equity able to utilize a project's Tax Benefits (this type of tax-based investor is known as a "Tax Investor"), while still allowing the developer to retain an interest in the project. It is also the simplest of the "special allocation partnership flip structures" involving equity from a Tax Investor. The name of the structure reflects the fact that it has been used primarily by strategic investors (i.e., actively involved Tax Investors who have a long-term, strategic interest in the wind sector) seeking an active role in wind projects; examples include Edison Mission and John Deere. The project developer negotiates a percentage ownership share with the strategic investor, and the initial allocation of project cash flows and Tax Benefits are proportional to the respective ownership interests of the parties. In effect, this partnership structure is similar to a basic 50/50 joint venture structure. However, three key elaborations set it apart from a conventional joint venture.

The first key difference is that the Tax Investor provides almost all of the project equity, and in turn is initially allocated almost all of the cash and Tax Benefits. For example, with an undercapitalized developer (such as a community wind developer), the Tax Investor might contribute equity for up to 99% of the total project cost, while the developer provides the remaining 1%. Under this structure, the Tax Investor and developer are initially allocated the same respective 99% and 1% shares of the distributable cash and Tax Benefits (IRS Revenue Procedure 2007-65 requires the developer to have at least a 1% interest in the project's Tax Benefits).

The second elaboration involves the concept of a "flip" in the percentage allocations of the project cash flows and Tax Benefits once the Tax Investor has reached a pre-negotiated internal rate of return ("IRR") on its investment (the "Flip Point"). This Flip Point is usually projected to occur on or shortly after the tenth anniversary of the project's commercial operation date, since the PTC is available only during the first ten years of operations. Since developers using this structure typically do not have the ability to utilize Tax Benefits efficiently, they do not want the flip to occur prior to the end of year ten. However, the Flip Point could, and most likely will, occur earlier (e.g., any time after the end of year 5 to avoid tax penalties) if either the 30% ITC or the equivalent cash grant is elected in lieu of the PTC.

After the Flip Point, the percentage allocations of project cash flow and Tax Benefits change to a second set of sharing ratios that allocate most project flows away from the Tax Investor in favor of the developer. Although the Flip Point and the pre- and post-flip allocations are negotiated by the two parties, IRS Revenue Procedure 2007-65 dictates that the Tax Investor's minimum allocation of Tax Benefits (e.g., post-flip) should never be less than 5% of its maximum

allocation of Tax Benefits. Thus, continuing with the example of a 99%/1% pre-flip allocation, the Tax Investor's minimum post-flip allocation would be 4.95% (i.e., 5% of 99%). It may, however, be necessary to allocate more of the post-flip flows to the Tax Investor to achieve its overall twenty-year IRR target, which is negotiated between the parties. It is also possible to have a second, later Flip Point and to have the inversion of the percentage allocations be staged across the two Flip Points. For example, a transaction could include an initial 99%/1% allocation that flips to 55%/45% after the first Flip Point and then to 5%/95% after the second Flip Point.

The third difference, relative to a traditional joint venture, is that the Strategic Investor Flip structure typically includes an option for the project developer to purchase the ownership interests held by the Tax Investor after the Flip Point. Revenue Procedure 2007-65 requires that the purchase price must be based on fair market value determined at the time of the purchase, and that the purchase may not occur during the project's first five years. This 5-year requirement is not restrictive, since the purchase option is typically structured to first be available on or after the Flip Point has been reached – i.e., at the end of 10 years (or 5 years minimum in the case of the ITC or equivalent cash grant). The reduction in the Tax Investor's allocations after the Flip Point serves to reduce the fair market value of the Tax Investor's ownership interests and, consequently, the price that the developer must pay for such interests.

In general, this structure is useful for those project developers lacking both the financial strength to fund initial capital costs and the appetite for Tax Benefits, but who are nonetheless unwilling to simply sell the project outright. This structure is also amenable to the use of project-level term debt. In these cases the capital contribution and sharing ratios remain the same as in the previous example (i.e., 99%/1%); just the dollar amount of the up-front equity investment is reduced. In other words, this structure is well-suited to community wind projects that have little cash equity to invest, and seek long-term cash flow from the project, rather than a one-time development fee. This structure has been used extensively in Minnesota for this purpose.

3.1.3 Institutional Investor Flip

The Institutional Investor Flip Structure is similar to the Strategic Investor Flip structure, in that the project developer brings in a separate Tax Investor to use the Tax Benefits, there is a Flip Point at which the allocations of cash and Tax Benefits change, and the developer typically has a purchase option exercisable after the Flip Point.

Beyond these similarities, there are several important differences.⁶ First, the name of the structure reflects the fact that it was devised to bring in less-active, more-passive equity capital from Institutional Investors (historical examples have been large insurance companies and commercial banks, such as JP Morgan). Second, the Institutional Investor Flip structure has historically been an all-equity structure, while the Strategic Investor Flip structure is typically used in levered projects. Lastly, in contrast to the Strategic Investor Flip, the initial allocations of cash and Tax Benefits are not proportional to each investor's respective equity contributions.

⁶ For more information on the Institutional Investor Flip structure, as well as the Strategic Investor Flip structure, see Harper et al. (2007).

Specifically, in exchange for the developer contributing a greater portion of the initial equity capital (e.g., 30% - 40% of the total), *all* of the distributable cash from the project is initially allocated to the developer either (a) until it fully recovers its capital or (b) for a specified period of time. The former has historically been used for projects electing the PTC, with the capital recovery typically taking place over the first four to six years of the project. The latter is a structure that has been proposed for projects selecting the ITC or cash grant, with the capital recovery period lasting between one and four years. In either case, after the developer's capital recovery period has ended, 100% of the cash is then allocated to the Tax Investor until the Flip Point is reached.

Separately, the Tax Benefits are initially allocated in a 99%/1% sharing ratio in favor of the Tax Investor (IRS Revenue Procedure 2007-65 requires that the developer maintain at least a 1% interest in the project's Tax Benefits). Once the Flip Point has been reached (again, on or shortly after the end of year ten if the PTC is elected, or perhaps earlier if the ITC or cash grant is elected), a majority of both the cash and Tax Benefits, typically around 90%, are allocated to the developer.

The Institutional Investor Flip structure was developed to address limitations of the Strategic Investor Flip for various types of developers and investors. Specifically, some developers have capital to invest and the interest in doing so, but lack the ability to use the Tax Benefits. For such investors, the Strategic Investor Flip, with its proportional link between the percentage of equity invested and receipt of cash and Tax Benefits, does not provide the means to invest capital without being saddled with unwanted Tax Benefits. The Institutional Investor Flip addresses this issue with disproportionate allocations of cash and Tax Benefits. Many Institutional Investors, meanwhile, like this structure because it obliges the project developer to invest more capital than under the Strategic Investor Flip, thereby becoming more vested in the success of the project.

Though popular in the commercial wind market, the Institutional Investor Flip structure is perhaps less-well-suited than the Strategic Investor Flip for community wind projects, for a number of reasons (Bolinger, 2008). First, community wind investors may not be able to raise the amount of cash equity required by the Institutional Investor Flip structure (i.e., instead, much of their contribution is likely to come from "sweat equity"). Likewise, community wind investors may be more interested in the post-flip, long-term income stream thrown off by the project than they are in recouping their equity investment over the initial 1-6 years of the project.

Second, differences in the type of Tax Investors attracted to each respective structure hold important implications. Strategic Tax Investors (e.g., Edison Mission Energy, John Deere) are generally seasoned project developers with access to turbines, are willing to invest in a project prior to the construction phase, can provide operations and maintenance ("O&M") services, and may want to maintain a stake in the project post-flip – all of these characteristics fit well with most community wind projects. Institutional investors (e.g., JP Morgan, Wells Fargo), on the other hand, typically have only limited development and/or O&M experience, are unlikely to invest in a project until it is operational, and may want to fully exit the project after the flip – these characteristics are less-useful to a typical community wind project, which is likely to require more assistance than a typical institutional investor is willing to provide.

Finally, the Strategic Investor Flip structure is simpler to understand, set up, and document – the importance of which should not be underestimated.

All that said, IRS Revenue Procedure 2007-65 provided explicit safe harbor guidelines for the Institutional Investor Flip structure, which has led to increasing comfort with and greater standardization of this structure. Furthermore, community wind investors may find innovative ways to pool enough equity capital – e.g., through cooperative arrangements, or by “back-leveraging” their equity capital⁷ – to make this structure work for their projects. And local or regional Tax Investors of the institutional variety may emerge to work with locally-owned projects; these Tax Investors may prefer the Institutional Investor Flip structure over the Strategic Investor Flip structure. For these reasons, the Institutional Investor Flip structure is worth considering for community wind in Pennsylvania.

3.1.4 Sale/Leaseback

In many sectors of the economy, leasing has become a commonplace financial structure. Prior to the February 17, 2009 passage of ARRA 2009, however, leasing was not viable for wind projects, because Section 45 of the Internal Revenue Code requires that the project owner must also operate the project in order to claim the PTC. This requirement effectively rules out the option of lease financing, since in a leasing arrangement, the owner and operator are separate entities.

Now that wind projects can choose between the PTC and the ITC (at least through 2012), however, leasing has become a viable financing structure for wind (at least for projects that elect the ITC instead of the PTC). Unlike the PTC, the ITC does not require the owner and operator to be the same entity, which opens the door to a variety of leasing structures. The most relevant of these is what’s known as a sale/leaseback structure.⁸

In a sale/leaseback structure, the developer (the lessee) builds the project and then sells it to a leasing company (the lessor – typically a Tax Investor, or else backed by one), who in turn leases it back to the developer through an operating lease. Throughout the lease term, the developer is responsible for operating and maintaining the project, and is entitled to use or sell the power that it generates. In exchange for this use of the project, the developer (lessee) makes a series of recurring lease payments to the lessor; these payments must be made irrespective of how well the project performs. As the owner of the project, the lessor not only receives the recurring lease payments (again, regardless of how well the project performs), but also makes use of the project’s Tax Benefits.

At the end of the lease term, the remaining useful life of the project must be at least one year or 20% of the originally estimated useful life (whichever is greater), the residual value of the project must be at least 20% of the original cost, and any purchase option granted to and

⁷ The term “back-leverage” refers to debt assumed at the developer (or community wind investor) level, rather than project level. In other words, the developer or community wind investor takes on debt to help finance a larger equity stake in the project.

⁸ Operating leases and sale/leaseback structures have been used on a numerous occasions to finance solar projects (Bolinger, 2009), so there is precedence for the use of leasing structures in the renewable energy sector.

exercised by the lessee must be priced at the project's fair market value, as determined at that time. Operating leases are also required to be "pre-tax positive," though in the wake of IRS Revenue Procedure 2007-65, Tax Investors have generally been taking the position that the ITC can be treated as a cash-equivalent for this purpose.⁹

Sale/leaseback structures are potentially attractive to community wind projects for a number of reasons. First, unlike the partnership flip structures described earlier, which require the developer to invest at least some equity, a sale/leaseback provides 100% project financing (i.e., the lessor finances and owns the entire project). Second, because leases are a familiar structure to most banks and leasing companies, sale/leasebacks could significantly broaden the Tax Investor base beyond the dozen or so large institutions that have, at least historically, engaged in partnership flip structures in recent years (i.e., there might be a number of smaller Tax Investors that are not comfortable with partnership flip structures, but that are comfortable with leasing structures). Third, a sale/leaseback allows for the efficient monetization of the project's Tax Benefits, because the lessor/Tax Investor owns 100% of the project (as opposed to a partnership flip structure, which allows the Tax Investor to capture a maximum of 99% of the Tax Benefits).

On the other hand, it will be more expensive for community wind investors to buy out the Tax Investor in a sale/leaseback than it is in a partnership flip structure. In the latter, the buyout usually occurs after the Flip Point, at which time the Tax Investor's interest in the project is negligible, which leads to a lower fair market value buyout price. In a lease, the Tax Investor's interest in the project never flips down, which means that the lessee must pay essentially the full fair market value of the *entire* project in order to buy out the Tax Investor.

3.2 Public Sector Structures

Tax-exempt, public sector entities are not able to make use of the various Tax Benefits provided to private sector renewable energy projects. Likewise, the new federal cash grant program – intended to mimic the economics of the ITC, but in cash rather than through a tax credit – is also not directly available to such entities.

Although this lack of tax appetite places publicly-owned wind projects at a disadvantage, certain tax-exempt governmental entities are able to tap into the capital markets by issuing low-cost, tax-advantaged debt. Of most relevance to this report are traditional municipal bonds and CREBs. For public sector projects, the host owns the project and finances most of it with these attractive sources of tax-advantaged debt.

Before proceeding, it is worth noting that public sector ownership of a community wind project – and in particular one that is intended to sell power to the grid, rather than displace on-site power consumption – is fraught with potential pitfalls (Bolinger et al., 2004). First, it is unclear whether public sector entities are even able to own electricity generation projects (other than for on-site self-generation) in the first place. This question has been examined in several states, with

⁹ In other words, when computing pre-tax returns as part of the "economic substance" test (which requires that pre-tax returns are positive), one can include the contribution of the ITC, even though it does not provide pre-tax revenue.

differing degrees of resolution. Second, although the use of tax-advantaged debt may be possible if the project's power will primarily be consumed on site (i.e., a behind-the-meter project), if power is sold to a utility (i.e., a grid-supply project), such a sale will most likely be considered by the IRS to be a "private business use" of the project (as opposed to "government use").¹⁰ As such, the bonds may be characterized as "private activity" bonds, and potentially lose their tax-exempt status. In general, no more than 10% of the proceeds of any tax-exempt municipal bond issuance can be used for private business use. Although the financial pro forma model (described later) will simulate a grid-supply project owned by a tax-exempt entity (and financed using tax-advantaged debt), it is important for the reader and model user to keep in mind these important considerations involving private activity bonds, and to consult with qualified tax counsel before proceeding down this path.

3.2.1 Municipal Debt

State and local governments have the authority, with voter approval, to issue bonds featuring tax-exempt (and therefore relatively low) interest payments. These bonds typically fall into one of two categories: (1) general obligation bonds, which are backed by the full taxing authority of the municipality, or (2) revenue bonds, which are backed solely by the revenue generated (or, in the case of a behind-the-meter project, the utility expense avoided) by the project being financed. Most municipalities also maintain cash reserve funds that could be used to finance at least a portion of a wind project; in general, the opportunity cost of reserve funds is assumed to be the cost of issuing debt to replenish those funds.

For modeling purposes, we assume that the project sponsor (i.e., the town or municipality that is financing the project) will inject a small amount of equity (e.g., roughly 10% of total installed project costs) into the project, and will finance the remainder using tax-exempt municipal debt, with terms of up to 20 years or more. There are no Tax Investors involved in this structure.

3.2.2 Clean Renewable Energy Bonds

With the passage of the Energy Policy Act of 2005, certain tax-exempt entities now also have access to CREBs, which provide the bondholder with a tax credit in lieu of an interest payment. As such, CREBs offer the promise of a 0% interest rate to the borrower over a 10- to 15-year term; in practice, however, transaction costs and differences in credit ratings (from that assumed by the Treasury when setting the amount of the credit) have reportedly eroded some of this promise, and have led to the need for supplemental interest payments in some cases. As with municipal bonds, CREBs are not available to (non-governmental) non-profit entities; only projects sponsored by governmental entities, electric cooperatives, and public power providers are eligible for CREB financing. Furthermore, the typical maturity of a CREB – 10 to 15 years – is shorter than the 20- to 30-year maturity often seen for municipal bonds.

Once again, for modeling purposes, we assume that the project sponsor (i.e., the town or municipality that is financing the project) will inject a small amount of equity (e.g., roughly 10% of total installed project costs) into the project, and will finance the remainder using CREBs, with terms of up to 15 years. Supplemental interest payments (i.e., above and beyond the tax

¹⁰ The sale of renewable energy certificates from the facility might also be considered a private business use.

credit provided by the federal government) in the range of 1%-2% may be required. There are no Tax Investors involved in this structure.

4. Modeling the Various Financing Structures

As noted earlier, this is a two-part study; in addition to this report, we were also tasked with the creation of a financial pro forma model capable of handling the various financial structures described in the report. Our charge was to create a sophisticated – yet not “deal quality” – model that is flexible, transparent, and readily transferable to staff of the Renewable Energy Center, who will use it to preliminarily assess the economic viability of various sites on which it is working. If sites are found to viable using this screening tool, then more-sophisticated modeling may be warranted to confirm these findings and fine-tune the analysis in preparation for discussions with financiers.

To facilitate the evaluation of multiple financing structures, the model is constructed with a template wind project that is common to all the structures. For example, characteristics such as plant capacity, capacity factor, annual operating costs, hard capital costs, tax rates, grants, etc., are the same for each underlying structure. Using a central template project for all structures helps contrast the costs and implications of using various financing structures.

By design, the model has the flexibility to be run either in a “forwards” or “backwards” direction. Running the model in a forwards direction requires specifying the revenue available to the project (along with all other relevant assumptions), and then solving for the financial return that the project generates. Running the model in a backwards direction requires specifying a target return that investors will require from the project (along with all other relevant assumptions), and then solving for the amount of revenue that will yield that return.

The model can be run by hand when moving in a forwards direction, simply by plugging in all relevant assumptions and noting the resulting returns. When running the model backwards, however, the user is advised to make use of Excel’s “Solver” function (a simple linear programming tool) to automatically iterate to a final solution (i.e., a revenue per MWh that provides the user-specified rates of return). Although Solver can be run from the “Tools” menu in Excel, for each structure we have added buttons linked to short Visual Basic macros whose sole purpose is to automatically run the Solver for the user.

The modeling workbook begins with two worksheets that contain input assumptions. The “General Project Assumptions” worksheet contains assumptions that are common to all financial structures, while the “Structure-Specific Assumptions” worksheet contains those assumptions that might vary by structure. Modeling results are also presented at the top of the “Structure-Specific Assumptions” worksheet (since modeling results will also vary by structure).

In addition to these two worksheets, the modeling workbook contains five additional worksheets, each home to a pro forma financial model for one of the six structures described in earlier sections of this report (because we were able to combine the Municipal Bonds and CREBs

structures, we have only five worksheets for six structures). Finally, there are a number of worksheets that present graphs of key modeling outputs.

This purpose of this section of the report is simply to familiarize the reader with the primary modeling assumptions and inputs necessary to run the model. To accomplish this, Section 4.1 provides a high-level overview of the “General Project Assumptions” worksheet, while Section 4.2 does the same for the “Structure-Specific Assumptions” worksheet. Then, for illustrative purposes only, Section 4.3 presents the modeling output that results from the assumptions shown in Sections 4.1 and 4.2.

4.1 General Project Assumptions

The first worksheet in the model workbook is titled “General Project Assumptions,” and is where the user specifies modeling assumptions that are not structure-specific in nature (i.e., those that are common to the template project and therefore for all five financial structures). These general assumptions are grouped into seven distinct boxes, titled as follows: Basic Project Info, Annual Operating Expenses, Installed Costs (Hard Costs), Tax Rates and Incentives, Federal and State Grants, Miscellaneous, and Depreciation Schedules. The layout of each box is shown in Figure 2 (on the next page), and the general contents of each box is discussed below. Note that blue text represents a user-defined input, while black text represents formulas and calculations that should not be changed.

4.1.1 Basic Project Info

The Basic Project Info box is where the user specifies the project name, the commercial operation date, the project’s nameplate capacity, and its expected capacity factor.

- Because the financial structures are modeled in half-year increments (by calendar year), the project must commence commercial operations either on January 1 or July 1 of any year between 2009 and 2014.
- The model is technology-agnostic, which means that the user need not specify any particular make or model of wind turbine; rather, the important inputs are the nameplate capacity of each turbine, as well as the number of turbines in the project (set to twelve, 1.5 MW turbines in Figure 2, for 18 MW total). With those inputs, the model simply assumes that the chosen turbine is one that has been commercially proven, and that spare parts and service are easily obtained – both pre-requisites to securing financing.

General Project Assumptions

Blue text denotes user-defined inputs

Black text denotes formulas/calculations (do not change cells with black text)

BASIC PROJECT INFO

Project Name	SFU Wind Project
COD	
COD Year	2010
COD Month	1-Jan
COD	1-Jan-10
Project Capacity	
Number of Turbines	12
Capacity Per Turbine (MW)	1.50
Total Capacity (MW)	18.00
Annual Net Capacity Factor	25.0%

ANNUAL OPERATING EXPENSES

O&M	
Fixed O&M (\$/kW-yr)	25.00
Variable O&M (\$/MWh)	0.00
Additional O&M Escalator (Both Fixed & Variable)	
Escalation Rate Over Inflation	0.00%
Year Escalation Begins	5
Land Lease Payment (Greater of:)	
Annual Payment (\$/MW - inc w/ inflation)	4,000
% of Gross Revenue	4.0%
Management Fee (\$, inc w/ inflation)	
Fee Included in Developer Return?	Yes
Property Taxes	
% of Project Hard Costs Subject to Tax	100.0%
Assessed Value of Property (\$000)	37,800
Annual Property Tax Rate	0.25%
Property Value Reduction Per Year	5.0%
Property Value Floor (% of initial value)	20.0%
Insurance (\$/Turbine - increase with inflation)	10,000
PPA LOC	
LOC Amount (\$000)	2,500
LOC Term	20 Yrs
Annual LOC Interest Rate	1.50%

INSTALLED COSTS (HARD COSTS)

\$/kW	
Development Costs	150
Wind Turbines	1,400
Balance of Plant	400
Interconnection	150
Total (\$/kW)	2,100
Total (\$000)	
Development Costs	2,700
Wind Turbines	25,200
Balance of Plant	7,200
Interconnection	2,700
Total	37,800

TAX RATES & INCENTIVES

Tax Rates	
Federal	35.0%
State	
Rate	9.99%
NOL Treatment	NOL Carryforward
Federal Tax Incentives	
Incentive Selected	ITC
PTC	
PTC Base Year (\$/MWh)	15.00
Most Recent Inflation Adjustment Factor	
Year	2009
Inflation Adjustment Factor	1.4171
2010 Inflation Adjustment Factor	1.4454
Years Available	10
Maximum PTC Haircut	50%
ITC	
Value (%)	30%
Form of ITC	Cash Grant
First Year Federal Bonus Depreciation	0.0%
State Tax Incentives	
ITC	
Value (% of Adjusted Project Cost)	15%
Total ITC Value Limit (\$000)	1,000
Realized ITC Value (% of ITC Value)	50%

FEDERAL & STATE GRANTS

<i>Note: Non-taxable grants reduce the ITC; PTC reduction based on other factors.</i>	
Grant 1 (e.g., USDA, Energy Harvest, PEDA, or DCED)	
Amount (\$000)	500
Income Tax Treatment (relevant to ITC)	Taxable
Does this reduce the PTC?	Yes
Are tax-exempt entities eligible for this grant?	No
Grant 2 (e.g., USDA, Energy Harvest, PEDA, or DCED)	
Amount (\$000)	750
Income Tax Treatment (relevant to ITC)	Taxable
Does this reduce the PTC?	Yes
Are tax-exempt entities eligible for this grant?	Yes
Grant 3 (e.g., USDA, Energy Harvest, PEDA, or DCED)	
Amount (\$000)	0
Income Tax Treatment (relevant to ITC)	Taxable
Does this reduce the PTC?	Yes
Are tax-exempt entities eligible for this grant?	Yes

MISCELLANEOUS

Inflation Rate	2.00%
Interest on Reserves	2.00%

DEPRECIATION SCHEDULES

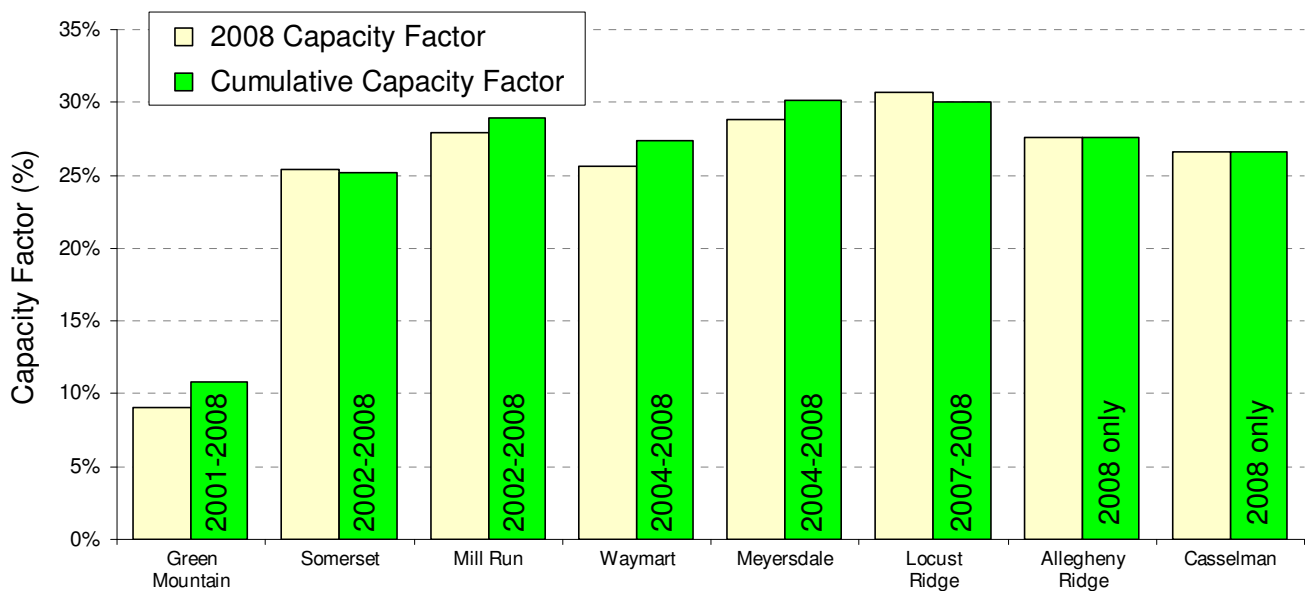
(% of Total Project Cost Allocated to Each Schedule)	
5-yr MACRS	90.0%
15-yr MACRS	2.0%
5-Yr SL	0.5%
15-yr SL	2.0%
20-yr SL	2.0%
39-yr SL	0.0%
Non-Depreciable	3.5%
Total	100.0%

STRUCTURE SELECTED FOR GRAPHING

Selected Structure	Institutional Investor Flip
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Figure 2. Screen Shot of “General Project Assumptions” Worksheet

- The expected capacity factor is specified on a net annual basis (i.e., with no monthly or seasonal variation), but could also be linked to the output of wind resource assessment software, such as Windographer. In order to provide a sense for what a reasonable capacity factor assumption might be for modeling purposes, Figure 3 shows the actual historical capacity factors for eight Pennsylvania wind farms built since 2000. The beige bars show the capacity factor of each project in 2008, while the green bars show the cumulative average annual capacity factors over the periods noted (in most cases, there is not much variation between these two different metrics). To date, most commercial wind projects in Pennsylvania have experienced annual capacity factors in the range of 25%-30%, with one project notably lower. Given the likelihood that community wind projects will be less able (than these commercial projects) to optimize site selection, a capacity factor of 25% is probably a reasonable starting point for generic analysis.



Source: FERC Electronic Quarterly Reports

Figure 3. 2008 and Cumulative Capacity Factor of Pennsylvania Wind Projects

4.1.2 Annual Operating Expenses

Annual operating expenses consist of some combination of O&M costs, land lease payments, any management fees paid to the developer/operator, property tax payments, insurance, and possibly costs associated with posting a letter of credit to support a power purchase agreement.

- Certain O&M costs are fixed (i.e., not dependent on the amount of production), while others vary with the amount of power generated. Both fixed and variable O&M costs are assumed to increase over time at the rate of inflation. In addition, the user can specify whether O&M costs should escalate at a rate even faster than inflation, and if so in what year that escalation adder should begin. For example, one might assume that O&M costs increase with inflation during the project's first ten years, but then rise more quickly thereafter as the project begins to age and therefore requires more maintenance.

- Land lease payments are typically structured as the greater of either a fixed \$/MW payment each year, or a certain percentage of gross revenue from the sale of power. The user is free to specify one or both of these parameters.
- In addition to O&M costs, a management fee is often paid to the entity operating the project (most often the developer). For projects financed using partnership flip structures, where the developer is not allocated much cash during the project's early years, a management fee often provides a significant portion of the developer's (or community wind investor's) cash flow during the pre-flip period. The user can specify whether this management fee should be included in the developer's (i.e., community wind investor's) return from the project, or whether it should be considered separately (i.e., outside of the project).
- Property taxes from a wind project can be calculated in a number of different ways, and often property taxes are not paid at all, if the developer and the local community reach agreement on a Payment In Lieu of Taxes ("PILOT") arrangement, or if some form of property tax abatement is in effect. Pennsylvania currently has no statewide standard for taxing wind projects, but suggests that local assessors use an approach based on the capitalized value of the land-lease payments associated with the project (www.dsireusa.org). Due to uncertainty surrounding this method, the fact that property tax methods may vary from county to county, and the likelihood of PILOT arrangements, the model takes a more-standard approach to calculating property tax payments. This approach begins by specifying the portion of hard project costs that should be included in the assessed value (set to 100% in Figure 2), and then specifies the rate at which that assessed value will be taxed (0.25% in this case), as well as the rate at which the assessed value will decrease each year (by 5%), down to a minimum percentage of the original assessed value (20% in Figure 2).
- If the project is selling its output through a power purchase agreement ("PPA"), the buyer (typically a utility) may require the project to post a letter of credit ("LOC") in order to provide some security to the buyer that the project will meet its obligations under the PPA. An LOC is typically secured with a bank, which will charge the project an annual fee based on the amount of the credit.

4.1.3 Installed Costs (Hard Costs)

Here the user specifies the installed project costs – prior to the inclusion of financing costs and other soft costs – in \$/kW terms (to enable the model to scale up and down more easily for different project sizes). Costs are broken out into four basic categories – development costs, turbine costs, balance of plant costs, and interconnection costs. The model multiplies these \$/kW costs by the total project capacity to arrive at total dollar costs.

In order to provide a sense for what a reasonable installed cost might be for modeling purposes, Figure 4 shows the estimated installed costs for eleven Pennsylvania wind projects built since 2000. As shown, installed cost trends in Pennsylvania have risen over time, as they have elsewhere in the United States, reflecting an increase in the cost of raw materials used to build wind turbines, rising labor costs, increasing profit margins among wind turbine manufacturers as demand outpaces supply, weakness in the U.S. dollar, and a rapid upscaling of turbine size and

sophistication (which increases \$/kW installed costs, but presumably reduces the \$/MWh cost of the wind power generated by the turbine).

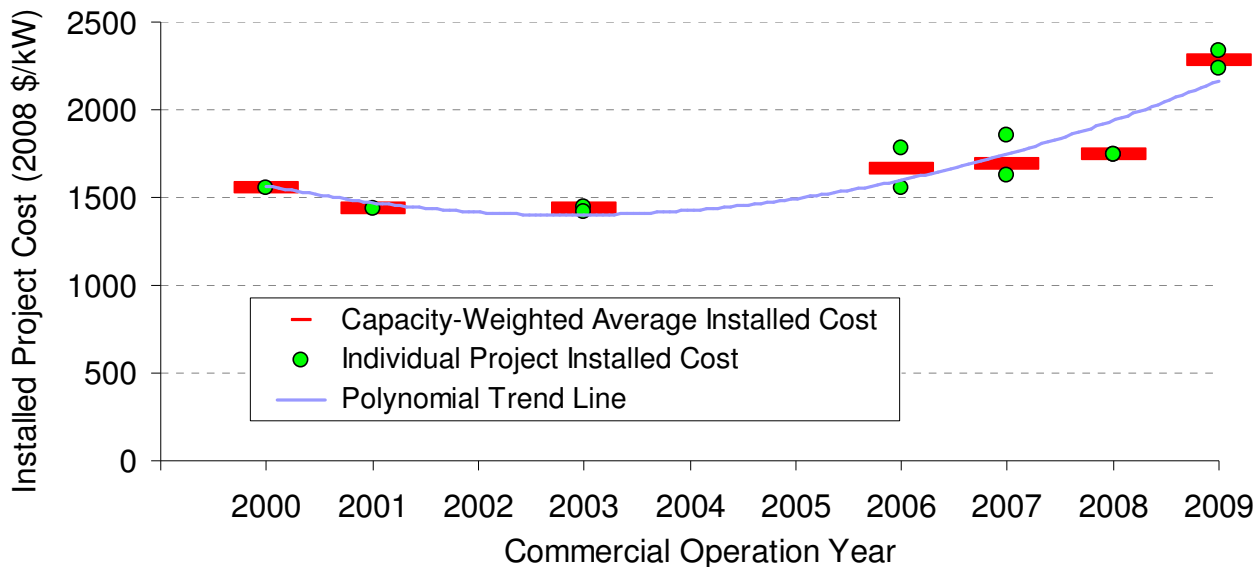


Figure 4. Installed Cost of Pennsylvania Wind Projects Over Time

With installed costs in the range of \$2,000/kW for recent commercial wind projects in Pennsylvania and elsewhere, one might expect the cost of a community wind project to be somewhat higher, due to smaller project size (i.e., difficulties in capturing economies of scale) and less-experienced developers. Figure 2 assumes \$2,100/kW hard costs, which end up translating into nearly \$2,500/kW total installed costs once soft costs are factored in.

4.1.4 Tax Rates and Incentives

The Tax Rates section sets the applicable federal (35%) and state (9.99%) income tax rates. At the federal level, the model generally assumes that net operating losses will be absorbed by investor income from other sources (i.e., apart from the wind project).¹¹ At the state level, however, the model allows the user to specify whether net operating losses are used as they are generated each year (i.e., to offset income from other sources outside of the project), or alternatively are rolled forward into the future, until they can be used by income from the project itself. The different treatment of net operating losses at the federal and state level reflects the presumption that *all* investors will have federal tax liability (regardless of in which states they operate), but some may not have sufficient state tax liability in a particular state to efficiently absorb losses as they are generated.

¹¹ The exception to this general rule comes from the Cooperative LLC and Sale/Leaseback structures. In the Cooperative LLC structure, there is no Tax Investor, and the developer may have a more difficult time (than Tax Investors) absorbing net operating losses. As such, the user can choose (in the “Structure-Specific Assumptions” worksheet, described later) to roll them forward if need be. In the Sale/Leaseback, the developer eventually purchases the project from the Tax Investor, at which time it can re-depreciate the project (albeit based on the new, reduced project basis), which again could lead to a situation where net operating losses cannot be immediately absorbed.

The Federal Tax Incentives section allows the user to specify whether the project will take the PTC or the ITC (as allowed under ARRA 2009). If the PTC, the user must specify the basic parameters that govern that incentive. If the ITC, the user must then specify whether the ITC will be taken as a tax credit or equivalent cash grant. If available, bonus depreciation can also be specified in this section.

The State Tax Incentives section implements the recently enacted Alternative Energy Production Tax Credit program. The user must not only specify the size of the credit (15%, capped at \$1 million), but also the amount of the credit that the user anticipates realizing. The realized value may be less than 100% if the size of the credit is pro-rated downwards (due to excessive demand), or if the user anticipates selling the credit (presumably at a discount) to an entity that is better able to use it.

4.1.5 Federal & State Grants

This box allows the user to specify up to three federal and/or state-level grants that it expects to receive. These might include a USDA grant (e.g., under the REAP) or a Pennsylvania Energy Harvest grant, PEDA grant, or DCED grant. In each case, the user must specify not only the amount of the grant, but also whether that amount is considered taxable income, whether receipt of the grant will reduce the value of the PTC (i.e., cause a “PTC haircut”), and whether the grant is available to tax-exempt entities. In most cases, grants *will* be considered taxable income, and therefore *will not* negatively impact the value of the federal ITC or equivalent cash grant. However, most grants *will* likely negatively impact the value of the PTC, potentially reducing its value up to a maximum of 50%.

4.1.6 Depreciation Schedules

This box allows the user to specify what percentage of total installed project costs are depreciable for tax purposes, and under which depreciation schedules. In general, the vast majority (>95%) of a wind project will be depreciable, with much (~90%) of the cost depreciated according to a 5-year MACRS schedule.

4.2 Structure-Specific Assumptions

The “Structure-Specific Assumptions” worksheet houses not only those assumptions that might vary by structure, but also the respective modeling results. This section covers just the assumptions.

	Strategic Investor Flip	Institutional Investor Flip	Cooperative LLC	Sale/Leaseback	Tax-Exempt Muni/CREBS
Structure-Specific Assumptions					
Blue text denotes user-defined inputs					
Black text denotes formulas/calculations (do not change cells with black text)					
CAPITAL COSTS (\$000)					
Total Hard Costs (from General Project Assumptions sheet)	37,800	37,800	37,800	37,800	37,800
Soft Cost Assumptions					
Construction Financing					
Debt	50%	50%	50%	50%	50%
Equity (from Developer only)	50%	50%	50%	50%	50%
Interest During Construction (IDC)					
Interest Rate	6.00%	6.00%	6.00%	6.00%	6.00%
Construction Period (assumes outstanding for half time)	12 Months	12 Months	12 Months	12 Months	12 Months
Debt Closing Fees (% of total debt amount)					
Construction Debt	1.25%	1.25%	1.25%	1.25%	1.25%
Term Debt	1.25%		1.25%		1.25%
Soft Cost Totals (\$000)					
Interest During Construction (IDC)	571	571	571	571	571
Debt Closing Costs (legal, consultants, etc.)	150		150		150
Debt Closing Fee - Construction	236	236	236	236	236
Debt Closing Fee - Term	249		257		450
Debt Service Reserve	1,092		1,127		1,500
Equity Closing Costs	200	200		200	-
Developer Fee	2,000	2,000	2,000	2,000	2,000
Working Capital	500	500	500	500	500
Contingency (5% of Hard Costs)	1,890	1,890	1,890	1,890	1,890
Total Soft Costs	6,888	5,397	6,731	5,397	7,297
Total Hard Costs (from above)	37,800	37,800	37,800	37,800	37,800
Total Capital Costs	44,688	43,197	44,531	43,197	45,097
Total (\$/kW)	2,483	2,400	2,474	2,400	2,505
REVENUE ASSUMPTIONS					
Sales Profile					
"1" - Grid Supply	1	1	1	1	1
"2" - Behind the Meter					
Grid Supply					
First-Year Energy Price (\$/MWh)	102.77	134.88	105.41	104.46	105.66
First-Year REC Price (\$/MWh)	-	-	-	-	-
First-Year Total Revenue (\$/MWh)	102.77	134.88	105.41	104.46	105.66
Price Escalation Rates					
Energy	Inflation	Inflation	Inflation	Inflation	Inflation
REC	Inflation	Inflation	Inflation	Inflation	Inflation
User-Defined Escalation Rate					
Energy	1.50%	1.50%	1.50%	1.50%	1.50%
REC	2.50%	2.50%	2.50%	2.50%	2.50%
Behind the Meter					
% of Sales					
Retail Offset	80.00%	80.00%	80.00%	80.00%	80.00%
Excess (delivered to grid)	20.00%	20.00%	20.00%	20.00%	20.00%
First-Year Price (\$/MWh)					
Retail Offset	104.61	144.48	108.11	107.24	108.27
Compensation for Excess	50.00	50.00	50.00	50.00	50.00
REC	10.00	10.00	10.00	10.00	10.00
First-Year Total Revenue (\$/MWh)	103.69	135.59	106.49	105.79	106.62
Price Escalation Rates					
Retail Offset	Inflation	Inflation	Inflation	Inflation	Inflation
Compensation for Excess	Inflation	Inflation	Inflation	Inflation	Inflation
REC	Flat	Flat	Flat	Flat	Flat
User-Defined Escalation Rate					
Retail Offset	2.50%	2.50%	2.50%	2.50%	2.50%
Compensation for Excess	1.00%	2.50%	2.50%	2.50%	1.50%
REC	2.50%	2.00%	2.50%	3.00%	2.50%
Behind the Meter Conditions					
Is there a Qualifying Sale for PTC Purposes?	Yes	Yes	Yes	Yes	Yes
Is there a Land Lease Payment?	Yes	Yes	Yes	Yes	Yes
Is the Site Host the Project Owner?	No	No	No	No	No

Figure 5. Screen Shot 1 (of 3) of "Structure-Specific Assumptions" Worksheet

4.2.1 Capital Costs

This section converts the “hard” capital costs (from the “General Project Assumptions” worksheet) into total capital costs, by adding in structure-specific soft costs.

Construction financing (some user-specified combination of debt and/or equity, set in Figure 5 to a 50%/50% mix) is assumed to only come from the developer, as any Tax Investor will likely not invest in the project until it has been built. If construction debt is used, the user must specify the interest rate and construction period, so that the model can calculate interest during construction. Debt closing fees (for both construction and any term debt) must also be specified.¹²

The developer fee is compensation to the developer for having successfully developed the project, and is separate from any return that the developer might earn from investing in the project during its operational period. In other words, the developer fee is capitalized into total installed project costs, and is not included as part of the developer’s project-level return from investing in the project.

As shown at the bottom of the Capital Costs box in Figure 5, total installed costs (including soft costs) come to around \$2,400-\$2,500/kW, with slight differences among structures depending on whether that structure uses debt, etc.

4.2.2 Revenue Assumptions

The user must specify (either by hand or by clicking on the appropriate Solver button at the top of this worksheet) whether it is modeling a “grid-supply” or “behind-the-meter” project. The former is a typical wind farm that sells power to a utility for resale to its customers. The latter is a one- or two-turbine project installed on the customer’s side of the meter for the purpose of displacing power purchased from the utility.

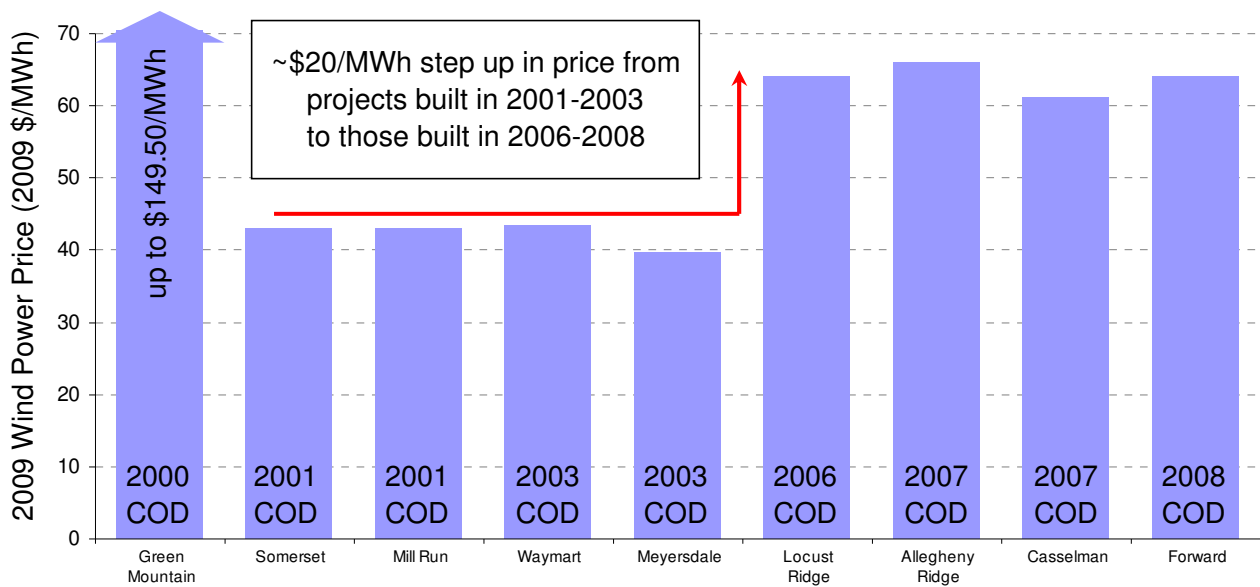
For grid-supply projects, the user can – if running the model in a forwards direction – specify the starting energy and renewable energy certificate (“REC”) prices that the project is expected to earn, as well as how those prices are expected to escalate over time: either not at all (“Flat”), at the rate of inflation, or by some user-specified rate. For behind-the-meter projects, the user must specify what percentage of the project’s output displaces retail sales (and therefore earns the full retail rate) versus being compensated at the utility’s “price to compare” (which includes generation and transmission, but not distribution, costs), at the end of each 12-month period.

Finally, for behind-the-meter projects, the user must specify whether there is a qualifying sale for PTC purposes (recall that only power sold to an unrelated party is eligible for the PTC), whether there is a land lease payment (there might not be if the project owner also owns the project site), and if the site host is also the project owner (if not, the model assumes that a letter of credit is

¹² If neither construction nor term debt are used, the user can still specify the relevant assumptions in this section, without jeopardizing the integrity of the model. In other words, in both the “General Project Assumptions” and “Structure-Specific Assumptions” worksheets, assumptions governing debt only come into play if debt is actually in use for that particular modeling run. If debt is not in use, the model ignores the assumptions governing debt. The one exception to this general rule is “Debt Closing Costs,” which must be zeroed out by the user if debt is not in use.

required to support what is presumably a PPA arrangement between the site host and project owner).

In order to provide a ballpark sense for what a reasonable starting price (for both energy and RECs bundled together) might be for grid supply projects, Figure 6 shows bundled wind power prices in the year 2009 from nine Pennsylvania wind projects built between 2000 and 2008. Ignoring the Green Mountain project (which is an outlier both in terms of capacity factor and cost of energy), projects built between 2001 and 2003 are contractually selling their output in 2009 at prices just north of \$40/MWh (for energy and RECs combined). Meanwhile, projects built from 2006-2008 – a period of higher installed costs, as well as higher wholesale power prices in general – are contractually selling their energy and RECs in 2009 at bundled prices just north of \$60/MWh.



Source: FERC Electronic Quarterly Reports

Figure 6. 2009 Contract Prices for Pennsylvania Wind Power

Given a likely increase in installed costs for projects built in 2009 (Figure 4 hints at this increase), along with a higher cost of equity in the wake of the 2008 financial crisis, bundled wind power prices in the \$70-80/MWh range from commercial projects built in 2009 would not be overly surprising. Community wind projects, meanwhile, will likely require even more revenue, to the extent that they experience incrementally higher installed costs and lower capacity factors.

Meanwhile, standalone prices for renewable energy certificates (for Tier 1 Pennsylvania RECs) have been trading somewhere in the \$10/MWh range (Wiser and Bolinger, 2009).

	Strategic Investor Flip	Institutional Investor Flip	Cooperative LLC	Sale/ Leaseback	Tax-Exempt Muni/CREBS
CASH & TAX ALLOCATIONS					
PARTNERSHIP STRUCTURE					
Term Equity Capital Contributed					
Developer	1.00%	30.00%	100.00%		15.83%
Tax Investor	99.00%	70.00%		100.00%	
Cash Sharing					
During Capital Recovery					
Maximum Capital Recovery Duration (months)		36			
Actual Capital Recovery Period (months)		36			
% of Invested Capital Recovered		100.0%			
Portion of ITC Cash Grant Allocated					
Developer		1.00%			
Tax Investor		99.00%			
Pre-Flip					
Developer	1.00%	0.00%			
Tax Investor	99.00%	100.00%			
Post Flip					
Developer	90.00%	90.00%			
Tax Investor	10.00%	10.00%			
Tax Benefit Sharing					
Pre-Flip					
Developer	1.00%	1.00%			
Tax Investor	99.00%	99.00%			
Post Flip					
Developer	90.00%	90.00%			
Tax Investor	10.00%	10.00%			
IRR/Flip Targets					
IRR Target	10.00%	9.00%	12.00%	11.00%	10.00%
IRR Target Date (End of Year)	Year 10	Year 9	Year 20	Year 17	Year 20
Target Entity	Tax Investor	Tax Investor	Developer	Tax Investor	Developer
Developer Federal Tax Loss Utilization (either used when generated or carried forward)			NOL Carryforward	NOL Carryforward	
Lease Structure					
Lease Term (Years)				17	
Annual Developer Margin					
Amount (\$/kW)				12	
Amount (\$000)				216	
Annual Escalation				2.00%	
Fair Market Value Purchase Price Valuation					
Expected Project Life (total years of expected cash flow)				25	
Discount Rate for Calculating Purchase Price				10.00%	
Purchase Price as % of Original Project Value				61.33%	
PROJECT DEBT					
Commercial Bank Debt					
Is there Leverage on the Project?	Yes		Yes		
Debt Tenor (Years)	12		12		
All-In Annual Interest Rate	6.50%		6.50%		
Debt Service Coverage Ratio	1.45		1.45		
Annual Agency Fee (\$000 flat)	25		25		
Back Leverage					
Is there Back Leverage?		Yes			
Capital Recovery Discount Period (months)		6			
Debt Tenor (years)					
(Based on investment recovery period)		2.50			
All-In Annual Interest Rate		7.00%			
Cash Sweep		100.0%			
Closing Costs & Fees (\$000)		150			
Debt Service Coverage Ratio		1.45			
Annual Agency Fee (\$000)		25			
Tax Exempt Municipal Debt/CREBS					
Is there Municipal/CREB Debt?					Yes
Debt Sizing					
Amount (\$000)					37,208
% of Total Capital					82.51%
Max Amount of Debt Possible (as a % of Total Project Cost)					90.00%
Debt Tenor (yrs)					20
All-In Annual Interest Rate					5.00%
Debt Service Coverage Ratio					
Minimum					
Target Minimum					1.10
Actual Minimum					1.10
Average					1.37
Debt Agency Fee (\$000 flat)					25

Figure 7. Screen Shot 2 (of 3) of "Structure-Specific Assumptions" Worksheet

4.2.3 Cash and Tax Allocations

This box (shown in Figure 7) specifies how much each of the two relevant parties (developer and Tax Investor) invest in the project (in the post-construction period only; the developer is already assumed to have shouldered construction financing), and what they get out of the project in return for their investment. The two partnership flip structures involve both the developer (or community wind investor) and a Tax Investor, whereas the other three structures involve only one or the other of the two parties (at least for the purposes at hand).

Cash sharing is relevant only to the two partnership flip structures, and dictates how cash generated by the project will be allocated. For the Strategic Investor Flip structure, only the pre-flip and post-flip periods are relevant. For the Institutional Investor Flip structure, the developer initially recovers some or all of its equity investment by being allocated 100% of all cash for a given time period (generally not to exceed a few years). Once that period has ended, then the pre-flip and post-flip allocations come into force.

Tax benefit sharing is also relevant only to the two partnership flip structures, and does not differ (at least structurally) between the two structures. IRS Revenue Procedure 2007-65 requires that the developer maintain at least a 1% interest in the project's taxable income, while the Tax Investor's interest in taxable income may never fall below 5% of its maximum allocation at any time during the project. Hence, maximum tax efficiency would be reached with allocations that start out 99%/1% in favor of the Tax Investor, and then flip to 95%/5% in favor of the developer once the Tax Investor's IRR target has been reached. In practice, however, the Tax Investor often needs to maintain a higher post-flip allocation in order to yield a sufficient 20-year IRR. In Figure 7, we therefore assume that a 99%/1% initial tax allocation flips to a 90%/10% post-flip allocation.

Particularly if running the model "backwards" (as the Solver does – i.e., starting with a target return and backing into the amount of revenue required to generate that return), the user must specify the IRR target at a given time period (e.g., 9% after-tax IRR at the end of year 10).

For the Cooperative LLC and Sale/Leaseback models, the user must specify whether the developer can immediately absorb net operating losses on its federal tax return, or whether it should roll them forward until they can be fully absorbed by the project (as previously described in footnote 11).

Finally, the Sale/Leaseback structure requires some specialized inputs regarding the term of the lease (which, per IRS regulations, cannot exceed 80% of the useful life of the equipment), the amount of margin (over and above the revenue required to support the lease payment) that the developer will take in as profit while serving as lessee, and the expected total project life, which will be used to determine the fair market value of the project at the end of the lease term, when the developer buys the project from the lessor. In practice, the lease payment will be contractually set and any developer margin will fluctuate depending on project performance. However, to enable running the model both backwards and forwards, the developer margin is set as an input.

4.2.4 Project Debt

Standard project-level term debt from a commercial bank is an option in two of the structures – the Strategic Investor Flip and the Cooperative LLC. The Institutional Investor Flip structure may involve “back leverage,” which is when the developer finances its equity contribution with bank debt *outside* of the project (i.e., the debt is secured by the developer’s interest in the project, rather than by the project itself). But in general, the Institutional Investor Flip structure has not used term debt at the project level, for two reasons: (1) institutional investors have historically not been comfortable having lenders involved in their projects, given the associated default risks, and (2) the lower cost of capital benefit associated with debt is significantly reduced by transaction costs and the up-front funding of reserve accounts to the point where the actual return benefit can be marginal.

Tax-exempt entities may be able to tap into two forms of tax-advantaged debt to finance the bulk of their projects: tax-exempt municipal bonds and Clean Renewable Energy Bonds. To preserve the integrity of the model (and also to reflect general reality), the model limits the amount of either bond to 90% of total project costs,¹³ with the remainder financed by some combination of grants and sponsor equity (no Tax Investors are involved). Municipal bonds might have terms of 20 years or longer, along with relatively low interest rates (reflecting their tax-exempt nature). CREBs generally have terms of 15 years or less, and theoretically need not pay any interest on principal, since the tax credit is meant to replace interest. In practice, however, it is likely that CREB issuers will need to make a small supplemental interest payment, in the range of 1-2%, in order to attract buyers.

The model assumes that both municipal bonds and CREBs are repaid using mortgage-style amortization. Mortgage-style amortization is common (though not required) for municipal bonds, and is allowed (though not necessarily common) for CREBs, or at least for “new CREBs.” Specifically, one of the changes that distinguish new CREBs from old CREBs is the ability for new CREBs to be issued with a bullet repayment at maturity, which means that no principal is repaid during the life of the bond, and instead all of it is repaid at maturity. The advantages of a bullet maturity are several-fold: (1) the ability to defer principal payments gives the project time to begin generating income before principal payments are due (under old CREBs, which require equal principal repayments each year, this has been a problem); (2) the bond-holder receives a constant, rather than declining, tax credit and supplemental interest payment (if any) over the life of the bond; and (3) bullet maturities are reportedly more popular in the market for these types of securities, which could enhance the demand for CREBs. With bullet maturities, however, the issuer is typically required by the bondholder to make periodic payments into a “sinking fund” (i.e., a reserve fund), in order to ensure that there will be sufficient cash on hand to repay the full principal at maturity. Although there are no doubt subtle differences between the two, making periodic sinking fund payments is not too dissimilar from simply repaying principal over time via mortgage-style amortization. As such, to simplify the modeling process, we have assumed that CREBs, like municipal bonds, will be repaid using mortgage-style amortization.

¹³ The debt limit is a user input assumption that can be changed. However, if the debt limit is set too high, thus reducing the amount of equity to a negligible level, the Solver may not be able to find a valid solution.

	Strategic Investor Flip	Institutional Investor Flip	Cooperative LLC	Sale/Leaseback	Tax-Exempt Muni/CREBS
PROJECT DISCOUNT RATES					
	Strategic Investor Flip	Institutional Investor Flip	Cooperative LLC	Sale/Leaseback	Tax-Exempt Muni/CREBS
Project WACC	7.91%	12.01%	8.08%	10.68%	5.07%
NPV Equity Discount Rates					
Overall Project	10.0%	10.0%		10.0%	
Developer	10.0%	10.0%	10.0%	10.0%	10.0%
Tax Investor	10.0%	10.0%		10.0%	
Discount for LCOE Calculation					
Overall Project	10.0%	10.0%	10.0%	10.0%	10.0%
DEPRECIATION (\$000)					
Total Project Cost	44,688	43,197	44,531	43,197	
Non-Depreciable Amount	1,564	1,512	1,559	1,512	
Asset Basis	43,124	41,685	42,972	41,685	
Basis Reduction for Grants (if non-taxable)					
Grant 1 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	
Grant 2 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	
Grant 3 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	
Adjusted Depreciable Basis	43,124	41,685	42,972	41,685	
Federal ITC					
ITC Amount	12,937	12,505	12,892	12,505	
Depreciation Basis Reduction (50% of ITC amount)	6,469	6,253	6,446	6,253	
Basis After ITC Reduction	36,655	35,432	36,526	35,432	
First-Year Bonus Depreciation	-	-	-	-	
Remaining Basis	36,655	35,432	36,526	35,432	
State ITC (\$000)					
Total Project Cost	44,688	43,197	44,531	43,197	
Less: Federal ITC	12,937	12,505	12,892	12,505	
Less: Grants					
Grant 1 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	
Grant 2 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	
Grant 3 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	
Adjusted Project Value for State ITC	31,751	30,691	31,639	30,691	
Gross State ITC Amount	4,763	4,604	4,746	4,604	
State ITC Amount Limit	1,000	1,000	1,000	1,000	
State ITC Amount (lesser of gross amount and limit)	1,000	1,000	1,000	1,000	
Realized State ITC Amount	500	500	500	500	

Figure 8. Screen Shot 3 (of 3) of “Structure-Specific Assumptions” Worksheet

4.2.5 Project Discount Rates

As shown in Figure 8, discount rates must be specified so that the net present value (“NPV”) of equity investment can be calculated for the developer, Tax Investor, and project as a whole. In addition, a separate discount rate is needed to calculate the levelized cost of energy under each structure. Although 10% seems to be a suitable nominal discount rate for these purposes, the project’s weighted-average cost of capital (“WACC”) is also calculated and shown, in case the user wishes to set one or more discount rates equal to the project’s WACC.

4.2.6 Depreciation and State ITC

These two sections contain only calculations – no user inputs. The depreciation section calculates the applicable depreciable basis, after taking into account reductions for non-taxable grants and the federal ITC (or equivalent cash grant). The state ITC section calculates the gross and realized value of the state ITC, after deducting state and federal subsidies.

4.3 Structure-Specific Modeling Results

At the top of the “Structure-Specific Assumptions” worksheet are two boxes highlighted in yellow. These boxes, a screen shot of which is shown in Figure 9, contain the modeling results, which are broken out into two main categories: returns and capital structure.¹⁴

	Strategic Investor Flip	Institutional Investor Flip	Cooperative LLC	Sale/Leaseback	Tax-Exempt Muni/CREBS
Results					
RETURNS (After-Tax)					
Return Target					
Target Year	10.0	9.0	20.0	17.0	20.00
Target IRR	10.00%	9.00%	12.00%	11.00%	10.00%
Year Reached	10.0	9.0	20.0	17.0	20.00
Return Target Party	Tax Investor	Tax Investor	Developer	Tax Investor	Developer
Tax Investor					
IRR					
@ Flip Date/Target	10.00%	9.00%		11.00%	
@ Year 20	11.39%	10.17%		11.00%	
NPV (\$000)					
@ Flip Date/Target	(2)	(814)		1,823	
@ Year 20	502	155		1,823	
Developer					
IRR					
@ Flip Date/Target	2.33%	-1.04%	12.00%	0.00%	10.00%
@ Year 20	17.99%	17.49%	12.00%	9.21%	10.00%
NPV (\$000)					
@ Flip Date/Target	(757)	(2,170)	2,182	(4,529)	(4)
@ Year 20	3,621	6,211	2,182	(147)	(4)
Total Revenue (\$/MWh)					
Initial Year	102.77	134.88	105.41	104.46	105.66
Levelized 20-Year	117.56	154.29	120.58	119.50	120.87
CAPITAL STRUCTURE (\$000)					
CONSTRUCTION					
Debt	18,900	18,900	18,900	18,900	18,900
Equity	18,900	18,900	18,900	18,900	18,900
Total	37,800	37,800	37,800	37,800	37,800
TERM (Cumulative)					
Debt	19,904		20,530		37,208
Tax Equity	23,299	29,363		41,947	
Developer Equity	235	12,584	22,750		7,139
Grants					
Grant 1 (e.g., USDA, Energy Harvest, PEDA, or DCED)	500	500	500	500	-
Grant 2 (e.g., USDA, Energy Harvest, PEDA, or DCED)	750	750	750	750	750
Grant 3 (e.g., USDA, Energy Harvest, PEDA, or DCED)	-	-	-	-	-
Total	1,250	1,250	1,250	1,250	750
Total Capital	44,688	43,197	44,531	43,197	45,097
% of Total					
Debt	44.5%	0.0%	46.1%	0.0%	82.5%
Tax Equity	52.1%	68.0%	0.0%	97.1%	0.0%
Developer Equity	0.5%	29.1%	51.1%	0.0%	15.8%
Grants (non-ITC)	2.8%	2.9%	2.8%	2.9%	1.7%
Total Capital	100.0%	100.0%	100.0%	100.0%	100.0%
WACC (after-tax)	7.91%	12.01%	8.08%	10.68%	5.07%

Figure 9. Screen Shot of Modeling Results on “Structure-Specific Assumptions” Worksheet

¹⁴ Though it is perhaps slightly confusing, the modeling results are housed in the same worksheet as the structure-specific assumptions for two reasons. First, the results are also structure-specific in nature, and require a similar format as already exists on this worksheet. Second, and more important, Excel’s Solver function requires that all variables and constraints be located on the same worksheet, which limited our ability to separate out the results into their own worksheet.

4.3.1 Returns

The “Return Target” section pulls in the target IRR, whose target it is (i.e., the Tax Investor or developer), and the year the target is to be reached. It also shows the year that the target IRR is actually reached; if “year reached” does not equal “target year,” the cells will become shaded in red, indicating a potential problem.

The Tax Investor section shows the Tax Investor’s IRR and NPV at two different points in time: the flip or target date and the end of year 20. The “Developer” section does the same for the project developer (or community wind investor).

The “Total Revenue” section pulls in the combined revenue from both power and RECs sales in the first year of the project, as well as levelized over a 20-year period. If the revenue escalation parameters are set to “Flat,” these two numbers will be the same. Based on the assumptions shown in Figures 2, 5, 7, and 8, first-year total revenue starts out in the \$103-135/MWh range and escalates, such that the 20-year levelized revenue reaches the \$118-\$155/MWh range. Although these revenue requirements are currently above-market, this does not necessarily mean that community wind is not viable in Pennsylvania. These revenue estimates are based on generic (and perhaps conservative) modeling inputs that are not specific to any particular project, and as such are not intended to be broadly representative.

4.3.2 Capital Structure

This portion of Figure 9 simply breaks down the cost of the project into the various sources of funding used to finance the project (e.g., debt, cash equity, tax equity, grants). This is done for both construction financing and term financing. Note that the 30% federal cash grant (taken in lieu of the ITC or PTC) is not listed as a source of capital in this table, since the grant is not awarded until after the project has achieved commercial operations. In other words, the federal cash grant must still be financed, even though it is received shortly after the commencement of commercial operations. In structures involving Tax Investors, the vast majority of the federal cash grant will instead show up as tax equity, while for those structures without Tax Investors, the grant will show up as developer equity. Finally, the weighted-average after-tax cost of capital (WACC) for the project as a whole is calculated.

5. Conclusions

Featuring a respectable wind resource, proximity to mid-Atlantic markets (which are very liquid), and a favorable political climate, Pennsylvania has proven to be one of the stronger wind power states in the Eastern U.S. As of August 2009, there were 525 MW of commercial wind already online in the state, with another 150 MW possible by year end. To date, none of this capacity falls into the category of community wind.

Although the state has not specifically targeted community wind development as a priority, it has nevertheless enacted policies that are amenable to community wind development. These include

an aggressive net metering policy, several grant programs that are suitable for community wind projects, an investment tax credit, and a broader renewable portfolio standard. In addition, a number of regional public benefits funds and other organizations – such as the Renewable Energy Center – stand ready to lend support to community wind projects, through various means.

Meanwhile, at the federal level, the timing has potentially never been better for community wind. As a result of the ARRA 2009 stimulus legislation, wind projects can, for a limited time only, receive a cash grant from the federal government equal to 30% of a project's qualifying costs. This grant is in lieu of the federal tax credits (e.g., the PTC and ITC) that community wind projects in particular have had difficulty using in the past. It is important to stress, however, that unless the ARRA 2009 policy changes are extended,¹⁵ there is only a very short window of opportunity to make use of this grant provision. Specifically, projects must have at least begun construction by the end of 2010, and must be completed prior to 2013.

For this reason, the Renewable Energy Center's sponsorship of this study is quite timely. In particular, the financial models that have been created as part of this study are equipped to handle the ARRA 2009 policy changes, allowing the user to assess the latest financing structures available to community wind projects in Pennsylvania. At the same time, the models can also be used to assess more-traditional structures that have been used over the years – and that may come back into fashion if the ARRA 2009 provisions are not extended.

Finally, we reiterate that this report and these models are neither intended nor expected to provide all of the answers. Rather, they are intended to inform the financing process by describing the array of viable financing structures that exist today, and by providing the user with a detailed – yet not “deal-quality” – screening tool to assess the various options. Individual projects that hold promise based on this screening tool will need to conduct more-detailed financial analysis when approaching financiers.

Looking ahead, policies and markets will change, and financing structures will evolve as a result. Although we have endeavored to build in the flexibility to allow the model to evolve along with them, it is ultimately the responsibility of the user to be knowledgeable enough to judge whether or not the model is performing as expected under changed future conditions. As a tool to facilitate analysis, the model should – like any other tool – continue to perform well into the future, if used with skill and properly maintained.

¹⁵ At this point, an extension of the federal grant seems unlikely, as demand for the program has reportedly been strong, making it likely that the Treasury will spend much more than it had anticipated on this program.

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