A Comparative Analysis of Community Wind Power Development Models

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Abstract

For years, farmers in the United States have looked with envy on their European counterparts' ability to profitably farm the wind through ownership of distributed, utility-scale wind projects. Only within the past few years, however, has farmer- or community-owned wind power development become a reality in the United States. The primary hurdle to this type of development in the United States has been devising and implementing suitable business and legal structures that enable such projects to take advantage of tax-based federal incentives for wind power. This article discusses the limitations of such incentives in supporting farmer- or community-owned wind projects, describes four ownership structures that potentially overcome such limitations, and finally conducts comparative financial analysis on those four structures, using as an example a hypothetical 1.5 MW farmer-owned project located in the state of Oregon. We find that material differences in the competitiveness of each structure do exist, but that choosing the best structure for a given project will largely depend on the conditions at hand; e.g., the ability of the farmer(s) to utilize tax credits, preference for individual versus "cooperative" ownership, and the state and utility service territory in which the project will be located.

1. Introduction

The amount of wind power capacity installed in the United States has risen sharply in recent years, from fewer than 1,900 megawatts (MW) at the end of 1998 to nearly 6,400 MW at the end of 2003.[1] With this growth, farmers in many of the windier parts of the United States are now harvesting a new cash crop. For each utility-scale wind turbine they host on their land,[2] farmers may receive income in the range of $2,000-$10,000/year in lease or royalty payments. Since each turbine typically removes less than an acre from production, and in most cases livestock can continue to graze right up to the base of the turbine tower, this extra income from hosting wind turbines is literally a windfall for farmers. On some farms, annual income from hosting wind turbines can meet or exceed annual income from all other farming activities (Smith 2004).

While hosting wind turbines can provide a much-needed boost in income to farmers struggling to maintain their livelihood, the lease payments made to farmers by commercial wind project developers typically pale in comparison to the amount of income the farmer could earn if he instead owned the turbine himself, or in conjunction with other members of his local community. Of course, project ownership entails significantly more risk than merely leasing land to a commercial wind developer. Unlike the typical land-lease arrangement, which requires no cash outlay and only passive involvement from the farmer, so-called "farmer-owned" or "community-owned" wind projects require the farmer(s) to make an up-front capital investment in the project, as well as oversee (though not necessarily undertake) the construction, operations, and maintenance of the project. Risks of cost overruns or project failure are generally manageable,[3] however, and in conjunction with the considerable rewards of ownership, there is a growing interest among farmers located in windy areas throughout the United States in owning their own utility-scale wind turbine.[4] As of the end of 2003, roughly 100 MW of the nearly 6400 MW of wind power installed in the United States was owned by farmers or other local investors (not including school districts, municipal utilities, or rural electric cooperatives).

Interest in farmer-owned wind in the United States is being spurred by at least two factors. First, several northern European countries, including Denmark, Sweden, and Germany, have

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[1] Because of variability in the wind, a utility-scale wind turbine will only generate about one-third of the energy it is technically capable of generating over the course of a year (i.e., its capacity factor will be around 33%). At a 33% capacity factor, each MW of wind power capacity generates 2,893 MWh/year, which equals the amount of electricity used each year by roughly 320 households, assuming that each household consumes 9 MWh/year (0.75 MWh or 750 kWh/month) on average.

[2] For the purposes of this article, we define utility-scale wind turbines to be those greater than 500 kW in nameplate capacity.

[3] For example, construction risk can be managed through a turnkey engineering, procurement, and construction (EPC) contract, while risk of mechanical failure can be managed through operations and maintenance agreements, extended turbine warranties, and insurance (either third party insurance or self-insurance through the establishment and maintenance of a repair and replacement reserve fund). Allowances for other contingencies can be built into project pro formas to reduce the risk of surprises.

[4] For example, the American Corn Growers Foundation 2004 Wind Producers Survey found that 39.4% of the 500 farmers surveyed believe the best way for farmers to reap the financial rewards from wind power is through ownership of large-scale turbines – either through investing in a farmer-owned "wind power co-operative" (29.8%) or by owning and placing a large-scale turbine on their own land (9.6%). This compares to 35% of respondents who favored leasing a small portion of their farm to a commercial wind developer. An additional 12% favored purchasing a small wind turbine for individual on-farm use, while 12.8% did not have an opinion and 0.8% refused to answer the question. See www.acgf.org for complete results.

successfully demonstrated the farmer- or community-owned wind power development model for decades (Bolinger 2001), and American farmers have for many years looked with envy on their European counterparts' ability to profitably farm the wind. Second, in recent years, a number of states, as well as the federal government, have begun to provide incentives specifically targeting farmer-owned wind projects, in some cases sufficient to make them economically viable.

Even with incentives in hand, however, developing a farmer-owned wind project can be challenging. A number of financial, regulatory, market, and technical issues must be considered (Bolinger et al. 2004). Chief among these considerations, in that it both embodies *and* influences many of these issues, is choice of ownership structure: farmers interested in owning a utility-scale wind project must choose from a variety of legal or business structures that could potentially be employed to finance, own, and operate the project.

This article describes and analyses the various business structures that farmers might employ to develop and own utility-scale wind power projects. Its purpose is to assess the economics of, and financial barriers to, farmer- or community-owned wind power in the United States, and to determine which business structures offer the best promise of resulting in economically viable projects that are able to meet or exceed the farmer's rate of return expectations. Because such structures are likely to be those that enable a project to capture the full array of state and federal incentives for wind power, we begin by briefly describing state and federal incentive programs for farmer-owned wind projects in the United States. We then discuss the limitations of the two most important federal incentives for wind power in general – the production tax credit (PTC) and accelerated depreciation – and the implications of those limitations on choice of wind project ownership structure. Next, we describe four ownership structures potentially suitable for farmer-owned wind projects, and designed to maximize the value of both federal and state incentives. Finally, using the state of Oregon as a test case, we comparatively analyze the financial attractiveness of each of the four structures previously described. This analysis is intended to inform those interested in understanding the economics of this new development approach for wind in the United States, as well as farmers interested in understanding tradeoffs in different ownership structures.

2. State and Federal Incentives for Farmer-Owned Wind Projects

Until recently, targeted support for farmer-owned wind power in the United States has come primarily at the state level. Several rural states – most notably those in the upper Midwest – have incentives in place to encourage local or farmer ownership of utility-scale wind projects (Bolinger 2004). For example, Minnesota is (or will be) providing a 10-year cash production incentive of 1.5¢/kWh to 200 MW of small (<2 MW), locally owned wind projects. By the end of 2003, this program had been fully tapped, with 132 MW of wind power already built and receiving the production incentive, and the remaining 68 MW expected to be built in the near future. A number of other states, including Iowa, Illinois, Massachusetts, and Oregon, either have in place or are developing incentive programs to support community- or farmer-owned wind power (Bolinger 2004).

With the passage of the 2002 Farm Bill, however, the federal government has, for the first time, provided incentives specifically to encourage the development of farmer-owned wind projects. Section 9006 of the 2002 Farm Bill authorizes the Secretary of Agriculture to distribute $23 million/year from 2003-2007 in the form of loans, loan guarantees, and grants to farmers, ranchers, and rural small businesses to purchase renewable energy systems and make energy efficiency improvements.[5] To date, roughly $14.5 million in grants, or one-third of the more-than-$44 million grant dollars awarded in aggregate under Section 9006 in 2003 and 2004, have gone to "large" wind projects (defined by the USDA as 100 kW or larger in nameplate capacity). More than 80% of this $14.5 million for large wind has gone to farmer-owned projects.

In addition to this relatively recent and targeted Farm Bill support, federal support for wind power *in general* (i.e., not just for farmer-owned projects) has traditionally come primarily from the federal production tax credit (PTC), as well as accelerated depreciation. The PTC provides a 10-year inflation-adjusted tax credit, which in 2004 stood at 1.8¢ for each kWh of electricity sold to an unrelated party, while accelerated depreciation provides a tax deduction equal to the capital cost of the project spread over a 6-year period. Each of these tax-based incentives typically provides roughly one-third (i.e., roughly two-thirds together) of the "revenue" associated with wind projects. As such, capturing these two incentives is vitally important to the economic viability of *any* wind power project, and in particular farmer-owned wind projects, which tend to be too small to benefit from economies of scale. Because of the way they are structured, however, the PTC and accelerated depreciation have historically favored large corporate wind project ownership over other forms of ownership.

[5] For more information on Section 9006 of the 2002 Farm Bill, see http://www.rurdev.usda.gov/rbs/farmbill/.

3. Limitations of the PTC and Accelerated Depreciation in Supporting Farmer-Owned Wind Projects

Tax-based incentives such as the PTC and accelerated depreciation are obviously only available to project owners with tax liability, a fact that handicaps ownership structures involving non-taxable entities such as cooperatives or non-profits.[6] Furthermore, because power must be sold to an unrelated party in order to qualify for the PTC, farmers who interconnect wind projects on their – not the utility's – side of the meter to offset their own power consumption will not be eligible for the PTC.[7]

The size and type of tax liability is also important. In order to fully benefit from the PTC and accelerated depreciation, the project owner must have *substantial* tax liability that is not subject to the alternative minimum tax (AMT).[8] The AMT provision narrows the field of potential investors, and combined with the need for substantial federal tax liability, is perhaps the primary reason why the majority of new wind power capacity in the United States is concentrated in the hands of just a few corporate owners, including Florida Power & Light, American Electric Power, PacifiCorp, and Shell.

The problem becomes even more acute when specifically talking about farmer-owned wind projects owned by individual, rather than corporate, investors. A 1.5 MW single-turbine wind project with a 33% capacity factor will generate a PTC of roughly $85,000 per year on average for 10 years. Depreciation provides a comparable amount of tax savings over the first 6 years, resulting in a minimum tax liability well in excess of $100,000 per year in order to fully benefit from the combination of these two incentives. Since the proportion of US farmers with federal tax liabilities in excess of $100,000 per year is quite small, there will be very few farmers able to absorb – on their own – the *full* federal tax benefits of a small commercial wind project.

It may be possible to reach critical mass on tax liability by spreading ownership in the project among many local farmers, though this carries its own challenges.[9] The Internal Revenue Service will consider any investor not involved in the day-to-day management of the project (i.e.,

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[6] While there has historically been another federal incentive – the Renewable Energy Production Incentive, or REPI – intended to provide a similar amount of value as the PTC to non-taxable entities, funding for the REPI has been limited and subject to annual congressional appropriations (as opposed to the PTC, which requires no budgetary line items and is guaranteed for 10 years), rendering it of significantly less worth than the PTC. Furthermore, non-taxable entities that do capture the REPI still cannot benefit from accelerated depreciation, for which there is no cash equivalent. Finally, it deserves note that both the REPI and PTC expired in late 2003, and while the PTC has since been retroactively extended through 2005, the REPI has yet to be re-authorized.

[7] On-site, behind-the-meter projects are, however, eligible to benefit from accelerated depreciation, presuming that the farmer has sufficient tax liability to deduct depreciation losses.

[8] The AMT is designed to make sure that wealthy individuals and corporations do not avoid paying taxes by investing in tax shelters. In such situations, the taxpayer is required to calculate taxes as usual as well as under the AMT rules, and ultimately adopt whichever method yields a higher tax bill. If that method turns out to be the AMT, then the taxpayer may not be able to fully utilize the PTC. The September 2004 legislative extension of the PTC through 2005 also included an exemption from the requirements of the AMT for the first four years of a wind project's life. Since the PTC lasts for 10 years, however, this 4-year exemption only offers partial relief.

[9] In addition to the tax-related challenge presented in this paragraph, spreading ownership may trigger the need to register the project's equity shares as "securities" with the Securities and Exchange Commission at the federal level, and/or its state-level counterpart. Securities regulation will be discussed in more detail later in this article.

presumably the case for most of the investors) to be a *passive* investor in the project. Such passive investors must have other passive forms of income (e.g., rental income, but *not* interest and dividend income) against which to claim the PTC. In other words, in this instance, the PTC cannot offset more typical forms of "active" or "ordinary" income (e.g., wage income). Since most individuals do not have passive income, this passive/active distinction further limits the universe of potential investors that are able to access the sizable federal incentives for wind power.

Another possibility is to "transfer" the tax credits to a taxable entity that can use them, but this is more complicated than simply selling the credits. Currently, only the owner(s) of a wind project can claim the PTC on federal tax returns. This means that the PTC is not "tradable" – i.e., it cannot simply be sold to a third party able to use the credits. Instead, that third party must become an owner in the project in order to utilize the credits. At least one ownership structure being employed for farmer-owned wind projects, known as a "flip" structure, does just that – brings in a tax-motivated equity partner to effectively own the project during the period of PTC and accelerated depreciation (i.e., the first 10 years of the project's life). This structure will be described in more detail later.

Finally, certain types of governmental incentives (both state and federal, including Section 9006 USDA grants) will trigger a reduction in the value of the PTC. The US tax code contains such "anti-double-dipping" provisions to limit the aggregate amount of governmental subsidy going to any particular project. In general, government incentives that are tied to the capital cost of the project – such as grants, investment tax credits, and subsidized financing – will reduce the value of the PTC, while production-based (e.g., $/kWh) incentives will not (Ing 2002, Wiser et al. 2002).[10]

In summary, wind power in the US is primarily supported at the federal level through tax-based incentives that are not very accessible to average citizens or farmers, and furthermore are reduced by certain state-level incentives. For these reasons, farmers and other individuals interested in investing in wind power have mixed feelings about the PTC in particular: most wind projects, and especially farmer-owned wind projects that are too small to capture economies of scale, will not be economically viable without it, yet its structure greatly restricts the types of entities that can profitably invest in wind power. As demonstrated in the next section, this reality can have a major impact on the choice and profitability of ownership structure employed in farmer-owned wind development.

[10] In addition, capital-based incentives will either be considered taxable income (like a production-based incentive) or alternatively will reduce the depreciable basis of the project, thereby reducing the value of accelerated depreciation.

4. Potentially Viable Business Structures for Farmer-Owned Wind Projects

Fortunately, farmers and the wind developers and lawyers who work with them have in recent years devised a number of innovative ownership structures able to negotiate the US tax code as it relates to wind power (and as described in the previous section). The list of potentially viable structures described in this section includes projects that are owned through a limited liability company (LLC) consisting of multiple local investors/farmers, two types of "flip" structures, and on-site projects intended to displace power consumption (rather than sell power to an unrelated party).

Perhaps surprisingly, this list does not include one of the most familiar business structures employed in the agricultural sector – cooperatives. The primary reason is that cooperatives are organized around the concept of patronage – the cooperative exists to serve its member-owners,[11] and the cooperative member-owners benefit based on how much they *use* or *patronize* the cooperative, rather than how much they have *invested* in it. In the case of a farmer-owned wind project organized as a cooperative, cooperative members would invest in the wind project, and benefit by patronizing the project through purchasing its energy at cost. Patronage would require either cooperation from the local utility or distribution company (to deliver the wind power to members on behalf of the cooperative), or the cooperative to act as a competitive energy service provider, delivering power to its members. The latter is not possible in the many parts of the country that lack retail electricity choice, while the former – utility cooperation in matters concerning wind power – is perhaps an unlikely prospect anywhere in the United States.

Furthermore, since it distributes its earnings among its members (according to their patronage), a cooperative itself generally has little or no tax liability, and thus little or no appetite for tax credits. While taxation of cooperative distributions may occur at the individual member level, very few individuals have a sufficient amount or type (e.g., passive) of taxable income needed to benefit from the PTC and accelerated depreciation. Cooperatives have in the past been eligible for the REPI, but the value of the REPI over time has been much less certain than the value of the PTC, and furthermore the REPI expired towards the end of 2003 and at the time of writing has not been reinstated (for more information on the REPI, see footnote 6).

As a result of these two factors – patronage requirements and lack of tax credit appetite – the "wind cooperatives" that one typically associates with northern Europe are not a particularly viable or financially attractive model in the United States. In fact, despite their reputation as such, very few European community wind projects are legally organized as cooperatives. Most Danish community wind projects, for example, are structured as general partnerships, while German "wind funds" are typically organized as limited partnerships (Bolinger 2001).

While the cooperative legal structure itself faces significant challenges with respect to a farmer-owned wind project, the cooperative principles at the heart of most cooperatives have widespread appeal among proponents of farmer-owned or "community" wind. Fortunately, other ownership structures discussed in the rest of this article, though not legally cooperatives, can be organized according to cooperative principles. For example, one promising vehicle appears to be a limited

[11] For example, the Internal Revenue Code requires that at least 85% of a rural electric cooperative's annual income must come from its members.

liability corporation (LLC), which combines the single taxation of a partnership (i.e., an LLC can elect to be taxed like a partnership, where income from the LLC is reported solely on the individual investors' tax returns) with the limited liability of a corporation, and is also sufficiently flexible to serve as an investment vehicle organized according to cooperative principles. In this way, an LLC can offer many of the benefits of a cooperative (e.g., open membership, democratic control), without the associated financial restrictions (e.g., benefits tied to patronage rather than investment, difficulty using tax-based incentives). The first ownership structure described below – i.e., the *multiple local owner* structure – provides a good example of an LLC set up to resemble a cooperative.

4.1 Multiple Local Owner

In the *multiple local owner* model, one or more farmers conceive of a farmer-owned wind project, and then solicit sufficient equity investment to support the project from among the local farming community. In Minnesota, the pioneering *Minwind* projects – the only working examples of this particular structure in the US to date – have accomplished this through the formation of limited liability companies (LLCs) in which investors can buy shares for as little as $5,000 per share (Windustry 2002). The LLC obtains debt from a local bank, or in some states, perhaps from a state-sponsored energy loan program. The project sells power to a utility through a negotiated long-term power purchase agreement, and investors split the income and tax benefits (if able to capture them) proportionally, according to their level of investment in the project.

Though in concept the *multiple local owner* structure is quite straightforward, there are a number of barriers to making it also be profitable. First, equity shares in a farmer-owned wind project that are offered to the public will most likely be considered "securities" under both federal and state securities law. Such laws, codified at the federal level under the Securities Act of 1933, are intended to protect the public from fraudulent investment schemes. A primary means of protection is a requirement that securities be "registered" with the Securities and Exchange Commission (SEC) at the federal level (states have similar requirements). Registration requires the offeror to disclose detailed information about the security to the offeree, most commonly through a prospectus.

Registering securities can be costly. While there are fees involved, they pale in comparison to the cost of legal assistance that is typically required to fulfill the registration obligation, which can run as high as several hundred thousand dollars (Arends 2004). Fortunately, the SEC recognizes that the registration process can be financially and administratively burdensome for small businesses, and has created rules to exempt certain securities and securities transactions from having to register. Likewise, most states have rules providing for certain exemptions from registration. State and federal exemptions may not be well coordinated, however, which makes it harder to avoid registration; to escape registration, one effectively needs both a federal and state exemption, since essentially the same information (and legal expense) is required in either case. Furthermore, even filing for an *exemption* from full registration could result in tens of thousands of dollars in legal fees.

Finally, to increase profitability, investors will ideally have state and federal income tax liability against which to offset their share of depreciation and the PTC. Any investor considered by the

IRS to be a *passive investor* in the project (likely to be most of the investors) will also need some form of passive income against which to take the PTC. As noted earlier, very few individual investors have passive income, which includes rental income, but *does not* include interest and dividend income. On the other hand, farmers in particular may in many instances have at least some passive income from renting out fields, pastures, or even machinery.

4.2 Minnesota-Style "Flip" Structure

One way to address the problem of individual farmers likely not being able to efficiently utilize PTC and depreciation benefits is for those farmers to bring in a corporate, tax-motivated equity partner that is easily able to absorb the credits. We refer to this model, which was pioneered in Minnesota, as the "Minnesota-style flip structure," to distinguish it from the "Wisconsin-style flip structure" examined later.

As developed in Minnesota,[12] this structure involves a single farmer/landowner who wishes to develop a utility-scale wind project on his land, but has little or no stable tax liability against which to utilize the PTC and depreciation. To improve the economics of the project, the farmer/landowner forms a limited liability company (LLC) with a tax-motivated corporate equity partner (typically a C-corporation) that is able to make use of the PTC and other tax benefits.[13] The local farmer/landowner ("local partner") initially contributes as little as 1% of the equity in the LLC, with the corporate partner contributing up to 99%.

During the first 10 years of the project, all cash flows and tax benefits from the project are divided among the corporate and local partners proportional to their level of investment in the LLC (e.g., 99% to 1%). At the end of 10 years (once the PTC is no longer available), or potentially later if the corporate partner requires more income to meet a return hurdle, ownership in the LLC "flips" to 99% local, 1% corporate. At the time of the flip the corporate partner typically has the option to either maintain its 1% ownership position for the remaining life the project, or else sell its 1% interest to the local partner at fair market value. Since there is virtually no economic difference between these two options, given the size of the share in question (i.e., 1%), the corporate partner is perhaps more likely to stay in the project, if only to demonstrate to the IRS the long-term nature of its investment, and that it was not simply seeking a tax shelter. Either way, after the flip the local partner – having contributed only 1% of project equity at inception – essentially owns a debt-free, utility-scale wind project that should continue to operate and generate substantial income for at least another decade.

4.3 Wisconsin-Style "Flip" Structure

In 2003, Cooperative Development Services of Madison, Wisconsin, released a report titled *Wisconsin Community Based Windpower Project Business Plan* that describes a variant on the

[12] While wind power developers in Minnesota were the first to apply "flip" structures to farmer-owned wind projects, flips have been commonly employed in the commercial wind sector between developers with little tax liability and tax-motivated equity investors.

[13] John Deere is one example of a corporation that has voiced its willingness to partner with farmers in wind project flip structures. John Deere has chosen to enter this market not only because it is financially attractive, but also because its involvement will increase the prosperity of rural America, its core client base. Farmers earning income from successful wind projects have more money with which to buy tractors.

Minnesota-style flip structure, in which multiple local investors (rather than a single farmer or landowner) provide debt (rather than equity) financing to the wind project. As described in the *Plan*, a group of local investors with limited or no tax credit appetite pool enough capital (through sales of $5,000 shares) into an LLC to cover 20% of the total costs of a 3 MW wind project. The LLC "loans" this amount to a tax-motivated corporate investor, who in turn contributes another 30% of total project costs in the form of equity, and borrows the remaining 50% from a commercial lender, resulting in a debt/equity ratio of 70%/30% for the project as a whole. The corporate investor owns 100% of the project for the first ten years and benefits from the federal PTC and accelerated depreciation, as well as revenue from the sale of power and renewable energy credits (RECs).[14] At the same time, it services the project's debt, repaying the entire 10-year commercial loan, as well as interest – but not principal – on the loan from the local LLC.[15] At the end of the tenth year, with its minimum return hurdle met, the corporate investor simply drops out of the project, retaining the LLC's loan principal as payment for the project. At this point, the local LLC assumes 100% ownership of the project, which is now free of debt, and therefore quite profitable.

This structure differs from the *Minnesota-style flip* structure in three main ways. First, the local LLC is comprised of a group of local investors, rather than a single farmer/landowner. Second, the local LLC's capital contribution is structured as a loan, and the income it receives over the first 10 years therefore comes in the form of interest payments. Finally, though we call this a "flip" structure because ownership in the project effectively flips from the corporate investor to the local investors at the end of 10 years, a more accurate characterization would be that – unlike in the *Minnesota-style flip* – the local investors buy out the corporate investor's 100% stake in the project. This distinction means that the required level of local investment is higher than under the *Minnesota-style flip*.

As this model is somewhat of a hybrid between the *multiple local owner* and *Minnesota-style flip* structures, it faces barriers common to both. Specifically, because we assume the presence of multiple local investors, securities regulation is likely to be a consideration, and administrative costs are likely to be relatively high. Unlike the *multiple local owner* model, however, PTC appetite among the local investors in a *Wisconsin-style flip* project is irrelevant, since the locals provide debt rather than equity financing. As with the *Minnesota-style flip*, identifying and engaging a corporate equity partner could present another barrier. Finally, for all three of the structures described so far, finding a willing off-taker and negotiating a suitable power purchase agreement could be challenging.

In addition, it is important to note that the *Wisconsin-style flip* structure has yet to be implemented in the United States, and so has not been vetted as thoroughly as the two previous structures. As such, there may be tax or other issues that have not yet been identified. For example, it is not entirely clear how the IRS would view a "pre-sale" agreement such as

[14] A renewable energy credit, or REC, is a financial instrument that represents the environmental attributes of renewable generation. RECs can either be bundled and sold along with the commodity electricity produced by the renewable generator, or alternatively stripped off and sold separately from the power.

[15] These limited, though steady, interest payments provide the sole source of income to the local LLC over the initial 10-year period of corporate ownership.

contained in this model, where the two parties agree at project inception on the sales price 10 years hence.

4.4 On-Site Projects

Finally, we consider an on-site project designed to provide power to the farm, rather than selling it to a utility. This model is fairly straightforward, and involves a large end-use electricity consumer (e.g., a large farm operation) financing and interconnecting a utility-scale wind turbine on its side of the meter to supply on-site power and thereby displace power purchased from the utility. At first blush, a wind project that offsets the full retail rate a customer pays for electricity may provide the highest value to its owners. This is because retail rates for commercial customers such as farmers typically average around 7¢/kWh – well above the 3-4¢/kWh that a wind project might earn by selling its power on the wholesale market.

Taxable business entities such as farmers, however, face a rather unique barrier to on-site wind development (or any type of on-site generation): the electricity bill savings that result from the project are, in effect, taxable, since they reduce the amount of utility payments that the owner can deduct as a business expense. Partly for this reason, most on-site utility-scale wind projects installed to date in the US have been owned by *tax-exempt* large electricity users, such as schools.[16]

Whether taxable or tax-exempt, on-site wind projects are likely to face a number of challenges. First, because it is not sold to an unrelated party, power generated and consumed on site is not eligible for the PTC. This financial handicap may be compensated for by "earning" retail, rather than wholesale, prices for the wind power, but in cases where the farm is served under a utility tariff containing a *demand* and/or *standby* charge, it will not be able to earn the full retail rate for on-site wind generation.

A demand charge is based on the customer's peak demand measured during a specified period each month. If the wind is not blowing during that period, then on-site wind generation will not reduce peak demand. In such a situation, if demand charges account for half of the farmer's electricity bill, then the per-kWh savings from the wind turbine will only be *half* of the full retail rate.

Conversely, a standby charge is based on any shortfall of actual demand below "normal" or contractual demand, and is intended to compensate the utility for continually "standing by" ready to serve in the event that on-site demand for power exceeds the on-site supply of power. In other words, a standby charge allows the utility to recover its fixed costs (e.g., transmission and distribution costs, reserve costs) of standing ready to serve self-generating customers. Whereas demand charges erode the value of on-site wind generation if the wind generation *does not* reduce peak demand, standby charges work in reverse, reducing the value of on-site generation if the wind turbine *does* reduce peak demand. In either case, the generator will not earn the full retail electricity rate for power produced.

[16] For example, this model has been popular among public schools in Iowa, at least eight of which have taken advantage of the state's generous net metering program, the absence of demand and standby charges, and a zero interest revolving loan fund. For more information, see Bolinger (2004).

Demand and standby charges are typically waived under *net metering* tariffs, which enable the on-site generator to temporarily "store" excess power on the grid (by spinning the meter backwards whenever on-site supply exceeds the level of on-site demand), and then use that stored power later when on-site demand exceeds on-site supply. While more than 35 states require utilities to offer net metering tariffs, only a few of those states – California (1 MW), Iowa (500 kW), Ohio (no size limit), and New Jersey (2 MW) – have set high enough limits on the capacity of generators eligible for net metering to be applicable to modern utility-scale wind turbines, which range in capacity from 600 kW up to 2 MW for typical on-shore applications.

Finally, this development model faces the fundamental truth that relatively few farmers will have large enough operations to be able to absorb the generation from a modern utility-scale wind turbine. A few states or utilities, however, allow farms to participate in a limited form of what is known as *aggregate net metering*, whereby farmers who install eligible renewable energy systems can use the power produced by the system to offset the aggregate demand from *all* meters on the farm (rather than just the specific meter behind which the project is interconnected).

5. A Comparative Analysis of Ownership Structures in Oregon

Which of the four ownership structures described in the previous section is "best" or most competitive depends largely on the situation at hand – one size does not fit all. Determining factors include, but are not limited to, a farmer's ability to utilize tax credits, preference for individual versus "cooperative" ownership, rate structure of the utility tariff serving the farm, and state of residence (as incentives will vary by state). Controlling for some of these variables by considering a farmer-owned project located in the state of Oregon, this section provides an example of the type of comparative financial analysis that farmers might do to inform their choice of ownership structure.

To analyze the four ownership structures described above, we have developed a spreadsheet-based, 20-year pro forma cash flow model. Using Microsoft Excel's "Solver" tool,[17] the model optimizes the project's capital structure (i.e., debt/equity ratio) to arrive at the minimum amount of revenue required to meet *both* the lender's minimum debt service coverage requirements *and* the equity investors' after-tax internal rate of return requirements. Potential sources of revenue to farmer-owned wind projects include the sale of energy, renewable energy credits (RECs), and potentially capacity (as well as any existing state incentives). On-site, behind-the-meter projects, meanwhile, will earn (or more appropriately, save) at least the avoided energy (if not demand) component of the retail rate for all generation consumed on site (less standby charges), and likely the utility's avoided costs for any production in excess of consumption.

To identify those structures that are likely to be most competitive in Oregon, we look at the degree to which each project's revenue requirement (to satisfy all equity return hurdles and lender constraints) is above or below the "market" or benchmark power price accessible to that project. For projects that effectively displace purchased power (i.e., on-site projects), we set as the benchmark power price the relevant utility tariff being displaced (including all applicable demand and standby charges). Based on Pacificorp's Oregon tariffs for end-use customers large enough to host a 1.5 MW wind turbine, the benchmark power price comes to just $33.59/MWh.[18] For projects that instead sell power to the state's investor-owned utilities (i.e., *multiple local owner*, *Minnesota-* and *Wisconsin-style flips*), we use as the benchmark a 20-year nominal levelized power price that – based on the experience of The Energy Trust of Oregon – is intended to represent what such projects are likely to earn through a long-term power purchase agreement. This 20-year nominal levelized price is $39.40/MWh. It is important to note that *neither* of these benchmark prices include revenue from a project's renewable energy credits (RECs), but rather represent revenue from power sales only; RECs could potentially be stripped out and sold separately to generate an additional revenue stream.

Other assumptions to the model include:

- All projects consist of a single 1.5 MW wind turbine operating at a 33% net capacity factor (i.e., the turbine produces 4,339 MWh per year).

[17] *Solver* is a linear programming tool that uses an iterative process to hone in on the optimal solution, subject to user-defined constraints.

[18] For details on the specific tariff chosen and assumptions about the project's impact on demand and standby charges, see Bolinger et al. (2004).

- The capital and operating costs of the project vary slightly by structure depending on several factors, including financing fees. Capital costs are, on average, around $1.88 million, while annual operating costs range from $80,000-$90,000 in the first year, with some portion of operating costs escalating over time at the rate of inflation. For details on our capital and operating cost assumptions, as well as how we arrived at them, see Bolinger et al. (2004).
- Unless otherwise specified by the user, the model presumes that the project owner has sufficient tax liability to utilize all tax benefits. The model also accounts for offsetting interactions between state and federal tax (and other) incentives where warranted (e.g., anti-double-dipping provisions).
- Because the USDA's Section 9006 program is competitive *and* may be under-funded in future years, we assume in our base case that the project is *not* in receipt of a Section 9006 grant. We do, however, conduct sensitivity analysis assuming that the project is able to secure such a grant, and present those results.
- The Oregon Business Energy Tax Credit (BETC) is a 35% investment tax credit taken either over a 5-year period, or alternatively paid out at project inception as a discounted (to 25.5%) lump sum cash payment from a "pass-through" partner (who, in turn, takes the 35% 5-year credit). The pass-through option allows all projects – even those without Oregon tax liability – to take advantage of the BETC. Our model assumes that projects choose to take the Oregon Business Energy Tax Credit (BETC) as a lump-sum, discounted pass-through payment rather than as a 5-year credit, since doing so reduces the amount of up-front cash that needs to be raised (and also reduces the need for state tax liability). We assume that the BETC will trigger the PTC's anti-double-dipping provisions and thereby reduce the value of the PTC, though this is an issue that is currently under review by the IRS.
- The project obtains 10-year debt financing from Oregon's Energy Loan Program. This program is unique in its ability to offer loans financed by either tax-exempt or taxable bond issuances, regardless of the borrower's tax status. Interest rates are either 4.5% or 5.5% for tax-exempt or taxable debt, respectively. Because we assume that tax-exempt financing will trigger the PTC's anti-double-dipping provisions, only those projects that cannot otherwise utilize the PTC will take advantage of tax-exempt debt. The Energy Loan Program is also somewhat unique in its willingness to allow monetization of the PTC and BETC towards meeting the minimum required average annual debt service coverage ratio of 1.25.
- Local investors (e.g., farmers) require a 10% after-tax internal rate of return from the project, while corporate investors (if any) require a 15% after-tax internal rate of return.
- Marginal federal and state income tax rates are 35% and 6.6%, respectively, for corporate investors (if any) and 25% and 9%, respectively, for individual investors.
- The rate of inflation equals 2% per year.
- Wind projects in Oregon incur no sales tax expense (Oregon does not have a sales tax).

Select summary modeling results are presented in Table 1. Each project's *revenue requirement* can be thought of as the 20-year nominal levelized amount of revenue (on a $/MWh basis from some combination of power sales, REC sales, and incremental financial support above and beyond those incentives embedded in the model) required to satisfy all equity return hurdles and lender constraints. Each *benchmark power price* should be thought of as 20-year nominal levelized revenue available to the project from *just* the power sales component. For a project to be economically viable under our assumptions, any *revenue shortfall* (i.e., the positive difference, if any, between the *revenue requirement* and the *benchmark power price*) must be

made up through sales of RECs and/or incremental financial support (e.g., from the USDA Section 9006 program, or an additional state incentive).

Table 1. Modeling Results for 1.5 MW Farmer-Owned Wind Projects Located in Oregon

	Multiple Local Owner	MN-Style Flip	WI-Style Flip	On-Site (Taxable)
ASSUMPTIONS				
PTC-Eligible?	Yes	Yes	Yes	No
Energy Loan Program 10-Yr Debt Interest Rate	5.5%	5.5%	5.5%	4.5%
Local 10-Yr Debt Interest Rate	NA	NA	7.0%	NA
RESULTS				
Financing (2004 $)				
Corporate Equity	$0	$421,900	$402,509	$0
Local Equity	$575,615	$4,262	$0	$111,002
Energy Loan Program 10-Yr Debt	$845,036	$998,860	$885,186	$1,311,498
Local Farmer 10-Yr Debt	$0	$0	$136,061	$0
BETC Pass-Through Payment	$459,102	$456,552	$459,102	$448,902
Total Project Cost	$1,879,753	$1,881,574	$1,882,858	$1,871,402
Project Economics (nominal $/MWh)				
Revenue Requirement	$39.7	$44.3	$41.2	$49.6
Benchmark Power Price	$39.4	$39.4	$39.4	$33.6
Revenue Shortfall	$0.3	$4.9	$1.8	$16.0
After-Tax Internal Rate of Return				
Corporate IRR	NA	15%	15%	NA
Local IRR	10%	87%	10%	10%

Below, we briefly discuss the modeling results presented in Table 1, as well as their implications.

5.1 Multiple Local Owner

As shown, local farmers would need to raise $575,615 through the sale of equity shares in the project (e.g., at a price of $5000 per share, 115 shares would need to be sold). The remainder of the project would be financed through a BETC pass-through payment of $459,102, along with a 10-year, 5.5% interest loan of $845,036.

The $39.67/MWh revenue requirement essentially matches the benchmark power price of $39.40/MWh, suggesting that the *multiple local owner* structure will require little if any additional support in order to meet the 10% after-tax hurdle rate of return.[19] We stress, however, that these results assume that the project is able to efficiently utilize the PTC and other tax benefits. As noted earlier, this assumption is perhaps unrealistic. The only working examples of this structure – i.e., the first two *Minwind* projects in Minnesota – have reportedly been less tax-

[19] In fact, if we assume that the project is awarded a Section 9006 USDA grant equal to 25% of capital costs, or $450,100, the revenue requirement drops to $34.32/MWh – well below the benchmark price.

efficient than originally envisioned, and although the per-share PTC allocation is rather modest when spread over numerous shares, achieving 100% tax efficiency is perhaps overly optimistic.

With this in mind, Figure 1 below shows the impact on revenue requirement of relaxing the PTC efficiency assumption.[20] As shown, the project is only economically viable (relative to the presumed benchmark power price of $39.40/MWh) on its own if able to take full advantage of the PTC. Once PTC efficiency falls below about 70%, the *Minnesota-style flip* structure – which is the primary alternative to the *multiple local owner* model – is likely to be more advantageous, at least in terms of having a lower revenue requirement (of $44.28/MWh, per Table 1).

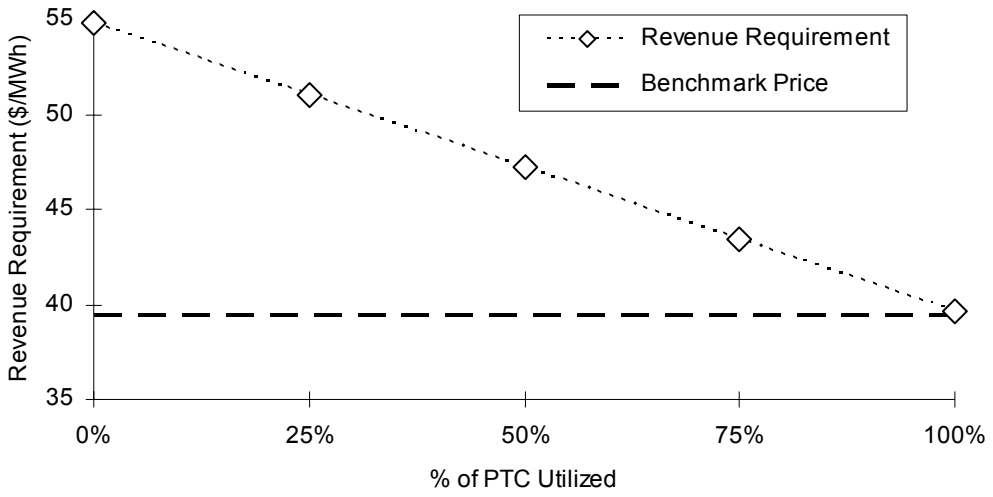

Figure 1. Revenue Requirement as a Function of PTC Efficiency

5.2 Minnesota-Style "Flip" Structure

We assume that the original LLC ownership split is 99% corporate, 1% local, and then flips to 1% corporate, 99% local after 10 years. As shown in Table 1, this project's revenue requirement of $44.28/MWh is about $4.6/MWh higher than that for the *multiple local owner* structure (assuming 100% tax efficiency). This is due in part to the involvement of a corporate equity partner with a higher after-tax hurdle rate (15%, as opposed to 10% for the local partner).

It is also due to the fact that the local partner's after-tax IRR equals 87% – *well in excess of* its 10% hurdle rate. This excess return to the local partner results from the project being constrained by the corporate partner's assumed 15% after-tax return hurdle. In order to reach that corporate hurdle rate while meeting required minimum debt service coverage ratios, the project must earn a certain amount of revenue (e.g., $44.28/MWh). Since the local partner initially owns a 1% share of the project, it also earns approximately the corporate hurdle rate (which, at 15%, exceeds the local hurdle rate of 10%) over the first 10 years. More importantly, however, in years 11-20 the local partner earns 99% of the income from the project while having invested only 1% of the equity in the project. The end result is a 20-year after-tax IRR of 87%.

[20] Since the intent in this case is to try and capture the full value of the PTC, we presume that the project will elect to use taxable debt (at 5.5%) from the Energy Loan Program, so as to avoid reducing the value of the PTC.

Presumably the local partner can command, and the corporate partner is willing to concede, such excess returns for a number of reasons. First, without the local partner, there would be no wind project. The local partner presumably brings to the table not only control of a windy site, but also a project that has largely been developed and is ready to be constructed. Furthermore, at least in Minnesota, where this structure was first introduced, the local partner has historically also brought to the table the state 1.5¢/kWh 10-year production incentive, which the corporate partner would not otherwise be able to access. Second, the local partner – who more than likely lives near the project site – may provide at least some project oversight, which has a value. Third, the local partner provides a convenient "buyer" of the project at the end of 10 years, allowing the corporate partner to effectively withdraw from the project at minimal transaction costs once it has maximized its return. As a passive, tax-motivated equity investor, the corporate partner likely does not have much intrinsic interest in owning and operating wind projects, particularly as such projects age beyond 10 years and major equipment failure becomes more likely to occur. In this sense, the ability to easily withdraw from the project after 10 years has some value.

While this structure is highly attractive to the local partner (while also satisfying the corporate partner), the fact that the local partner earns well in excess of his hurdle rate means that the revenue requirement of $44.28/MWh – nearly $5/MWh above the benchmark price – is higher than it needs to be, and therefore the project is not as competitive as it could be.

5.3 Wisconsin-Style "Flip" Structure

One way to limit the excess returns earned by the local partner in the *Minnesota-style flip* structure, as well as reduce the revenue requirement of the project, is to completely de-couple the local partner's investment from equity ownership in the project during the first ten years (i.e., the period of interest to the corporate investor). The *Wisconsin-style flip* structure effectively accomplishes this de-coupling by having the local investors initially provide debt, rather than equity, financing to the project. The loan from the local LLC is essentially unsecured and is considered to be subordinate to the loan from the Energy Loan Program; as such, it carries a higher interest rate of 7% for the same 10-year term. The amount of up-front cash required of the farmers – $136,061 – is much lower than the $575,615 under the *multiple local owner* structure, suggesting that the *Wisconsin-style flip* structure may require fewer investors and, as a result, may have an easier time qualifying for an exemption from securities registration. Finally, the revenue requirements are lower than those seen in the *Minnesota-style flip* structure, primarily because here it is possible to limit the local investor to the 10% after-tax hurdle rate. Even so, at $41.18/MWh, the 1.5 MW project is still $1.78/MWh above the benchmark power price. This is well within striking distance of economic viability, however: though not shown in Table 1, a Section 9006 USDA grant equal to 25% of capital costs (i.e., $450,100) would reduce the revenue requirement to $36.45/MWh, nearly $3/MWh below the benchmark price of $39.40/MWh.

5.4 On-Site Projects

With no sale of power, the PTC and REPI are irrelevant, and even taxable project owners are therefore free to make use of tax-exempt (i.e., lower interest, 4.5%) debt from the Oregon Energy

Loan Program, without fear of triggering a reduction in the value of the PTC. The benchmark price that such a project is able to earn (or more appropriately, save) is surprisingly low at $33.6/MWh, due to the presence of demand and standby charges. Moreover, power bill savings effectively become taxable income by reducing the amount of utility expenditures that can be deducted as a business expense. In part for this reason, the on-site project's revenue requirement is relatively high at $49.6/MWh, which, in combination with the relatively low benchmark power price of $33.6/MWh, implies that on-site wind projects are not likely to be a viable option in Oregon.

6. Conclusions

Spurred on by recent targeted financial support from various states and the USDA, working examples of farmer-owned wind projects in Europe and Minnesota, and the lure of significantly higher income than a land lease agreement can provide, many farmers in windy parts of the United States are becoming increasingly interested in utility-scale wind project ownership. Once the wind resource has been determined to be viable, perhaps the most fundamental decision facing a farmer is how to finance, own, and operate the turbine in order to maximize income. As described in this article, the tax-based nature of federal support for wind power makes choice of business structure a particularly important consideration. Fortunately, the choice of ownership structure is one that lends itself to comparative quantitative analysis under a set of common assumptions.

Using the state of Oregon as a test case, the modeling results presented in this article suggest that certain ownership structures are more likely than others to be successful in Oregon. Specifically, those structures that can capture the PTC by selling power to an unrelated party – i.e., the *multiple local owner*, *Minnesota-* and *Wisconsin-style flip* structures – all appear to be more competitive and/or attractive than *on-site* projects, which cannot access the PTC and also are saddled with demand and standby charges. Open questions remain, however, regarding the viability, or even legality, of the *Wisconsin-style flip* structure. This leaves the *multiple local owner* and *Minnesota-style flip* structures as proven models that are also fairly competitive; which of these two is *more* competitive will depend in large part on the tax credit appetite of the local investors involved. As shown, without 100% tax efficiency, the economics of the *multiple local owner* structure deteriorate rather quickly to the point (at around 70% PTC efficiency) where *Minnesota-style flip* structures become more competitive.

While these results reflect regulatory and market conditions, as well as state incentives, particular to Oregon, they also support a more general message: business or legal structures that allow farmers to profitably own utility-scale wind projects exist and are being employed in the United States. Such structures enable the project to benefit from the traditional tax-based federal incentives for wind power – the PTC and accelerated depreciation – as well as newer, more-targeted support for farmer-owned wind projects from the USDA as well as several states. With the help of these incentives, farmer-owned wind projects can provide competitively priced power as well as a means to bolster and stabilize farm-based income. This combination is making wind power an important new cash crop in many rural areas of the United States.

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