A Comparative Analysis of Community Wind Power Development Options in Oregon

Prepared for the Energy Trust of Oregon

by

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Mr. Juhl has pioneered conservation and renewable energy technologies, particularly wind power, in the Midwest for over 25 years. During his tenure in the wind industry, Mr. Juhl's activities have covered every aspect of the technology including R&D, design, manufacturing, development, installation, and O&M. He has also been instrumental in helping to form public policy by working with legislators and regulators on the workings and benefits of utilizing renewables in the energy mix, and is considered to be one of the nation's leading experts on locally owned renewable distributive generation. Mr. Juhl currently owns and manages two companies active in the renewable energy business, including a 10.2 MW wind farm on the Buffalo Ridge in Southwest Minnesota.

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Executive Summary

Background

The Northwestern United States is currently home to several large, commercially developed wind projects. With many more in the development pipeline, large commercial wind projects will likely dominate wind power development in the Northwest for years to come. Recently, however, there has also been growing interest throughout the Northwest in wind projects of a smaller scale, yet still using modern utility-grade wind turbines – i.e., so called "community wind." For the purposes of this report, we define "community wind" power development to mean locally owned projects, consisting of one or more utility-scale wind turbines that are interconnected on either the customer or utility side of the meter.[1]

Community wind power development, which began in Denmark in the late 1970's, has historically been the dominant form of wind power development in northern Europe. At the end of the year 2000, roughly 80% of all wind power capacity in Germany, Denmark, Sweden, and the United Kingdom combined could be considered community-owned. Even today, as the wind industry matures and attracts the attention of big business, community wind continues to thrive in Germany, which is by far the world's leader in installed wind power capacity. Thus, despite its quaint-sounding name, community wind has historically been responsible for large amounts of installed wind power capacity.

Yet applying the European community wind power development model in the United States has proven to be challenging. Most of the drivers of community wind in Europe – including feed-in tariffs, which require utilities to purchase wind power at premium prices for extended terms – are generally not present in the United States. In addition, community wind power development in the United States faces a number of barriers, which can be loosely categorized as follows:

- **Financial:** inability of most individual investors to efficiently utilize tax credits for wind power, determining a feasible ownership structure for the project, financing the project, potentially poor economies of scale
- **Regulatory:** securities regulation and the potential need to register equity shares in a wind power project with the Securities and Exchange Commission, unfavorable utility rate structures
- **Technical:** an interconnection process geared towards much larger power plants, limitations on where wind turbines can be interconnected to the distribution grid
- **Market:** wind easements already sold to commercial wind developers, "all-requirements" contracts that limit the ability of a rural electric cooperative to purchase wind power, lack of on-site project opportunities, identifying potential revenue sources, negotiating a power purchase agreement.

[1] We define "locally-owned" to mean that one or more members of the local community have a significant direct financial stake in the project, other than through land lease payments, tax revenue, or other payments in lieu of taxes. For new projects, as will be the case in Oregon, we define "utility-scale" to mean projects consisting of one or more turbines of 600 kW (currently the smallest turbine size offered by the major wind turbine manufacturers) or greater in nameplate capacity.

As a result of these barriers (the most important of which will be discussed later in conjunction with specific ownership structures), success in developing community wind projects in the US has been slow in coming.

Despite the challenges encountered, emerging experience in several states shows that community wind is possible in the US if the right combination of policies and conditions exist. For example, community wind development in Minnesota has been driven by requirements that the local utility purchase – under standardized wind tariffs – a certain amount of power from smaller wind projects, and by state production incentives for those projects. Similarly, favorable net metering rules and utility rate structures in Iowa have spurred large, on-site installations. In general, specific *state* policies that *differentially* support community wind have been necessary to drive this form of wind development.

Drawing on experience with community wind in Europe and the US, this report – which was funded by the Energy Trust of Oregon (Energy Trust) – begins to evaluate the advantages, barriers, costs, and financing structures associated with community wind generally, and in Oregon specifically. The Energy Trust's goal in commissioning this report is to gain a better understanding of the likely ownership structures that will be used for community wind projects in the Northwest, as well as the types and levels of financial and non-financial support that may be required to make such projects viable. Armed with such an understanding, the Energy Trust will be in a better position to evaluate community wind proposals that it receives through its Open Solicitation program, as well as to support community wind projects through a targeted community wind program.

Analysis

The analysis in this report is based on a pro forma yearly cash flow model developed to analyze and compare the financial attractiveness (using each project's revenue requirement as the primary metric) of various community wind ownership structures that have been either contemplated or implemented in the US. Specific development models or ownership structures examined include:

- **Cooperative Ownership:** Cooperative members invest in a community wind project, and benefit by patronizing the project through purchasing its energy and/or tradable renewable certificates (TRCs) at cost. Patronage of the project's power will likely require either cooperation from the utility (to deliver the power 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 a possibility in Oregon, where retail choice exists only for the largest end-users, while the former is perhaps unlikely in Oregon or anywhere else in the US (and is one reason why no wind cooperatives have been developed in the US). As a result, we describe and discuss cooperative ownership in the full report, but do not model it.
- **Aggregate Net Metering:** A group of local investors develop and own a centrally located (*not* on-site) utility-scale wind turbine, and apply their portion of the turbine's output against their on-site electricity consumption. This model – which is similar to cooperative ownership, but in the US is more likely to be structured as a limited liability company (LLC) – requires utility cooperation, or more likely legislative or regulatory action to force utility

cooperation. As a result, aggregate net metering has to date been implemented in only a very limited fashion in the US, for farm-based biogas systems in both Vermont and California.

- **On-Site, Behind-the-Meter:** A large electricity customer (either a taxable business or a tax-exempt entity such as a school) installs a utility-scale wind turbine on the customer side of the meter to supply on-site power and thereby displace power purchased from the utility. This model has been popular among public schools in Iowa, at least eight of which have taken advantage of the state's generous net billing program (which historically imposed no size limit on net-metered generators), single-part tariffs, and a zero interest revolving loan fund.
- **Multiple Local Owner:** Local landowners and investors, ideally with tax credit appetite, pool their resources into an LLC to own and operate the project, selling output to the local utility. This structure most closely resembles the *Minwind* projects in Minnesota.
- **Minnesota-Style "Flip" Structure:** A local investor (typically the owner of a windy site) without tax credit appetite brings in a tax-motivated corporate equity partner to own most of the project for the first ten years (i.e., the period of tax credits), and then "flip" project ownership to the local investor thereafter. This structure has been popularized in Minnesota (along with the *multiple local owner* structure described in the previous bullet).
- **Wisconsin-Style "Flip" Structure:** Similar to a Minnesota-style flip, though involving a *group* of local investors who provide *debt*, rather than equity, financing to the project, and then purchase the entire project from the corporate partner at the end of ten years. This structure, which has yet to be implemented, is developed and described in a generic business plan funded by Wisconsin's clean energy fund.
- **Town-Owned:** A municipality develops and owns a utility-scale wind project, potentially financed with tax-exempt municipal bonds, and sells the power to an unrelated party. This model is currently being pursued by a school district in Minnesota, as well as by the Massachusetts *Community Wind Collaborative*.

To analyze these various ownership structures, we have developed an Excel-based, 20-year cash flow model. Using Excel's "Solver" tool,[2] the model optimizes the project's capital structure (i.e., debt/equity ratio) to arrive at the minimum amount of revenue (on a $/MWh basis, originating from the sale of power or tradable renewable certificates (TRCs), as well as financial support from the USDA, Energy Trust, or some other source) required to meet *both* the lender's debt service coverage requirements *and* the equity investors' after-tax internal rate of return requirements. 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 interactions between state and federal tax (and other) incentives where warranted (e.g., anti-double-dipping provisions).

For each structure (with the exception of on-site projects, for which a 10.5 MW project is irrelevant), we model both a 1.5 MW and 10.5 MW project.[3] We assume that, in aggregate, the

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

[3] At the low end of the range, the 1.5 MW project is intended to represent a project that is within financial reach of most potential community wind investors. It is interconnected to, and its power is consumed within, the local distribution system. The 10.5 MW project, meanwhile, is *not* intended as an upper bound on the size of community

1.5 MW project has an installed cost of around $1.88 million, or $1,250/kW, while the 10.5 MW project comes in about 7% cheaper at approximately $1,160/kW, or $12.2 million.[4] On a $/kW basis, these aggregate costs are higher than those experienced by many of the community wind projects being installed in Minnesota, but perhaps slightly lower than those assumed in some of the community wind projects currently planned in Oregon.

In addition to these one-time capital costs and fees, the project will also incur ongoing operating costs. Table ES-1 lists our assumptions for such costs in the first year of a Minnesota-style flip project (like capital costs, operating costs will vary somewhat with ownership structure – see the full report for more details). With the exception of property tax,[5] we assume that each of the line items listed in Table ES-1 will escalate at the annual rate of inflation over the 20-year project life.

Table ES-1. First Year Operating Costs for a Minnesota-Style "Flip" Structure

	1.5 MW		**10.5 MW**	
	($/year)	**($/kW-yr)**	**($/year)**	**($/kW-yr)**
Operations & Maintenance (O&M)	$15,000	$10	$105,000	$10
Warranty/Equip. Repair and Replacement Fund	$27,000	$18	$189,000	$18
Management/Administrative	$5,000	$3	$26,250	$3
Property Taxes	$21,306	$14	$138,053	$13
Land Lease	$4,000	$3	$28,000	$3
Equipment Insurance	$14,000	$9	$93,100	$9
Miscellaneous	$1,000	$1	$6,300	$1
Project Total	**$87,306**	**$58**	**$585,703**	**$56**

In addition to capital and operating costs, other base-case modeling assumptions include:

- All projects operate at a 33% net capacity factor.
- The federal production tax credit (PTC) and renewable energy production incentive (REPI), both of which expired in 2003, are re-instated (we conduct sensitivity analysis on this assumption).
- The project is unsuccessful at securing a Section 9006 USDA grant, due to intense nationwide competition among wind and other renewable energy projects for what is likely to be an uncertain (and perhaps under-funded) pool of grant money. We conduct sensitivity analysis on this assumption.
- Projects always take the Oregon Business Energy Tax Credit (BETC), despite the fact that it will trigger the PTC's anti-double-dipping provisions and thereby reduce the value of the PTC. The BETC is a 35% investment tax credit taken either over a 5-year period, or alternatively paid out as a discounted (to 25.5%) lump sum cash payment from a "pass-

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wind projects (which can theoretically be much larger), but rather is merely intended to be of sufficient size to trigger the construction of a substation to interconnect to the higher voltage transmission system.

[4] These aggregate installed costs were derived through a bottom-up approach, the results of which are presented in Table 7 of the full report. Total installed costs vary somewhat with ownership structure (those cited are for a Minnesota-style flip structure), as well as with the project's debt/equity ratio (as the amount of debt will impact the size of the loan fee and debt service reserve fund).

[5] We assume that property tax is assessed at a rate of 1.19% of total project costs in year one, and that the taxable basis of the project depreciates at 8% per year until reaching 20% of its original value in year 11, at which level it remains through year 20.

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.
- 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 debt, 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. We run sensitivity analysis on the interest rate, as well as PTC/BETC monetization.
- Local investors 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 and 25% and 9%, respectively, for individual investors.
- The rate of inflation equals 2% per year.
- The rate of interest earned on the debt service reserve fund equals 2% per year.
- The output of the model – the project's revenue requirement – does not escalate over time, and so can be thought of as a 20-year nominal levelized requirement.
- Community wind projects in Oregon incur no sales tax expense (Oregon does not have a sales tax).

To identify those structures that are likely to be most promising in Oregon, we look at (among other factors) 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 (cooperatives, aggregate net metering, and on-site projects), we set as the benchmark power price the relevant Pacificorp tariff being displaced (including all applicable demand and standby charges). For projects that instead sell power to Pacificorp or PGE (multiple local owner, Minnesota-style flips, Wisconsin-style flips, and town-owned projects), we use as the benchmark a 20-year nominal levelized power price provided by the Energy Trust of Oregon that is intended to represent what such projects are likely to earn through a long-term power purchase agreement.[6] This levelized price is $39.40/MWh for "distributed generation" projects that are interconnected to, and whose power is consumed within, the local distribution system (in our analysis, only the 1.5 MW projects), and $34.60/MWh for projects interconnected to, or whose power is delivered over, the high-voltage transmission system (in our analysis, only the 10.5 MW projects).

It is important to note that *none* of these benchmark power prices include a value for a project's tradable renewable certificates (TRCs). Since the Energy Trust's policy is to take title to a project's TRCs in proportion to the percentage of that project's above-market costs that it funds, most projects supported by the Energy Trust will retain few, if any, of their TRCs. As a result, the Energy Trust has requested that our analysis *not* consider the potential value of TRCs to a

[6] To levelize the price streams provided by the Energy Trust, we discounted and amortized the first 20 years of each price stream (to correspond to the 20-year term of our model) using an 8% nominal discount rate. A discount rate of 10% would have resulted in levelized prices that are roughly 0.5¢/kWh lower than those used, while a discount rate of 6% would have resulted in levelized prices that are roughly 0.5¢/kWh higher than those used.

project, and instead treat TRCs as an incentive design issue, the details of which will be determined by the Energy Trust on a case-by-case basis.

Thus, in Tables ES-2 and ES-3, each project's *Revenue Requirement* can be thought of as the 20-year levelized amount of revenue (on a $/MWh basis from some combination of power sales, TRC sales, and financial support from the USDA, Energy Trust, or some other source) required to satisfy all equity return hurdles and lender constraints. Each *Benchmark Power Price* should be thought of as the 20-year levelized amount of revenue available to the project from *just* power sales. 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 TRCs and/or additional financial support (from the USDA, Energy Trust, etc.). While *Revenue Shortfall* is also denoted in 20-year levelized terms, it is important to note that the structure and timing of any incentive designed to close that shortfall could vary from year to year (or even within a year); we make no attempt in this report to identify the optimal incentive type or timing (e.g., up-front grant versus ongoing production incentive, etc.).

Tables ES-2 and ES-3 present our 1.5 MW and 10.5 MW base-case modeling results for each ownership structure (again, on-site projects are not included in Table ES-3, since a 10.5 MW on-site project is unlikely). As noted earlier, the competitiveness of each structure is a function not only of revenue requirements (where lower is better), but also the market price available to each structure (where higher is better). Thus, even though aggregate net metering has a relatively high revenue requirement, it is – at least in theory – the most competitive structure, because we assume that it is able to earn the full average residential retail rate of $71/MWh, which is $18.77/MWh *higher than* the revenue requirement of $52.23/MWh (for a 1.5 MW project). Of all the ownership structures presented, however, aggregate net metering faces perhaps the most – and most severe – obstacles to implementation. Chief among them is the fact that utilities are currently not required to offer aggregate net metering, and – barring regulatory intervention, which itself is unlikely – are not likely to move in that direction. Hence, this is a potentially interesting model, but perhaps too far removed from reality in the United States to warrant much attention from the Energy Trust at this time.

Both on-site models, whether owned by taxable businesses or tax-exempt entities such as schools, have revenue requirements that are well above their respective benchmark power prices. This is due to a combination of unfavorable utility rate structures (e.g., the presence of demand and standby charges), generally low retail rates in the Pacific Northwest, and the taxability of power bill savings (if the owner is a taxable business). Even with an expansion of net metering to include projects as large as 1.5 MW, such projects are still not all that attractive. This, along with our sense that there are likely to be relatively few opportunities for on-site utility-scale wind development in Oregon (especially those connected to Pacific Power or PGE's distribution system), suggests that the Energy Trust should focus its attention elsewhere.

Table ES-2. Base-Case Modeling Results Under Different Ownership Structures (1.5 MW Project)

	Aggregate Net Metering	On-Site Taxable	On-Site Tax-Exempt	Multiple Local Owner	MN-Style Flip	WI-Style Flip	Town-Owned
ASSUMPTIONS[1]							
Form of BETC	5-Year	5-Year	Lump	5-Year	Lump	Lump	Lump
PTC	No	No	No	Yes	Yes	Yes	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	4.5%	4.5%	5.5%	5.5%	5.5%	4.5%
Local 10-Yr Debt Interest Rate	NA	NA	NA	NA	NA	7.0%	NA
Corporate Contribution to Equity	0%	0%	0%	0%	99%	100%	0%
Local Contribution to Equity	100%	100%	100%	100%	1%	0%[2]	100%
Landowner-Owned?	No	Yes	Yes	No	Yes	No	Yes
% of REPI/Tradable PTC Captured	NA	NA	NA	NA	NA	NA	50%
Taxable Power Bill Savings (nominal $/MWh)	NA	$33.59	NA	NA	NA	NA	NA
RESULTS							
Financing (2004 $)							
Corporate Equity	$0	$0	$0	$0	$421,900	$402,509	$0
Local Equity	$1,012,941	$562,870	$529,688	$1,062,308	$4,262	$0[2]	$452,026
Energy Loan Program 10-Yr Debt	$865,687	$1,308,294	$859,261	$815,133	$998,860	$885,186	$967,530
Local 10-Yr Debt	$0	$0	$0	$0	$0	$136,061	$0
BETC Pass-Through	$0	$0	$448,902	$0	$456,552	$459,102	$456,552
Total Project Cost	$1,878,628	$1,871,165	$1,837,851	$1,877,440	$1,881,574	$1,882,858	$1,876,108
Minimum Local Investment	$675	$562,870	$529,688	$5,000	$4,262	$5,000	$452,026
Number of Shares	1,500	NA	NA	212	NA	27	NA
Project Economics (nominal $/MWh)							
Revenue Requirement	$52.23	$64.81	$46.94	$38.58	$44.28	$41.18	$40.03
Benchmark Power Price	$71.00	$33.59	$33.59	$39.40	$39.40	$39.40	$39.40
Revenue Shortfall (Surplus)	($18.77)	$31.22	$13.35	($0.82)	$4.88	$1.78	$0.63
After-Tax Internal Rate of Return							
Corporate IRR	NA	NA	NA	NA	15%	15%	NA
Local IRR	10%	10%	10%	10%	87%	10%	10%

[1] Additional assumptions that do not vary by ownership structure are not included in the table, but include: all projects count the BETC and/or PTC towards the Energy Loan Program's required annual average debt service coverage ratio of 1.25, the BETC (both as a 5-year credit and a pass-through payment) triggers a PTC haircut, the BETC pass-through payment is considered taxable income, all tax-motivated corporate equity investors require an after-tax internal rate of return of 15%, all local investors require an after-tax internal rate of return of 10%, and the revenue requirements and benchmark power prices shown are fixed for 20 years and do not escalate.
[2] In this structure, the local contribution comes in the form of debt, not equity. See Section 6.6 for further explanation.

Table ES-3. Base-Case Modeling Results Under Different Ownership Structures (10.5 MW Project)

	Aggregate Net Metering	Multiple Local Owner	MN-Style Flip	WI-Style Flip	Town-Owned
ASSUMPTIONS[1]					
Form of BETC	5-Year	5-Year	Lump	Lump	Lump
PTC	No	Yes	Yes	Yes	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	5.5%	5.5%	5.5%	4.5%
Local 10-Yr Debt Interest Rate	NA	NA	NA	7.0%	NA
Corporate Contribution to Equity	0%	0%	99%	100%	0%
Local Contribution to Equity	100%	100%	1%	0%[2]	100%
Landowner-Owned?	No	No	Yes	No	Yes
% of REPI/Tradable PTC Captured	NA	NA	NA	NA	50%
Taxable Power Bill Savings (nominal $/MWh)	NA	NA	NA	NA	NA
RESULTS					
Financing (2004 $)					
Corporate Equity	$0	$0	$2,966,676	$2,850,013	$0
Local Equity	$6,280,946	$6,599,579	$29,966	$0[2]	$3,042,093
Energy Loan Program 10-Yr Debt	$5,899,969	$5,575,089	$6,639,257	$5,899,358	$6,567,692
Local 10-Yr Debt	$0	$0	$0	$900,050	$0
BETC Pass-Through	$0	$0	$2,550,000	$2,550,000	$2,550,000
Total Project Cost	$12,180,915	$12,174,668	$12,185,900	$12,199,421	$12,159,786
Minimum Local Investment	$598	$5,000	$29,966	$5,000	$3,042,093
Number of Shares	10,500	1,320	NA	180	NA
Project Economics (nominal $/MWh)					
Revenue Requirement	$50.35	$35.85	$40.94	$37.82	$38.69
Benchmark Power Price	$71.00	$34.60	$34.60	$34.60	$34.60
Revenue Shortfall (Surplus)	($20.65)	$1.25	$6.34	$3.22	$4.09
After-Tax Internal Rate of Return					
Corporate IRR	NA	NA	15%	15%	NA
Local IRR	10%	10%	87%	10%	10%

[1] Additional assumptions that do not vary by ownership structure are not included in the table, but include: all projects count the BETC and/or PTC towards the Energy Loan Program's required annual average debt service coverage ratio of 1.25, the BETC (both as a 5-year credit and a pass-through payment) triggers a PTC haircut, the BETC pass-through payment is considered taxable income, all tax-motivated corporate equity investors require an after-tax internal rate of return of 15%, all local investors require an after-tax internal rate of return of 10%, and the revenue requirements and benchmark power prices shown are fixed for 20 years and do not escalate.

[2] In this structure, the local contribution comes in the form of debt, not equity. See Section 6.6 for further explanation.

Among those community wind ownership structures that have actually been implemented in the United States (which is important, if only to demonstrate practicality), the *multiple local owner* model is most competitive, with revenue requirements that are slightly *below* the 1.5 MW benchmark power price, and slightly *above* the 10.5 MW benchmark power price (assuming 100% tax efficiency – i.e., local investors are able to use 100% of the PTC). This structure also has the advantage of relative simplicity, and in some sense is the "purest" community wind model, in that multiple local investors own the project without corporate assistance. What appear to be relatively stringent securities regulations in Oregon, however, may add additional expense to this ownership structure if securities registration cannot be avoided. Furthermore, without 100% tax efficiency, the economics of this structure deteriorate rather quickly to the point where flip structures make more sense (at around 65% PTC efficiency). Up to that point (and perhaps even beyond), however, the *multiple local owner* structure is certainly worthy of consideration by the Energy Trust (presuming additional support is necessary – our modeling results suggest that it may not be at high levels of tax efficiency, or with modest revenue from TRC sales).

Flip structures are also relatively attractive models, particularly if the local investors' appetites for tax credits are low. The Wisconsin-style flip has a roughly $3/MWh advantage over the Minnesota-style flip, but has not yet been implemented in the United States, and may face scrutiny from the IRS regarding the pre-arranged sale of the project after ten years. More research is warranted on this issue. Minnesota-style flips, on the other hand, have several years' worth of experience and operating history under their belts, and therefore are more of a known entity.

Assuming it can capture at least half the REPI, or alternatively at least half the value of a tradable PTC if implemented, the town-owned project selling power to a utility results in a revenue requirement that roughly matches the benchmark power price (at least for the 1.5 MW project – the 10.5 MW project is less competitive). Questions remain as to whether this particular structure – which effectively involves a town getting into the power business – is even legal, however.

Finally, 10.5 MW projects are generally less competitive than their 1.5 MW counterparts, despite in all cases having lower revenue requirements (from capturing at least some economies of scale). This is a function of the 10.5 MW projects (which are assumed to require power delivery over the transmission system) having a 20-year nominal levelized benchmark power price that is $4.80/MWh lower than the 1.5 MW projects (which are considered to be distributed generators whose power is consumed locally). It also reflects a $10 million cap on costs eligible for the BETC: with the 10.5 MW projects costing more than $12 million, the BETC represents a lower proportion of total project costs than in the case of a 1.5 MW project that costs less than $10 million. Similarly, though not shown in Tables ES-2 or ES-3, USDA Section 9006 grants are limited to the greater of 25% of project costs or $500,000, which renders them far less useful to a 10.5 MW project than they are to a 1.5 MW project. Finally, Table ES-3 shows that the number of equity shares in 10.5 MW projects can be quite large, making it likely that such projects would need to undergo full securities registration, and thereby incur extra legal costs not reflected in our cost inputs. The cost of registration would make such projects even less competitive than shown, both on an absolute basis and relative to a 1.5 MW project that is able to qualify for an exemption from securities registration.[7] Given these considerations, the Energy Trust should not automatically assume that a 10.5 MW project will require less support than a 1.5 MW project; in fact, our modeling shows the reverse to be the case.

Conclusions

Experience with community wind power development in both Europe and the United States demonstrates that community wind is possible if the right combination of policies and conditions exist. Above all else, revenue certainty is paramount to attracting community wind investors. Thus, policies that provide stability (and profitability) to community wind in Oregon will be essential.[8] If the past is any indication of the future, such policies are not likely to arise at the federal level; rather, specific *state* policies that *differentially* support community wind will be necessary to drive this form of development.

Along these lines, Oregon appears to be in a rather unique position. The state already has in place an aggressive Energy Loan Program and a valuable Business Energy Tax Credit, both of which are *potentially* (see below) accessible to each of the seven different community wind ownership structures examined in this report. The BETC in particular favors small over large projects, as eligible project costs against which the credit can be claimed are capped at $10 million.[9] Furthermore, the Oregon Public Utilities Commission is currently considering a favorable expansion of PURPA contract terms, which, if implemented, could prove to be a critical keystone for the development of community wind in Oregon. Finally, the Energy Trust of Oregon has both the interest and means to support community wind power development, and has commissioned this report as a first step in thinking about how it might do so.

The modeling results presented in this report suggest that certain ownership structures are more likely than others to be successful in Oregon. Specifically, those structures that can capture the PTC (or REPI) by selling power to an unrelated party – i.e., the *multiple local owner*, *Minnesota-* and *Wisconsin-style flip*, and the *town-owned* structures – all appear to be more competitive and/or attractive than structures that depend upon selling power to investors (i.e., *cooperative-owned*, *aggregate net metering*, and *on-site* projects).[10] Open questions remain regarding the viability, or even legality, of two of the more attractive structures, however – *Wisconsin-style flips* and *town-owned* projects. This leaves *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. Assuming local investors are able to use 100% of the PTC, the *multiple local owner* structure is more competitive; as overall PTC capture falls below 65%, however, the *Minnesota-style flip structure* becomes more competitive.

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[7] Of course, spreading the cost of registration over a greater amount of capacity (i.e., 10.5 MW instead of 1.5 MW) will mitigate this impact somewhat.
[8] Such policies should also drive the development of a strong wind project construction and operations infrastructure to cost-effectively support such projects.
[9] This is one reason why our results show that 1.5 MW, or even 10.5 MW, community wind projects may require less incremental support than one might otherwise think, based on the level of additional support recently sought by much larger wind projects: the BETC is worth proportionally less to projects that cost in excess of $10 million.
[10] As shown in Tables ES-2 and ES-3, *aggregate net metering* actually appears to be the *most competitive* structure. As noted, however, this particular structure likely faces perhaps the most significant barrier to implementation – strong utility opposition – and as such, should perhaps be discounted.

As with any modeling exercise, however, our results are only as good as our assumptions, and we note that several of our assumptions could – pending additional time, budget, and expertise – be refined with greater certainty. Since several of these assumptions are critical not only to our modeling results, but more importantly to the viability of those community wind projects that are already in development in Oregon, we recommend that among the Energy Trust's first steps in developing a community wind program should be to resolve the following outstanding questions:

1) Will taxable loans from the Energy Loan Program trigger the PTC's anti-double-dipping provisions? If so, then projects hoping to use the PTC will need to seek other sources of debt, most likely on less favorable terms (with respect to debt service coverage ratios, PTC/BETC monetization, and perhaps also interest rate).
2) Pending favorable resolution of the previous question, can the $20 million cap on the Energy Loan Program's ability to issue "private use" (taxable) bonds be increased to ensure that there is sufficient loan capacity to support an Energy Trust community wind program?
3) Does the BETC (both as a 5-year credit *and* pass-through payment) trigger the PTC's anti-double-dipping provisions?
4) Should the BETC pass-through payment be treated as taxable income, or as a reduction in depreciable basis (and if so, for Oregon purposes, Federal purposes, or both)?
5) Should Section 9006 USDA grants be treated as taxable income, or as a reduction in depreciable basis (and if so, for Oregon purposes, Federal purposes, or both)?
6) What requirements must be met to avoid having to register securities in Oregon? We provide a layman's interpretation in the full report, but a more detailed opinion on this matter from a lawyer knowledgeable in Oregon securities law is warranted.
7) Are municipalities in Oregon permitted to own wind projects? If so, under what conditions may they use their bonding authority to issue tax-exempt municipal debt to finance a wind project?
8) Does the Wisconsin-style flip structure pass muster with the IRS?
9) What role will the Energy Trust allow TRC's to play in providing an additional source of revenue to community wind projects?

Publicly resolving these specific questions will help reduce the transaction costs of developing a community wind project in Oregon. Furthermore, the answers to these questions could have major implications for both the relative and absolute competitiveness of various ownership structures, and therefore the amount of financial support the Energy Trust might ultimately need to provide. As such, we encourage the Energy Trust to pursue these questions, and to the extent that the correct answers to these questions are not consistent with our modeling assumptions, revise the model accordingly to reflect a more accurate picture of how community wind is likely to develop in Oregon.

More generally, a number of program design lessons arise from experience with community wind in both Europe and the United States, as well as our financial analysis of community wind in Oregon. Perhaps the most important of these is that community wind has thrived wherever there are long-term, stable policies that enable local investors to earn a reasonable rate of return while incurring minimal transaction costs. For example, feed-in tariffs in Denmark, Sweden, and

Germany have enabled community wind to dominate in those three countries. Closer to home, community wind in Minnesota – the only state in the US where community wind can be considered to be thriving – has developed primarily under what equates to a feed-in tariff with Xcel Energy. These lessons underscore the importance of the current PURPA proceeding in Oregon: if the proceeding does not result in a long-term standard offer power purchase agreement (PPA) suitable for community wind, working independently with Pacific Power and PGE to negotiate such a tariff should become a high priority for the Energy Trust.[11]

Even with a long-term PPA, however, some sort of incremental state incentive may still be required to make community wind projects economically viable in Oregon. The question of whether, and if so how much, additional financial support (beyond the BETC and Energy Loan Program) is required can be addressed with financial modeling, as presented in this report. Under current Pacificorp tariffs, benchmark PPA prices provided by the Energy Trust, and our modeling assumptions, we find that on-site projects would require substantial incremental support, while several of the ownership structures that sell power to an unrelated party may not require much – if any – additional support.

Given the potentially limited need for ongoing, long-term financial support for some of these structures, the Energy Trust may wish to focus on supporting *near-term* projects that demonstrate *replicable* ownership models that can ultimately be applied at a scale sufficient to reduce transaction costs, lead to infrastructure development, and minimize possible diseconomies of scale. In supporting this first wave of "groundbreaking" projects, the Energy Trust should recognize that such projects are perhaps likely to incur higher costs than the hypothetical projects modeled in this report.

Specific efforts targeted at building infrastructure to minimize transaction costs and bring community wind up to scale may also be warranted. For example, Wisconsin began by developing a community wind business plan, while Illinois funded a 3-year wind resource monitoring program targeted at sites suitable for community wind. Massachusetts has gone even farther by retaining a stable of consultants to provide developmental assistance, and a pool of "preferred partners" to reduce transaction costs during the construction phase. The Energy Trust should consider what types of infrastructure-building activities are appropriate (i.e., in addition to this report, as well as the anemometer loan program). At a minimum, the Energy Trust should continue to offer its anemometer loan program (and consider expanding its range to include areas outside of Pacific Power and PGE service territories), and should endeavor to answer the nine tax and legal questions listed above. More aggressive steps might include proactive efforts to reduce construction costs by, for example, attracting new local entrants into the crane business (which should reduce mobilization fees), perhaps through an Energy Trust guarantee of some minimal amount of business. Similarly, as an organization in tune with the evolving status and schedule of most wind projects in the Northwest (large and small), the Energy Trust may be in a unique position to help community wind projects to "piggyback" on top of larger commercial wind projects (even when not sited contiguously) in order to capitalize on lower turbine costs (i.e., through bulk purchases) or shared crane mobilization fees.

[11] Since our financial modeling shows that even attractive on-site tariffs may not be sufficient to justify on-site wind in Oregon, working to establish reasonable on-site tariffs should be relegated to a second-tier priority.

Finally, a few other near-term activities should also be considered. Recognizing that the availability of USDA grants may reduce the need for incremental financial support,[12] the Energy Trust should work to connect potential projects to possible USDA funds, through workshops, referrals, or other forms of information dissemination. The Energy Trust may also wish to open a dialogue with rural electricity cooperatives (RECs) and Bonneville Power Administration (BPA) in the hopes of attaining reasonable wheeling tariffs for community wind projects located in REC service territories.[13] And, given that several of the ownership structures modeled in this report can become significantly more or less attractive depending on possible changes to policies (particularly changes involving the PTC and REPI), the Energy Trust would be well-served to closely monitor the policy arena and be prepared to adapt its program to a changing policy environment.

[12] Our modeling suggests that a USDA grant equal to $450,000, or 25% of the costs of a 1.5 MW project owned by *multiple local owners*, reduces revenue requirements by about 0.5¢/kWh (and also reduces the amount of equity that must be raised to finance the project).

[13] To be eligible for support from the Energy Trust, a community wind project that is located in the service territory of a REC must wheel its power – through BPA – to Pacificorp or PGE.

1. Introduction

The Northwestern United States is home to some very large, commercially developed wind projects. These projects can potentially capitalize on scale economies to lower the cost of wind-generated electricity, and can contribute to significant aggregate wind capacity additions. While such projects are likely to remain the predominant form of wind development in the Northwest, there has also been growing interest in wind projects of a smaller scale, yet still using modern utility-grade wind turbines – i.e., so called “community wind.” This report begins to evaluate the advantages, barriers, costs, and financing structures associated with community wind generally, and in Oregon specifically.

Definitions of community wind vary. For the purposes of this report, we define community wind power development to mean locally owned projects, consisting of one or more utility-scale turbines that are interconnected on either the customer or utility side of the meter.[14] This relatively broad definition includes most – but not all – of the models that are in place in the United States today.[15]

Community wind power development of this scale has been purported to provide a number of benefits relative to the conventional commercial wind power development common in the U.S., as well as relative to small, on-site wind power projects. The list of potential benefits includes the following:

- Community wind projects tap into a latent and potentially lower-cost source of capital to fund utility-scale wind development.[16]
- With local investment dollars at stake, community wind projects may benefit from increased community support (as the Danes say, “your own pigs don’t stink”), which might translate into a smoother permitting process, relative to commercially owned projects.
- In some areas, interconnecting smaller projects to the distribution grid (embedded generation) can provide distributed generation benefits (e.g., enhance grid stability). While such benefits vary by situation and are far from universal, widely dispersed wind development (as opposed to sizable wind farms) should at least reduce the impact of wind resource variability, through geographic diversification.
- In instances where power from a community wind project is consumed on site, or is otherwise sold directly to investors in the project, the project owner should directly benefit from the price stability of wind power.

[14] We define “locally-owned” to mean that one or more members of the local community have a significant direct financial stake in the project, other than through land lease payments, tax revenue, or other payments in lieu of taxes. For new projects, as will be the case in Oregon, we define “utility-scale” to mean projects consisting of one or more turbines of 600 kW (currently the smallest turbine size offered by the major wind turbine manufacturers) or greater in nameplate capacity. We recognize, however, that community wind projects in Europe and elsewhere have been around for many years, and that utility-scale wind turbine sizes have increased rapidly in recent years. For these older projects, we will not strictly adhere to the 600 kW threshold.

[15] Note, however, that this definition excludes: (1) on-site, home-sized smaller wind turbines (including innovative uses of these systems, e.g., Our Wind Co-op in the Northwest), and (2) projects owned by public power utilities.

[16] Community-based investors may settle for a lower return on equity than commercial investors would be willing to accept, thereby improving project economics

- Small community wind projects may be able to utilize existing infrastructure (e.g. roads, distribution lines, etc.), and if interconnected directly to the distribution grid may avoid the need to build a substation. These factors could offset some or all of any diseconomies of scale associated with smaller projects.
- Individual investors may be more tolerant than commercial investors of annual variability in revenues.
- Traditional commercial wind development is often "lumpy" on a year-to-year basis, and community wind may be able to fill some of the interim "valleys" that are all too common.
- Small community wind projects could be an effective means of quickly proving out various wind resource areas for later expansion through larger projects.
- Community wind projects may enhance local economic development benefits relative to other forms of wind power development, due to the participation of local investors, and perhaps greater use of local contractors.
- Relative to small, home-sized wind turbines (e.g., 10 kW or less) in which local investors might otherwise invest, utility-scale turbines are more cost-effective on a per-kWh basis, which should generally translate into greater return for each dollar invested.

We note that some of the purported advantages and disadvantages of community wind development – relative to the commercial model – are uncontroversial, while others have generated debate. It is not the purpose of this report to resolve this debate or to address, in detail, the philosophical or practical advantages of one wind development model relative to another. As such, other than briefly noting them here for contextual reasons, this report will *not* specifically investigate the purported benefits of community wind listed above.[17] Later in this report, however, a chapter on *barriers* to community wind power development will address several potential *disadvantages* of community wind development relative to the standard commercial model, such as potentially poor economies of scale and high transaction costs.

This report has been motivated and funded by the Energy Trust of Oregon (Energy Trust). The Energy Trust is a relatively new, nonprofit organization created to invest "public purpose" funding for energy efficiency and renewable energy in Oregon over at least the next 10 years. This mandate emerged from energy reform legislation (Senate Bill 1149) passed in 1999, which included a 3% system-benefits charge to apply to Portland General Electric and Pacific Power ratepayers in the state. With an annual budget of approximately $45-50 million – about $10 million of which is dedicated to renewable energy – the Energy Trust is expected to have a sizable impact on the energy future of the state.

The Energy Trust has developed a number of programs to support renewable energy, including programs for on-site photovoltaics and larger-scale renewable energy development. The Energy Trust is now exploring opportunities to support community-scale and small-scale wind

[17] We note, however, that a companion report is being prepared by ECONorthwest, in conjunction with NWSEED and with funding from the Energy Trust of Oregon, the Washington Department of Community, Trade, and Economic Development, and A World Institute for a Sustainable Humanity (AWISH), to investigate the economic development benefits of community wind power in the Pacific Northwest. Another report currently underway, funded by NREL and prepared by the Renewable Energy Policy Project (REPP), will compare the local benefits of community and "commercial" wind power development in a generic setting. We refer readers interested in the local economic development benefits of community wind to these two reports.

development. In initiating this report, the Energy Trust's goals are to gain a better understanding of the likely ownership structures that will be used for community wind projects in the Northwest, to explore the barriers, opportunities, and costs associated with community wind, and ultimately to better understand the types and levels of financial and non-financial support that may be required to make such projects viable.

The report proceeds by first briefly describing experience with community wind in Europe (Chapter 2), and then contrasting that with experience in the US (Chapter 3). Chapter 4 goes on to explore a number of barriers to community wind development in the US, and in the Pacific Northwest in particular. In Chapter 5, we develop a standardized set of cost inputs, assumptions, and parameters that are applied in modeling the economics of several different community wind ownership structures. Chapter 6 describes the various structures analyzed and presents results from the modeling exercise. Chapter 7 offers some final conclusions from our analysis.

2. Community Wind in Europe

Europe is the birthplace of community wind power development, which began in Denmark in the 1970s. This chapter provides brief context on the development of community wind in Europe, the unique factors that have driven this particular form of wind development, and what lessons have been learned that might be applicable to community wind in the United States.

2.1 History and Current Status

In early 2004, nearly three-quarters of the world's installed wind power capacity resided in Europe. One reason that wind power has flourished in Europe, particularly relative to other industrialized regions, is community participation in, and resulting acceptance of, wind power development. Table 1, adapted from Bolinger (2001), shows that at the end of the year 2000, roughly 80% of all wind power capacity in four northern European countries – Germany, Denmark, Sweden, and the United Kingdom – could be considered community-owned. Given that these four countries hosted roughly half of the world's installed wind power capacity at that time, community-owned projects accounted for at least 40% of world wind power development at the end of 2000. Thus, despite its quaint-sounding name, community wind has historically been responsible for large amounts of installed wind power capacity.

Table 1. Community Wind Power Development in Select European Countries (2000)

	Total Wind Capacity (MW)	Community-Owned Wind Capacity (MW)	% Community-Owned	Number of Household Investors
Germany	6,161	~5,400	88%	~100,000
Denmark	2,268	~1,900	84%	~175,000
Sweden	240	~30	13%	~15,000
The UK	414	~3	1%	~2,000
Total	**9,083**	**7,333**	**81%**	**292,000**

In the years since 2000, community wind has lost some ground in both Denmark and Sweden, as both countries have transitioned away from a support system based on feed-in tariffs to a more "market-based" support system.[18] The uncertainty surrounding this transition has contributed to a slower pace of onshore wind development in both countries. In contrast to Denmark and Sweden, community wind power in Germany continues to thrive, as that country – with ongoing feed-in tariffs – has more than doubled its installed wind capacity since 2000. In fact, demand among German "wind funds" for projects in which to invest is so strong that at least one early-stage 240 MW offshore wind project – a relatively risky endeavor – is being financed by a community wind fund. Community wind has also advanced somewhat in the UK, as the once-local Baywind Energy Cooperative continues to expand its presence throughout the British Isles, in part by teaming up with large wind developers to parcel off small portions of larger projects for community investment.

[18] A "feed-in tariff" is a premium price that a utility must pay to any wind projects that delivers (i.e., "feeds in") power to it over the grid. For more information, see Section 2.3 below.

2.2 European Ownership Structures

Of interest and particular relevance to this report, the community wind capacity in Table 1 has been developed under at least four different ownership structures, varying by country in response to local laws, customs, conditions, and policy support systems.

For example, the famous Danish wind "cooperatives" are technically not cooperatives at all, but rather *general partnerships*.[19] While cooperatives are used extensively in Denmark for other endeavors (and are even widely used in the energy sector with combined heat and power), Danish electricity law has historically required that wind turbines be directly owned by electricity consumers. A partnership, which is understood to be a contractual relationship between several entities (i.e., electricity consumers) to pool certain resources in order to run a business, has historically been the only joint form of ownership to qualify under Danish power law (Bolinger 2001).

In Sweden, meanwhile, community ownership schemes have generally fallen into one of two models: *real estate communes* and *consumer cooperatives*. The real estate commune is based on the traditions of common law and communal ownership of physical resources, such as fishing or grazing rights, which were often attached to land titles (e.g., one must own land along a stream or in a village in order to fish in that stream or pasture livestock in the village field). Somewhat unique to Sweden, this common law tradition has evolved into a modern vehicle for communal ownership of public facilities such as parking lots, playgrounds, and now wind turbines. The other common ownership structure used for community wind projects in Sweden – the consumer cooperative – is more familiar to US citizens, and has been successful in Sweden largely due to utility cooperation in enabling cooperative members to "patronize" the wind turbine(s) (Bolinger 2001).[20]

Community wind projects in Germany are most often owned by *limited partnerships,* with a developer's limited liability company serving as general partner (GmbH & Co. KG). In this tax-advantaged structure, a wind developer initially incorporates his business as a limited liability company (GmbH). For each project undertaken, the developer forms a limited partnership (KG) with his limited liability company as general partner and individual investors as limited partners. Project revenues are distributed proportionate to the level of each partner's investment.

The UK does not have a specific cooperative law, which means that it is possible to structure almost any legal form of business along cooperative principles. While there are potentially as many as six legal structures suitable for community wind ownership in the UK, a legal structure known as an *industrial and provident society* (IPS), which is appropriate for organizations pursuing both economic as well as social goals, has so far dominated. An IPS will generally be

[19] A cooperative is "a business owned and democratically controlled by the people who use its services and whose benefits are derived and distributed equitably on the basis of use" (Frederick 1997). A general partnership is a business structure in which two or more partners jointly own, control, and operate a business. Each partner is "jointly and severally" liable for all debts incurred by the partnership, and any income generated by the partnership is taxed at the level of the individual partners.

[20] The cooperative structure relies on a system of patronage, whereby each cooperative member benefits in proportion to how much he or she uses – or patronizes – the cooperative. For a wind power cooperative to function, members must be able to patronize the wind turbine.

organized according to cooperative principles, such as open membership, one member one vote, and distribution of profits (e.g., the Baywind Energy Cooperative is structured as an IPS). Because an IPS is not technically by law a cooperative, however, there is considerable room for flexibility in operations. For example, an IPS need not abide by the strict cooperative practice of basing dividends on the degree of patronage (see Section 6.1.2 for more on this), but rather may pay dividends according to the level of investment. An IPS also has the unrestricted ability to advertise shares to the public (Bolinger 2001).

2.3 European Drivers of Community Wind

Community wind power development in Europe has been driven by a number of factors, as shown in Table 2, and described below.

Feed-in laws that require utilities to purchase wind power at premium prices have created accessible, stable, and profitable markets for community wind projects in Denmark and Sweden (historically), as well as Germany (to this day). Such laws provide long-term revenue certainty with relatively little associated transaction costs. The importance of feed-in laws to community wind can be seen in both Denmark and Sweden, where new community wind development has in recent years effectively come to a halt as both countries transitioned away from feed-in tariffs towards more market-based (i.e., uncertain) support systems.

Standardized interconnection rules and procedures in Denmark, Sweden, and Germany remove the uncertainty over who pays for interconnection and any necessary transmission upgrades. Furthermore, the presence of a relatively strong, three-phase electrical grid throughout much of Europe facilitates the interconnection of distributed, utility-scale wind projects by minimizing power quality impacts and the need for costly transmission upgrades (Cohen and Wind, 2001).

Favorable tax treatment for wind power enhances its appeal as an investment. In Denmark and Sweden, for example, community wind investors are typically not taxed on income generated by wind projects, up to certain limits. Furthermore, several European countries tax energy consumption and CO_2 emissions, and in some cases wind project owners receive a refund on these taxes. Finally, up until recently, German tax law allowed depreciation and other losses from investments in wind projects to offset taxes on ordinary (e.g., wage) income, thereby making community wind investments a popular tax shelter among wealthy Germans.

Table 2. Historical Drivers of Community Wind Power Development

	Denmark	Sweden	Germany	UK
Feed-In Laws	✓	✓	✓	
Standardized Interconnection	✓	✓	✓	
Tax-Free Production Income	✓	✓		
Energy/CO_2 Tax Refund	✓	✓		✓
Flow-Through Depreciation			✓	
Wind Turbine Manufacturing Industry	✓		✓	
Ownership Restrictions	✓			
Permitting Denials				✓

The presence of a strong **domestic wind turbine manufacturing industry** has been an important driver in Denmark, where, in the 1980s and 1990s, turbine manufacturers sent sales representatives out into the countryside to organize and facilitate community wind projects, with the ultimate objective of consummating turbine sales. Through this sales strategy, Danish wind turbine manufacturers co-evolved with the market for their product. In other words, by steadily filling orders for just a few turbines at a time, as opposed to hundreds or thousands of turbines destined for large wind farms, Danish turbine manufacturers were able to test new products and discover and solve technical problems prior to mass production (van Est 1999).

In Denmark, government-imposed **ownership restrictions** have historically *required* that wind projects be owned by the local community, based on the notion that those who benefit from feed-in laws should also bear the visual and aural burden of living near the wind turbine. Over the years, as the market for "local" community wind projects has become increasingly saturated, Denmark has gradually relaxed its ownership restrictions, to the point where anyone in the European Union can now invest in a Danish wind project.

Finally, while the United Kingdom lacks most of the drivers historically present in Denmark, Sweden, and Germany, there has nevertheless been a concerted push towards community wind power development in the UK, in part as a result of the rash of **permitting denials** for larger commercial projects that swept the countryside a few years ago. Giving the local community a financial stake in the success of a project is one way to bolster community support for that project.

2.4 Lessons Learned

Community wind is neither "quaint" (e.g., see Table 1) nor part of a bygone era (e.g., see ongoing development in Germany and the UK), but conditions in Europe are unique, and will be difficult to replicate elsewhere, particularly in the United States. In fact, on a national level, the United States has few of the drivers that have historically supported community wind in Europe (listed in Table 2). That said, there are a number of lessons learned in Europe that might be applicable to the US in general, and the Pacific Northwest in particular.

First, revenue certainty is paramount to attracting community investors. Experience in Denmark and Sweden (where new community wind power development has largely ground to a halt following the demise of feed-in tariffs), as well as Germany (where community wind continues to thrive amidst renewed feed-in tariffs) suggest that stable, long-term feed-in tariffs are superior to a more market-based support system such as renewable portfolio standards (RPS) in providing sufficient revenue stability to enable community investment. While such feed-in tariffs may be unlikely to be directly replicated in the US, policy structures that provide stability and profitability to community wind will be essential.

Second, experience in Europe shows that a strong wind turbine operations and support infrastructure is necessary to facilitate community wind cost-effectively. As such, community wind projects are likely to be most cost-effective when deployed in significant quantities (thereby directly supporting the development of a support infrastructure), and in areas where a wind turbine support infrastructure already exists (due, for example, to large wind development activities in the region). The latter condition potentially exists in Oregon.

Third, the taxation of carbon emissions and energy consumption in some European countries provides policymakers with additional options when designing financial support systems for renewable energy. These options – such as refunding those taxes to wind projects – are not open to countries without these taxes, such as the United States. However, the U.S. federal government – and individual states – do have available to them a basket of other policy options that could be used to support community wind, including income, sales, and property tax benefits, direct financial incentives, low-interest loan programs, and ownership restrictions (on incentives). These programs can, in aggregate, be sufficient to support community wind.

Fourth, the standardized interconnection procedures and strong grids common in Europe are not currently replicated in the United States. Standardized interconnection procedures are starting to be developed in the U.S., but local regulatory bodies can do more to encourage progress in this area. Generally weak distribution grids, on the other hand, may ultimately constrain community-based wind development to some degree, though an examination of the ability of the grid to handle community-scale or other forms of wind development was outside the scope of this project.

Finally, the specific ownership and transactional structures used for community wind development in Europe vary by country, and depend critically on local customs, conditions, and policy support systems. Appropriate ownership structures that are tailored to maximize wind project profitability under US conditions will need to be identified and developed. This process has been underway in the Midwestern United States for a number of years, and is now yielding a number of interesting models that will be summarized in the next chapter, and discussed in more detail in Chapter 6.

3. Community Wind in the United States

The conditions that favor community wind power development in northern Europe are unique, and are not easily transplanted from country to country (even within Europe – e.g., witness the substantial difference between the UK and Denmark in Tables 1 and 2). In fact, as noted earlier, the United States has historically lacked virtually all of the drivers of community wind power development that exist in Europe. Moreover, the primary forms of federal support for wind power in the United States – namely the federal production tax credit and accelerated depreciation – are largely targeted at commercial, rather than community, investors. While federal grants from the US Department of Agriculture (USDA) have recently supported community wind projects in rural areas, future funding for this program is uncertain. As a result of these factors, applying the European community wind model in the United States has historically posed a challenge.

An increasing number of states, however, are actively taking on the community wind challenge, motivated by a number of factors. In rural Midwestern states such as Minnesota, Iowa, Wisconsin, and Illinois, community wind is seen as a way to help supplement and stabilize farmer income, and thereby contribute to the preservation of farming communities and the rural landscapes and values they sustain. Meanwhile, in the Northeast, densely populated states such as Massachusetts are recognizing that siting large-scale commercial wind power development is difficult, and are turning to community-scale wind development to increase not only the amount of wind power on the grid, but also the public's knowledge, perception, and acceptance of wind power. This chapter covers experience with state policy support for community wind in these five states (more limited community wind activity in a few additional states is described in Bolinger 2004).

3.1 History and Current Status

Currently, the primary working examples of community wind projects in the US (at least as defined in this report) are located in Minnesota and Iowa, states that first began pursuing community wind in the mid-1990s. Other states, such as Wisconsin, Illinois, and Massachusetts, have only begun to pursue community wind in the past year or so. Thus, the history of community wind power in the United States is brief, particularly relative to Europe.

3.1.1 Minnesota

A combination of favorable state policies specifically targeting "small" (2 MW or less) wind projects, a good wind resource, a largely rural agrarian population, motivated local wind developers, and active and well-organized advocacy groups have made Minnesota both the birthplace *and* current hotbed of community wind power in the United States. More than 100 MW of small community wind projects are currently selling power to utilities in Minnesota, with hundreds of additional megawatts planned. This development has been driven by a combination of purchase mandates and feed-in tariffs, production incentives, and capital grants:

- **Purchase Mandates and Feed-In Tariffs:** In exchange for the ability to store nuclear waste at its Prairie Island nuclear plant, Xcel Energy – the state's largest utility – must support the development of 1,125 MW of wind power: 425 MW by 2002 (met), an additional 400 MW by 2006 (60 MW of which must be from two or more aggregations of projects that are 2 MW or less), and another 300 MW by 2010 (100 MW of which must be from projects of 2 MW or less). In addition, Xcel is required to meet Minnesota's Renewable Energy Objective, which starts at 1% of retail sales from eligible renewables in 2005, and increases by 1% per year until reaching 10% in 2015 (only the final 300 MW of Xcel's wind energy mandate may be applied towards the Objective). Other Minnesota utilities must make a *good faith effort* to comply with the Objective.

To facilitate its mandated purchase of wind generation from small wind projects (and at the direction of the Minnesota Public Utilities Commission), Xcel offers a standard "wind generation purchase agreement" as well as a "small distributed wind generation purchase tariff" through which it will buy power from wind projects of 2 MW or less at a fixed nominal price of 3.3¢/kWh for up to twenty years. Standardized interconnection procedures and agreements are also being developed. These standardized purchase tariffs and agreements – which, when coupled with Xcel's purchase mandate and state production incentives (discussed below), resemble a European-style feed-in tariff (though less lucrative) – help to minimize transaction costs and provide a more stable market within which small projects might thrive.

- **Production Incentives:** A state cash production incentive of 1.5¢/kWh paid to small (2 MW or less) wind projects for the first 10 years of turbine operation has been just as important as the combined impact of Xcel's wind mandate, small wind tariff, and standard purchase agreement in driving the development of community wind in Minnesota.[21] Enacted in 1997, this incentive was originally limited to the first 100 MW of small wind capacity to apply. In May 2003, however, the legislature expanded the incentive to cover an additional 100 MW of small wind capacity. While it took more than five years to reach the initial 100 MW limit, the second 100 MW was fully subscribed in *only six months*, so this incentive is currently not available to new projects.

- **Capital Grants:** Community wind projects in Minnesota have also benefited from three recent or ongoing sources of capital grants. Xcel's Renewable Development Fund (RDF) has held competitive solicitations for innovative renewable energy projects – including community wind projects – on two occasions to date. In early 2004, the Minnesota Department of Commerce State Energy Office awarded, again through a competitive solicitation, a total of $300,000 of oil overcharge funds to two community wind projects. Finally, in 2003, Minnesota community wind projects dominated the Section 9006 grants from the 2002 Farm Bill, capturing 16 of the 25 grants, or $3.9 of the $7.2 million awarded to "large" wind projects.[22] At least 14 of these projects also successfully reserved Minnesota's 1.5¢/kWh 10-year production incentive before it was fully subscribed in November 2003.

[21] Because the energy must be sold in order to qualify for this incentive, grid-supply projects have dominated the program. Net metered projects are eligible (there are currently around 40 net metered installations totaling 1.55 MW that receive the incentive), but the incentive is only paid on any net excess generation that is "sold" back to the utility, rendering it much less valuable than it is to grid-supply projects, whose entire output captures the incentive.

[22] Few of these projects are truly "large" by today's standards; most involve only one or two turbines. The label "large" is simply intended to differentiate these utility-scale projects from much smaller (e.g., 10 kW) wind projects that were also funded under Section 9006. The remaining nine large wind grants were distributed among seven

In combination, the three primary drivers described above should eventually lead to *at least 460 MW* of "community wind" in Minnesota (though see below for qualifications):

- 200 MW of small wind projects (i.e., projects that are, at least nominally, 2 MW or less in size[23]) that receive the 1.5¢/kWh production incentive;
- an additional 160 MW (60 MW by 2007, another 100 MW by 2010) of small wind projects as part of Xcel's wind mandate; and
- the 100 MW Trimont wind project (see below), which Great River Energy plans to apply towards Minnesota's Renewable Energy Objective.

As of late January 2004, roughly 132 MW of the 200 MW of small projects slated to receive Minnesota's production incentive had been built, and the remaining 68 MW was likely (presuming imminent extension of the federal PTC) to come online before mid-2005, given that projects must be built within 18 months after reserving the incentive. Furthermore, there were *more than 50 MW* of additional projects on a "waiting list" established at the time the program became fully subscribed in November 2003.

While many, but not all, of the projects that have been built are locally owned (and therefore fit within our definition of "community wind"), only two of them are owned by multiple local investors who each purchase one or more shares in the project (i.e., the "multiple local owner" structure). Specifically, Minwind I and II are two 1.9 MW projects (subdivided as such so as to qualify for Minnesota's 1.5¢/kWh production incentive for projects of 2 MW or less) collectively owned by 66 local farmers and investors.[24] The majority of the rest of the projects are financed either through traditional commercial avenues,[25] individual personal wealth,[26] or what is known

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states, including Iowa (2 grants), Idaho (1), Illinois (2), Massachusetts (1), New York (1), Texas (1), and Virginia (1). A few of these other grants are mentioned later.

[23] In some instances, what would otherwise be considered a much larger project (based on contiguous turbine siting, and/or related ownership) has been legally sub-divided into a number of smaller projects of 2 MW less in order to capture the Minnesota production incentive. While the incentive legislation contains provisions to guard against this sort of gaming, developers and project owners have devised a number of creative ways to effectively bypass such provisions while remaining within the letter of the law.

[24] The two Minwind projects reportedly cost a total of $3.6 million, 70% of which was financed through loans from a local bank, while the remaining 30% was raised through the sale of project shares (at $5,000/share). The LLC agreement specifies that 85% of each project's shares must be farmer-owned, and no single person can own more than 15% of a project's shares. The equity required to finance both projects (i.e., ~$1.1 million) was reportedly raised from among 66 investors in just 12 days, with each investor cognizant of the passive income limitations on the PTC (see Section 4.1.1 for more on this) and investing accordingly. With the federal PTC, Minnesota's production incentive, and a 15-year power purchase agreement with Alliant Energy, Minwind investors can reportedly expect to earn an average annual return of 17% over the project's life. Interest in the first two Minwind projects was so strong that there are currently seven additional 1.65 MW projects – Minwind III-IX – in development. More than $6 million in local equity was reportedly raised for these next seven projects over the course of just two meetings. Each of these seven projects will receive the Minnesota production incentive, as well as a USDA grant of $178,201.

[25] For example, Northern Alternative Energy packaged together and financed approximately 30 MW of small wind projects in Minnesota with $25 million in debt from the now-defunct ABB Energy Capital. ENEL North America, a subsidiary of the large Italian utility, owns a majority stake in the projects. Although these projects were fully in compliance with the production incentive program rules at the time (the program rules have since changed), they cannot legitimately be classified as community wind.

[26] For example, Garwin McNeilus is a wealthy Minnesotan who has reportedly used his savings to develop and own at least 19 wind projects (totaling 34.5 MW) that have been funded by the Minnesota production incentive to date.

as a "flip" structure, whereby a tax-motivated corporate investor passively owns most of the project for the first 10 years, and then "flips" the ownership of the project to the local investor(s) thereafter.[27]

Of these various ownership structures, commercially financed projects do not conform to our definition of community wind, while projects financed through individual personal wealth (which *do* qualify as community wind under our definition) represent a model that is most likely not widely replicable. That leaves the "multiple local owner" and "flip" structures, which are the most interesting from a community wind perspective, since they enable local individuals to participate in the ownership of a commercial wind project without undue capital outlay. Both of these structures will be discussed in more detail in Chapter 6.

Finally, an emerging model in Minnesota relates to the proposed 100 MW Trimont wind project, which was conceived by an LLC consisting of 45 local landowners and investors who undertook most of the pre-development. Recently, the local LLC has brought in a subsidiary of PPM Energy to develop, construct, own, and operate the project for the duration of its lifetime. This transfer of control did not occur through a sale of the project, however. Instead, the local investors have effectively granted the project to PPM in exchange for a secured interest in the project's success (i.e., a percentage of gross revenue contingent on the project achieving certain performance targets). If all goes well, this arrangement – in which the locals share in the project's performance risk – should prove to be more lucrative to the local investors than an outright sale of the project would have been. This emerging model, which combines the economies of scale from a large project, the credibility and expertise of a large wind developer, and community "owners" who can deliver community acceptance of the project (along with associated transmission development), is reportedly garnering attention elsewhere in the Midwest.

While it is important for the Energy Trust to be aware of the Trimont development model, we will not devote any further attention to this model in the remainder of this report, for several reasons. First, mechanically speaking, this model is not particularly interesting – it is essentially a commercial project with potentially higher-than-normal payments to the local landowners. Second, in contrast to most of the other ownership structures examined here, this development model will by definition *always* require more revenue (e.g., a higher PPA price) than if no locals were involved (that is, presuming the project is able to hit its performance targets, thereby triggering above-normal payments to the locals). Finally, it is perhaps questionable whether the Energy Trust would want to provide support to projects of this scale under the auspices of a community wind program.

McNeilus donates a portion of the proceeds from at least six of these projects to organizations that provide support for underprivileged children in developing countries around the world.

[27] The relative proportions of the various financing/ownership structures employed among the 132 MW of projects that have been built under Minnesota's production incentive to date are roughly as follows: commercial (40%), individual personal wealth (26%), flip (22%), municipal utilities (7%), multiple local owners (3%), and school projects (<1%). Including the additional 68 MW of projects in the queue (i.e., to get to the 200 MW total), the relative proportions shift to roughly 29%, 17%, 39%, 4%, 8%, and 2%, respectively, reflecting a likely increase in "flips" and projects financed by multiple local owners.

3.1.2 Iowa

Community wind projects in Iowa have been dominated by on-site, utility-scale wind installations,[28] primarily at public schools. Currently, eight schools host ten wind turbines ranging in size from 50 kW up to 750 kW, with a combined capacity of 3.6 MW. In addition to Iowa's strong and widely distributed wind resource, two main factors have historically converged to create a favorable environment for this particular model.[29]

First, Iowa's 1993 statewide net metering (called "net billing" in Iowa) law is unusual in that it does not specify a limit on the size of eligible generators. While legal challenges from the state's investor-owned utilities have resulted in recent changes to net billing practices (more on this below), historically the lack of a size limit has enabled the use of utility-scale wind turbines in net-metered applications. In conjunction with single-part tariffs (i.e., just an energy charge, with no separate demand or standby charges) available to many non-residential customers, net billing has historically enabled schools and other medium to large end-users to essentially eliminate their monthly electricity bills, resulting in savings of roughly 8¢/kWh (the retail rate) for all generation up to total consumption, and revenue of 2¢/kWh (the utility's avoided cost) for any net excess generation. In addition, net excess generation at schools has historically earned the federal renewable energy production incentive (REPI), which stood at 1.8¢/kWh before expiring in late 2003.

Second, in some cases turbine owners need not produce any up-front cash, making wind projects a budget-neutral (or even budget-positive) investment. Iowa's Alternate Energy Revolving Loan Program (AERLP) enables customers served by investor-owned utilities to finance a wind turbine project at attractive interest rates. The AERLP will provide half of the required loan (up to $250,000) *at 0% interest* for terms not exceeding 20 years. The AERLP requires that the remainder of the loan (i.e., half or more of total financing) come from a private lending institution of the applicant's choice, thereby ensuring that the project passes not only technical due diligence (performed by the AERLP), but also financial due diligence (performed by the private lending institution).[30]

The end result is that Iowa schools have been able to completely finance the installation of a utility-scale (e.g., 750 kW) wind turbine at blended interest rates of just 3-4%. In combination with net billing, this low rate of interest has in some cases created immediate positive cash flow, allowing loans to be repaid in just 4-6 years (Wind 2004, Windustry 2003). Five of the eight school districts with wind turbines have financed their projects in this manner.

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[28] On-site installations are also often referred to as being "behind the meter" or "on the customer side of the meter." Such projects are often, though not always, net metered.

[29] It should be noted that the environment is favorable not only to wind at schools, but also to wind at private commercial facilities. There are, however, only two utility-scale wind turbines sited at commercial facilities in Iowa: Schafer Systems, Inc. installed a 225 kW wind turbine behind the meter in 1995, while the Story County Hospital installed a 250 kW turbine in 1993 (in addition, a radio station and a truckstop each host a 65 kW wind turbine). One potential reason that the private sector has generally lagged behind schools with respect to on-site wind is that any power bill savings are, in effect, taxable, in that they reduce expenditures on utility bills, which can typically be written off as an expense of doing business.

[30] In contrast, Oregon's Energy Loan Program (described later in Section 5.4.2) performs *both* technical and financial due diligence in house.

While attractive loan programs and net billing policies have made Iowa fertile ground for school-based wind development in the past, the outlook for this type of development going forward is mixed. In late 2001, MidAmerican – the state's largest utility – reached a settlement with stakeholders over its multi-year legal challenge to Iowa's net billing law. The settlement included limiting the capacity from net-metered generators to 500 kW,[31] and rolling any net excess generation (from the 500 kW net metered portion of a project) forward indefinitely from month to month, with no obligation to ever pay for it.[32] In early 2002, the Iowa Utilities Board granted MidAmerican a waiver implementing these changes. The state's other major utility – Interstate Power & Light Company (IP&L) – received a similar waiver in January 2004. This 500 kW net billing size limit, along with the utilities' refusal to buy back net excess generation, makes the economics of a school-based wind turbine much less attractive than it has been in the past.[33] This reality, in combination with the demonstrable success of farmer-owned community wind projects just across the border in Minnesota, has driven a movement in Iowa to implement a production incentive for community wind projects similar to, though perhaps lower in magnitude than, that seen in Minnesota. While this movement failed to result in legislation this year, a tradable state income tax credit of 1¢/kWh for *all* wind generation (not just from community wind projects) was signed into law (AWEA 2004a).[34]

3.1.3 Wisconsin

Community wind is just beginning to take root in Wisconsin, which lacks not only the superior wind resource of its neighbor to the west, but also the broad range of policies and incentives supporting smaller wind projects in Minnesota.[35] In 2003, *Wisconsin Focus on Energy* (the state's clean energy fund) funded Cooperative Development Services of Madison to develop, with assistance from a group of stakeholders, a generic and replicable business plan for community wind projects in Wisconsin. The resulting "Wisconsin Community Based Windpower Project Business Plan" is a thoroughly researched and detailed reference document describing a variation on the "flip" structures employed in Minnesota (both structures will be described further in Chapter 6). Accompanying financial analysis of the Wisconsin model reveals that, even with no state incentives and reasonable cost and revenue assumptions, the

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[31] Importantly, the 500 kW limit specifies the maximum amount of *capacity* that will be net metered at any one location, and does not limit the maximum size of the *generator* to be net metered. In other words, a customer that installs a 750 kW wind turbine can still be on a net metering tariff, but only the first 500 kW of power from the turbine will be net metered (any excess power will be sold to MidAmerican through standard or PURPA contracts).
[32] If the project is unable to *sell* net excess generation back to the utility, it forfeits not only avoided cost revenue for that amount of generation, but also the chance to earn the federal PTC or REPI (depending on the tax status of the project owner) on that generation.
[33] For this reason, interested stakeholders have petitioned the Iowa Utilities Board to require the utilities to implement a more favorable method of determining the amount of energy qualifying for net billing from wind turbines larger than 500 kW.
[34] A typographical error in the legislation, however, limits the credit to just $3.20/MW each year for 10 years. Corrective actions will be considered during the 2005 legislative session (AWEA 2004a).
[35] Wisconsin's clean energy fund – Wisconsin Focus on Energy – principally targets demand-side applications for renewable energy, based on the assumption that the state's RPS will adequately support supply-side renewables. As such, community wind projects that sell power to the grid are unlikely to qualify for financial incentives. *Focus on Energy* is, however, supporting community wind in other ways, such as through the business plan described in this section.

project offers attractive returns to both the corporate and local investors. With the business plan recently completed, the stakeholder group continues to meet and is now focusing its efforts on marketing and outreach activities, in the hopes of identifying a project sponsor to put the plan into action. For more information on the Wisconsin-style flip structure described in the business plan, see Section 6.6.

3.1.4 Illinois

The Illinois Clean Energy Community Foundation (ILCECF) has supported three community wind projects in the past two years. ILCECF awarded two grants to a planned 750 kW on-site school project: one for a feasibility study, and a second to cover roughly 35% of the project's capital cost.[36] ILCECF funding for the second project – a 1.65 MW turbine owned by a rural electric cooperative – was a bit more innovative: a $175,000 payment in the form of an advance purchase of ten years' worth of tradable renewable certificates (TRCs). While the structure of this incentive was driven by restrictions on ILCECF's ability to provide grants to certain types of entities rather than by PTC double-dipping concerns (the project is not eligible for the PTC), this type of incentive – an up-front payment for future production-based services – warrants further investigation as a way to provide grant-like incentives potentially without triggering the PTC's anti-double dipping provisions.[37] Finally, ILCECF has recently provided a 1.5 MW project to be owned by Illinois State University with a $500,000 grant, and has also funded a 3-year statewide wind resource monitoring program that targets sites suitable for community-scale development.

3.1.5 Massachusetts

In September 2003, the Massachusetts Technology Collaborative (MTC), which administers the state's Renewable Energy Trust Fund, launched a $4 million "Community Wind Collaborative" ("the collaborative"). The collaborative was conceived out of the sharp contrast between the highly publicized debate over the proposed 420 MW offshore Cape Wind project, and the nearly unanimous community support for Hull Municipal Light's single 660 kW turbine on the rim of Boston Harbor. Notwithstanding the potential merits of the Cape Wind project, in a state (and region) that has to date experienced very little wind power development, projects of the scale seen at Hull arguably provide a less divisive introduction to modern utility-scale wind power. Yet such small projects are often not sufficiently lucrative to attract the interest of a typical commercial wind project developer. Seeking to fill this gap, MTC launched the community wind collaborative to provide pre-development and development services for such projects on behalf of the community, with the goal of not only increasing the capacity of wind power in the state, but at the same time nurturing a positive perception of wind power throughout local communities statewide.

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[36] Because most of this project's power will be consumed on site and therefore will not be eligible for the PTC, the fact that construction grants generally trigger the PTC's anti-double dipping provisions (unless structured in certain ways – see next footnote) is moot.

[37] This is similar to the approach taken by the Energy Trust of Oregon in supporting the 41 MW Combine Hills project. The Energy Trust provided a one-time $3.8 million advance payment to purchase the tradable renewable certificates that will be generated by the project over time. Like a traditional production incentive that is paid on a $/MWh basis as the project generates power, this up-front variant is not likely to trigger the PTC's anti-double-dipping provisions.

MTC kicked off the collaborative with a series of informational outreach workshops at which it distributed town-by-town maps overlaying modeled wind speed projections and public lands. These maps aided communities in self-screening opportunities prior to detailed local wind measurement. Any city or town in Massachusetts with a sufficient wind resource is eligible to participate in the collaborative. MTC has identified seven phases of development that it will support through the collaborative:

1) Project conceptualization and site identification,
2) Wind measurement and monitoring,
3) Feasibility analysis (both technical and economic),
4) Public outreach and feedback,
5) Project financing,
6) Project construction, and
7) Project operation and maintenance.

At present, MTC will provide – at no cost to the local community – technical expertise and resources to help eligible cities and towns proceed through the first four phases. If, after completing phase 4, a wind project proves to be feasible and the community is interested in proceeding, MTC will support development phases 5-7 primarily through its Preferred Partner Program, which will offer communities access to bundled equipment, construction, and extended O&M packages with favorable prices, low transaction costs, and a streamlined timetable.

MTC envisions that the collaborative will result in projects that sell power over the grid to unrelated parties, as well as on-site projects interconnected behind the meter. Participation in the collaborative is limited to municipalities, though MTC does not rule out the possibility that a municipality may bring in a private entity to develop and own the project. Hence, while the focus on phases 1-4 is on municipalities and publicly owned land, it is not a foregone conclusion that projects developed through the collaborative will be municipal-owned. Of course, until the federal PTC is re-authorized, tax-free municipal financing – if, in fact, available to such projects (see Section 6.7) – may be hard to beat.

Although the collaborative has only been operative for a few months, it has made good progress to date. More than forty communities have expressed interest in the collaborative and are at various stages of project development. Wind monitoring (i.e., phase 2 of the 7-phase development process) is already underway in six communities, and an additional four meteorological towers will be installed by June 2004. A pool of technical consultants should be on retainer by the end of April 2004 to begin feasibility analyses and outreach (phases 3 and 4), and MTC anticipates that three feasibility studies will be underway by July 2004. Finally, the preferred partnership solicitation (applicable to phases 5-7) will be issued shortly.

3.2 Lessons Learned

On a national basis, the US lacks many of the drivers and conditions that have spurred community wind development in Europe. In addition, as discussed in the next chapter, there are a number of potential barriers to community wind domestically. In general, the US landscape is (in many places) suitable for large-scale wind development, and the economies that come with that scale of development; as such, community wind power development in the US has historically played “second fiddle” to large-scale wind development.

Despite the challenges encountered, emerging experience in several states shows that community wind is possible in the US if the right combination of policies and conditions exist. For example, community wind development in Minnesota has been driven by requirements that the local utility purchase – under standardized wind tariffs – a certain amount of power from smaller wind projects, and by state production incentives for those projects.[38] Similarly, favorable net metering rules and tariff structures in Iowa have spurred large, on-site installations. In general, specific *state* policies that *differentially* support community wind have been necessary to drive this form of wind development. Looking ahead, the possible availability of federal USDA grants may reduce the need for state support somewhat, though intense competition for what appears to be limited and uncertain funding may ultimately limit that program’s impact.

Experience in Minnesota in particular has demonstrated that suitable ownership structures can be developed to allow community wind projects to take advantage of both state and federal wind incentives in the US. The standardization of these ownership structures, and dissemination of information on these structures, is beginning to reduce transactions costs for new community wind projects, which can otherwise be substantial.

Finally, as more and more community wind projects are built, development costs are also declining, due to the emergence of a local network of contractors experienced in wind power project construction, as well as increasing developer experience in managing the development process. As a result, small community wind projects in Minnesota and, to a lesser extent, Iowa generally do not cost appreciably more per MW of installed capacity than commercial projects in the 10-20 MW size range.[39] This experience, along with that of community wind in Europe, highlights the importance of a long-term policy focus that will allow the emergence of a development infrastructure to cost-effectively support community wind projects.

[38] Although we have not delved into the social drivers of community wind development in this report, it is perhaps worth noting here that a very receptive and proactive investor base has been another significant driver of community wind in Minnesota. While strong interest in community wind among Minnesota farmers can be attributed in part to the “rich” incentives provided by the state, perhaps just as important is the farmers’ familiarity and comfort with cooperative ownership of other agricultural businesses (e.g., nearly all investors in the first two *Minwind* projects were also members of the same ethanol cooperative). Whether such a cooperative tradition exists in Oregon remains to be seen.

[39] In fact, by some accounts, small community-owned projects in Minnesota cost *less* per installed MW than larger commercial projects. The relative costs of small and large wind projects is discussed in greater detail in Section 4.1.4.

4. Potential Barriers to Community Wind in the US (and Oregon)

Despite the positive experience with community wind that has recently emerged in a few states, there are a number of financial, regulatory, technical, and market barriers to such development. Some of these barriers pertain to only certain project types (e.g., utility standby charges only impact on-site, behind-the-meter projects) or ownership structures, while others are universally applicable to all types of community wind projects, regardless of structure (e.g., lack of uniform interconnection standards). To understand the relative scope and importance of the barriers discussed in this chapter, each must be considered within the context of the different ownership structures that will be described and modeled in Chapter 6. Very briefly, these include:

- **Cooperative Ownership:** Cooperative members invest in a community wind project, and benefit by patronizing the project through purchases of energy and/or tradable renewable certificates (patronage will likely require either utility cooperation, or the services of a competitive energy service provider).
- **Aggregate Net Metering:** A group of local investors develop and own a centrally located (*not* on-site) utility-scale wind turbine, and apply their portion of the turbine's output against their on-site electricity consumption (this model requires utility cooperation, or more likely legislative or regulatory action).
- **On-Site, Behind-the-Meter:** A large electricity customer installs a utility-scale wind turbine on the customer side of the meter to supply on-site power and thereby displace power purchased from the utility (most closely resembles the Iowa school projects – see Section 3.1.2).
- **Multiple Local Owner:** Local landowners and investors, ideally with tax credit appetite, pool their resources to own and operate the project, selling output to the local utility (most closely resembles the Minwind projects in Minnesota – see Section 3.1.1)
- **Minnesota-Style "Flip" Structure:** A local investor (typically the owner of a windy site) without tax credit appetite brings in a tax-motivated corporate equity partner to own most of the project for the first ten years (i.e., the period of tax credits), and then "flip" project ownership to the local investor thereafter.
- **Wisconsin-Style "Flip" Structure:** Similar to a Minnesota-style flip, though involving a *group* of local investors who provide *debt*, rather than equity, financing to the project, and then purchase the entire project from the corporate partner at the end of ten years.
- **Town-Owned:** A municipality develops and owns a utility-scale wind project, potentially financed with tax-exempt municipal bonds, and sells the power to an unrelated party (this resembles the path being pursued by Massachusetts – see Section 3.1.5).[40]

This chapter briefly describes the primary financial, regulatory, technical, and market barriers that could potentially impact one or more of these seven models, using Oregon-specific information where possible. Chapter 6 will draw heavily upon this chapter when describing and discussing the pros and cons of each model.

[40] It is relevant to note that Oregon's Energy Loan Program is able to issue tax-exempt bonds to finance long-term loans for both tax-exempt *and* taxable wind projects. Thus, in Oregon at least, town-owned projects may not have the financing advantage enjoyed elsewhere.

4.1 Financial Barriers

Besides the fact that wind power is often considered to be an above-market resource (especially in the absence of federal or state incentives), there are a number of other financial barriers specific to *community* wind power development in the United States. This section briefly discusses these financial barriers, which include a general lack of tax incentive appetite among likely community wind investors, determining a feasible financial structure, financing the project, and potentially poor economies of scale, at least relative to some of the very large projects proposed in the Northwest.

4.1.1 General Inability to Utilize Tax Incentives

Federal support for wind power in the United States has come primarily from the production tax credit (PTC), as well as 5-year accelerated depreciation. The PTC provides a 10-year inflation-adjusted tax credit, which in 2003 stood at 1.8¢/kWh, while accelerated depreciation provides a tax deduction equal to the capital cost of the project spread over a 6-year period. Community wind investors – as well as commercial wind developers, to a lesser extent – have somewhat of a love/hate relationship with the PTC: most wind projects are not viable without it, yet its structure greatly restricts the types of entities that can profitably invest in wind power.

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 (as well as publicly owned utilities).[41] While there is 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 is 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, even if non-taxable entities are able to capture the REPI, they 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. While the PTC is expected to be extended at some point (and may be extended in a way that includes certain non-profit entities), there is less certainty about the extension of the REPI.

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).[42] 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

[41] While this statement is currently true at the federal level, it is perhaps important to note that Oregon's Business Energy Tax Credit (discussed in more detail in Section 5.4.2) is tradable and therefore available (at a discount) to businesses that do not have Oregon tax liability.

[42] 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 Senate tax bill (S.1637) that contains an extension of the PTC also exempts wind projects from the requirements of the AMT for the first four years of the project's life. The corresponding House tax bill (H.R. 4520), however, contains no such exemption.

hands of just a few project owners, including Florida Power & Light, American Electric Power, PacifiCorp, and Shell.

The problem becomes even more acute when specifically talking about community wind projects owned by individual, rather than corporate, investors. A 1.5 MW 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. Figure 1 combines the impact of the PTC and accelerated depreciation on a 1.5 MW wind project to arrive at the minimum tax liability required to fully benefit from these incentives (i.e., more than $100,000 for each of the first six years).[43] Since the proportion of US households with federal tax liabilities in excess of $100,000 per year is quite small, there will be very few community wind investors able to absorb – on their own – the *full* federal tax benefits of a small commercial wind project.

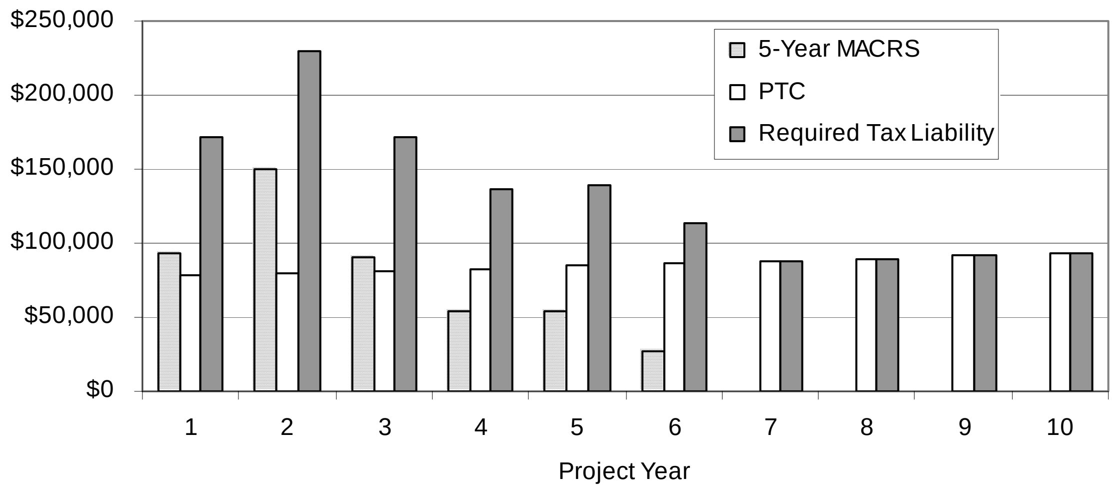

Figure 1. Tax Liability Required to Reap Full Tax Benefits of a 1.5 MW Wind Project

It may be possible to reach critical mass on tax liability by spreading ownership in the project among many local, individual investors, though this carries its own challenges. Investment in a community wind project will be considered a *passive* investment for most investors not involved in the day-to-day management of the project.[44] As a result, such investors must have other *passive* forms of income (e.g., rental income, but *not* interest and dividend income) against

[43] Figure 1 assumes a 33% capacity factor, $1250/kW installed costs, a 25% federal tax bracket (not subject to the Alternative Minimum Tax), and a PTC that starts at 1.8¢/kWh and escalates at 2% per year for 10 years.

[44] IRS Publication 925, "Passive Activity and At-Risk Rules," notes that "there are two kinds of passive activities: (1) trade or business activities in which you do not materially participate during the year, and (2) rental activities, even if you do materially participate in them, unless you are a real estate professional." Publication 925 lists seven tests, any of which can be used to substantiate *material participation* in a trade or business activity. While too numerous and lengthy to exhaustively list here, these tests include: working more than 500 hours in the trade or business during the year; working more than 100 hours – and at least as much as any other person – in the trade or business during the year, and; working any amount of time in the trade or business during year, provided that your work represented substantially all of the work by all individuals during the year. For more information on these and additional material participation tests, see http://www.irs.gov/pub/irs-pdf/p925.pdf.

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 community wind investors that are able to access the sizable federal incentives.

Another possibility is to "transfer" the tax credits to an 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 community wind ownership model, 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 in Chapter 6.

Finally, certain types of governmental (both state and federal) incentives will trigger the PTC's anti-double-dipping provisions. In general, government incentives that are tied to the capital cost of the project – such as grants, investment tax credits (such as Oregon's Business Energy Tax Credit), and subsidized financing (such as a "tax-exempt" loan from Oregon's Energy Loan Program,[45] or a zero interest loan program) – will reduce the value of the PTC, while production-based incentives will not (Ing 2002).[46] When triggered, the PTC "haircut" is not one-for-one; instead, about 40% of the value of the state incentive is typically "taken back" by the PTC's anti-double-dipping provisions (Wiser et al. 2002). Thus, though their value is eroded, state incentives that trigger the PTC's anti-double-dipping provisions still generally provide roughly 60% of their intended value to a wind project. Moreover, if the PTC is not reinstated, such incentives will retain their full intended value.

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, and furthermore are reduced by certain state-level incentives. As shown in the next section, this reality can have a major impact on the choice of ownership structure employed in community wind development.

4.1.2 Determining a Feasible Financial Structure

Would-be community wind investors are faced with a variety of legal structures that could potentially be employed to finance, own, and operate a community wind project. These include limited liability companies (LLCs), for-profit or non-profit corporations, and cooperatives. In choosing a structure, community wind investors must balance a number of potentially conflicting goals, such as maximizing profitability (by capturing state and/or federal incentives) while minimizing risk and liability, accomplishing social objectives while still making a return on

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[45] Oregon's Energy Loan Program also has the ability to issue *taxable* bonds to finance loans, which may not result in a reduction in the value of the PTC (i.e., a PTC "haircut"). To our knowledge, however, this question has not yet been answered definitively, and it is possible that other aspects of the Energy Loan Program besides the tax-status of the particular bond issuance could be deemed as "subsidized financing," and thereby trigger the anti-double-dipping provisions in Section 45 of the US tax code.

[46] 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.

investment, and efficiently managing the project while potentially operating according to cooperative or democratic principles. While legal structures exist to facilitate most or all of these objectives, in the end the need for a financially viable project may dominate all other considerations. As Minneapolis wind project attorney Jeff Paulson put it, "Structural challenges and issues are less legal and more practical." (Paulson 2004). For example, while a community group may ideally wish to open up participation and investment to all interested parties, the associated cost of complying with securities law may be prohibitive (see Section 4.2.1).

Without discounting the wide range of reasons why one may want to form or invest in a community wind project, this report will focus primarily on the financial motive – i.e., we will focus on those ownership structures that offer the best promise of resulting in economically viable projects that require the least amount of state incentives. Such structures are likely to be those that enable a project to capture the federal PTC and accelerated depreciation. For example, because such incentives are not available to non-taxable entities (and the REPI is of substantially less value than the PTC), the "wind cooperatives" that one typically associates with northern Europe are not a financially attractive model in the United States.[47] A more promising vehicle appears to be a limited liability corporation (LLC), which combines the single taxation of a partnership (i.e., 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., difficulty using tax-based incentives, benefits tied to usage rather than investment).

While the LLC vehicle is readily available, the investors that form the LLC must still have tax incentive appetite (and, as noted above, in most cases *passive* tax incentive appetite) in order to benefit from the PTC and accelerated depreciation. This need has given rise to at least two community wind ownership structures in Minnesota: (1) an LLC comprised of multiple local investors, each with potentially sufficient passive tax credit appetite (i.e., the "multiple local owner" model listed at the beginning of this chapter), and (2) an LLC comprised of a single local investor (e.g., a farmer) with insufficient tax credit appetite, and a tax-motivated corporate investor who effectively owns the project (at least financially) during the period of tax benefits (i.e., the first ten years), and then flips ownership to the local investor thereafter (i.e., the "flip" structure listed at the beginning of this chapter).

Other ownership structures designed to capture the PTC (or REPI) are also possible. For example, the Wisconsin business plan suggests a hybrid of the two approaches used in Minnesota – i.e., an LLC comprised of *multiple* local investors and a tax-motivated corporate investor. Massachusetts, meanwhile, envisions municipal-owned community wind projects that will either sell power to third parties (and thereby earn the REPI, if available) or offset on-site

[47] In fact, as noted earlier in Section 2.2, 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). For information on the barriers to cooperative ownership of a community wind project, see Section 6.1.2.

power consumption (in which case the project will potentially be offsetting the full retail rate, which might compensate for the lack of a REPI).[48]

Additional ownership structures are not as dependent on the PTC or REPI. For example, on-site projects do not receive the PTC or REPI for power produced and consumed on site, but may compensate for this shortfall by earning a higher price (i.e., the retail rate) for most or all of the power that is produced (provided that standby charges do not apply). Similarly, in what is known as *aggregate net metering*, a group of individual utility customers pool their capital to install a centrally located (i.e., *not* on-site) utility-scale wind turbine and – with the utility's cooperation – apply their share of the project's output against their on-site electricity consumption, thereby potentially earning the value of the full retail rate (but not the PTC or REPI).[49]

Furthermore, if other state and federal incentives are sufficient, even the multiple local owner model described above, which was set up with the intent of capturing the PTC, ultimately may not be dependent on the PTC for success. For example, the first two Minwind projects in Minnesota, which are currently the only working examples of the multiple local owner model in the US (see Section 3.1.1 and footnote 24 for more information on Minwind), have not been efficient at utilizing federal tax benefits in the year they accrue (though Minwind investors may eventually come out whole – less the time value of money – by rolling any unused tax credits forward).[50] In some cases, other forms of passive income (against which to claim the PTC) have not materialize as expected, while in other cases investors willingly invested knowing that they would likely never be able to use the credits. In light of this general tax inefficiency, as well as the availability of valuable (and time-sensitive) state production incentives and USDA grants, the next seven Minwind projects are proceeding with development despite the fact that the PTC expired at the end of 2003 and has not yet been re-authorized. In other words, while these projects could benefit from the PTC (and likely will, at least to some extent, if the PTC is re-authorized before they come on line), in the presence of other Minnesota and federal incentives, they are not dependent on it. A similarly friendly state policy environment may exist in Oregon, where the state's Business Energy Tax Credit and Energy Loan Program may mitigate the importance of the federal PTC to community wind projects (Oregon's programs and tax credits will be described in more detail in Chapter 5).

To summarize, there are a fairly wide range of financial structures available to a community wind project, and figuring out which structure is most appropriate for a given situation, and

[48] One barrier that Massachusetts is currently grappling with is whether sales of renewable energy credits generated by municipal-owned wind projects will violate "private use" restrictions on the use of tax-free municipal debt. For more information, see Section 6.7.

[49] While the concept of aggregate net metering has been around for some time, to date there are only two very limited examples of it in the United States, in part because utilities are not required to offer such services. Thus, this is one ownership model that would likely require legislative or regulatory policy intervention.

[50] If the PTC can not be fully used in the year it is earned, any unused balance can be carried back 1 year (requiring the taxpayer to file an amended tax return for the previous year) and, if still not fully used, carried forward 20 years (though carrying the credit forward diminishes its value, due to the time value of money). Any unused balance that remains at the end of year 20 can be taken as a deduction in year 21 (further diminishing the value of the credit, as a deduction is generally worth less than a credit). Thus, while the tax code allows for considerable flexibility in using the PTC, it is economically preferable to utilize the credit in the year it accrues.

apply it, can result in high transaction costs. For example, the first two Minwind projects (totaling 3.8 MW) reportedly spent $198,000 investigating ownership structures and ultimately forming an LLC (Arends 2002).[51] The good news is that much work has already been done in this area, particularly in Minnesota, where a number of viable community wind ownership structures are now being demonstrated and documented. To the extent that the finer details of some of these models are somewhat dependent on Minnesota's unique policy environment, however, choosing ownership structures suitable for Oregon may still require more thought, as well as legal expertise.

4.1.3 Financing the Project

Given the tax considerations discussed in Section 4.1.1, as well as the typically small size of community wind projects, attracting suitable equity and debt investment in a project is challenging.

Attracting Equity Investment

Presuming the local project sponsor does not have the financial wherewithal to front the equity for the entire project, other equity partners will be needed.[52] These will either be other local investors (for the "multiple local owner" model) or a tax-motivated corporate equity investor (for the "flip" structure), depending on the ownership structure being pursued and the appetite for tax credits among the local equity investors. Finding either type of equity investor could present a challenge, though experience in Minnesota suggests that willing local equity participants abound. For example, the first two Minwind projects (totaling 3.8 MW) reportedly raised $1.1 million in equity from 66 local investors in just 12 days (Windustry 2002), while the next seven Minwind projects (totaling 11.55 MW) that are currently in development have reportedly raised more than $6 million in equity over the course of two meetings, and have had to turn away more than 75 interested investors. This popular appeal can in large part be attributed to the generous state policy incentives that have made community wind projects an attractive investment in Minnesota. Local visibility, enhanced by the existence of similar working projects in the area, is also no doubt a factor. Whether sufficient levels of interest exist, or can be developed, in Oregon may ultimately depend on the level of financial and policy support for such projects.

Furthermore, even strong interest among local investors may not translate into a viable project if none of those investors can make full use of federal tax incentives. If federal tax incentives are needed to make the economics of the project work, and the local equity has insufficient tax liability to efficiently utilize the credits, then a tax-motivated corporate equity partner will likely be needed (the "flip" structure).[53] In Southwestern Minnesota, community wind projects have partnered with a number of large corporate entities, and by now there is enough of a track record and network of relationships that corporate equity partners may not be too difficult to find. Again, finding similar equity partners for community wind projects in Oregon may be more

[51] This total reportedly includes some development expenses as well.

[52] Note that this is not always the case; several wind projects interconnected behind the meter at Iowa schools have been financed entirely by debt, while a number of projects in Minnesota have been funded entirely by one local equity participant.

[53] As noted earlier, this may not be the case in Minnesota, where an attractive state production incentive and USDA grants are apparently sufficient to stimulate the next seven Minwind projects. The same may be true in Oregon, where the BETC and tax-exempt Energy Loan Program financing provides nearly equal value as the PTC.

difficult, at least initially. However, the pass-through option on the state's Business Energy Tax Credit (BETC) – which pairs qualifying energy project sponsors not able to take the BETC with corporate partners who are willing to pay a discounted lump sum payment in exchange for the stream of tax credits – likely has familiarized Oregon corporations with the concept. Furthermore, with the pass-through option on the BETC, the corporate equity partner need not be based in Oregon; the same corporations investing in Minnesota wind projects could also invest in Oregon projects and receive the BETC as a pass-through payment.

Securing Debt

Leveraging the equity investment with lower cost debt capital can also present a challenge for community wind projects, which typically fall below the size range considered by the major wind project lenders. Due to their limited needs, however, community wind projects may be able to work with local banks, which may not be as familiar with wind power as some of the more-seasoned larger lenders, yet may have a pre-existing banking relationship with the wind project sponsors. This is the case in Southwestern Minnesota, where at least one local bank has financed a number of small community-owned wind projects under reasonable terms that include: a 30% minimum equity requirement, variable or fixed rates, 10-year amortization with quarterly payments, a minimum debt reserve fund equal to one quarter's debt payment, a loan origin fee of 1%, and a required debt service coverage ratio of just 1.25 (Eichacker 2002).

In Oregon, however, a ready and potentially attractive alternative to bank debt exists: Oregon's Energy Loan Program, which is unique in its ability to finance commercial-scale renewable energy projects through the sale of either tax-exempt or taxable bonds. While loans financed by tax-exempt bond sales will likely trigger the anti-double-dipping provisions in the federal PTC, loans financed by taxable bonds may not, presuming they are offered at terms similar to what is obtainable in the private market (though we note that this issue has not yet been resolved). The terms of the Energy Loan Program are favorable: a minimum annual average debt service coverage ratio of just 1.25 (with the PTC counted as revenue for DSCR purposes), combined with a 6-month debt reserve fund. Despite these favorable terms, so far only one utility-scale wind project (notably, a planned community wind "flip" project) in Oregon has sought – and recently been approved for – debt financing from the program.[54]

4.1.4 Potentially Poor Economies of Scale

Large wind projects potentially have a cost advantage over smaller wind projects in that large projects may be able to purchase components in bulk, spread installation and balance of system costs, as well as legal, permitting, and financing transactions costs, over a greater number of kWh, and more efficiently operate and maintain the project. On the other hand, smaller projects may be able to cut corners in the development process by, for example, making use of existing physical infrastructure such as substations and access roads. While the ability of large wind projects to reap economies of scale relative to small projects is therefore project-specific and, in

[54] Columbia Energy Partners, developers of the planned 4.95 MW Mar-Lu wind farm near Arlington, Oregon announced on April 12, 2004 that they had received a letter of commitment from the Energy Loan Program for $2.75 million in debt financing (see http://www.columbiaep.com/news7.htm). This project is organized as a "flip" structure designed to capture the PTC; as such, Columbia opted for the taxable, rather than tax-exempt, debt financing (to avoid triggering the PTC's anti-double-dipping provisions).

the experience of several of the authors of this report, may not be universally applicable (at least over a moderate range of project sizes), if true, cost disadvantages among small projects could be a significant barrier to small community wind power development in the Northwest, where opportunities (and plans) for large projects abound.[55] This section begins by presenting general estimates of the impact of project size from the literature on this topic, and then proceeds to qualify those literature estimates based on the actual project development experience of several of the authors in Minnesota and Iowa.

Table 3 presents data compiled by the U.S. Department of Energy (DOE) and Electric Power Research Institute (EPRI) in 1997 (US DOE and EPRI 1997). Though a bit dated, these data have been thoroughly vetted with the US wind power industry, and should therefore provide a credible estimate of project size effects in the US at that time. As shown, DOE/EPRI estimates that a 10 MW project would cost about 20% more than a 50 MW project, and 33% more than a 200 MW project (i.e., the differential is nonlinear).

Table 3. Estimated Impact of Project Size on Project Cost

Plant Size (MW)	% of 50 MW Cost
10	120
25	110
50	100
100	95
200	90

Source: US DOE and EPRI (1997)

More recently, the American Wind Energy Association (AWEA) published similar, though even more aggressive, figures. According to AWEA (2002), a 3 MW wind project will produce a levelized cost of energy that is nearly 40% higher than an otherwise identical 51 MW wind project (AWEA 2002).[56] Lower transaction costs per kWh and greater O&M efficiencies (but *not* vendor discounts on high-volume orders) are cited as reasons for the differential.

Multiple regression analysis conducted by Lawrence Berkeley National Laboratory (LBNL) on the impact of project size, capacity factor, contract term, and completion date on the levelized cost of wind energy implies a more modest size effect. With a sample of 28 recent US wind projects totaling nearly 2,100 MW of installed capacity, the impact of project size on levelized costs is statistically significant at the 90th percentile, and the multiple regression equation estimates that a 9 MW wind project will produce levelized costs that are about 6% higher than an

[55] While community wind projects need not necessarily be small, we assume for the purposes of this section that most community wind projects will be in the range of several megawatts, which is well below the size of existing and planned commercial wind projects in Oregon.
[56] Specifically, while the 3 MW project produces power at 5.9¢/kWh, the 51 MW project produces power at 3.6¢/kWh (both including the PTC). Though AWEA (2002) does not state its source, we believe this cost information may pertain to *hypothetical* wind projects (and as such should perhaps be discounted relative to some of the numbers presented in this section resulting from actual experience) located in Pennsylvania, a state that did not have a strong wind power development and support infrastructure in place at the time these estimates were generated.

otherwise identical 50 MW project, and roughly 36% higher than an otherwise identical 200 MW project (Wiser 2003).

A pro forma modeling study prepared by a wind power developer for the National Renewable Energy Laboratory (NREL) estimates that a 10 MW project produces a 38% higher levelized cost of energy than a 50 MW project, but that a 2 MW project *can be competitive* with a 10 MW project if development is managed well (Rackstraw 2001). In other words, the impact of size on levelized cost is not necessarily linear, and furthermore, size is not the sole determinant of cost, even in otherwise physically identical projects.

A report from Cohen and Wind (2001) builds on this notion that size may not be the sole driver of cost differentials between otherwise similar projects. As shown in Table 4, data from that report depict a typical size impact in the US – i.e., small projects being 15%-30% more expensive than large projects – but a *much lower* size effect in Germany, where small projects are only about 4% more expensive than large projects. Furthermore, while the report contains insufficient data to make a small versus large project comparison in Denmark, small projects in Denmark are shown to be roughly *the same cost* as large projects in the US. These comparisons imply that the impact of project size on costs is highly dependent on institutional context. That is, project size has much more limited effects in Denmark and Germany – where an extensive network of wind turbine installation and support services is available – than in the United States, where such infrastructure is largely lacking (Cohen and Wind 2001).

Table 4. Estimated Capital Cost Ranges for Small and Large Wind Projects

Country	Small Projects ($/kW)	Large Projects ($/kW)
USA	1,110-1,400	950-1,050
Denmark	950-1,050	insufficient data
Germany	1,200-1,300	1,150-1,250

Source: Cohen and Wind (2001)

Geography and topography are also important. If the project is remote from any other wind farms using the same manufacturer's wind turbine, then there may not be any nearby technicians trained to provide scheduled maintenance and warranty services to the project. Therefore the manufacturer will have to schedule in technicians from a distant location to provide maintenance and warranty services. This adds to the cost of the maintenance and increases the length of any forced outages, which ultimately reduces the amount of energy generated by the project.

Because Germany and Denmark are both relatively small countries (Germany's land area being slightly larger than Oregon's, while Denmark's is much smaller) with a high concentration of wind turbines, no wind project is ever too far removed from the network of wind construction and O&M workers. Furthermore, due to relatively benign and consistent topography throughout all of Denmark and the windiest areas of Germany, project sites tend to be easily accessible and characterized by relatively uniform conditions, reducing the need for specialized site preparation. These physical features, along with the strong infrastructure of wind turbine installation and support services mentioned above, contribute to the tight spread of project costs in both countries, as shown in Table 4.

Actual project experience from Minnesota and, to a lesser extent, Iowa bears out the notion that geography, topography, and a strong local wind project construction and service infrastructure can help keep community wind costs low. The presence of both large and small wind projects in southwestern Minnesota (a relatively small land area characterized by flat farmland) has led to the emergence of a network of local contractors and developers skilled in constructing, operating, and maintaining wind projects. As in Europe, this network has helped to reduce the cost differential between small and large projects, to the point where some single- or two-turbine projects are now being constructed for less than $1,000/kW.[57] Were this infrastructure not in place, costs would likely be at least $100/kW higher, and likely even more if the turbine vendor were to construct the project on a turnkey basis. The existence of what is effectively a feed-in tariff for small projects in Minnesota (i.e., Xcel's small wind tariff in combination with a standardized power purchase agreement) is also a contributor in keeping costs competitive, as it reduces the transaction costs of searching for and negotiating with a power purchaser.

Oregon comprises a much larger land area than either southwestern Minnesota or Denmark, and features more complex and challenging terrain. That said, the presence of a number of large wind projects in Oregon and Washington – many of them located close to the Columbia River Gorge – suggests that a regional wind project construction and service infrastructure does exist.[58] Whether that infrastructure can be effectively mobilized for the purposes of supporting small community wind projects remains to be seen. Presuming it can, experience in Minnesota and Iowa suggests that any cost differential between small and large projects should decline over time as the industry gains more experience in constructing and servicing small projects.

In Chapter 5, we develop cost inputs to a financial cash flow model for both a 1.5 MW and 10.5 MW project located in Oregon. The numbers we arrive at estimate the 1.5 MW project to be about 8% more expensive than the 10.5 MW project.

4.2 Regulatory Barriers

Community wind projects face a number of regulatory barriers as they attempt to raise capital, interconnect to the grid, and sell power. Some of these barriers are surmountable, but at a cost. Given the small size of these projects, transaction costs imposed through regulatory barriers can be particularly damaging to the economics of a community wind project.

4.2.1 Securities Regulation

At least one of the ownership structures discussed in Section 4.1.2 – the *multiple local owner* model – involves selling equity "shares" in a community wind project to local investors. Equity shares in a community wind project that are offered to the public, however, will most likely be

[57] In particular, one of the authors of this report has developed several 1.5 MW wind projects in Minnesota for less than $900/kW installed, and more recently a number of 1.9 MW projects for just over $900/kW.
[58] As will be noted in Section 5.2.2, however, it appears as if the nearest crane large enough to stack a modern utility-scale wind turbine is based 1,000 miles away from the mid-Columbia gorge area, suggesting that at least one key element of a wind turbine industry infrastructure is not yet in place.

considered "securities" under both federal and state securities law.[59] 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,[60] they pale in comparison to the cost of legal assistance that is typically required to fulfill the registration obligation, which has been estimated by one law firm to be "…in the tens of thousands of dollars or more for a low seven figure offering" (Chretien and Wobus 2003), and by a founder of the Minwind projects to range between $300,000 and $600,000 (Arends 2004).[61] 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.

Below we briefly discuss the most relevant federal exemptions, followed by potential state exemptions for which a community wind project might qualify in Oregon. While the information below has been drawn from existing state and federal statutes as well as general second-hand legal counsel (Cooperative Development Services 2003, Chretien and Wobus 2003), we emphasize that the information in this section is general in nature and should not be construed as legal advice. Those undertaking a community wind project are strongly advised to seek legal counsel (alternatively, the Energy Trust of Oregon may wish to retain a lawyer knowledgeable in securities law to draft a more detailed general opinion on this issue).

Federal Exemptions

There are a number of exemptions from registration for which a community wind project might qualify at the federal level. Perhaps the most straightforward of these exempts *intrastate offerings*, which apply when the business offering the securities is incorporated in the same state

[59] As defined in the Securities Act of 1933, a "security" is "…any note, stock, treasury stock, security future, bond, debenture, evidence of indebtedness, certificate of interest or participation in any profit-sharing agreement, collateral-trust certificate, preorganization certificate or subscription, transferable share, investment contract, voting-trust certificate, certificate of deposit for a security, fractional undivided interest in oil, gas, or other mineral rights, any put, call, straddle, option, or privilege on any security, certificate of deposit, or group or index of securities (including any interest therein or based on the value thereof), or any put, call, straddle, option, or privilege entered into on a national securities exchange relating to foreign currency, or, in general, any interest or instrument commonly known as a "security", or any certificate of interest or participation in, temporary or interim certificate for, receipt for, guarantee of, or warrant or right to subscribe to or purchase, any of the foregoing."

[60] For example, Oregon fees max out at $500, per ORS 59.065.

[61] Note that Minwind I and II did not incur such expenses, as each project qualified for an exemption from registration at both the federal and state levels. Even so, each project estimates (as portrayed on Securities and Exchange Commission Form D, which each project filled out in claiming a Regulation D exemption) that it spent $20,000 in legal fees "in connection with the issuance and distribution of the securities in this offering" and excluding organizational expenses. This suggests that even claiming an exemption from registration can be relatively costly.

where the securities are being offered, will carry out a significant portion of its business there, and will only offer or sell securities to residents of that state. Residents cannot re-sell their securities to non-residents for a full year. So, it appears as if an LLC (or other form of business) incorporated in Oregon and offering shares in a community wind project only to Oregon residents would be exempt from registering such securities with the SEC.

Other federal exemptions hinge on the amount and manner of the offering, as well as the number and type of offerees. For example, Section 4(2) exempts "transactions by an issuer not involving any public offering." The requirements for a Section 4(2) nonpublic offering (i.e., private placement) are unclear, but have evolved through SEC case law to apply to "sophisticated" investors who do not need the protection of the Securities Act of 1933, and who agree not to re-sell the securities to the general public (Chretien and Wobus 2003). Rule 504 under Regulation D exempts offers and sales of up to $1 million worth of securities in any 12-month period to an unlimited number of accredited or non-accredited investors. Meanwhile, Rule 505 under Regulation D exempts offers and sales of up to $5 million worth of securities in any 12-month period to an unlimited number of "accredited" investors, and up to 35 additional non-accredited investors.[62] Finally, Rule 506 exempts the sale of an *unlimited* dollar amount of securities to an unlimited number of accredited investors, and up to 35 additional non-accredited, but "sophisticated", investors. In all three cases (Rules 504, 505, and 506), the offering of securities must be private, and cannot be advertised through solicitations, advertisements, articles, or seminars. In addition, purchasers cannot freely re-sell securities sold under a Regulation D exemption.

Though a legal opinion should be sought, it seems likely that a company established for the purposes of developing and owning a community wind project in Oregon could reasonably qualify for one of the federal exemptions described above.

Oregon Exemptions

State exemptions are likely to be more challenging to obtain. That said, Oregon Securities Law (Oregon Revised Statutes, Chapter 59) does exempt certain securities, as well as certain transactions involving securities, from registration.

Of the many exempt *securities* described under ORS 59.025, most are unlikely to be relevant in the vast majority of instances.[63] Several of the exempt *transactions* defined in ORS 59.035, however, appear to be at least more relevant, if not more promising. For example, any securities

[62] Section 2(a)(15)(ii) of the Securities Act of 1933 defines an accredited investor as "any person who, on the basis of such factors as financial sophistication, net worth, knowledge, and experience in financial matters, or amount of assets under management qualifies as an accredited investor under rules and regulations which the Commission shall prescribe." Rule 215 modifies and expands upon this definition, to include (among other things) individuals or couples with net worth in excess of $1,000,000, as well as individuals with income in excess of $200,000 (or $300,000, including spousal income) in the past two years (with reasonable expectation of reaching the same income level in the current year). While these income limits are not entirely prohibitive, they are restrictive, and increase the likelihood that some form of registration will be necessary.

[63] Those that are *potentially* relevant, but that do not look particularly promising, include those in which both the issuer and issuance is under the supervision, regulation, or control of the Oregon Public Utilities Commission; those issued by an agricultural cooperative corporation to evidence interest in patronage dividends; and federal "covered" securities, which (among other things) include securities sold to "qualified" purchasers, as ruled by the SEC in response to specific circumstances.

transaction with an accredited investor (defined under Section 2 (15) of the Securities Act of 1933; see footnote 52) is exempt from registration, provided there is no public advertising or general solicitation in connection with the transaction. Furthermore, an offering that results in purchases by no more than 10 non-accredited investors during any twelve consecutive months is also exempt, again provided that the offering is not advertised. Combining these two, a private offering to an unlimited number of accredited investors, and up to 10 non-accredited investors within any 12-month period, would appear to be exempt from Oregon securities registration (assuming that the offering is not advertised). Again, however, this layman's interpretation of Oregon Securities Law should in no way be construed as a legal opinion, and anyone contemplating such an offering should seek qualified legal counsel.

These regulations and restrictions have obvious implications for the type of ownership structure chosen, and could be one reason why to date the only community wind projects for which securities law has been relevant are the *Minwind* projects in Minnesota. At the federal level, both Minwind I and II claimed a Regulation D exemption under Rule 504 (i.e., private offering of $1 million or less to any type of investor). At the state level, both Minwind I and II qualified for the "private placement exemption" (Minnesota Statute 80A.15 Subdivision 2(a)(2)), which allows for the sale of unregistered securities to up to 25 non-accredited investors and an unlimited number of accredited investors, provided the sale is not advertised.[64] Since most of the investors in the original Minwind projects were members of a local ethanol cooperative, news of the projects spread by word of mouth, precluding the need to publicly advertise the sale.

Of course, failing to qualify for an exemption is not necessarily a project killer, but rather simply means that the project will likely incur additional legal expenses. Whether or not those additional expenses are prohibitive, or outweigh any benefits of offering shares to a wide range of investors, must be determined on a case-by-case basis. Furthermore, there may be ways to minimize the cost of registration by spreading it over more project capacity, for example by offering shares in multiple projects, or in a project company who will subsequently invest in specific wind projects.

4.2.2 Utility Rate Structures

The economic viability of an on-site, behind-the-meter community wind project will depend in large part on the types of tariffs offered by the customer's electricity supplier. Unlike in Iowa, where this type of development has flourished under favorable policies and utility rate structures, Oregon tariffs and rate structures do not currently favor behind-the-meter utility-scale wind development.

Net Metering

Oregon imposes a 25 kW limit on the nameplate capacity of any net-metered generator. This limit falls below our minimum size threshold for community wind projects, and therefore means that in order for a behind-the-meter community wind project to consistently earn the retail rate for its power output, it must be offsetting on-site electricity consumption most of the time it is generating electricity. Given the ever-increasing size of utility-scale wind turbines, this is no

[64] According to each project's SEC Form D, there are 21 and 19 non-accredited investors in Minwind I and II, respectively, and 11 and 17 accredited investors.

small feat, and would require a project sponsor that consumes a very large amount of electricity (not to mention having a load profile that generally matches the wind production profile).

Rate Structure
For a behind-the-meter wind project to be cost effective, the savings in the electric power bill must be enough to cover the cost of the project. The savings in the power bill depends in large part upon the structure of the customer's particular electric rate schedule. Residential electricity consumers are typically served by *single-part* tariffs that include only an energy (i.e., $ per kWh) charge (plus perhaps a small monthly service fee). Larger electricity consumers (such as commercial and industrial customers), however, typically face multi-part tariffs that include not only an energy charge, but also a demand (i.e., $ per maximum measured kW) charge.

Unless diurnal and seasonal wind profiles closely match the customer's load profile (i.e., unless the wind power consistently reduces not only the customer's energy consumption, but also maximum or billing demand[65]), multi-part tariffs will reduce the financial benefits of behind-the-meter wind projects. For example, if a wind project does not reduce the owner's peak demand and if the demand charges are half of the owner's power bill, then the wind turbine savings per kWh will be half of the retail electric rate. Furthermore, without net metering, perhaps only a fraction of the wind project's generation may be coincident with the electricity needs of the owner. The remainder of the wind project's energy may have to be sold at a much lower avoided cost rate to the utility.

Not only is a tight match between production and load unlikely to occur in most cases, even if it did exist, *standby charges* (i.e., charges based on any shortfall of actual demand below contractual demand – see next section) might then apply. For these reasons, a variable generator such as a wind turbine will fare best in a behind-the-meter application under a single-part tariff based solely on energy consumption (and not demand). Most commercial and industrial customers (i.e., those potentially sizable enough to absorb the full output of a modern utility-scale wind turbine – see previous section) in Oregon, however, are served under a two-part tariff that includes both energy and demand charges.

Standby Charges
Customers that generate some or all of their own power needs outside of the protection of net metering regulations are often subject to what is known as a "standby charge." A standby charge is intended to compensate the electricity provider for continually "standing by" ready to serve such customers in the event that on-site demand for power exceeds the on-site supply of power. In other words, standby charges allow the utility to recover its fixed costs (e.g., transmission and distribution costs, reserve costs) of standing ready to serve self-generating customers.

Both Pacificorp and PGE assess standby charges under their "partial requirements" tariffs (i.e., those tariffs applicable to self-generating customers who only require "partial" service from the utility).[66] Pacificorp's standby charge, for example, is calculated by multiplying 50% of the

[65] Based on the experience of one of the authors, monthly peak demand reductions can vary from 0% to 60% of the nameplate rating of a 600-750 kW wind turbine, depending upon various factors.
[66] Pacificorp's Oregon Schedule 36, "Partial Requirements Service, Less Than 1,000 kW Delivery Service" (www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule2124.pdf), and Oregon Schedule 47,

applicable *demand* charge by the number of kW by which the customer's *actual* highest 15-minute demand (net of any self generation) over the course of the month falls below the *contractually stated* demand expectations. In other words, a customer with a behind-the-meter community wind turbine will pay both a *demand charge* based on the maximum amount of power it buys from Pacificorp each month, and a *standby charge* (i.e., equal to half the demand charge) based on the amount by which that maximum demand falls below expected demand.

Whereas demand charges erode the value of behind-the-meter wind turbines if the wind production profile *does not* closely match the customer's load profile, standby charges work exactly in reverse, reducing the value of on-site generation if the wind production profile *does* closely match the customer's load profile. Since the standby charge is only half as large as the demand charge on a per kW basis, however, a generator should still prefer to have production match load on net. This is particularly true given that, outside of a net-metering tariff, *energy* revenue will be highly dependent on production closely matching load, because any production during times of low load will likely earn only the utility's avoided cost rate.

4.3 Technical Barriers

There are two main technical areas that can be barriers to community wind power development: (1) the interconnection process, and (2) limitations on where wind turbines can be interconnected to the distribution system. Depending upon the situation, these factors can increase total project costs, increase operating costs, or reduce energy generation, all of which will increase the delivered cost of energy from the project. These technical barriers are discussed below.

4.3.1 The Interconnection Process

Large wind farms typically have dedicated collection circuits and substations that are connected to the high voltage transmission system. The design of these facilities and the interconnection process are very technical and sometimes lengthy endeavors involving numerous engineers, technicians, studies, and reports that can potentially cost several hundred thousand dollars. When such costs are spread over a large wind farm, they are fairly modest. However, if the interconnection process is not proportionately reduced in scale and complexity for a smaller community wind power development, the cost on a per unit basis can be higher than for a large wind farm. Community wind power developments sized from one to a few wind turbines are often connected to the existing distribution system serving the area around the wind turbine site. The process for interconnecting such projects should, in theory, be proportionately simpler and less costly; however, it may not be. The key factor here is whether the transmission service provider or local utility treats the community wind power development just like any other larger generator in the interconnection and transmission service application and approval process. If so, then the community wind power project must pay the same fees and have the same technical studies as those performed for a larger generator.

"Large General Service/Partial Requirements Service – 1,000 kW and Over Delivery Service" (www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule2126.pdf), are likely to be the most applicable tariffs for on-site, utility-scale wind turbines.

In some areas, there is a size or impact threshold for small generators that triggers a simpler, streamlined interconnection and transmission service approval process with waivers for more technical analysis and certain other requirements. For example, the transmission service impact on the grid of wind projects less than 1 MW might not be scrutinized to the same level as larger projects. If there is a transmission bottleneck in the area that is preventing other generators from obtaining transmission service, a small wind turbine might still be allowed to interconnect and operate, simply because of its proportionately smaller impact on the transmission grid and bottleneck. However, if the wind project has over 1 MW of capacity, then it may trigger the same interconnection process as a 500 MW generator. The studies required should still be simpler and less costly, but not 500 times less costly. Another example of a test or threshold that determines how involved interconnection studies will need to be is if the local substation to which the wind project is connected ever exports power to the higher voltage system. If the distribution substation always takes power from the grid regardless of the local load and the wind project output, then the local substation still appears as a load to the grid. However, if the local substation occasionally exports power to the grid, then it appears to be a generator for the grid, which would trigger a more comprehensive interconnection process.

The final destination of the power from a community wind power development may also affect the complexity of the interconnection and approval process. For example, if the power will be purchased by the local utility, then it will likely be considered a network resource for the utility and blended in with the utility's other resources. The local utility may not bother with scheduling the wind power from a small project and simply accept its variable output as part of the variable load. However, if the power is sold by the community wind project to a utility in another control area, then it must be scheduled through the first utility on to the next utility. This arrangement adds complexity to the interconnection and transmission service process as well as to the operations, all of which result in higher costs. Furthermore, if transmission pathways between the project and an interested power purchaser are regularly congested, then the prospect of regular curtailment could limit the ultimate size of the project, or alternatively lead to abandonment altogether. For all of these reasons, *it is always less expensive to develop a project where the power is used locally or sold to the local utility*.

Unless the local utility or area's transmission service provider has a provision for simplifying the interconnection process for smaller generators, such as those less than 10 MW, then small community wind power projects will have higher interconnection process costs per unit of power than larger generators.

4.3.2 Limitations on Interconnecting Wind Turbines to the Distribution System

Small community wind power developments with less than 3 to 5 MW are often connected to the local distribution system rather than the higher voltage transmission system. Connection to the local distribution system is much less expensive than installing a new substation connected to the local area higher voltage transmission system. For example, a new 5 MW 69 kV substation will likely cost between $300,000 and $750,000, depending upon its design. This cost would be paid by the community wind power project. However, if the local distribution system is strong enough, the wind turbines could be connected directly to it at a cost of $15,000 to $100,000.

Clearly, direct interconnection to the local distribution system can save a considerable amount of money compared to a transmission interconnection.

Although interconnecting to the local distribution system can save money, it is not always possible or practical, depending upon several factors. The table below indicates circumstances under which an interconnection to the local distribution system would be possible:

Table 5. Factors Affecting the Ability to Interconnect to the Distribution System

Factor	Consideration
Ownership	To avoid wheeling fees that would make the project uneconomical, the distribution system should be owned by the purchaser of the wind power.
Availability of 3-Phase Lines	All large wind turbines require a full 3-phase line. There are many rural areas that only have 1-phase lines, rather than 3-phase lines. For example, in Iowa, only about 1/3 of the rural areas are within ½ mile from a 3-phase line.
Strength of 3-Phase Distribution System at Interconnection Point	If the wind turbine site is too far away from the substation, then the distribution system may be too weak, in which case wind turbines will adversely affect power quality by causing high voltage levels or voltage flicker to a degree that is unacceptable to nearby electric customers. In general, the distribution system needs a short-circuit capability of about 10 or more times the rating of one wind turbine at the point of interconnection. For example a 1500 kW wind turbine could typically be connected at a point up to 3 line miles from a 3,000-kVA substation on a 4/0 conductor 12.47 kV feeder. If the site is farther than this from the substation, then a dedicated extension might be needed to connect back to the feeder. Larger substation transformers, larger conductors, or higher distribution system voltages increase the allowable interconnection point distance from the substation.
Experience of Utility	If a utility has little or no experience with interconnecting such systems, it may not allow interconnections which would otherwise be acceptable.

Utilities serving rural areas often have little or no experience with interconnecting large wind turbines to their distribution systems. This lack of experience often results in an extra measure of conservatism in what the utility will allow because the utility does not want to take any chances with causing power quality problems for nearby customers. For example, there have been a couple of installations on rural electric distribution systems in the Midwest where power quality problems occurred because the rural utility did not understand and evaluate the power quality impacts ahead of time.

Furthermore, an Electric Power Research Institute (EPRI) study on distributed generation (DG) recommended that the DG (e.g., utility-scale wind turbine) penetration rate on a distribution feeder be limited to 15% of the feeder's load, in order to prevent reverse flow of power to the transmission system. Of course, given the size of today's wind turbines, a single large wind turbine on a rural feeder will usually exceed this 15% guideline.[67] With war stories and recommendations like this circulating through the rural electric industry, rural utility managers often take a very conservative stance in allowing large wind turbines to interconnect to their

[67] This 15% guideline is not relevant for large wind turbines interconnected to the transmission system and generating bulk power for the system as a whole.

distribution systems. When utility managers better understand the power quality impacts ahead of time, and the conservatism (for most wind projects) behind EPRI's 15% penetration recommendation, they will allow a wider range of interconnection points to their distribution system.

The type and cost of electrical interconnection equipment required by utilities for connection to the distribution system varies depending upon the experience of the utility. The least expensive interconnections use three single-phase fused disconnects and a primary metering system which might – at least in the Midwestern United States – cost $10,000 to $20,000.[68] The fused disconnects provide the utility with a means to manually disconnect the wind turbine from the distribution system if necessary. The sophisticated controller in the wind turbine is designed to trip the wind turbine off line for any electrical disturbance on the utility's distribution system. A few utilities might require a separate primary voltage circuit breaker that also disconnects the wind turbine for disturbances on the utility's system. This extra circuit breaker is largely redundant and might add $20,000 to $30,000 to the interconnection cost. Other utilities might require a Supervisory Control and Data Acquisition System (SCADA) to the interconnection with a real time communication system providing wind power generation level data back to the utility's control center. Such equipment might add another $25,000 to $75,000 to the interconnection cost plus on-going dedicated telephone line or radio costs for the real time data link. Depending upon the particular utility and their requirements, the interconnection cost to the distribution system might vary from $15,000 to $100,000 for the interconnection equipment. This does not include any 3-phase line extensions that might be needed to reach the wind turbine site.

Issues Pertaining to On-Site Projects

Some high electricity usage customers have considered the economics of adding a large wind turbine on site to provide part of their energy needs. In such cases, the wind turbine will usually be connected to the load side of the utility's meter so that the wind generation can first be used by the customer to displace energy normally purchased from the utility. Interconnecting to the customer's side of the meter, however, may require some additional expense to reconfigure the customer's metering or to reconnect lines.

For example, many large electric customers, such as schools, colleges, or businesses have several electric service metering points where they take power from the utility to serve various buildings and facilities. In such cases, the utility typically owns all of the primary voltage (typically 12.47 kV) overhead and underground lines, the transformers, and the meters. If the customer wants to add a large wind turbine, it must be connected to the primary voltage system because of its large size and voltage impact. Connection to the primary voltage system, however, would be on the utility side of the meter, which is the wrong side of the meter to net out the wind generation and customer usage. Furthermore, with several different metering locations, the wind turbine could not be connected at any single point to provide electric power to all buildings.

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[68] All interconnection costs and issues discussed in this section are based upon one of the authors' experience interconnecting wind projects in the Midwestern United States. These costs – and perhaps even some of the issues – may not be directly relevant to Oregon.

To enable this large electric customer to install a wind turbine and connect it behind the meter, the customer would have to purchase some of the electrical facilities from the utility so that the wind turbine could be connected to the primary voltage *and* behind the meter. Specifically, the customer would need to purchase the underground primary cables and transformers from the utility, and replace the multiple old metering points on the secondary voltage with one new meter on the primary distribution voltage. The wind turbine would then be connected to the primary voltage at one of the transformers. Any power generated by the wind turbine would now be used first by the multiple buildings, with any excess power going backwards through the new primary metering system. Although the customer must purchase the underground cables and transformers, there should be a small discount in the power rates to account for the reduced investment by the utility. Of course, for this reconfiguration of electric service to be made, the utility must be willing to sell its facilities.

4.4 Market Barriers

In addition to the financial, regulatory, and technical barriers discussed earlier that might impede a community wind project, several market-oriented barriers also exist. For example, a landowner may have already sold or leased the rights to wind on his property, and therefore may be prohibited from developing any type of utility-scale wind project on his land. Even if he retains his wind rights, the landowner might be located in the service territory of a rural electric cooperative that has no appetite for wind power due to a pre-existing "all-requirements" contract. Alternatively, the landowner may be limited to pursuing certain development models, because others (in particular, a behind-the-meter project) may be not be suitable at that site. In this case, the landowner could incur high transaction costs in the search for a power purchase agreement. These barriers in producing and delivering a product to market are discussed in more detail below.

4.4.1 Wind Easements Already Sold

In Southwestern Minnesota, many farmers living along the wind-rich Buffalo Ridge had reportedly sold their wind easements to either developers or Xcel Energy as early as 1997 (Schoenrich and Nadeau 1997) – i.e., several years before the first community wind project was developed in Minnesota. In order to develop their own wind power projects, such farmers would effectively need to buy back their wind rights, which, while possible, could also be expensive, given the value of the resource.[69]

Several wind project developers in the western US have implied that a similar situation may exist in the Pacific Northwest, where most of the best wind power sites are already under the control of commercial wind developers. In light of the Bonneville Power Administration's 2001 1,000 MW wind power solicitation (which drew 2,600 MW of responses), the Energy Trust of Oregon's 2002 solicitation to support up to 100 MW of wind power (which drew 500 MW of responses), Pacificorp's 2004 1,100 MW renewables solicitation (which generated nearly 5,000 MW of wind proposals, though not all from the Pacific Northwest), and more modest (though

[69] Notwithstanding the content of this paragraph, we note that restricted access to usable and unconstrained transmission is a much larger barrier to community wind power development on the Buffalo Ridge than is the sale of wind rights.

still sizable) solicitations from other Northwest utilities such as Portland General Electric and Puget Sound Energy, the fact that developers have already secured most sites suitable for large commercial wind projects (i.e., those that combine a good wind resource over large tracts of land with easy access to transmission) is not surprising.

While affirming this to generally be the case, however, one Oregon-based developer noted that the "Achilles heel" of large commercial wind projects in the West – i.e., the need for proximate access to high-voltage transmission – is not necessarily applicable to smaller community wind projects (Woodin 2004). In other words, while commercial wind developers have secured promising sites with access to high-voltage transmission, they have in many cases ignored similarly windy sites served by 69 or 34.5 kV distribution lines. Such sites can be perfectly suitable for small (several MW) community wind projects, meaning that commercial and community wind power development need not necessarily compete for prime sites.[70] Furthermore, much of the land currently considered to be in marginal wind resource areas could become economically viable with the next generation of lower wind speed turbines.

4.4.2 All-Requirements Contracts

Though not universally true, community wind projects have most often been located in rural areas. In the United States, electricity service to such areas is often provided by rural electric cooperatives (RECs). More often than not, rather than generating the power needed to serve their members, RECs simply purchase power from generation and transmission (G&T) cooperatives or federal power agencies, such as the Western Area Power Authority (WAPA) or the Bonneville Power Administration (BPA). These power purchases typically occur through what is known as an "all-requirements contract" – i.e., the power supplier agrees to meet all of the REC's requirements for sufficient and stable power over a lengthy contract period (by maintaining adequate reserves, as well as providing firming, shaping, and other ancillary services).

While all-requirements contracts provide a simple and low transaction cost method of meeting a rural community's electricity needs, such contracts typically limit a REC's rights to purchase power from other sources, or even to generate its own power. As a result, a REC with an all-requirements contract will likely not be in a position to purchase power from a community wind project.[71] Similarly, such a REC may discourage or prohibit on-site generation, which could otherwise reduce the REC's load below minimum contractual capacity or energy requirements.

[70] One instance where commercial and community wind siting interests have overlapped in Oregon involves the Summit Ridge Landowners Group. This group of 23 landowners owns 48,000 contiguous acres south of the Columbia River gorge, less than 20 miles west of the 24 MW Klondike wind project owned by PPM. Several of these and other landowners in the area have had commercial wind developers assess the wind resource on their land and request lease commitments, but no members of the Summit Ridge group have committed. Instead, the group is hoping to develop and own a 10 MW wind project, and has received an $85,900 Value Added Development Grant from the USDA towards a project feasibility study and business plan.

[71] Lamar Light & Power (LL&P) in Colorado was recently able to amend its all-requirements contract with the Arkansas River Power Authority (ARPA) to allow it to own three GE 1.5 MW wind turbines, sited near the 162 MW commercial wind facility in Lamar (Sparks 2004). It is perhaps worth noting, however, that ARPA itself owns an additional two wind turbines as part of that same development, and that LL&P will operate all five turbines (two on behalf of ARPA). It is unclear to what extent this operating arrangement factored into ARPA's willingness to renegotiate the LL&P all-requirements contract.

As a result, what would otherwise be the most obvious "offtaker" of, or market for, community wind power – i.e., the local electricity provider – may not be a viable option in many rural areas, potentially resulting in the need for the project to incur costly wheeling charges to transmit power to a more distant buyer.[72]

In fact, an Oregon community wind project located in the service territory of a REC will be *required* to transmit or exchange its power through BPA to either Pacific Power or Portland General Electric (PGE) in order to be eligible for financial support from the Energy Trust. This is because the Energy Trust is funded by customers of Pacific Power and PGE, and as such is limited to supporting projects that benefit those ratepayers. Thus, an on-site community wind project in REC territory will be unable to access Energy Trust funding – a barrier in and of itself.

In Oregon, eighteen RECs serve over 10% of Oregon's electricity consumers, in service territories that span roughly two-thirds of the state's land area, and most of the state's windy land area (see www.oreca.org/map.htm and www.windpowermaps.org/windmaps/states.asp#oregon).[73] Many of these RECs purchase power from BPA under all-requirements contracts. While the authors of this report are not privy to the terms of these contracts, we understand that there is concern among at least some RECs that if they allow their customers to self-generate, or if they pursue other power supply options (such as community wind), they may forfeit their right to future BPA allocations of the displaced amount of power.

On the other hand, the fact that community wind projects will have to sell their power to either Pacific Power or PGE in order to access Energy Trust incentives suggests that wheeling costs may be more of a barrier than the all-requirements contracts themselves (at least for projects seeking Energy Trust support). While this issue warrants further investigation, it is at least clear that cooperation with RECs and BPA is critical to ensure that community wind development occurs throughout the state, and that such projects are able to cost-effectively wheel or exchange power from a REC's territory to Pacific Power or PGE.

4.4.3 Lack of On-Site Opportunities

Net metering in Oregon is limited to generators of 25 kW or less in nameplate capacity. Thus, to be economically viable, an on-site community wind project in Oregon would require a host (customer) located in a suitably windy area that uses enough electricity to absorb (in real time) most or all of the output from a utility-scale wind turbine. This combination will likely be hard to find, as much of Oregon is sparsely inhabited, Oregon's wind resource is somewhat localized (as opposed to a state like Iowa, which has good wind resources throughout much of the state), most large electricity users will not be located in windy areas, and the size of utility-scale wind turbines keeps increasing. Furthermore, there is a good chance that any viable candidates will be

[72] It is not clear to the authors whether PURPA trumps a RECs *all-requirements* contract, effectively rendering it a *partial-requirements* contract in the presence of QF's exercising their PURPA rights. If so, then a community wind project located in a REC service territory may still be able to sell to the REC through a PURPA contract, even if that REC is bound by an *all-requirements* contract. Because it does not deliver its power to Pacific Power or PGE, however, such a project would be ineligible for financial support from the Energy Trust.

[73] The rest of Oregon's electricity consumers are served primarily by two investor-owned utilities – Portland General Electric (PGE) in the greater-Portland area, and Pacific Power (a subsidiary of Pacificorp) – as well as several municipal-owned utilities, such as Eugene Water & Electric Board.

located in a REC service territory, and will therefore be ineligible for support that may otherwise be available from the Energy Trust. These physical realities, along with the relatively unfavorable utility rate structures discussed in Section 4.2.2, limit the opportunities for on-site community wind projects in Oregon.

4.4.4 Identifying and Securing Potential Revenue Sources

Potential sources of revenue to community wind projects in Oregon include the sale of energy, tradable renewable certificates (TRCs), and potentially capacity, either to one or more unrelated parties, or perhaps (under some structures) to project owners. On-site, behind-the-meter projects, meanwhile, will earn 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.

Unlike in Minnesota, where Xcel Energy has in place a standard power purchase agreement and small wind tariff, there is no standard wind tariff among Oregon's utilities at this time, even though both Pacificorp and PGE have made significant commitments to future purchases of wind power through the integrated resource planning (IRP) process. In January 2004, however, the Oregon Public Utilities Commission (OPUC) opened an investigation into possible changes to the standard 5-year PURPA contracts.[74] Currently, Oregon requires PGE, Pacificorp, and Idaho Power to offer standard 5-year avoided cost contracts to QF's of 1 MW or less in size (QF's greater than 1 MW must negotiate terms with the utilities). Pacificorp's current standard avoided cost rate varies by on-peak and off-peak hours, averaging 4.22¢/kWh,[75] while PGE's rate varies both seasonally as well as by on-peak and off-peak periods, averaging 4.78¢/kWh annually.[76] While these avoided cost rates are more generous than in some states,[77] and are potentially sufficient to support a wind project in Oregon, the 5-year PURPA contract term is too short to support financing, and the 1 MW size limit is also prohibitive, particularly in light of the continuing evolution towards individual wind turbines sized in excess of 1 MW.

In its PURPA proceeding, the OPUC will consider whether to raise the size limit and extend the contract term, and if so how to calculate the avoided cost under these new terms. While, at the time of writing, no resolution has yet been reached, initially the utilities jointly proposed to raise the size limit to 5 MW, and to increase the contract term for new projects to 15 years. OPUC

[74] Under the federal Public Utilities Regulatory Policies Act (PURPA) of 1978, electric utilities throughout the US are required to purchase power from qualifying facilities (QF's) at a price equal to the utility's avoided costs. PURPA defines QF's as cogeneration facilities or renewable generators of 80 MW or less in nameplate capacity. Contract terms and conditions, as well as the methodology for calculating avoided costs, have in large part been left to the discretion of each individual state.
[75] See Pacificorp Oregon Schedule 5, "Partial Requirements Service 1,000 kW or Less," at www.pacificorp.com/Regulatory_Rule_Schedule/Regulatory_Rule_Schedule2113.pdf.
[76] See Portland General Electric Schedule 201, "Small Power Production," at www.portlandgeneral.com/about_pge/regulatory_affairs/pdfs/schedules/sched_201.pdf.
[77] In Montana, for example, one wind power developer facing the imminent expiration of the PTC at the end of 2003, and frustrated by the regulatory quagmire surrounding Montana Power's somewhat controversial 2001 wind power solicitation, tried to bypass the solicitation process altogether by proposing to sell power from a planned 50 MW wind project to the utility under what it thought might be a less-lucrative, though still workable, QF contract. The deal never came to fruition, however, as the Montana Public Service Commission ruled that the applicable avoided cost rate was just 1¢/kWh. In comparison, PGE and Pacificorp's avoided costs look quite attractive.

staff subsequently countered with an 8 MW size limit and 15-year term, and the parties are currently working out their differences.

Such changes could potentially – depending on how avoided costs are calculated – provide a shot in the arm to community wind projects in Oregon, and would also likely drive community wind project sizes towards the new cap (e.g., 5-8 MW). A 15-year contract should be sufficient to enable financing of community wind projects under several of the ownership structures discussed in this report. Chapter 6 provides some indication of the level of avoided costs that such projects would require in order to be viable.[78]

Until the PURPA contract issues are resolved sufficiently to support project financing, however, community wind projects structured to sell into the bulk power market will likely need to go through the expense and hassle of identifying and securing a power purchase agreement with one of the state's utilities. This process could result in significant transaction costs,[79] although the Energy Trust of Oregon (the Energy Trust) may be willing to assist and shepherd those projects that it funds through this process.

Community wind projects that receive financial support from the Energy Trust, however, will likely have only limited (if any) access to the project's TRCs. As a way of securing the benefits of renewable energy for the state's ratepayers, the Energy Trust has a policy of retaining TRCs in proportion to the amount of funding it provides relative to the project's *above-market* costs (e.g., if the Energy Trust pays for half of the *above-market* cost of a project, it will retain half of the TRCs from that project, even though half of the above-market cost might equal only 5% of *total* project costs).[80] Notwithstanding its potential merits, this policy will restrict the TRC revenue available to community wind projects. As explained further at the beginning of Chapter 6, because of the Energy Trust's position on TRCs, our analysis does not take into account their potential value to a community wind project. Instead, we leave the treatment of TRCs as an incentive design issue to be worked out by the Energy Trust and selected projects on a case-by-case basis.

4.5 Summary of Barriers

Few of the potential barriers described above are insurmountable, or *directly* hinder the development of a community wind project. Many, however, will require significant time, attention, and monetary commitments to overcome, and therefore *indirectly* hinder community

[78] The revenue requirements presented in Chapter 6 are based on a 20-year contract. A modified version of the model, however, suggests that a 15-year contract would have the impact of raising the revenue requirement (in the *multiple local owner* structure) by about $1.4/MWh, or 3.6% – a fairly modest increase, suggesting that 15-year contracts are workable.

[79] For example, according to the president of the 1.9 MW Minwind II project in Minnesota, the most difficult part of the project was securing a 15-year power purchase agreement with Alliant Energy (Arends 2002). The Minwind projects are not sited within Xcel's service territory, and so did not have access to Xcel's standard purchase agreement and small wind tariff.

[80] The Energy Trust is flexible and works with the project in executing this policy. For example, the Energy Trust might agree to front- or back-load its claim on TRC's, rather than claim them on a constant proportional basis over the project's life. The Energy Trust also has the capability to sell any TRC it retains in order to generate revenue that can be recycled back into new projects.

wind development through higher transaction costs. Because community wind projects are likely to be small in size, the impact of transaction costs can be proportionally damaging.

Fortunately, not all of the barriers described above are applicable to all types of community wind projects. Table 6 summarizes which of the barriers discussed above are applicable to which of the ownership structures that will be examined in Chapter 6. While Table 6 will be useful for framing the discussion of ownership structures still to come in Chapter 6, no clear trends emerge from it, other than that on-site projects appear to face the fewest barriers to development. As will be shown in Chapter 6, however, on-site projects are also the least economically viable in Oregon, demonstrating that the number of barriers to development is not the sole consideration in choosing an appropriate ownership structure.

Table 6. Barriers Matrix

Barrier Type	Barrier	Co-op	Aggregate Net Metering	On-Site	Multiple Local Owner	MN-Style Flip	WI-Style Flip	Town-Owned
Financial	Inability to Efficiently Use Tax Credits	✓	✓	✓	✓			✓
	Determining a Feasible Ownership Structure	✓	✓		✓	✓	✓	
	Financing the Project	✓	✓		✓	✓	✓	✓
	Poor Economies of Scale	✓			✓	✓	✓	✓
Regulatory	Securities Regulation	✓	✓		✓		✓	
	Tariff Structures	✓	✓	✓				
Technical	Interconnection Process	✓	✓	✓	✓	✓	✓	✓
	Limited Ability to Interconnect	✓	✓	✓	✓	✓	✓	✓
Market	Wind Easements Already Sold	✓	✓		✓	✓	✓	✓
	All-Requirements Contracts	✓	✓	✓	✓	✓	✓	✓
	Lack of On-Site Opportunities			✓				
	Identifying Potential Revenue Sources / Securing a PPA				✓	✓	✓	✓

Which of these barriers are most important depends in part on the development or ownership structure under consideration. Continuing with the example of on-site projects, by far the largest barrier to development of such projects is unfavorable utility tariff structures, followed by lack of on-site opportunities. These two barriers, however, are hardly relevant to some of the other structures that sell power to an unrelated party.

While it is, therefore, impossible to clearly delineate the relative importance of each barrier independently of ownership structure, *in general* the following barriers represent the largest hurdles to development of community wind projects in Oregon:

- **Inability to efficiently use tax credits:** This barrier (which is *not* specific to Oregon) impacts virtually every structure except for flip structures, which were created specifically to overcome this barrier.
- **Identifying potential revenue sources and securing a PPA:** There is currently no viable standard offer in Oregon, and projects that receive support from the Energy Trust will essentially forfeit income from TRCs.
- **Poor economies of scale:** Though not universally true throughout the US or world, small wind projects in Oregon may experience a cost disadvantage relative to the very large wind projects being built in the region, particularly with respect to crane mobilization fees.
- **Securities regulation:** Oregon appears to have a particularly stringent requirement to qualify for an exemption from securities regulation, which could make certain structures prohibitively expensive.

As for the remaining barriers not yet mentioned: *feasible ownership structures* suitable for Oregon are already being demonstrated in the Midwest; *financing* appears to be readily available from Oregon's Energy Loan Program and Business Energy Tax Credit; *interconnection issues* may be largely project-specific; the *sale of wind easements* may be an issue for larger projects, but perhaps not for sites suitable for community-scale development; and *all requirements contracts* may not be as much of a barrier as the cost of wheeling power from a REC territory to PGE or Pacificorp.

5. Development of a Standard Set of Assumptions for Comparative Financial Analysis

This chapter lays the groundwork for the modeling exercise presented in Chapter 6. After briefly describing the cash flow model we have developed for our analysis, we then move on to discuss the assumptions used in our model. These assumptions fall into four broad categories: project costs (both capital and operating costs), project performance, federal and state incentives, and financing assumptions. Any assumptions specific to certain modeling runs will be discussed in Chapter 6 within the context of the ownership structure being modeled.

5.1 Description of Financial Model

To analyze the various community wind ownership structures, we have developed an Excel-based, 20-year cash flow model. Using Excel's "Solver" tool,[81] the model optimizes the project's capital structure (i.e., debt/equity ratio) to arrive at the minimum amount of revenue (on a $/MWh basis, originating from power or TRC sales, as well as financial support from the USDA, Energy Trust, or some other source) required to meet *both* the lender's debt service coverage requirements *and* the equity investors' after-tax internal rate of return requirements. 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 interactions between state and federal tax (and other) incentives where warranted (e.g., anti-double-dipping provisions). Select summary modeling results are presented in Chapter 6.

5.2 Project Cost Assumptions

Wind project costs are a function of many variables, including, but not limited to, project size, ownership structure, location and characteristics of a particular site, turbine and turbine manufacturer, exchange rates (if foreign turbines are used), and even commodity costs (e.g., the cost of steel). In developing our modeling inputs, we have attempted to capture the impact of just the first two variables listed – i.e., project size and ownership structure – by modeling both a 1.5 MW and 10.5 MW project across the seven different ownership structures briefly described at the beginning of Chapter 4, and discussed in more detail in Chapter 6.[82] This is consistent with our over-arching intent to provide a modeling overview and comparison of different community wind ownership structures under common and generic conditions, rather than to try and accurately represent costs for a specific project using a specific turbine at a specific site.

That said, to the extent practical for a generic exercise of this nature, we have tried to reflect costs that might be representative of community-scale wind projects in Oregon. Our sources include the experience of two of the authors (Dan Juhl and Tom Wind) in developing numerous

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

[82] At the low end of the range, the 1.5 MW project is intended to represent a project that is within financial reach of most potential community wind investors. It is interconnected to, and its power is consumed within, the local distribution system. The 10.5 MW project, meanwhile, is *not* intended as an upper bound on the size of community wind projects (which can theoretically be much larger), but rather is merely intended to be of sufficient size to trigger the construction of a substation to interconnect to the higher voltage transmission system.

similar projects in Minnesota and Iowa, respectively, as well as detailed numbers provided by the recent *Wisconsin Community Based Wind Power Project Business Plan*, which modeled a hypothetical 3 MW project in Wisconsin. In recognition of the fact that project costs in the Midwest – where both community and "commercial" wind power development is flourishing – may not be representative of costs in Oregon, we also reviewed cost assumptions for a small wind project planned for Sherman County, Oregon.

Based on these four sources, we developed modeling cost inputs for a single-turbine, 1.5 MW project. These input assumptions reflect a combination of the various sources, and as such should not be attributed to any single source. We derived cost inputs for the larger 10.5 MW project by scaling up the single-turbine numbers, and then making what we considered to be appropriate adjustments to those line items where economies of scale are likely to be realized.

Table 7 lists the resulting cost input assumptions for both the 1.5 MW and 10.5 MW projects, assuming a Minnesota-style "flip" structure.[83] In aggregate, the 1.5 MW project has an installed cost of around $1.8 million, or $1,200/kW, while the 10.5 MW project comes in about 7.5% cheaper at approximately $1,100/kW, or $11.6 million. On a $/kW basis, these aggregate costs are higher than that experienced by many of the community wind projects being installed in Minnesota, but perhaps slightly lower than those assumed in some of the community wind projects currently planned in Oregon.[84] In recognition that some development costs should decline with increased community wind experience in Oregon (as they have in the Midwest), our intent is not to accurately model the costs of the *very first* (or perhaps even *first few*) projects in Oregon, but rather to represent those costs that should be achievable as a "steady state" in the near future.

The length of time or number of projects necessary to reach "steady state" costs is hard to estimate, and may be outside of the control of project sponsors. For example, the pace of cost reductions may be heavily influenced by the PURPA contract proceeding before the OPUC, or even by the entrance of a competing crane company. The pace may be quicker if a single developer hones and specializes in an appropriate development and ownership structure than if multiple developers are all trying something different. On the other hand, the single developer may be overlooking cost-cutting measures, and lack of competitive pressure from other developers may therefore slow the pace of progress. In short, it is difficult to say – and beyond the scope of this project to estimate – when or how "steady state" costs will be achieved.

[83] We choose to portray costs for a Minnesota-style flip rather than one of the other ownership structures because a flip structure is perhaps one of the most likely ownership structures that will be employed in Oregon. In fact, there are at least two Oregon projects currently in development that are structured as Minnesota-style flips.

[84] We also note that our assumed project costs are comparable to those revealed by Cohen and Wind (2003), which sampled 10 wind projects consisting of turbines 600 kW or larger in size and ranging in total size from 900 kW to 48.1 MW. After deleting the high and low project costs, which were reportedly outliers due to a combination of inexperience and mountainous terrain at the high end and significant sweat equity contributions at the low end, the total installed cost of the remaining eight projects ranged from $921/kW to $1,333/kW, with an average of $1,167/kW.

Table 7. Capital Costs for a Minnesota-Style "Flip" Structure

	1.5 MW		10.5 MW	
	($)	($/kW)	($)	($/kW)
Turbine and Works				
Turbine and Tower	$1,175,000	$783	$8,225,000	$783
Freight	$55,000	$37	$385,000	$37
FAA Lighting	$5,000	$3	$35,000	$3
Cold Weather Package	$7,500	$5	$52,500	$5
Subtotal	**$1,242,500**	**$828**	**$8,697,500**	**$828**
Balance of Plant				
Site Development	$25,000	$17	$105,000	$10
Pad Mount Transformer	$25,000	$17	$175,000	$17
Concrete and Rebar	$31,000	$21	$217,000	$21
Foundation Labor	$12,000	$8	$67,200	$6
Tower Imbeds/Bolts	$25,000	$17	$175,000	$17
Cranes, Crane & Erection Labor	$120,000	$80	$378,000	$36
Construction Supervision	$20,000	$13	$126,000	$12
Monitoring System	$2,500	$2	$21,000	$2
Subtotal	**$260,500**	**$174**	**$1,264,200**	**$120**
Interconnection				
High Voltage Line Extension	$15,000	$10	$105,000	$10
Interconnection and Metering[1]	$80,000	$53	$560,000	$53
Electrical Labor	$10,000	$7	$70,000	$7
Subtotal	**$105,000**	**$70**	**$735,000**	**$70**
Soft Costs				
Legal[2]	$20,000	$13	$140,000	$13
Permitting	$12,000	$8	$84,000	$8
Development & Engineering	$40,000	$27	$266,000	$25
Insurance (Const. and Transport)	$10,000	$7	$63,000	$6
Met. Tower & Feasibility Study	$20,000	$13	$70,000	$7
Contingencies	$80,400	$54	$281,400	$27
Subtotal	**$182,400**	**$122**	**$904,400**	**$86**
Project Total	**$1,790,400**	**$1,194**	**$11,601,100**	**$1,105**

Notes to Table 7:

[1] *Interconnection and Metering* costs for on-site, behind-the-meter projects are assumed to decrease to $60,000 for the 1.5 MW project (we do not model a 10.5 MW on-site project).

[2] *Legal* costs are assumed to decrease to $10,000 for on-site, behind-the-meter projects, and increase to $30,000 (1.5 MW) and $210,000 (10.5 MW) for the *multiple local owner, aggregate net metering, and Wisconsin-style flip* structures.

While our cash flow model depends only on the aggregate installed cost of the project – and users can freely modify that input to represent a specific project if so desired – we derived the aggregate installed cost through a "bottom-up" approach. Below we briefly describe how, as part of that bottom-up approach, we arrived at numbers for each of the main input categories.

5.2.1 Turbine and Works

All four of our sources were fairly consistent in this category, placing the delivered cost of a single turbine at around $830/kW, including required FAA lighting and cold weather package. For the 10.5 MW project, we assume that seven turbines are not sufficient to trigger volume discounts, and thus have simply multiplied the single-turbine numbers by seven.

5.2.2 Balance of Plant

There was considerably greater variation among sources in total balance of plant costs. One source cited the cost of an engineering, procurement, and construction (EPC) contract to cover the *entire* balance of plant; this EPC contract was at the high end of the range. Another source, at the low end of the range, reflected the benefits and efficiencies of (a) being located in Southwestern Minnesota, where there is a strong wind power construction and servicing infrastructure in place, and (b) having developed many similar projects in the past. The Oregon source tended towards the high end of the range, driven primarily by crane costs, which were excessive due to the fact that the nearest crane large enough to erect a 1.5 MW turbine is reportedly based roughly 1,000 miles away, resulting in sizable mobilization fees just to bring a crane to the site.

In an attempt to reflect costs likely to be incurred by early (though again, perhaps not the first few) community wind projects in Oregon, the numbers we have assumed tend towards the top of the range. They are slightly lower than our Oregon source, however, in large part due to our use of lower crane costs, based on an assumption that a community wind project will be able to pull a crane away from another wind project site in Oregon or Washington, thereby significantly reducing mobilization costs.[85] We assume that the 10.5 MW project can realize varying economies of scale in site development (which primarily involves building access roads), labor in building the foundations, crane costs,[86] and construction supervision. Costs for a real-time monitoring system consisting of a personal computer connected by wire to the turbine's SCADA software, on the other hand, are likely to experience diseconomies of scale, as a larger project will require significantly more wire to be laid between turbines.

5.2.3 Interconnection

We assume that the 1.5 MW project will interconnect directly to the distribution grid (on either the utility or customer side of the meter, depending on the ownership structure being modeled), and all power will be consumed locally, while the larger 10.5 MW project will require construction of a substation, with power flowing to the higher-voltage transmission grid. With the exception of the *Wisconsin Business Plan*, which was an outlier on the low side, there was general agreement among sources that $70/kW is a reasonable representation of typical

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[85] Or, alternatively, based on the assumption that such high crane costs will eventually induce a competitor to set up shop in Oregon.

[86] Crane costs typically include mobilization fees, minimum monthly rental fees, and less-significant operator fees. The first two charges – the mobilization and minimum monthly rental fees – should be the same regardless of whether the project consists of one or seven turbines (presuming that all seven can be installed within a month). Thus, this is an area where a larger project can realize significant economies of scale.

interconnection costs (of course, this number is highly site-specific, and depends in large part on how far away from the project the interconnection is made). Despite the more onerous interconnection requirements for the larger project, offsetting economies of scale leave the net scalar more or less linear. In other words, the 10.5 MW project is right around the break-even point on a $/kW basis for constructing a substation: smaller projects (e.g., 5 MW) requiring the same substation would be more expensive on a $/kW basis than the 1.5 MW project that does not require construction of a substation, while larger projects (e.g. 15 MW) using the same substation would be less expensive on a $/kW basis than the 1.5 MW project that does not require construction of a substation.

We assume that on-site, behind-the-meter projects will experience only slightly lower interconnection costs, at $57/kW, than projects selling power to a third party over the grid. Again, interconnection costs are highly site-specific, and can easily range from $20-$80/kW, depending on the customer and site.

5.2.4 Soft Costs

Another area of fairly significant variation among sources involved the "soft costs" of developing a project, which include the cost of wind resource monitoring and feasibility studies (if any), legal and permitting costs, development and engineering costs, insurance during transportation and construction, and working capital set aside for contingencies.[87] Again, our Midwestern sources were significantly below our Oregon source, reflecting in large part the strong development infrastructure in the Midwest, as well as our sources having developed enough of these projects to enable an efficient "cookie cutter" approach to development. To reflect likely near-term experience in Oregon, our numbers tend towards, but do not quite reach, the high end of the range.

Among the various soft costs listed, only legal costs are likely to vary significantly among ownership structures. On-site, behind-the-meter projects, for example, are likely to require far fewer legal services than a project selling power to an unrelated party over the grid, and thus should be able to budget half of the $20,000 shown, which reflects the cost of forming an LLC with a corporate investor (i.e., a flip structure). At the other end of the spectrum, an LLC consisting of numerous local investors (i.e., the *multiple local owner*, *aggregate net metering*, or *Wisconsin-style flip* structures) is likely to incur more than $20,000 in legal expenses, if only for the sheer number of investors involved, as well as the potential requirement to "register" the securities being offered, or at least apply for an exemption from full registration (see Section 4.2.1 for more information on securities registration requirements). While the first two Minwind projects reportedly spent a total of $198,000 in legal costs forming their two LLCs consisting of 66 investors (Arends 2002), some of this can be attributed to one-time, first-project research costs that need not be incurred again, now that the Minwind model exists. We will assume that each of these three structures incur $30,000 in legal costs (for a 1.5 MW project), presuming that securities registration can be avoided.[88]

[87] Note that our model implicitly assumes that working capital set aside for contingencies will in fact be needed and used to construct the project.
[88] Recall from Section 4.2.1 that the Minwind I & II projects estimate (as revealed in each company's Form D filed with the SEC) that each incurred $20,000 in legal expenses associated with the issuance and distribution of the

In addition to those "soft" costs shown in Table 7, projects are likely to experience a number of fees as well, related to obtaining debt financing (perhaps through Oregon's Energy Loan Program) and accessing Oregon's Business Energy Tax Credit (BETC). These fees, which are *not* included in Table 7 because they depend on the aggregate project cost *derived* in Table 7 as well as the amount of debt in the project, will likely average around $11,000 and $14,000, respectively, and are calculated and accounted for endogenously within each modeling run. Finally, although our model implicitly assumes that it will never be tapped, we provide for a 6-month debt service reserve fund, which is required by Oregon's Energy Loan Program (in addition to the project achieving a minimum debt service coverage ratio). The project posts the 6-months' worth of debt service (both principal and interest) in a savings account, earns interest on the deposit over the life of the loan, and withdraws the funds upon loan maturity. This reserve fund, along with the fees mentioned above, will serve to increase the total installed project costs above and beyond the project totals shown in Table 7.

5.2.5 Operating Costs

In addition to the one-time capital costs shown in Table 7 and described above, the project will also incur ongoing operating costs. Table 8 lists our assumptions for such costs in the first year of the project. These numbers are at the high end of the range exhibited by our sources, in part because Oregon's property tax is significantly higher than that in Minnesota, Iowa, and Wisconsin (each of which provides some form of property tax exemption). With the exception of property tax,[89] we assume that each of the line items listed in Table 8 will escalate at the annual rate of inflation over the 20-year project life.

Several of these line items warrant brief explanation. Operations and Maintenance (O&M) represents the cost of an annual contract to routinely maintain and service the turbines. Within the limited size range of these projects, O&M costs are typically quoted on a per-turbine per-year basis, meaning the 10.5 MW project is unable to realize scale economies. The next line ("Warranty/Equip. Repair and Replacement Fund") represents either the cost of maintaining a parts and service warranty, or alternatively placing cash into an Equipment Repair and Replacement (R&R) Fund to cover unexpected service or equipment failure. While our various sources account for O&M, Warranty, and R&R Fund expenses differently, in aggregate these three items are typically assumed to cost around $40,000 per year; we have assumed $42,000 combined. The *Miscellaneous* line item could include electric usage, a decommissioning escrow, telephone service, and other minor items.

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securities in their respective offerings. Presuming that not all of this expense was related to the registration (or exemption) process, our estimate of $10,000 *incremental* legal expense to deal with registration issues does not seem unreasonable.

[89] We assume that property tax is assessed at a rate of 1.19% of total project costs in year one, and that the taxable basis of the project depreciates at 8% per year until reaching 20% of its original value in year 11, at which level it remains through year 20.

Table 8. First Year Operating Costs for a Minnesota-Style "Flip" Structure

	1.5 MW		10.5 MW	
	($/year)	($/kW-yr)	($/year)	($/kW-yr)
Operations & Maintenance (O&M)	$15,000	$10	$105,000	$10
Warranty/Equip. Repair and Replacement Fund	$27,000	$18	$189,000	$18
Management/Administrative[1]	$5,000	$3	$26,250	$3
Property Taxes[2]	$21,306	$14	$138,053	$13
Land Lease[3]	$4,000	$3	$28,000	$3
Equipment Insurance	$14,000	$9	$93,100	$9
Miscellaneous	$1,000	$1	$6,300	$1
Project Total	**$87,306**	**$58**	**$585,703**	**$56**

Notes to Table 8:
[1] *Management/Administrative* costs are assumed to decrease to $1,000 (1.5 MW) and $5,250 (10.5 MW) for on-site as well as town-owned projects, and increase to $10,000 (1.5 MW) and $52,500 (10.5 MW) for projects owned by multiple local owners (i.e., the *multiple local owner, aggregate net metering,* and *Wisconsin-style flip* structures).
[2] *Property Taxes* are assumed to not apply to town-owned projects sited within the town's borders, and will otherwise vary slightly among project structures as capital costs vary.
[3] *Land Lease* costs are assumed not to exist for on-site, behind-the-meter projects as well as town-owned projects, where the project owner is also the landowner. For Minnesota-style flip projects, which are perhaps also likely to ultimately be landowner-owned, we assume that land lease costs remain intact, due to the arms-length relationship between the landowner and the project LLC. In such cases, however, the model allows the user to specify that the land lease costs flow through to the local investor as taxable income.

Of the seven line items listed in Table 8, only the *Management/Administrative, Property Taxes,* and *Land Lease* costs are likely to vary significantly by ownership structure. *Multiple local owner*, *aggregate net metering*, and *Wisconsin-style flip* projects are likely to incur higher *Management/Administrative* costs, given the large number of investors (we'll assume twice as high, at $10,000 per year for a 1.5 MW project), while at the other end of the spectrum, on-site, behind-the-meter projects as well as town-owned projects may require as little as $1,000 per year in such costs. Furthermore, we assume that town-owned projects sited on town-owned land will be exempt from *Property Taxes*. Finally, landowner-owned projects, such as most on-site, behind-the-meter projects as well as town-owned projects, will likely not incur land lease costs.[90]

Finally, though not shown here, a flip structure may incur an additional "expense" in the form of a "management fee" (i.e., separate from and in addition to the *Management/Administrative* costs) that is paid to the local investor, based on what the project can bear and still meet the corporate investor's equity hurdle rate as well as debt service coverage ratio requirements. In cases where the local investor has only fronted 1% of the equity (and so receives only 1% of net revenues), this management fee represents the majority of the income received by the local investor during the project's first ten years. While payment of a management fee to the local investor is common in Minnesota, and our model is equipped to provide such a fee, the fact that our modeling objective is to identify the *lowest* amount of revenue (on a $/MWh basis) required to support a community wind project while meeting all parties' financial objectives effectively means that the

[90] Most Minnesota-style flip projects are also likely to be primarily landowner-owned. Where the LLC includes a corporate tax-motivated equity investor in addition to the landowner, however, it will still be necessary to show a land lease expense in the pro forma (even though this essentially means that the landowner is leasing land from himself). In fact, the bank will likely require a land lease agreement as one of several items (including a power purchase agreement) needed to collateralize the loan.

model will always set the management fee equal to zero *unless* the local investor otherwise fails to reach his internal rate of return hurdle, which is generally not the case with Minnesota-style flip structures. In other words, local investors in Minnesota-style flip structures are typically able to meet or exceed their internal rate of return hurdles *without* receiving the management fee; as such, the model sets the fee to zero.

5.3 Project Performance Assumptions

Since we are modeling a generic project with no specific site or turbine in mind, we are unable to calculate annual turbine performance based on wind speed data and a turbine power curve. Instead, we have simply assumed that the project will perform at an annual 33% net capacity factor, which appears to be broadly consistent with existing wind projects in Oregon. The model ignores the possibility of good and bad wind years, as well as intra-annual variations, and simply assumes that the turbines will achieve a 33% net capacity factor each year over the 20-year project life.

5.4 Incentive Assumptions

Both the federal government and the state of Oregon provide a number of incentives potentially applicable to community wind projects. Some of the state incentives (and even one of the federal incentives) interact with and potentially offset one or more of the federal incentives. Below we describe our treatment of both federal and state incentives in our modeling analysis.

5.4.1 Federal Incentives

Federal Production Tax Credit (PTC) and Renewable Energy Production Incentive (REPI)
Prior to their respective expirations at the end of December and September 2003, the federal PTC and REPI provided a 10-year inflation-adjusted tax credit (PTC) and cash payment (REPI) to taxable and tax-exempt entities, respectively. For 2003, the inflation-adjusted value of both the PTC and REPI stood at 1.8¢/kWh. While there is a high likelihood that the PTC will eventually be reinstated (though perhaps in an altered form[91]), the future of REPI is less certain, in part because Congress is currently considering whether to make the PTC into a "tradable" credit, which would allow certain tax-exempt project owners to receive and sell the PTC to taxable entities able to benefit from it, thereby obviating the need for the REPI. While a tradable PTC would arguably provide more revenue certainty than REPI historically has to tax-exempt wind projects,[92] on the other hand a tax-exempt wind project would have to trade or sell the PTC at a

[91] For example, the corporate tax bill that passed the Senate in early May 2004 would extend the PTC through 2006, with the following changes: eliminate the inflation adjustment provision starting in 2005; exempt the PTC from the Alternative Minimum Tax (AMT) for the first four years of turbine operation; expand the PTC to other resources; and allow a tradable credit for rural electric cooperatives, state agencies and municipalities, Indian Tribal governments, and the Tennessee Valley Authority (AWEA 2004a). The proposed House version of the corporate tax bill, however, contains only a two year PTC extension and maintains the inflation adjustment provision, while neither extending the credit to other technologies, nor providing for a tradable credit (AWEA 2004b). If the House ultimately passes this version of the corporate tax bill, the differences between it and the Senate version will need to be resolved in conference committee.

[92] Although a qualifying project is technically eligible for REPI for 10 years, there is no guarantee that the project will actually receive full REPI payments for this duration, for at least two reasons. First, since REPI involves a cash

discount to its full value in order to attract a taxable buyer. Given the limited number of corporations able to use the PTC (at least in its historical form), it is not unreasonable to expect that the market for tradable PTC's would be a buyers market, requiring fairly deep discounts.

Notwithstanding the uncertainties raised in the previous paragraph, our modeling analysis assumes that both the PTC and REPI (or alternatively, a tradable PTC) will be reinstated in their current form, but we also perform sensitivity analysis on these variables in many instances. We assume that Oregon's Business Energy Tax Credit (BETC) will trigger the PTC's anti-double-dipping provisions, as will tax-exempt loans from Oregon's Energy Loan Program and Section 9006 grants from the USDA (see below). The REPI, meanwhile, does not contain anti-double-dipping provisions.

5-Year Accelerated Depreciation (MACRS)

We assume that the full capital cost of the project can be depreciated using the 5-year MACRS (200% declining balance method, half-year convention) schedule.[93] Since Oregon follows federal depreciation rules, 5-year MACRS is used on both the state and federal tax returns.

Because there appears to be limited consensus on this issue, the model allows the user to specify whether capital grants reduce the project's depreciable basis (for state and/or federal purposes), or whether they are instead treated as taxable income.[94] Our base assumption for all modeling runs is that cash incentives (e.g., USDA grants, BETC pass-through payments, any incentives from the Energy Trust of Oregon) are treated as taxable income, and therefore do not also reduce the depreciable basis of the project.

USDA Grants

While grants from the USDA under Section 9006 of the 2002 Farm Bill have been available to community wind projects in fiscal years 2003 and 2004, we do not include such grants in our base case modeling runs, for two reasons. First, even more so than in fiscal year 2003, there is

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payment (rather than a tax credit), it is subject to annual budgetary appropriations, and so each year runs the risk of being under-funded or cut altogether. Second, as a budgetary line item, only a certain amount of money is authorized for REPI payments each year. As more and more qualifying wind projects come on line and apply for limited REPI funding, the payment to each wind facility may have to be reduced on a pro rata basis to something less than the stated ¢/kWh incentive. For these reasons, REPI is considered to be a less effective incentive than its taxable counterpart, the PTC.

[93] Specifically, the 5-year MACRS schedule depreciates 20%, 32%, 19.2%, 11.52%, 11.52%, and 5.76% of the depreciable basis in years 1 through 6, respectively. Because it is slated to expire at the end of 2004, we do not include the 50% first year "depreciation bonus" in our analysis.

[94] One point of uncommon clarity on this issue is that capital grants cannot *both* reduce depreciable basis *and* be considered taxable income (which would effectively result in double taxation), but rather must do one or the other. The lack of consensus on *which* may simply be indicative of different ways in which the same type of grant can be put to use. If, for example, a grant recipient directly applies the grant towards the capital cost of the project, then perhaps it is reasonable to assume that the grant reduces the project's depreciable basis. If instead, the grant recipient pays for the project in full and applies the grant towards some other purpose, then perhaps it is reasonable to treat the grant as taxable income rather than as reducing the project's depreciable basis. Or, ultimately, legal requirements may dictate one treatment over another (see footnote 95). Practically speaking, whether a lump-sum incentive is considered taxable income or instead reduces depreciable basis does not make much difference, since either way the value of the incentive will be reduced by the income tax rate. The only difference is how quickly the reduction occurs – e.g., in one year if considered taxable income, or over six years if through depreciation. Thus, the time value of money is the sole consideration.

likely to be intense nationwide competition among different renewable energy technologies and projects on a going forward basis for a limited pool of USDA grant funding, perhaps making it unrealistic for any particular project to bank on receiving a grant. Second, funding for the Section 9006 program may be reduced in the future, as the program's funding status was changed from "mandatory" to "discretionary" in FY04, and the President has reportedly proposed a roughly 50% reduction in funding for FY05 (Hagy 2004). Also note that, as they have been structured in the past – i.e., as a grant to reduce a project's up-front capital cost – Section 9006 grants will trigger the PTC's anti-double-dipping provisions, reducing the value of the grant to projects that are also trying to capture the PTC. Furthermore, as mentioned above, we presume that USDA grants will be considered taxable income, further eroding their value.[95]

5.4.2 Oregon Incentives

Business Energy Tax Credit (BETC)

Oregon businesses investing in, among other things, renewable energy projects in Oregon can claim a Business Energy Tax Credit (BETC) equal to 35% of eligible project costs (with eligible costs capped at $10 million). The 35% credit is taken either over five years (10% in the first two years, and 5% for the next 3 years),[96] or alternatively as a discounted, lump-sum, up-front cash payment from a "pass-through" partner in exchange for the five-year credit. The pass-through option was designed to allow tax-exempt entities (e.g., schools) to benefit from the BETC by "selling" it to taxable businesses able to use the credit, and that is primarily how it has been used to date. Even taxable entities, however, may choose to seek pass-through partners and take the BETC as a lump-sum cash payment. The pass-through cash payment is currently equal to 25.5% of eligible project costs (as opposed to 35% of eligible costs for the 5-year tax credit), a discount that is set by the Oregon Department of Energy (which administers the BETC) and is revisited annually.

Not only does the *amount* of the BETC differ depending on whether it is taken as a 5-year credit or a lump-sum pass-through, but so do the tax implications. While it is fairly clear that the 5-year Oregon tax credit is not considered taxable income, and does not impact the depreciable basis of the project at either the state or federal level (per ORS 315.354(6) and (7)), tax treatment of the lump-sum pass-through payment is less clear, and is currently under investigation by the Oregon Department of Energy. Our model allows the user to specify whether the pass-through payment reduces the project's depreciable basis (for Oregon and/or federal tax purposes), is treated as taxable income, or neither. Our base case assumption is that the pass-through should

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[95] The instructions for IRS Form 6497 ("Information Return of Nontaxable Energy Grants or Subsidized Energy Financing") state that "Grants are always taxable to recipients unless specifically exempted by the Federal statute authorizing the grants" (see http://www.irs.gov/pub/irs-pdf/f6497.pdf). Since the 2002 Farm Bill appears to be silent on taxation, this guidance suggests that Section 9006 USDA grants are taxable.

[96] It is important to note that while the BETC is a *business* credit, investors in an LLC that receives the BETC and has elected to be taxed as a partnership will effectively take the credit against their *personal* income taxes.

be treated as taxable income,[97] and that both the pass-through payment and the 5-year credit trigger the federal PTC's anti-double-dipping provisions.[98]

Our modeling analysis assumes that the project always takes the BETC, because – even with the PTC haircut – the BETC always adds value. The specific ownership structure in question determines whether we model the BETC as a pass-through payment or a 5-year credit. Ownership structures that involve a corporate investor providing most or all of the equity during the 5-year BETC period are more viable (in terms of requiring less revenue) taking the BETC as a lump-sum pass-through payment. This is because the corporate investor's assumed discount rate (15%) is high enough to bring the net present value of the 5-year credit to 24.9%, which is less than the regulated 25.5% pass-through rate. Conversely, ownership structures in which local investors provide most or all of the equity during the 5-year BETC period are more viable taking the BETC as a 5-year credit. This is because at the local investors' assumed discount rate (10%), the net present value of the 5-year stream of credits equals 27.6%, which is higher than the 25.5% pass-through rate. Of course, given that the BETC pass-through payment reduces the need for up-front cash – which may be particularly constraining – local investors may opt for the pass-through payment even though it results in a slightly higher revenue requirements (or slightly lower return for the same amount of revenue). In other words, our assumed 10% discount rate may not adequately reflect the local investor's preference for up-front cash incentives. To allow for this possibility, in Chapter 6 we present certain modeling results both ways – with the BETC taken as a 5-year credit, and also as a lump-sum pass-through payment.

In situations where it makes economic sense to take the BETC as a pass-through payment, we assume that pass-through partners are readily available. We also assume that "eligible costs" for the BETC include total project capital costs.

For more information on the BETC, see www.energy.state.or.us/bus/tax/taxcdt.htm.

Energy Loan Program

Oregon's Energy Loan Program is unique in its ability to issue either taxable or tax-exempt Oregon general obligation bonds to finance, among other things, commercial renewable energy projects (such as a community wind project). The terms of a loan through the Program are generally attractive: interest rates are competitive, and in the case of tax-exempt financing, even below-market; the debt service coverage ratio is low (a minimum of 1.25 on an average annual basis), and can be met in part by applying monetized tax credits from the federal PTC and state BETC;[99] terms can be as long as 20 years; and fees are reasonable (at least for larger projects).

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[97] Since state income tax payments are deductible from federal taxable income, even the 5-year BETC can be thought of as taxable income at the federal level. The BETC, taken as a credit, reduces state income tax liability, which in turn reduces the federal deduction for state income taxes paid, thereby increasing federal taxable income.

[98] Were the size of the credit the same in both cases, the pass-through option would result in a larger PTC "haircut" than the 5-year credit, because the pass-through payment is provided as an up-front lump sum, as opposed to the 5-year credit, which is metered out over a 5-year period. Because the pass-through payment is discounted to 25.5% (from 35%), however, it actually results in a slightly *smaller* PTC haircut than the 5-year credit.

[99] In addition to this debt service coverage ratio, the Energy Loan Program requires the borrower to establish a debt reserve fund equal to six months' worth of debt service payments (both principal and interest).

As does the BETC, however, a loan from the Energy Loan Program may trigger the federal PTC's anti-double-dipping provisions. A loan financed by tax-exempt bonds most certainly will, while a loan financed by taxable bonds is perhaps likely, though not certain, to. A key issue is interpreting what constitutes "subsidized energy financing" for the purposes of the PTC legislative language contained in Section 45 of the US tax code. Section 45 does not define subsidized energy financing. However, under Section 48(a)(4)(C), which pertains to the investment tax credit for commercial solar and geothermal projects, the term "subsidized energy financing" means "…financing provided under a Federal, State, or local program a principal purpose of which is to provide subsidized financing for projects designed to conserve or produce energy." The instructions to IRS Form 6497 ("Information Return of Nontaxable Energy Grants or Subsidized Energy Financing") expand upon the Section 48 language, noting that "Subsidized energy financing can also include financing under a Federal, state, or local program having two or more principal purposes, but only if one of the principal purposes is to provide subsidized financing for energy conservation or production projects…" and "Financing is subsidized if the terms of the financing provided to the recipient in connection with the program *or used to raise funds for the program* are more favorable than terms generally available commercially." [*emphasis added*] However, "The source of the funds for a program is not a factor in determining whether the financing is subsidized."

Materials provided by the Oregon Department of Energy, which administers the Energy Loan Program, suggest that a principal purpose (or at least one of the principal purposes) of the Program is, in fact, to provide subsidized financing for such projects. For example, an Energy Loan Program brochure states that the program "…offers low-interest, fixed-rate, long-term loans…" and that "bonds [*used to raise funds for the program*] sell at low rates because they are backed by the state of Oregon and, in many cases, the bond interest is tax exempt" (see www.energy.state.or.us/loan/selp.pdf). This language, in combination with the IRS guidance quoted in the previous paragraph, implies that even loans financed through the issuance of taxable bonds may still be considered "subsidized" for purposes of the PTC.[100]

To date, however, no commercial wind project has used the Energy Loan Program (perhaps due to its potential – though uncertain – impact on the PTC), so there are no precedents on which to rely.[101] Furthermore, to our knowledge, no wind project owner has yet requested a private letter ruling on this matter from the IRS. Given the potential importance of the Energy Loan Program to the viability of community wind projects in Oregon, it is paramount that the issue of whether or not taxable loans from the Program trigger the PTC's anti-double-dipping provisions be resolved as soon as possible, and before the Energy Trust develops a community wind program.

Furthermore, it is important to note that the Energy Loan Program is authorized to loan only $20 million in "private use" (non-tax-exempt) bonds in the next two years (out of $80 million total).

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[100] The evidence is far from conclusive, however. As Energy Loan Program manager Jeff Keto points out, the Program does not directly pass through the bond yield to the borrower, but instead adds 100-150 basis points to cover program expenses, thereby potentially erasing any interest rate advantage (Keto 2004).

[101] Recently, however, a 5 MW project structured as a flip has received approval for a $2.75 million 15-year loan from the Energy Loan Program. The project chose taxable (rather than tax-exempt) bond financing, suggesting that it hopes to avoid a PTC haircut (otherwise it would have chosen tax-exempt debt in order to secure a lower interest rate). Because the project is not yet in construction and new bonds must be sold to finance the loan, the loan interest rate has not yet been set.

With at least $2.75 million in private use bonds already committed (see footnote 101), the Energy Loan Program's capacity to finance additional community wind projects should be carefully assessed to ensure that it is sufficient to support any Energy Trust community wind program.

Despite the lack of clarity over the interaction of the Energy Loan Program with the PTC, all of our modeling runs assume that financing is provided by the Program – on either a taxable or tax-exempt basis, as conditions dictate – and that taxable financing will *not* trigger a PTC haircut (while tax-exempt financing will). Even if taxable financing from the Energy Loan Program *does* prove to trigger a PTC haircut, commercial financing should be readily available to serve as an alternative, albeit at somewhat less attractive terms; we perform sensitivity analysis on debt terms in Chapter 6.

For more information on Oregon's Energy Loan Program, see www.energy.state.or.us/loan/selphme.htm.

Oregon Rural Renewable Energy Enterprise Zones

In 2003, the Oregon legislature passed a bill giving rural counties (or cities in rural counties) the ability to apply for certain land areas within their jurisdiction to be designated as "Rural Renewable Energy Development Zones." All renewable energy projects built within such zones will be exempt from paying property tax for at least three years, and potentially as long as five years. Though a community wind project may be able to persuade a county or town to pursue this option, we have ignored this possibility in our base modeling analysis.

5.5 Financing Assumptions

As mentioned in Section 5.1, we allow the model to determine the optimal capital structure of the project (i.e., that which minimizes the revenue requirement). As such, the user merely specifies the debt interest rate and term (along with the required debt service coverage ratio), as well as the equity providers' internal rate of return (IRR) requirements. As mentioned above in Section 5.4.2, despite general uncertainty surrounding interactions with the PTC, we assume that Oregon's Energy Loan Program will be the source of "commercial" debt in all cases.[102] Thus, our model adopts the Energy Loan Program's general terms and conditions,[103] as well as interest rates. Specifically, we assume that all debt will be 10 years in duration, and will carry an interest rate of 5.5% if taxable, or 4.5% if tax-exempt. These interest rates are 50 basis points higher than those shown on the Energy Loan Program web page (see www.energy.state.or.us/loan/rates.htm) as being effective April 7, 2004, and reflect the general increase in interest rates since that date, presuming the Program would have to issue new bonds in order to finance any new projects (Keto 2004). While some of the ownership structures (e.g., multiple local owner) could potentially utilize longer debt terms (e.g., 15 years), 10 years fits

[102] Under one of the ownership structures – the Wisconsin-style flip – the local investors provide debt rather than equity to the project, so that particular structure has two sources of debt: "commercial" debt from the loan program, and "local" debt from the local investors.

[103] Again, these include: minimum annual average debt service coverage ratio of 1.25, with PTC and BETC considered to contribute to debt service coverage; a debt service reserve fund equal to six months of debt service payments (both principal and interest); and all applicable fees as specified by the Program.

well with certain ownership structures (e.g., flip structures), and so for the sake of consistency across structures, we limit all projects to 10-year debt.[104]

On the equity side, we assume in all cases that corporate tax-motivated equity investors will require a leveraged after-tax IRR of 15%, while local investors (including businesses in the on-site models and municipalities in the town-owned model) will settle for a leveraged after-tax IRR of 10%. For purposes of comparison, the average compound annual return of a basket of large stocks (similar to the S&P 500) from 1926 through 2003 was 10.4% (Ibottson 2004), or about 8% after-tax assuming a 25% tax rate. Thus, we assume that both corporate and local investors require returns that exceed the historical long-term performance of the broad stock market. While this assumption seems reasonable for corporate investors (and 15% after-tax is more or less consistent with reported leveraged returns on commercial wind projects), some local investors may be satisfied with less than 10% after-tax, particularly given current bank and money market deposit rates of 2% or less pre-tax. While such deposit instruments are significantly less risky than investing in a community wind project, their interest rates may still be viewed by some local investors as "the competition" (or opportunity cost of capital). To account for the possibility that we are over- or under-estimating the local investor's return requirements, we conduct sensitivity analysis of this variable in Chapter 6.

Other financing-related assumptions in our base case modeling runs include:

- Marginal federal and state income tax rates for corporate investors are 35% and 6.6%, respectively.
- Marginal federal and state income tax rates for local investors are 25% and 9%, respectively (except for local businesses owning on-site turbines, which use the corporate tax rates of 35% federal and 6.6% state). This equates to a couple filing jointly and earning around $100,000 per year (i.e., *not* likely to be accredited investors).
- The rate of inflation equals 2% per year.
- The rate of interest earned on the debt service reserve fund equals 2% per year.
- The project's revenue requirement does not escalate over time.
- Community wind projects in Oregon incur no sales tax expense (Oregon does not have a sales tax).

[104] Furthermore, because we count the PTC towards satisfying the debt service coverage ratio, debt that is longer than 10 years can actually result in a *higher* revenue requirement needed to satisfy coverage ratios after year 10 (when the PTC ends).

6. Description and Modeling of Potential Ownership Structures

Informed by financial analysis, this chapter takes an in-depth look at seven different potential community wind power ownership structures, all of which have been introduced earlier in this report. We begin by examining those ownership structures or development models that rely on the local investor also "consuming" the power produced by the project – i.e., consumer cooperatives; aggregate net metering; and on-site, behind-the-meter projects (owned by both taxable businesses and tax-exempt governmental hosts). We then turn to those structures that involve selling power from the project to an unrelated party – i.e., multiple local owner LLCs, Minnesota-style flips, Wisconsin-style flips, and town-owned projects. In each case we describe the ownership structure, note any barriers to implementation (drawing heavily on material from Chapter 4), and finally present and discuss results from financial modeling of the structure using the model and assumptions described in Chapter 5.

The purpose of this chapter is two-fold. First, to foster a more comprehensive understanding of the mechanics of various community wind power ownership structures. Second, to identify those structures that are likely to be most promising in Oregon, based on a number of factors, including the degree to which the revenue requirement (to satisfy all equity return hurdles and lender constraints) of each project is above or below the "market" power price accessible to that project. For projects that effectively displace purchased power (cooperatives, aggregate net metering, and on-site projects), we set as the benchmark power price the relevant Pacificorp tariff being displaced (including all applicable demand and standby charges). For projects that instead sell power to Pacificorp or PGE (multiple local owner, Minnesota-style flips, Wisconsin-style flips, and town-owned projects), we use as the benchmark a levelized power price provided by the Energy Trust of Oregon that is intended to provide an indication of what such projects are likely to earn through a long-term power purchase agreement.[105] This levelized price is $39.40/MWh for "distributed generation" projects that are interconnected to, and whose power is consumed within, the local distribution system (in our analysis, only the 1.5 MW projects), and $34.60/MWh for projects interconnected to, or whose power is delivered over, the high-voltage transmission system (in our analysis, only the 10.5 MW projects).

It is important to note that *none* of these benchmark power prices include a value for a project's tradable renewable certificates (TRCs). Since the Energy Trust's policy is to take title to a project's TRCs in proportion to the percentage of that project's above-market costs that it funds (see Section 4.4.4 for more on this policy), most projects supported by the Energy Trust will retain few, if any, of their TRCs. As a result, the Energy Trust has requested that our analysis *not* consider the potential value of TRCs to a project, and instead treat TRCs as an incentive design issue, the details of which will be determined by the Energy Trust on a case-by-case basis.

Thus, each project's *revenue requirement* can be thought of as the 20-year levelized amount of revenue (on a $/MWh basis from some combination of power sales, TRC sales, and financial support from the USDA, Energy Trust, or some other source) required to satisfy all equity return

[105] To levelize the price streams provided by the Energy Trust, we discounted and amortized the first 20 years of each price stream (to correspond to the 20-year term of our model) using an 8% nominal discount rate. A discount rate of 10% would have resulted in levelized prices that are roughly 0.5¢/kWh lower than those used, while a discount rate of 6% would have resulted in levelized prices that are roughly 0.5¢/kWh higher than those used.

hurdles and lender constraints. Each *benchmark power price* should be thought of as 20-year 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 TRCs and/or additional financial support (from the USDA, Energy Trust, etc.). While *revenue shortfall* is also denoted in 20-year levelized terms, it is important to note that the structure and timing of any incentive designed to close that shortfall could vary from year to year (or even within a year); we make no attempt in this report to identify the optimal incentive type or timing (e.g., up-front grant versus ongoing production incentive, etc.).

6.1 Cooperative Ownership

Although community wind projects are often referred to somewhat generically as "wind cooperatives," in fact cooperative ownership of utility-scale wind projects is quite rare. Even in northern Europe, where community wind has flourished, cooperatives are a relatively uncommon ownership structure, seen with regularity only in Sweden. For reasons described below, cooperative ownership of community wind projects in the US is likely to be even more rare. Nonetheless, in acknowledgement of the historical – though technically incorrect – association of cooperatives with community wind projects, we include a brief discussion of cooperatives in this chapter. Our purpose is to describe in general terms the legal structure of cooperative ownership, and to then document its primary shortcomings as a model for wind power development in the United States, and Oregon in particular.

6.1.1 Description

In the most general terms, a cooperative is a business structure that "people use to provide themselves with goods and services" (Frederick 1997). While there are many different types of cooperatives, and therefore no standard definition of a cooperative, all have in common several "cooperative principles" that distinguish them from other types of businesses. These include:

- **User-Owned:** A cooperative is owned by those who use its services.
- **Democratic Control:** Each cooperative member has a direct say in the activities of the cooperative, typically through a "one member, one vote" policy.
- **Benefits Based on Usage:** The more cooperative members use the cooperative, the more goods and services they receive. Moreover, at the end of each year, any excess revenue is distributed to cooperative members proportionally through a "patronage" dividend or refund, which is based on how much each member used the cooperative during the year.

In addition to these three main principles, cooperatives are generally prohibited from being used for investment purposes, and most are also set up as non-profit enterprises (which may carry certain marketing or other advantages that will not be discussed in this report).

With respect to community wind, perhaps the most relevant type of cooperative would be a "consumer cooperative," where individuals would join together to invest in a utility-scale wind turbine, for the purposes of consuming its power and/or TRCs. Mechanically, the power would either have to be delivered by the cooperative to each member (to achieve and document patronage), or else financially netted by the local utility against each customer's electricity consumption (which, in essence, can be described as *aggregate net metering* and will be covered in the next section, albeit with an LLC as the legal ownership structure employed). Distributing and documenting patronage of TRCs, which are financial in nature and need not follow the flow of power, would be much less complicated (though, as noted earlier, projects funded by the Energy Trust might not have many TRCs remaining to distribute). The key point to note here is that the cooperative cannot simply sell power and/or TRCs to an unrelated party and distribute the revenue to its members; instead, cooperative members must serve as "the market" for power and/or TRCs.

Consumer cooperatives are among several different community wind power development models employed in Sweden, and have been structured in both of the ways described above – i.e., to deliver power to cooperative members, or more traditionally as an aggregate net metering arrangement.[106]

6.1.2 Barriers

In Oregon, retail electricity choice exists for only the largest electricity customers. Thus, other than possibly operating the cooperative to provide its members with just TRCs (an untested model of uncertain legality, and one that would likely not work in Oregon due to the Energy Trust's TRC retention policy), cooperative wind ownership in Oregon is only possible in an *aggregate net metering* situation, which requires either utility cooperation or regulatory change. In addition to these barriers specific to aggregate net metering (which will be discussed in Section 6.2.2), the cooperative structure itself encounters several barriers with respect to community wind projects in the United States. Specifically, taxation and patronage present challenges.

Most, though not all, cooperatives are organized as not-for-profit businesses. Thus, the cooperative organization itself generally has no tax liability, and as such cannot take advantage of the primary federal incentives for wind power in the US, namely the PTC and accelerated depreciation. While cooperatives are eligible for the REPI, the value of the REPI over time is much less certain than the value of the PTC, for reasons discussed in Section 5.4.1. Even if a cooperative were structured as a for-profit business, in most cases taxation would occur at the member, rather than cooperative, level, and as discussed in Section 4.1.1, few individuals are able to take full advantage of federal tax benefits for wind power.

Furthermore, for the project to claim the PTC, its power must be sold to an "unrelated person." Section 45 of the US tax code describes "related persons" as those "that would be treated as a single employer under the regulations prescribed under section 52(b)." Section 52(b), meanwhile, states that "…all employees of trades or businesses (whether or not incorporated)

[106] What has historically enabled consumer wind cooperatives to be viable in Sweden is that, prior to market liberalization, utilities for the most part cooperated with the cooperatives, netting production from the cooperative's turbine against cooperative members' power consumption (meaning that, in effect, cooperative members were patronizing the cooperative through the utility). In addition, Sweden's incentives for wind power have, unlike in the US, been relatively non-discriminatory against any particular development model.

which are under common control shall be treated as employed by a single employer…." This language suggests that a cooperative that owns a wind turbine and sells the power to its members might not qualify for the PTC, even if were a taxable entity.

Besides the tax issue, another hurdle relating to cooperatives involves the concept of "patronage" – i.e., cooperative members benefit based on how much they *use* the cooperative, rather than how much they have *invested* in it. Unless investment in a community wind project can somehow be tied to use of the wind power – which is challenging given the nature of electricity and how it is delivered over the grid – it is difficult to document patronage (though patronage of a project's TRCs would be a much easier transaction to document). In a competitive retail electricity market, it is possible that a cooperative could be formed for the purpose of building utility-scale wind projects and selling the power to its members through a "delivered product" (i.e., where the power is "delivered" – at least through a contract path – to the member). While a delivered product would enable clear documentation of patronage, it would also likely require the cooperative to perform all of the functions of a typical energy service provider, such as securing, scheduling, and delivering power to meet its members' loads at all times – even when the wind is not blowing. This would greatly increase the complexity and cost of the undertaking, beyond the scope and expertise of a typical community wind project.[107] Furthermore, since customer choice exists in Oregon for only the largest electricity end-users, this is a rather unrealistic scenario in Oregon.

6.1.3 Financial Analysis

Since cooperatives do not appear to be a promising (or even possible) ownership structure for community wind projects in Oregon (with the possible exception of a cooperative established solely to deliver TRCs to its members, though this is an unproven model of questionable legality and viability, particularly considering that the Energy Trust will take title to most or all of the TRCs from any project that it funds), we have foregone financial analysis of this structure.[108] While the cooperative legal structure itself faces significant challenges with respect to ownership of a wind project, the cooperative principles at the heart of most cooperatives have widespread appeal among proponents of community wind. Fortunately, other ownership structures discussed and modeled in the rest of this chapter, though not legally cooperatives, can be organized according to cooperative principles.

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[107] The complexity and expense of offering delivered power products are two reasons why green power models based on tradable renewable certificates (TRCs) – which require no specific power delivery – have gained favor in many parts of the country. It may be possible for a cooperative to construct community wind projects and sell the TRCs, rather than the power, to its members (though if the project is funded by the Energy Trust, the cooperative may not have many, or possibly any, TRCs at its disposal).

[108] Results of such an exercise, however, would likely be similar to those presented in the next section on "aggregate net metering."

6.2 Aggregate Net Metering

A second potential community wind ownership structure very similar to a consumer cooperative (at least as practiced in Sweden), but more likely to be organized as a limited liability company (LLC) in the United States, involves a concept known as "aggregate net metering." Aggregate net metering is an attempt to allow utility-scale wind projects to effectively earn lucrative residential retail rates (or, rather, to allow residential customers to access the greater efficiencies of a utility-scale wind turbine in a net-metered situation).

6.2.1 Description

Aggregate net metering differs from traditional net metering in that the generating equipment is (1) utility-, rather than residential-, scale; (2) jointly owned by multiple unrelated investors, rather than by a single household or business; and (3) centrally located and on the utility side of the meter, rather than on site and on the customer side of the meter. For wind power, aggregate net metering holds the promise of a significantly lower cost of energy (and therefore a significantly higher return compared to most on-site net-metered installations), due to the use of larger, more efficient utility-scale turbines that are sited where the wind resource is best, rather than smaller, less-efficient residential-scale turbines sited where a load is located. Each investor owns a share of generation from the turbine (most likely through an LLC arrangement, given the limitations of the cooperative structure discussed in the previous section), and the utility serving those investors nets that amount of generation against each investor's own electricity consumption, thereby valuing it at the full retail rate.

Aggregate net metering has its roots in the Swedish consumer cooperative model of community wind power development. Historically, any Swede living within the service territory of a common utility has been able to invest in part of a centrally located, utility-scale wind turbine, effectively purchasing a portion of the turbine's capacity such that the power produced by that portion does not exceed the individual's annual power usage.[109] The local utility then nets each individual's share of the wind generation against his or her electricity consumption, effectively treating the transaction as if the individual had purchased the power from the cooperative. This is essentially aggregate net metering implemented through a cooperative model.[110]

Closer to home, the Toronto Renewable Energy Cooperative (TREC) initially tried (and continues to strive) to structure its *WindShare* program as aggregate net metering, with its development partner – Toronto Hydro – serving as the retail electricity supplier that would perform the netting function on cooperative members' electricity bills (Bolinger 2001). Because the turbine would be embedded within Toronto Hydro's distribution system, TREC argued that cooperative members should earn the full retail rate – and not just the generation portion of that rate – for the turbine's output. Ultimately, the Ontario Energy Board ruled that TREC members would only earn the generation price, and tax consultants advised TREC that – contrary to treatment under traditional net metering – the bill savings from the turbine would likely be

[109] This limit on investment is necessary to maximize income under the cooperative "patronage" system – if the individual invested in more power than he consumed, then the excess power reserved but not consumed would remain "un-patronized" and so would not generate an optimal return.
[110] Since this model depends on utility cooperation, it is perhaps less likely to succeed in the United States.

considered taxable income. These two rulings, along with a discovery by Toronto Hydro that its billing software would require a costly upgrade to allow it to perform the netting function, ultimately caused TREC to fall back on a more traditional purchase and sale agreement with Toronto Hydro.

In the United States, Vermont has implemented a limited form of aggregate net metering for farms installing anaerobic digester systems. Such systems can be up to 150 kW in nameplate capacity (as compared to the 15 kW limit for non-farm net metered systems), and can offset power consumption from multiple meters on the farm. Wells Rural Electric Company in Nevada also reportedly has adopted a limited aggregate net metering policy applicable to a single customer taking service at multiple sites.

6.2.2 Barriers

The primary barrier to aggregate net metering in a regulated market such as Oregon's is that it either requires utility cooperation (to accept the arrangement and perform the net billing function), or else legislative or regulatory change (to force the utility to accept the arrangement and perform the net billing function). Utility cooperation is present in Sweden, and was, for the most part, in Toronto as well, while Vermont pursued legislative change. Obtaining such cooperation or regulatory change in Oregon is likely to be a difficult and time-consuming process.

Other barriers include:

- Any shares in the LLC owning the project may need to be registered as securities with the SEC and its state counterpart. As discussed in Section 4.2.1, registering securities at the federal and state level can result in costly legal fees, which are *not* reflected in our cost inputs (i.e., we assume the project qualifies for an exemption from registration).
- The large number of investors likely to be involved can increase the organizational and administrative burden substantially, resulting in higher costs.
- Generation from the project may not be eligible for the PTC.
- Finally, based on the Toronto Renewable Energy Cooperative's experience, any required changes to the utility's billing system may be prohibitively costly, and utility bill savings may be considered taxable income.

6.2.3 Financial Analysis

We presume that investors in an aggregate net-metered project are organized into an LLC, and thus are eligible for the BETC. Because investors in the LLC are likely to be individuals, and the wind turbine is not tied to any particular load, we assume that demand and standby charges do not apply, and investors will earn the full *residential* retail rate (which will serve as the benchmark power price) for their share of the wind turbine's generation.[111]

[111] Whether the project would earn the full retail rate or just the generation portion of that rate is likely to be a contentious issue. If the project is located within the distribution system of the local utility that serves all of the investors, and if the local load always exceeds the wind project's output (i.e., no wind power is ever exported), then the physical impact of an aggregate net metered project is little different than the physical impact of each investor

We assume that the offering would consist of 1,500 shares, with each share equal to 1 kW of capacity. To comply with Oregon's current net metering size limit, no investor would be allowed to purchase more than 25 shares (and most investors would purchase far fewer than 25 shares, as the size of investment would be limited by the amount of electricity consumed).

Table 9. Modeling Results – Aggregate Net Metering

	Aggregate Net Metering	Aggregate Net Metering	Aggregate Net Metering	Aggregate Net Metering
ASSUMPTIONS				
Project Size	1.5 MW	1.5 MW	10.5 MW	10.5 MW
Form of BETC	5-Year	Lump	5-Year	Lump
PTC	No	No	No	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	4.5%	4.5%	4.5%
Corporate Contribution to Equity	0%	0%	0%	0%
Local Contribution to Equity	100%	100%	100%	100%
Landowner-Owned?	No	No	No	No
RESULTS				
Financing (2004 $)				
Corporate Equity	$0	$0	$0	$0
Local Equity	$1,012,941	$522,290	$6,280,946	$3,554,138
Energy Loan Program 10-Yr Debt	$865,687	$899,764	$5,899,969	$6,090,739
BETC Pass-Through	$0	$459,102	$0	$2,550,000
Total Project Cost	$1,878,628	$1,881,156	$12,180,915	$12,194,878
Minimum Local Investment	$675	$348	$598	$338
Number of Shares	1,500	1,500	10,500	10,500
Project Economics (nominal $/MWh)				
Revenue Requirement	$52.23	$53.73	$50.35	$51.54
Benchmark Power Price	$71.00	$71.00	$71.00	$71.00
Revenue Shortfall (Surplus)	($18.77)	($17.27)	($20.65)	($19.46)
After-Tax Internal Rate of Return				
Corporate IRR	NA	NA	NA	NA
Local IRR	10%	10%	10%	10%

The first two columns of Table 9 show modeling results for two 1.5 MW aggregate net-metered projects, one taking the BETC as a 5-year credit, the other as a pass-through payment. Since power is not being sold to an "unrelated person," we assume that the PTC does not apply, meaning that both projects can use tax-exempt debt from the Energy Loan Program without fear of triggering a PTC haircut. For as little as $675 (or $348 with the BETC pass-through), an individual can invest in a utility-scale wind project. In order to earn a 10% after-tax return on investment, revenue (which, in this case comes primarily from power bill savings) of roughly $52-54/MWh is required. Pacificorp's standard residential retail rate (Schedule 4) is well above this requirement, ranging from roughly $64-$78/MWh (a simple average of $71/MWh), depending on which of three usage-based tiers apply. Thus, if this development model were able

installing (and net-metering) an on-site generator equal in capacity to his or her share of the aggregate net-metered project. Thus, one could argue that both types of projects should receive the same price – i.e., the full retail rate.

to clear what are likely to be *significant* regulatory hurdles, and investors were able to offset the *full* residential retail rate rather than just some portion of it,[112] then aggregate net metered projects would likely be economically viable on their own, with investors earning more than the 10% after-tax hurdle rate.[113] The final two columns of Table 9 show similar results for two 10.5 MW projects, differing only in how they take the BETC.

6.3 On-Site, Behind-the-Meter

Presuming that aggregate net metering will be difficult to implement, here we examine more traditional on-site, behind-the-meter community wind projects, including a project owned by a taxable business and a project owned by a tax-exempt entity (such as a town or school). As described in Section 3.1.2, this has been the primary type of community wind development in Iowa to date. We assume that only the 1.5 MW project size is relevant for most on-site applications in Oregon.

6.3.1 Description

This model is fairly straightforward, and involves a large end-use electricity consumer (taxable or tax-exempt, though as explained below, more likely to be tax-exempt) financing and installing a utility-scale wind turbine on the customer side of the meter to supply on-site power and thereby displace power purchased from a utility. As described in Section 3.1.2, this model has been popular among school districts in Iowa due to that state's aggressive net billing law, as well as the prevalence of single-part tariffs among large electricity users (see Section 4.2.2 for more on single- vs. multi-part tariffs). A wind project that offsets the full retail rate a customer pays for electricity – e.g., through net metering, or by displacing power purchases from the utility under a single-part tariff – may provide the highest value to its owners, particularly if tax-exempt (see below).

6.3.2 Barriers

Taxable businesses face a rather unique barrier to installing an on-site wind project (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. This tax quirk has a significant impact – roughly $17/MWh – on revenue requirements. For this reason alone, tax-exempt large electricity users, such as schools, are perhaps more likely than large taxable electricity users to install on-site wind projects.

Whether taxable or tax-exempt, however, projects pursuing this ownership structure are perhaps unlikely to be effective in Oregon, due to the following factors:

- Oregon's 25 kW limit on net metering, as well as the existence of demand and standby charges for large electricity customers – see Section 4.2.2 ("Utility Rate Structures")

[112] For example, Pacificorp's residential *generation supply* charge ranges from $25-38/MWh, which is insufficient on its own to achieve the 10% after-tax hurdle rate.
[113] At an average avoided retail rate of $71/MWh and assuming the same capital structure as presented in the first column of Table 9, the after-tax IRR would equal 19%, or nearly twice the hurdle rate of 10%.

- Power consumed on site is not eligible for the PTC or REPI
- Most of the windy areas of Oregon are sparsely populated, with relatively few large electricity users able to absorb the generation from a modern utility-scale wind turbine – see Section 4.4.3 ("Lack of On-Site Opportunities")
- If candidate sites do exist in Oregon, there is a good chance they will be located in the service territory of a REC, and therefore will not be eligible for Energy Trust support

6.3.3 Financial Analysis

In modeling on-site projects, we assume that a 10.5 MW project is too large to be relevant, and therefore analyze only a 1.5 MW project (we also present a side case of a 250 kW project installed in an agricultural setting). We make the simplifying assumption that all wind power will be consumed on-site, with none exported over the grid. With no sale of excess generation, the PTC and REPI are irrelevant, and even taxable projects are therefore free to make use of tax-exempt (i.e., lower interest) debt from the Oregon Energy Loan Program, without fear of triggering a PTC haircut.

In order to model the taxation of power bill savings (as discussed above in Section 6.3.2), as well as establish the benchmark power price against which revenue requirements will be measured, we need to make some assumptions about how the wind project interacts with the applicable utility tariff. We assume that in order to host a 1.5 MW wind turbine, the project owner would need to be sizable enough to purchase power under Pacificorp's "Large General Service (1,000 kW and Over)," which includes a combination of tariffs from Schedules 47, 48, and 200 (along with a number of supplemental schedules containing various riders and adjustments). We then consider two scenarios, intended to serve as lower and upper bounds:

(1) Power produced by the wind turbine displaces (a) all volumetric charges denominated in $/kWh, (b) 225 kW (i.e., 15% of the nameplate capacity of the wind turbine) from the $/kW Load Size Charge,[114] and (c) zero kW from the $/kW Demand Charge (and therefore no $/kW Standby Charges apply). This case represents a scenario in which the wind turbine's diurnal and seasonal generation profile is not very coincident with the host's load profile.

(2) Power produced by the wind turbine displaces (a) all volumetric charges denominated in $/kWh, and (b) 495 kW (i.e., 33% of the nameplate capacity of the wind turbine) from both the Load Size Charge and Demand Charge (both denominated in $/kW), meaning that 495 kW of Standby Charges also apply. This case represents a scenario in which the wind turbine operates at an average level of capacity (i.e., 33%) during the relevant time periods when the Load Size, Demand, and Standby Charges are being metered and assessed.[115]

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[114] To determine the Load Size Charge, the kW load size "shall be the average of the two greatest non-zero monthly demands established during the 12-month period, which includes and ends with the current billing month." Thus, by assuming that the turbine will displace 15% of its nameplate capacity, or 225 kW, from the Load Size Charge, we are acknowledging that the wind turbine will likely reduce *average* monthly demand somewhat, even if it is does not reduce 15-minute demand for purposes of the Demand Charge.

[115] In one of the author's experience, monthly peak demand reductions of 0-60% of the nameplate capacity rating of a wind turbine bounds the range of likely possibilities, so an assumption of 33%, which tends towards the middle of this range, is not unreasonable.

Assuming the customer takes electric service at primary voltage levels (since it might be difficult or impossible to interconnect a 1.5 MW wind turbine to anything less than the primary voltage system), the $/MWh bill savings generated by the on-site wind project under the two cases above would come to just $33.59/MWh and $36.02/MWh, respectively.[116] These are the benchmark power prices against which the project's revenue requirements will be measured, as well as the prices used to calculate the taxation of the power bill savings for taxable projects.

Table 10. Modeling Results – On-Site

	On-Site Taxable	On-Site Taxable	On-Site Tax-Exempt	On-Site Agricultural
ASSUMPTIONS				
Project Size	1.5 MW	1.5 MW	1.5 MW	250 kW
Form of BETC	5-Year	5-Year	Lump	5-Year
PTC	No	No	No	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	4.5%	4.5%	4.5%
Corporate Contribution to Equity	0%	0%	0%	0%
Local Contribution to Equity	100%	100%	100%	100%
Landowner-Owned?	Yes	Yes	Yes	Yes
Taxable Power Bill Savings (nominal $/MWh)	$33.59	$36.02	NA	$26.07
RESULTS				
Financing (2004 $)				
Corporate Equity	$0	$0	$0	$0
Local Equity	$562,870	$532,665	$529,688	$185,792
Energy Loan Program 10-Yr Debt	$1,308,294	$1,340,920	$859,261	$235,154
BETC Pass-Through	$0	$0	$448,902	$0
Total Project Cost	$1,871,165	$1,873,585	$1,837,851	$420,946
Minimum Local Investment	$562,870	$532,665	$529,668	$185,792
Number of Shares	NA	NA	NA	NA
Project Economics (nominal $/MWh)				
Revenue Requirement	$64.81	$65.98	$46.94	$69.56
Benchmark Power Price	$33.59	$36.02	$33.59	$26.07
Revenue Shortfall (Surplus)	$31.22	$29.96	$13.35	$43.49
After-Tax Internal Rate of Return				
Corporate IRR	NA	NA	NA	NA
Local IRR	10%	10%	10%	10%

The first two columns of Table 10 present the modeling assumptions and results for two taxable projects – the first representing the first scenario above (poor coincidence of generation with load, leading to bill savings of $33.59/MWh), the second representing the second scenario (average coincidence with load, leading to higher bill savings of $36.02/MWh). Both projects take the BETC as a 5-year tax credit, as that is more advantageous (i.e., leads to lower revenue requirements) at a 10% discount rate than taking it as a 25.5% pass-through payment. As shown, the revenue requirements are $64.81/MWh and $65.98/MWh, respectively – roughly $30/MWh

[116] At Secondary Voltage service, the savings increase to $36.44/MWh and $39.24/MWh, respectively. As noted above, these numbers are derived from Pacificorp's "Large General Service (1,000 kW and Over)", which includes a combination of tariffs from Schedules 47, 48, and 200, along with a number of supplemental schedules containing various riders and adjustments.

higher than the benchmark prices of $33.59/MWh and $36.02/MWh. As such, taxable on-site projects are not likely to be a competitive structure in Oregon.[117]

The third column of Table 10 presents assumptions and results for the tax-exempt project (e.g., owned by a school). Because this project has no tax liability, it must take the BETC as a pass-through payment, and does not benefit from depreciation (but on the flip side, it pays no taxes on operating income *or* power bill savings, and we also assume that it pays no property tax). With a revenue requirement of $46.94/MWh, a tax-exempt project is significantly more competitive than a taxable project. Still, a tax-exempt project would require $13.35/MWh of additional revenue (e.g., from the sale of TRCs, or from Energy Trust support) in order to generate a 10% after-tax internal rate of return.

The primary reason that the bill savings ($33.59/MWh and $36.02/MWh) are not greater is the presence of demand and standby charges. What if instead, Oregon's net metering limit were increased to 1.5 MW, and demand and standby charges therefore no longer applied? To answer this question, we turned to the Energy Information Administration (EIA), which tracks average revenue (i.e., with demand and standby charges rolled in) per kWh by sector for each utility in the United States. EIA data from 2002 for Pacificorp show the average retail rate per kWh to be $56.70/MWh for commercial customers, and $41.11/MWh for industrial customers (a volume-weighted average of the two sectors equals $49.97/MWh).[118] A look back at the first three columns of Table 10 shows that if Oregon's net metering size limit were increased to 1.5 MW, Pacificorp's commercial retail rates would likely be high enough to support a 10% after-tax IRR for only the tax-exempt project, while industrial rates would not support any of the projects.[119]

Since an expansion of the net metering size limit from 25 kW to 1.5 MW is quite ambitious, we also looked at the impact of expanding the net metering size limit to a more modest 250 kW. There is currently at least one 250 kW utility-scale turbine, from German manufacturer Fuhrländer, being offered in the United States. Assuming that this turbine has an installed cost of $400,000, or $1,600/kW (based upon Wind 2004), and that annual operating costs are the same (on a $/kW-year basis) as what we have assumed for a 1.5 MW on-site project, the final column of Table 10 above shows that revenue of $69.56/MWh would be required in order to provide the project sponsor with a 10% after-tax internal rate of return. Based on the implied net metering prices calculated in the previous paragraph, neither commercial ($56.70/MWh) nor industrial ($41.11/MWh) rates would reach that hurdle. Another potential use for a turbine of this size – agricultural pumping, which is served by Pacificorp Schedule 41 – is likely to be similarly unattractive, particularly at primary voltage levels, where the effective retail rate is just $26.07/MWh (note that this is the rate used to calculate the taxation of power bill savings in this particular modeling run).

[117] Even assuming that the project receives a USDA Section 9006 grant equal to $440,100 (i.e., 25% of costs), the revenue requirement – at $55.38/MWh – is still well in excess of the benchmark price of $33.59/MWh.
[118] See www.eia.doe.gov/cneaf/electricity/esr/table15.xls and www.eia.doe.gov/cneaf/electicity/esr/table16.xls for data.
[119] Note that the revenue requirements for a taxable project under a net metering situation would be *even higher* than that shown in Table 10, because the power bill savings – which are taxable – would be even greater than assumed in Table 10. Thus, our conclusion that taxable projects are not viable even under a net metering situation is conservative.

In summary, on-site community wind projects are not a particularly economic proposition in Oregon, particularly for taxable projects, which will effectively pay income tax on any bill savings. While a low net metering size limit (25 kW) and multi-part tariffs consisting of demand and standby charges certainly play a large role, our analysis above shows that even if the net metering size limit were increased to 250 kW – or even 1.5 MW – and demand and standby charges no longer applied, owners of on-site, behind-the-meter community wind projects would still largely be unable to achieve a 10% after-tax rate of return. These results are symptomatic of the relatively low retail electricity rates in the hydro-dominated Pacific Northwest, along with the fact that commercial and industrial sectors – i.e., the only customers large enough to consider hosting a 1.5 MW (or even 250 kW) wind turbine – typically pay the lowest retail rates of any customer class. While such projects could be made viable with additional financial support (e.g., from the USDA or Energy Trust), there are other ownership structures described in the remainder of this chapter that perhaps warrant greater attention.

6.4 Multiple Local Owner

We now turn our attention to those community wind power ownership structures that rely on revenue from power sales to an unrelated party (such as a utility). The most straightforward of these involves a number of local investors and landowners joining forces to develop and own a wind power project that sells its generation to a utility. We call this the "multiple local owner" model.

6.4.1 Description

In the multiple local owner model, one or more project sponsors conceive of a community wind project, and then solicit sufficient equity investment to support the project from among the local 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. The LLC obtains debt from a local bank, or in Oregon, perhaps the Energy Loan Program. The project sells power to a utility through a negotiated 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.

6.4.2 Barriers

Though in concept the "multiple local owner" structure is quite straightforward, there are a number of barriers to making it also be profitable:

- Shares in a community wind project will most likely be considered "securities," and so will either need to be registered as such at the federal and state levels, or alternatively the project may be able to apply for an exemption from securities registration. Either alternative requires expensive legal assistance, though applying for an exemption requires far less than registration. Our 1.5 MW project cost assumptions assume that the multiple local owner model incurs an additional $10,000 in legal expenses (relative to the Minnesota-style flip structure) to cover the cost of applying for an exemption from securities registration. Actual registration would result in substantially higher legal costs. See Section 4.2.1 for a more detailed discussion of securities regulation.

- Once the project has sold all of its shares and raised sufficient equity, keeping the multitude of investors informed, organized, and satisfied will require greater administrative expense than most other ownership structures evaluated. Our 1.5 MW project operating cost assumptions assume that the *multiple local owner* model will incur twice as much administrative expense as a *Minnesota-style flip* structure ($10,000 vs. $5,000 per year).

- In the absence of an attractive standard offer PURPA contract, this ownership structure will need to identify a willing purchaser of wind power, and negotiate a workable power purchase agreement. This was reportedly the largest hurdle to the first two Minwind projects (Arends 2002). In Oregon, in order for a project to receive support from the Energy Trust, the power purchaser will need to be one of two utilities – Pacific Power or PGE – and power may need to be wheeled to either utility through a REC. See Section 4.4.4 for additional information on identifying and securing potential revenue sources.

- Finally, investors will ideally have state and federal income tax liability against which to offset depreciation as well as the BETC and the PTC, and thereby enhance their rate of return. 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 in Section 4.1.1, very few individual investors have passive income, which includes rental income, but *does not* include interest and dividend income. On the other hand, farmers – who are perhaps more likely than others to invest in a community wind project – may in many instances have at least some passive income from renting out fields, pastures, or even machinery. Furthermore, since the BETC reduces the value of the PTC by roughly 25% (and a Section 9006 USDA grant, if applicable, would have a similar effect), the amount of passive tax liability needed to fully utilize the PTC is correspondingly lower as well.[120] Our base case modeling results presented below assume that all investors are able to fully and efficiently utilize all tax benefits of the project. Figure 2 then demonstrates what happens when we relax that assumption.

6.4.3 Financial Analysis

Table 11 below shows the base case modeling results for the *multiple local owner* structure. The two 1.5 MW projects shown in the table differ only in how they take the BETC – either as a 5-year credit (in the first column) or a lump-sum pass-through payment (in the second column). The same holds true for the two 10.5 MW projects in the final two columns. As shown in the *Results* section of Table 11, the two sets of projects have revenue requirements that are close to the benchmark power prices of $39.40 (1.5 MW) and $34.60 (10.5 MW) provided by the Energy Trust, suggesting that these projects require little if any additional support in order to meet or

[120] In our base case modeling run for a 1.5 MW project, each of the 212 equity shares (at $5000/share) in the project will produce about $288/year in PTC benefits on average, after accounting for the BETC haircut. With the addition of a 25% USDA grant, which increases the haircut, PTC benefits drop to $189/year on average. Thus, ignoring the potential impact of the Alternative Minimum Tax, it does not take very much passive income to enable efficient use of the PTC from a single share in the project.

exceed the 10% after-tax hurdle rate. In that same row, also note that it is more advantageous (i.e., resulting in a lower revenue requirement) for the project to take the BETC as a 5-year credit rather than as a pass-through payment.[121] Even so, however, we recognize that *multiple local owner* projects may instead opt for the pass-through payment, since doing so significantly reduces the amount of equity needed to be raised (e.g., for the 1.5 MW project, from 212 down to 115 shares, at $5,000 per share), and may also therefore reduce the risk of not being able to use the PTC in the future. Regardless of how it is taken, the BETC is worth proportionally less to the 10.5 MW projects than it is to the 1.5 MW projects, due to the $10 million cap on eligible costs (as shown, the 10.5 MW projects cost in excess of $12 million). As a result, an optimum project size may be a slightly smaller project that is still able to realize some economies of scale yet costs no more than $10 million (of course, the outcome of the OPUC's PURPA proceeding may drive the optimum project to a different size corresponding to the size limit on standard offer contracts).

Table 11. Modeling Results – Multiple Local Owner

	Multiple Local Owner	**Multiple Local Owner**	**Multiple Local Owner**	**Multiple Local Owner**
ASSUMPTIONS				
Project Size	1.5 MW	1.5 MW	10.5 MW	10.5 MW
Form of BETC	5-Year	Lump	5-Year	Lump
PTC	Yes	Yes	Yes	Yes
Energy Loan Program 10-Yr Debt Interest Rate	5.5%	5.5%	5.5%	5.5%
Corporate Contribution to Equity	0%	0%	0%	0%
Local Contribution to Equity	100%	100%	100%	100%
Landowner-Owned?	No	No	No	No
RESULTS				
Financing (2004 $)				
Corporate Equity	$0	$0	$0	$0
Local Equity	$1,062,308	$575,615	$6,599,579	$3,935,740
Energy Loan Program 10-Yr Debt	$815,133	$845,036	$5,575,089	$5,698,336
BETC Pass-Through	$0	$459,102	$0	$2,550,000
Total Project Cost	$1,877,440	$1,879,753	$12,174,668	$12,184,076
Minimum Local Investment	$5,000	$5,000	$5,000	$5,000
Number of Shares	212	115	1,320	787
Project Economics (nominal $/MWh)				
Revenue Requirement	$38.58	$39.67	$35.85	$36.74
Benchmark Power Price	$39.40	$39.40	$34.60	$34.60
Revenue Shortfall (Surplus)	($0.82)	$0.27	$1.25	$2.14
After-Tax Internal Rate of Return				
Corporate IRR	NA	NA	NA	NA
Local IRR	10%	10%	10%	10%

[121] As noted in Section 5.4.2, this is because at the local investor's 10% discount rate, the net present value of the 5-year tax credit is 27.6%, greater than the regulated 25.5% pass-through rate. Interestingly, the opposite is true for corporate investors, whose assumed 15% discount rate is high enough to reduce the net present value of 5-year credit stream to 24.9%, below the 25.5% pass-through rate. Thus, all else equal, corporate equity should always prefer the pass-through payment, while local equity should always prefer the 5-year credit (assuming that local, individual investors have sufficient Oregon state tax liability to absorb the 5-year BETC).

Using as a base case the first column of Table 11 above (i.e., a 1.5 MW project that takes the BETC as a 5-year credit), Table 12 below presents a number of sensitivity cases around that base case. In the first column of Table 12, we assume that the project secures a Section 9006 USDA grant equal to 25% of project costs (i.e., $450,100). Even though we treat the grant as taxable income, and it (along with the BETC) causes a PTC haircut, the USDA grant has the impact of reducing the number of shares in the project (from 212 to 172), as well as the revenue requirement (from $38.58/MWh to $33.35/MWh).

In the second column, we assume that the project is located within a Rural Renewable Energy Enterprise Zone, and is therefore exempt from paying property taxes for five years. Property tax payments resume as normal in the sixth year, at which point the project is assessed at 60% of its original value (the assessed value declines by 8% per year until reaching 20% in the eleventh year, at which point it remains flat through the twentieth year). This exemption has little impact on the capital structure of the project, but reduces operating costs sufficiently in the first five years to lower the revenue requirement from $38.58/MWh to $37.08/MWh.

In the third column, we assess what would happen if the Energy Loan Program did not allow the PTC and BETC to be "monetized" and applied towards debt service coverage (or alternatively, what would happen if a project were forced to seek a similar loan from a commercial bank that does not permit PTC/BETC monetization).[122] In order to meet the debt service coverage ratio under this scenario, the debt/equity ratio must decrease (e.g., the number of equity shares increases from 212 to 266) and the revenue requirement must increase (from $38.58/MWh to $41.26/MWh). Thus, the Energy Loan Program's aggressive position on this issue is worth nearly $3/MWh to the project, and transforms the project from one that would otherwise require modest additional support (to reach the 10% after-tax return hurdle) to one that may be viable on its own.

In the final column, we examine a scenario in which the PTC is not renewed. In this case, the project opts for tax-exempt debt (at 4.5% interest), since double-dipping is no longer a concern. As shown, the revenue requirement increases from $38.58/MWh to $52.23/MWh.[123] It is perhaps worth noting that in a no-PTC environment, "flip" structures (see next two sections) lose their primary purpose (i.e., capturing the PTC), and so the *multiple local owner* model would likely become the default community wind development model for *taxable* investors selling power to an unrelated party. With revenue requirements of $52.23/MWh, however, such projects would require nearly $13/MWh of additional revenue (e.g., from TRC sales or financial

[122] Note that disallowing monetization of at least the PTC may be wise under this particular ownership structure, given the relative uncertainties surrounding the tax efficiency of the project. If some portion of the local investors are likely to be unable to use the PTC (or at least not as much of it as originally envisioned), then the true debt service coverage ratio could be far lower than that projected in the pro forma. This is not as much of an issue with the BETC, which can be credited against ordinary income, or alternatively, taken as a lump-sum pass-through payment. Furthermore, the BETC is not dependent on production, and so is less risky in that sense as well.

[123] This difference of $13.65/MWh should *not* be considered the full value of the PTC to community wind projects, since the PTC is not fully utilized in the base case (due to a haircut triggered by the BETC) and because the sensitivity case assumes a lower debt interest rate than in the base case (4.5% rather than 5.5%). Both of these factors dampen the impact of transitioning to a no-PTC environment.

support from the USDA or Energy Trust) above the benchmark power price in order to reach the 10% after-tax hurdle rate.

Table 12. Sensitivity Results – Multiple Local Owner

	25% USDA Grant	5-Yr Property Tax Exemption	No Monetization	No PTC
ASSUMPTIONS				
Project Size	1.5 MW	1.5 MW	1.5 MW	1.5 MW
Form of BETC	5-Year	5-Year	5-Year	5-Year
PTC	Yes	Yes	Yes	No
Energy Loan Program 10-Yr Debt Interest Rate	5.5%	5.5%	5.5%	4.5%
Corporate Contribution to Equity	0%	0%	0%	0%
Local Contribution to Equity	100%	100%	100%	100%
Landowner-Owned?	No	No	No	No
RESULTS				
Financing (2004 $)				
Corporate Equity	$0	$0	$0	$0
Local Equity	$859,835	$1,099,311	$1,327,588	$1,012,941
Energy Loan Program 10-Yr Debt	$546,750	$775,028	$527,618	$865,687
BETC Pass-Through	$0	$0	$0	$0
USDA Grant	$450,100	$0	$0	$0
Total Project Cost	$1,856,685	$1,874,339	$1,855,206	$1,878,628
Minimum Local Investment	$5,000	$5,000	$5,000	$5,000
Number of Shares	172	220	266	203
Project Economics (nominal $/MWh)				
Revenue Requirement	$33.35	$37.08	$41.26	$52.23
Benchmark Power Price	$39.40	$39.40	$39.40	$39.40
Revenue Shortfall (Surplus)	($6.05)	($2.32)	$1.86	$12.83
After-Tax Internal Rate of Return				
Corporate IRR	NA	NA	NA	NA
Local IRR	10%	10%	10%	10%

With the exception of the "No PTC" run in Table 12, all other modeling runs in this section look reasonably attractive, with revenue requirements either under or within reach of the presumed benchmark power prices. We stress, however, that these cases all (again, with the exception of the "No PTC" run) assume that the project is able to efficiently utilize the PTC and other tax benefits. As noted above and in Section 4.1.1, 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-efficient than originally envisioned, and although the per-share PTC allocation is rather modest (see footnote 120), achieving 100% tax efficiency is perhaps overly optimistic.

With this in mind, Figure 2 below shows the impact on revenue requirement of relaxing the PTC efficiency assumption, for both the 1.5 and 10.5 MW projects.[124] As shown, the 1.5 MW project is only economically viable (relative to the presumed benchmark power price of $39.40/MWh)

[124] 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 a PTC "haircut."

on its own at relatively high PTC efficiency assumptions (i.e., >90%), while the 10.5 MW project would still require additional support or TRC revenue (relative to the presumed benchmark power price of $34.60/MWh) even assuming 100% PTC efficiency.[125] Furthermore, as will be demonstrated in the next section, Minnesota-style flip structures, which are perhaps the primary alternative to the *multiple local owner* model, are likely to be more advantageous (at least in terms of having a lower revenue requirement) once the PTC efficiency of the multiple local owner model falls below about 65%.

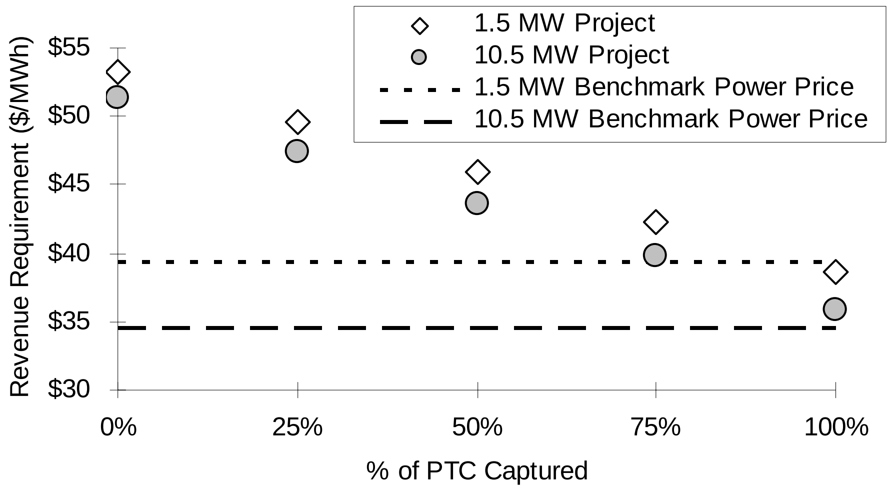

Figure 2. Revenue Requirement as a Function of PTC Efficiency

Another assumption that involves a great deal of uncertainty is the after-tax IRR required by locals investing in a community wind project. While we assume an after tax hurdle rate of 10% in our base case, it is equally easy to imagine local investors demanding either less or more than 10%. To address this uncertainty, Figure 3 below shows the impact on revenue requirement (in the *multiple local owner* structure) of varying the local after-tax hurdle rate between 5% and 15% (i.e., 5% on either side of our base-case assumption of 10%). The difference in revenue requirement over this range is roughly $11-12/MWh. All else equal, the 1.5 MW project is viable without further support at hurdle rates of 11% or less, while 9% is the corresponding IRR threshold for the 10.5 MW project.

[125] In fact, the economics would likely deteriorate even more than shown in Figure 2, which continues to assume that PTC monetization to meet debt service coverage is possible, even at low levels of PTC capture.

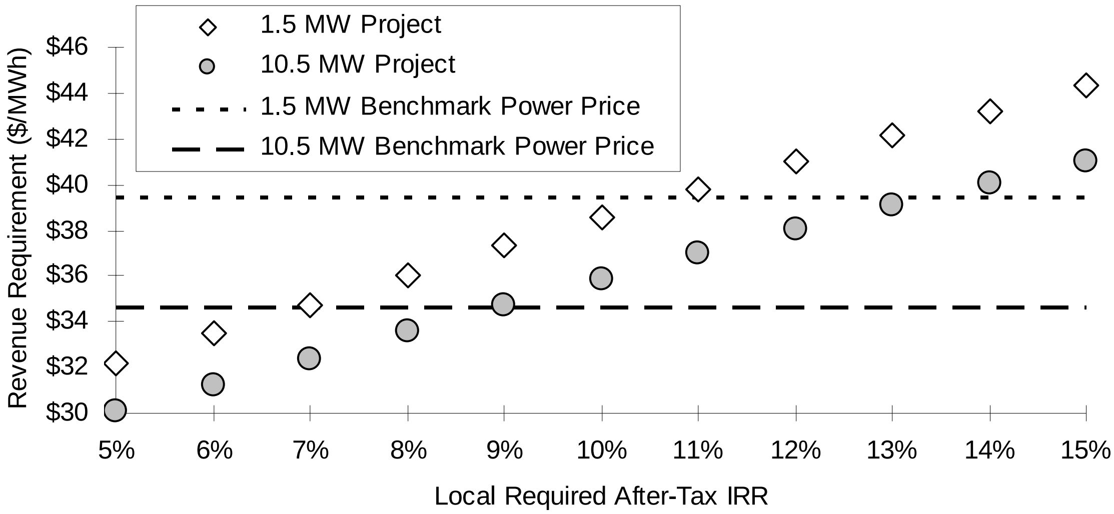

Figure 3. Revenue Requirement as a Function of Local Required After-Tax IRR

In addition to the cost of equity, the cost of debt is also uncertain, and will change with market interest rates. In addition, if taxable loans from the Energy Loan Program are found to trigger a PTC haircut, then community wind projects will likely instead seek commercial sources of debt (e.g., from local banks), which might be provided on less favorable terms. Assuming that the 10-year debt interest rate is 7% instead of our base-case assumption of 5.5%, but all other terms match the base case, the 1.5 MW project's revenue requirement increases from $38.58 in the base case to $40.02 – a modest increase of $1.44/MWh. At a 7% interest rate *and* no monetization of the PTC or BETC towards debt service coverage, the revenue requirement increases further to $42.19/MWh.

In summary, the multiple local owner model is quite attractive (in terms of having a low revenue requirement, a low minimum investment hurdle, and pure local ownership) if one assumes that high levels of PTC efficiency can be achieved, and that local hurdle rates are at or below our base case assumption of 10%. This structure is not highly sensitive to debt interest rates (within the range of plausible rates), but the combination of a slightly higher interest rate *and* the loss of PTC and BETC monetization towards debt service coverage – i.e., terms that are both perhaps likely to be encountered at a local bank – is noticeable, and highlights the importance of the Energy Loan Program.

6.5 Minnesota-Style "Flip" Structure

One way to address the problem of individual local investors likely not being able to efficiently utilize the PTC is for the locals 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.

6.5.1 Description

As developed in Minnesota, this structure involves a local farmer/landowner who wishes to develop a small wind project on his land (in Minnesota, such projects have typically been under 2 MW in order to qualify for the state's 1.5¢/kWh 10-year production incentive), but has little or no tax liability against which to utilize the PTC. To improve the economics of the project (such that selling to Xcel Energy under its small wind tariff of 3.3¢/kWh becomes profitable), 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. 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%.[126]

During the first 10 years of the project (or potentially longer if the corporate partner's hurdle rate is for some reason not reached at the end of 10 years), 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%). In many instances (at least in Minnesota, where Xcel's small wind tariff combined with the state production incentive is sufficient to allow it) the LLC also pays the local partner a "management fee," ostensibly for managing the project, but also as a way to supplement the local partner's income from the project during the first 10 years.[127]

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 income for at least another 10 years.

6.5.2 Barriers

While devising and implementing this ownership structure was no doubt a formidable hurdle in and of itself, with the structure now in place and being demonstrated throughout southwestern Minnesota, the two largest remaining barriers involve finding and engaging a corporate equity partner and identifying (and negotiating with) potential revenue sources. In Minnesota, most flip

[126] For purposes of complying with legislative requirements that projects be owned by certain entities in order to qualify for the state production incentive, the local partner maintains 51% voting rights in the project, despite having invested far less than that percentage of equity in the project.

[127] Note that project management activities performed by the local partner may be sufficient to substantiate the local partner as an "active" investor in the eyes of the IRS, meaning that the local partner can apply its portion of the PTC against ordinary, rather than passive, income. The payment of a management fee to the local partner may serve to strengthen the claim that the local partner is an active investor. In such cases where the local partner plans to actively manage the project and is relatively certain that it will be viewed as an active investor by the IRS, the local partner may wish to take a larger equity share (than just 1%) in the project, to capture more of the PTC.

projects have sold power to Xcel through its small wind tariff; Oregon currently has no viable equivalent, although a proceeding before the Oregon Public Utilities Commission concerning revisions to standard PURPA contracts may soon change that (see Section 4.4.4 for more on this proceeding).

6.5.3 Financial Analysis

All modeling results presented in this section assume that the original LLC ownership split is 99% corporate, 1% local. We also assume that the projects are "landowner-owned," which means that the land lease payment made by the LLC flows directly to the local partner (though as a distinct taxable entity from the LLC) as taxable income. Although our model allows for a management fee to be paid to the local partner if necessary to reach the 10% after-tax hurdle rate, in none of our modeling runs does this appear to be necessary.

In fact, as shown in the first two columns of Table 13 below, which presents our modeling results for a 1.5 MW and 10.5 MW project taking the BETC as a pass-through payment, the local partner's after-tax IRR equals 87% – *well in excess of* the 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 debt service coverage ratios, the project must earn a certain amount of revenue (e.g., $44.28/MWh, in the first column of Table 13). 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.[128] 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%.[129] If the local partner's equity stake in the project were 10% instead of just 1%, its after-tax IRR would fall to 33%, while the revenue requirement would not change (because the corporate partner's hurdle rate remains the constraining factor).

Presumably the local partner can command, and the corporate partner is willing to concede, such 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, in Minnesota at least, 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.

[128] In fact, the local partner's IRR during the first 10 years exceeds the corporate partner's IRR, due to the flow-through of the land lease payment as described above. Different income tax rates faced by the corporate and local partners will also impact the comparability of returns. Because the local partner's IRR greatly exceeds the assumed 10% *required* IRR, this structure – unlike the *multiple local owner* structure described in Section 6.4 – is not at all sensitive to changing assumptions about local hurdle rates of return. It is, however, sensitive to changes in assumed *corporate* hurdle rates; that said, our base-case assumption about corporate hurdle rates is much less uncertain than our base-case assumption about local hurdle rates.

[129] In Minnesota, where additional project management fees are often paid to the local partner as a means of bolstering local income during the project's first 10 years (see Section 5.2.5), the local partner's projected IRR is often even higher. For example, using the same assumptions from the first column of Table 13, and setting the local management fee equal to about $20,000/year (not unusual in Minnesota), the revenue requirement increases to $48.93/MWh, and the local partner's after-tax IRR increases to 395%.

Second, the local partner – who more than likely lives near the project site – may provide at least some project oversight (though may be explicitly compensated for that service through the owner management fee described above). 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 essentially withdraw from the project after 10 years has some value.

Table 13. Modeling Results – Minnesota-Style Flip

	MN Flip	MN Flip	MN Flip	MN Flip
ASSUMPTIONS				
Project Size	1.5 MW	10.5 MW	1.5 MW	10.5 MW
Form of BETC	Lump	Lump	Lump	Lump
PTC	Yes	Yes	Yes	Yes
Energy Loan Program 10-Yr Debt Interest Rate	5.5%	5.5%	5.5%	5.5%
Corporate Contribution to Equity	99%	99%	99%	99%
Local Contribution to Equity	1%	1%	1%	1%
Landowner-Owned?	Yes	Yes	Yes	Yes
RESULTS				
Financing (2004 $)				
Corporate Equity	$421,900	$2,966,676	$573,205	$3,922,738
Local Equity	$4,262	$29,966	$5,790	$39,624
Energy Loan Program 10-Yr Debt	$998,860	$6,639,257	$833,217	$5,593,730
BETC Pass-Through	$456,552	$2,550,000	$456,552	$2,550,000
"Transfer Payment" from Local to Corporate†	$0	$0	$143,906†	$908,931†
Total Project Cost	$1,881,574	$12,185,900	$1,868,764	$12,106,091
Minimum Local Investment	$4,262	$29,966	$149,696	$948,554
Number of Shares	NA	NA	NA	NA
Project Economics (nominal $/MWh)				
Revenue Requirement	$44.28	$40.94	$38.04	$35.31
Benchmark Power Price	$39.40	$34.60	$39.40	$34.60
Revenue Shortfall (Surplus)	$4.88	$6.34	($1.36)	$0.71
After-Tax Internal Rate of Return				
Corporate IRR	15%	15%	15%	15%
Local IRR	87%	87%	10%	10%

†This transfer payment is not tied to equity in the project, and thus does not impact the corporate and local share of equity in the project. It does, however, effectively increase the amount of local, and decrease the amount of corporate, *investment* in the project. The numbers in the *Corporate Equity* and *Local Equity* rows of the table represent equity investments, and are not adjusted downwards and upwards, respectively, by the amount of the transfer payment. As such, the total of all rows in this part of the table does not equal the *Total Project Cost*.

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 is higher than it needs to be – $44.28/MWh for a 1.5 MW project, and $40.94 for a 10.5 MW project. These requirements are roughly $5-6/MWh higher than the applicable benchmark power purchase agreement prices provided by the Energy Trust of Oregon.[130]

One way to optimize the model such that the local partner is constrained to the 10% after-tax hurdle rate is to assume that the local partner makes a cash "transfer payment" to the corporate partner at project inception. We refer to this as a transfer payment, rather than the local partner taking a greater stake in the project, because the cash is *not* tied to an equity position – the local partner essentially pays the corporate partner a fee for participating in the project.[131] In the model, the size of the transfer payment equals the amount needed to reduce the local partner's IRR from 87% down to the 10% after-tax hurdle rate. As shown in the third column of Table 13 above, the transfer payment equals $143,906, which brings the local partner's total investment in the project – i.e., equity contribution plus transfer payment – to $149,696 (and, though not shown, reduces the corporate partner's net investment in the project to $429,299). With the local partner now earning a lower return (10%), the revenue requirement drops accordingly, to $38.04/MWh, which is $1.36/MWh *below* the benchmark power price of $39.40/MWh. The final column of Table 13 shows similar results for a 10.5 MW project involving a transfer payment.

The idea of a "transfer payment" to constrain the local partner's return is, at this time, purely a modeling exercise. Whether such a payment is likely to ever happen in the real world potentially depends in part on which partner conceives of and controls the project. If it is the local farmer/landowner who offers the corporate investor a chance to earn a 15% after-tax return on investment, then no transfer payment is likely. If instead it is the corporate investor who offers the landowner (e.g., as a means of securing a site) the opportunity to earn a 10% after-tax return on investment, then perhaps the corporate partner will extract something akin to a transfer payment in order to constrain the local partner's return to 10%. To date in Minnesota, the locals appear to have had the upper hand, and as such are able to earn above-normal returns on investment.

[130] Though not shown in Table 13, a 25% USDA grant equal to $447,600 would reduce the 1.5 MW project's revenue requirement to $37.83/MWh, while increasing the local IRR to 111%. While this grant would make the project viable without further support, it is worth noting that it may be particularly difficult for Minnesota-style flip projects to secure a USDA grant, since each applicant must demonstrate financial need – likely to be a hard sell in the presence of corporate equity partners and triple-digit after-tax IRRs. A USDA grant has little impact on the 10.5 MW project, due to the $500,000 cap on the grant.

[131] Simply increasing the local partner's share of equity investment in the project also serves to reduce the local partner's IRR, but not down to the desired 10%. To reach 10%, the level of investment must be at least partially de-coupled from the share of equity in the project – the transfer payment accomplishes this.

6.6 Wisconsin-Style "Flip" Structure

In addition to the "transfer payment" discussed in the previous section, a second way to limit the excess returns earned by the local partner in the Minnesota-style flip structure 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). In 2003, Cooperative Development Services of Madison, Wisconsin, released a report titled *Wisconsin Community Based Windpower Project Business Plan* that describes a structure that effectively accomplishes this de-coupling by having the local investors initially provide debt, rather than equity, financing to the project. This section describes this ownership structure, which we call a "Wisconsin-style flip structure" in order to distinguish it from the closely related Minnesota-style flip structure previously described.[132]

6.6.1 Description

As described in the *Wisconsin Business Plan*, a group of local investors with limited or no tax 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 tradable renewable certificates (TRCs). 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.[133] 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%* (rather than 1%) stake in the project. This distinction has at least two interesting implications: (1) the required level of local investment is higher than under the Minnesota-style flip, and (2) the local

[132] Technically, the Wisconsin model is not a true flip structure, but rather involves an outright sale of the project after 10 years. We do, however, call this structure a "flip" because, like in Minnesota, project ownership flips from the corporate to the local investors at the end of ten years.

[133] 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.

LLC is able to re-depreciate the project starting in year 11 using 10-year straight-line depreciation with the starting basis equal to the locals' debt principal.[134]

6.6.2 Barriers

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 high (we assume they match those incurred by the *multiple local owner* model presented earlier). 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. Identifying and engaging a corporate equity partner could present another barrier, as could finding a willing off-taker and negotiating a suitable power purchase agreement.

In addition, it is important to note that this ownership structure has yet to be implemented, and so has not been vetted as thoroughly as some of the 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 contained in this model, where the two parties agree at project inception on the sales price 10 years hence. Further investigation is warranted.

6.6.3 Financial Analysis

The first two columns of Table 14 below show our base case modeling runs for this structure: a 1.5 MW and 10.5 MW project shown taking the BETC as a pass-through payment (again, because corporate equity, with its higher discount rate, is involved). 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 required number of local shares in the project – i.e., 27 for a 1.5 MW project – is low compared to some of the other structures involving multiple local owners, and suggests that this structure may have an easier time than others qualifying for an exemption from securities registration. Finally, the revenue requirements are lower than those seen in the Minnesota-style flip structures (without transfer payments), primarily because here it is possible to limit the local investor to the 10% after-tax hurdle rate (recall that this was *not* possible under the Minnesota-style flip structure, without a transfer payment). Even so, at $41.18/MWh and $37.82/MWh, respectively, the 1.5 MW and 10.5 MW projects are still $1.78/MWh and $3.22/MWh above the benchmark power prices.

[134] On a levelized basis, this re-depreciation is not worth much (we calculate only about $0.4/MWh), both because the value being depreciated is small (i.e., not the original cost of the project, but rather what the LLC paid for it), and because the depreciation occurs in years 11-20, and so is heavily discounted.

Table 14. Modeling Results – Wisconsin-Style Flip

	WI Flip	WI Flip	WI Flip	WI Flip
ASSUMPTIONS				
Project Size	1.5 MW	10.5 MW	1.5 MW	10.5 MW
Form of BETC	Lump	Lump	Lump	Lump
PTC	Yes	Yes	Yes	Yes
Energy Loan Program 10-Yr Debt Interest Rate	5.5%	5.5%	5.5%	5.5%
Local 10-Yr Debt Interest Rate	7.0%	7.0%	7.0%	7.0%
Corporate Contribution to Equity	100%	100%	100%	100%
Local Contribution to Equity[1]	0%[1]	0%[1]	0%[1]	0%[1]
Landowner-Owned?	No	No	No	No
RESULTS				
Financing (2004 $)				
Corporate Equity	$402,509	$2,850,013	$227,482	$2,651,355
Local Equity	$0	$0	$0	$0
Energy Loan Program 10-Yr Debt	$885,186	$5,899,358	$644,071	$5,632,041
Local 10-Yr Debt	$136,062	$900,050	$83,456	$845,620
BETC Pass-Through	$459,102	$2,550,000	$459,102	$2,550,000
USDA Grant	$0	$0	$450,100	$500,000
Total Project Cost	$1,882,858	$12,199,421	$1,864,212	$12,179,016
Minimum Local Investment	$5,000	$5,000	$5,000	$5,000
Number of Shares	27	180	17	117
Project Economics (nominal $/MWh)				
Revenue Requirement	$41.18	$37.82	$36.45	$37.12
Benchmark Power Price	$39.40	$34.60	$39.40	$34.60
Revenue Shortfall (Surplus)	$1.78	$3.22	($2.95)	$2.52
After-Tax Internal Rate of Return				
Corporate IRR	15%	15%	15%	15%
Local IRR	10%	10%	10%	10%

[1] In this structure, the local contribution comes in the form of debt, not equity.

The final two columns of Table 14 show the impact of adding a 25% USDA grant, capped at $500,000 for the 10.5 MW project. As shown, the 1.5 MW project becomes viable under the USDA grant, while the 10.5 MW project is little changed from the base case, due to the cap on the size of the grant.

6.7 Town-Owned

Finally, we examine the possibility of a town-owned wind project selling power to a utility. Note that we are *not* referring to ownership of a wind project by a municipal utility serving end-use customers – per Chapter 1, municipal utility ownership is excluded from our definition of community wind. Nor are we referring to town-owned wind projects used to offset on-site power consumption at municipal facilities – such projects have already essentially been covered in Section 6.3, through the tax-exempt model run. Rather, in this section we focus exclusively on town-owned projects that are not related to municipal utilities, and that sell their power to a utility. This is a model currently being pursued in Massachusetts through the *Community Wind Collaborative* (see Section 3.1.5 for more on the Collaborative). It is also a model being pursued by a school district (which can be thought of as part of a municipality) in Northfield, Minnesota.

6.7.1 Description

In this structure, a town or municipality (again – *not a municipal utility*) finances and owns a utility-scale wind project, and sells the power to a utility for the purposes of generating revenue to support the town budget. Since the project is owned by the town and presumably constructed on town-owned land, no land lease or property tax payments are required. Furthermore, it may be possible for the town to finance the project by issuing low-interest, tax-exempt municipal bonds, though as discussed below, this appears to be unlikely. If the Renewable Energy Production Incentive (REPI) is re-authorized, or alternatively a tradable PTC is implemented, the project would benefit from such incentives. Town-owned projects, however, are not eligible for USDA Section 9006 grants, which are reserved for agricultural producers and rural small businesses.

6.7.2 Barriers

Though relatively straightforward, this community wind structure is fraught with potential barriers. First, it is far from clear whether towns are even able to own electricity generation projects (other than for on-site self-generation) in the first place. Chretien and Wobus (2003) present a legal opinion on this question for Massachusetts (in relation to the *Community Wind Collaborative*), which finds that cities and towns in Massachusetts *do* have the authority to construct and own wind projects. In February 2004, however, the Minnesota Attorney General ruled (in relation to the planned Northfield School District project) that Minnesota school boards are *not* authorized to own wind turbines, since wind turbines are not "directly related to the services or activities in which the district participates" (AWEA 2004a). The Minnesota legislature has since drafted a bill (signed into law on May 19, 2004) specifically authorizing schools to own up to 3.3 MW of wind power capacity, provided they also integrate wind power into their curriculum (AWEA 2004a). In Oregon, Sherman County was initially interested in owning or investing in a community wind project, but has ultimately settled for a non-equity interest due to legal issues that restrict the county from being a business partner in a for-profit company (Woodin 2004). In short, this is an issue that would need to be resolved before pursuing this type of ownership structure.

Second, even if a town is authorized to own a wind project, it is perhaps unlikely that it will be able to finance it using low-interest tax-exempt municipal bonds. The use of tax-exempt municipal bonds may be possible if the project's power will primarily be consumed on site, but if power is sold to a utility (as we assume in this case), 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").[135] As such, the bonds will be characterized as "private activity" bonds, and 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. In Oregon, however, the magnitude of this particular barrier is muted, due to the ability of any project – taxable or tax-exempt – to obtain a tax-exempt loan from Oregon's Energy Loan Program.[136]

Opportunities for participation by local residents are also relatively weak, and are limited to the indirect benefit of potentially reduced municipal tax payments (presuming the project generates revenue for the town coffers) or increased municipal services, as well as possibly investing in and earning a return on municipal bonds used to finance the project (if possible). Alternatively, local residents or businesses could serve as BETC pass-through partners for the project.

Finally, as with all projects selling power to third parties, this structure also faces the more mundane but critical barrier of finding a long-term power and TRC purchaser.

6.7.3 Financial Analysis

Table 15 shows our modeling results for a 1.5 MW and 10.5 MW town-owned project. Given the issues raised above concerning the "private use" of municipal bonds, we assume that the project instead makes use of a tax-exempt loan (at 4.5%) from the Energy Loan Program. Because towns are tax-exempt entities, the project must take the BETC as a pass-through payment, and the benefits of the PTC and depreciation are not available (of course, the flip side is that income from the project is not taxable). Given the uncertainty surrounding re-authorization of the REPI or the future implementation of a tradable PTC, or the amount of value that could ultimately be extracted from such incentives, the base-case results presented here presume that the project is only able to capture 50% of the REPI or tradable PTC (we test this assumption with a sensitivity analysis presented below in Figure 4).[137] Under these assumptions, revenue requirements are relatively low, but not sufficiently low (as compared to the benchmark power prices) to avoid the need for additional support (or TRC sales revenue).

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[135] The sale of tradable renewable certificates (TRCs) from the facility might also be considered private business use.

[136] Because the Oregon Department of Energy adds 100-150 basis points to the bond yield in order to finance the activities of the Energy Loan Program, however, tax-exempt loans from the Energy Loan Program may not be as attractive as tax-free municipal debt.

[137] This assumption is broadly consistent with our base-case assumption for all other modeling runs that the PTC will be extended. In this case, however, we assume that a project is only able to capture 50% of the full value of the REPI because even if it is extended, it will likely be under-funded (or alternatively, if a tradable PTC is implemented, it will likely have to be sold at a discount).

Table 15. Modeling Results – Town-Owned

	Town-Owned	Town-Owned
ASSUMPTIONS		
Project Size	1.5 MW	10.5 MW
Form of BETC	Lump	Lump
PTC	No	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	4.5%
Corporate Contribution to Equity	0%	0%
Local Contribution to Equity	100%	100%
Landowner-Owned?	Yes	Yes
% of REPI/Tradable PTC Captured	50%	50%
RESULTS		
Financing (2004 $)		
Corporate Equity	$0	$0
Local Equity	$452,026	$3,042,093
Energy Loan Program 10-Yr Debt	$967,530	$6,567,692
BETC Pass-Through	$456,522	$2,550,000
Total Project Cost	$1,876,108	$12,159,786
Minimum Local Investment	$452,026	$3,042,093
Number of Shares	NA	NA
Project Economics (nominal $/MWh)		
Revenue Requirement	$40.03	$38.69
Benchmark Power Price	$39.40	$34.60
Revenue Shortfall (Surplus)	$0.63	$4.09
After-Tax Internal Rate of Return		
Corporate IRR	NA	NA
Local IRR	10%	10%

Moreover, as shown in Figure 4 below, revenue requirements are highly dependent on the degree to which the project can access the REPI or a tradable PTC, and range from roughly $32/MWh to $47/MWh. For a town-owned project to match the benchmark power prices of $39.40/MWh and $34.60/MWh (for the 1.5 MW and 10.5 MW projects, respectively), one would have to assume capture rates of roughly 50% and 75%.

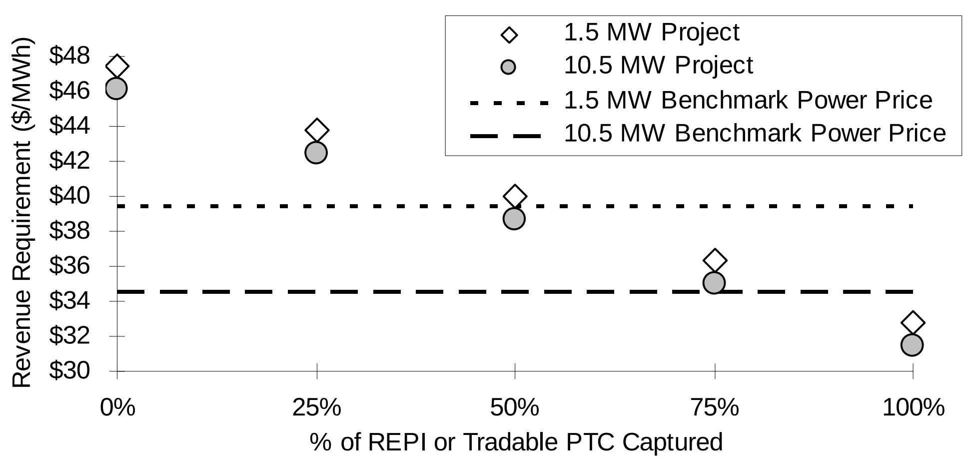

Figure 4. Revenue Requirement as a Function of REPI Availability

6.8 Summary

To facilitate comparison across structures, Tables 16 and 17 present our 1.5 MW and 10.5 MW base-case modeling results for each ownership structure described and modeled in this chapter (and in the same order, though note that on-site projects are limited to 1.5 MW and so are not included in Table 17). As alluded to throughout this chapter, the competitiveness of each structure is a function not only of revenue requirements (where lower is better), but also the market price available to each structure (where higher is better). Thus, even though aggregate net metering has a relatively high revenue requirement, it is – at least in theory – the most competitive structure, because we assume that it is able to earn the full average residential retail rate of $71/MWh, which is $18.77/MWh *higher than* the revenue requirement of $52.23/MWh (for a 1.5 MW project). Of all the ownership structures presented, however, aggregate net metering faces perhaps the most – and most severe – obstacles to implementation. Chief among them is the fact that utilities are currently not required to offer aggregate net metering, and – barring regulatory intervention, which itself is unlikely – are not likely to move in that direction. Hence, this is a potentially interesting model, but perhaps too far removed from reality in the United States to warrant much attention from the Energy Trust at this time.

Both on-site models, whether owned by taxable businesses or tax-exempt entities such as schools, have revenue requirements that are well above their respective benchmark power prices. Even with an expansion of net metering to include projects as large as 1.5 MW, such projects are still not all that attractive. This, along with our sense that there are likely to be relatively few opportunities for on-site utility-scale wind development in Oregon (especially those connected to Pacific Power or PGE's distribution system), suggests that the Energy Trust should focus its attention elsewhere.

Among those community wind ownership structures that have actually been implemented in the United States (which is important, if only to demonstrate practicality), the *multiple local owner* model is most competitive, with revenue requirements that are slightly *below* the 1.5 MW benchmark power price, and slightly *above* the 10.5 MW benchmark power price (assuming 100% tax efficiency). This structure also has the advantage of relative simplicity, and in some sense is the "purest" community wind model, in that multiple local investors own the project without corporate assistance. What appear to be relatively stringent securities regulations in Oregon, however, may add additional expense to this ownership structure if securities registration cannot be avoided. Furthermore, without 100% tax efficiency, the economics of this structure deteriorate rather quickly to the point where flip structures make more sense (at around 65% PTC efficiency). Up to that point (and perhaps even beyond), however, the *multiple local owner* structure is certainly worthy of consideration by the Energy Trust (presuming additional support is necessary – our modeling results suggest that it may not be at high levels of tax efficiency, or with modest revenue from TRC sales).

Flip structures are also relatively attractive models, particularly if the local investors' appetites for tax credits are low. The Wisconsin-style flip has a roughly $3/MWh advantage over the Minnesota-style flip, but has not yet been implemented in the United States, and may face scrutiny from the IRS regarding the pre-arranged sale of the project after ten years. More research is warranted on this issue. Minnesota-style flips, on the other hand, have several years' worth of experience and operating history under their belts, and therefore are more of a known entity. Furthermore, as a pre-condition of any financing provided to Minnesota-style flip projects, the Energy Trust could potentially require that a transfer payment be made from the local to the corporate partner, thereby resulting in a more competitive project with a lower revenue requirement (and hence, less potential need for Energy Trust support). Alternatively, starting in year eleven when financial control of the project flips to the local partner, the Energy Trust might require the local partner to reimburse the Energy Trust for some or all of any incentive provided during the first ten years of the project (i.e., the critical period of debt service). We have not modeled or evaluated such a "shared savings" incentive structure (or any other type of incentive structure, for that matter – all $/MWh numbers throughout this chapter are consistently presented in 20-year nominal levelized terms).

Assuming it can capture at least half the REPI, or alternatively at least half the value of a tradable PTC if implemented, the town-owned project selling power to a utility results in a revenue requirement that roughly matches the benchmark power price (at least for the 1.5 MW project – the 10.5 MW project is less competitive). Questions remain as to whether this particular structure is even legal, however.

Finally, as suggested in the previous paragraph, 10.5 MW projects are generally less competitive than their 1.5 MW counterparts, despite in all cases having lower revenue requirements (from capturing at least some economies of scale). This is a function of the 10.5 MW projects (which are assumed to require power delivery over the transmission system) having a benchmark power price that is $4.80/MWh lower than the 1.5 MW projects (which are considered to be distributed generators whose power is consumed locally). It also reflects the $10 million cap on costs eligible for the BETC; with the 10.5 MW projects costing more than $12 million, the BETC represents a lower proportion of total project costs than in the case of a 1.5 MW project that costs less than $10 million. Similarly, as mentioned earlier in this chapter (though not shown in Tables 16 or 17), USDA Section 9006 grants are limited to the greater of 25% of project costs or $500,000, which renders them far less useful to a 10.5 MW project than they are to a 1.5 MW project. Finally, Table 17 shows that the number of equity shares in 10.5 MW projects can be quite large, making it likely that such projects would need to undergo full securities registration, and thereby incur extra legal costs not reflected in our cost inputs. The cost of registration would make such projects even less competitive, both on an absolute basis and relative to a 1.5 MW project that is able to qualify for an exemption from securities registration.[138] Given these considerations, the Energy Trust should not automatically assume that a 10.5 MW project will require less support than a 1.5 MW project; in fact, our modeling shows the reverse to be the case.

[138] Of course, spreading the cost of registration over a greater amount of capacity (i.e., 10.5 MW instead of 1.5 MW) will mitigate this impact somewhat.

Table 16. Base-Case Modeling Results Under Different Ownership Structures (1.5 MW Project)

	Aggregate Net Metering	On-Site Taxable	On-Site Tax-Exempt	Multiple Local Owner	MN-Style Flip	WI-Style Flip	Town-Owned
ASSUMPTIONS[1]							
Form of BETC	5-Year	5-Year	Lump	5-Year	Lump	Lump	Lump
PTC	No	No	No	Yes	Yes	Yes	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	4.5%	4.5%	5.5%	5.5%	5.5%	4.5%
Local 10-Yr Debt Interest Rate	NA	NA	NA	NA	NA	7.0%	NA
Corporate Contribution to Equity	0%	0%	0%	0%	99%	100%	0%
Local Contribution to Equity	100%	100%	100%	100%	1%	0%[2]	100%
Landowner-Owned?	No	Yes	Yes	No	Yes	No	Yes
% of REPI/Tradable PTC Captured	NA	NA	NA	NA	NA	NA	50%
Taxable Power Bill Savings (nominal $/MWh)	NA	$33.59	NA	NA	NA	NA	NA
RESULTS							
Financing (2004 $)							
Corporate Equity	$0	$0	$0	$0	$421,900	$402,509	$0
Local Equity	$1,012,941	$562,870	$529,688	$1,062,308	$4,262	$0[2]	$452,026
Energy Loan Program 10-Yr Debt	$865,687	$1,308,294	$859,261	$815,133	$998,860	$885,186	$967,530
Local 10-Yr Debt	$0	$0	$0	$0	$0	$136,061	$0
BETC Pass-Through	$0	$0	$448,902	$0	$456,552	$459,102	$456,552
Total Project Cost	$1,878,628	$1,871,165	$1,837,851	$1,877,440	$1,881,574	$1,882,858	$1,876,108
Minimum Local Investment	$675	$562,870	$529,688	$5,000	$4,262	$5,000	$452,026
Number of Shares	1,500	NA	NA	212	NA	27	NA
Project Economics (nominal $/MWh)							
Revenue Requirement	$52.23	$64.81	$46.94	$38.58	$44.28	$41.18	$40.03
Benchmark Power Price	$71.00	$33.59	$33.59	$39.40	$39.40	$39.40	$39.40
Revenue Shortfall (Surplus)	($18.77)	$31.22	$13.35	($0.82)	$4.88	$1.78	$0.63
After-Tax Internal Rate of Return							
Corporate IRR	NA	NA	NA	NA	15%	15%	NA
Local IRR	10%	10%	10%	10%	87%	10%	10%

[1] Additional assumptions that do not vary by ownership structure are not included in the table, but include: all projects count the BETC and/or PTC towards the Energy Loan Program's required annual average debt service coverage ratio of 1.25, the BETC (both as a 5-year credit and a pass-through payment) triggers a PTC haircut, the BETC pass-through payment is considered taxable income, all tax-motivated corporate equity investors require an after-tax internal rate of return of 15%, all local investors require an after-tax internal rate of return of 10%, and the revenue requirements and benchmark power prices shown are fixed for 20 years and do not escalate.

[2] In this structure, the local contribution comes in the form of debt, not equity. See Section 6.6 for further explanation.

Table 17. Base-Case Modeling Results Under Different Ownership Structures (10.5 MW Project)

	Aggregate Net Metering	Multiple Local Owner	MN-Style Flip	WI-Style Flip	Town-Owned
ASSUMPTIONS[1]					
Form of BETC	5-Year	5-Year	Lump	Lump	Lump
PTC	No	Yes	Yes	Yes	No
Energy Loan Program 10-Yr Debt Interest Rate	4.5%	5.5%	5.5%	5.5%	4.5%
Local 10-Yr Debt Interest Rate	NA	NA	NA	7.0%	NA
Corporate Contribution to Equity	0%	0%	99%	100%	0%
Local Contribution to Equity	100%	100%	1%	0%[2]	100%
Landowner-Owned?	No	No	Yes	No	Yes
% of REPI/Tradable PTC Captured	NA	NA	NA	NA	50%
Taxable Power Bill Savings (nominal $/MWh)	NA	NA	NA	NA	NA
RESULTS					
Financing (2004 $)					
Corporate Equity	$0	$0	$2,966,676	$2,850,013	$0
Local Equity	$6,280,946	$6,599,579	$29,966	$0[2]	$3,042,093
Energy Loan Program 10-Yr Debt	$5,899,969	$5,575,089	$6,639,257	$5,899,358	$6,567,692
Local 10-Yr Debt	$0	$0	$0	$900,050	$0
BETC Pass-Through	$0	$0	$2,550,000	$2,550,000	$2,550,000
Total Project Cost	$12,180,915	$12,174,668	$12,185,900	$12,199,421	$12,159,786
Minimum Local Investment	$598	$5,000	$29,966	$5,000	$3,042,093
Number of Shares	10,500	1,320	NA	180	NA
Project Economics (nominal $/MWh)					
Revenue Requirement	$50.35	$35.85	$40.94	$37.82	$38.69
Benchmark Power Price	$71.00	$34.60	$34.60	$34.60	$34.60
Revenue Shortfall (Surplus)	($20.65)	$1.25	$6.34	$3.22	$4.09
After-Tax Internal Rate of Return					
Corporate IRR	NA	NA	15%	15%	NA
Local IRR	10%	10%	87%	10%	10%

[1] Additional assumptions that do not vary by ownership structure are not included in the table, but include: all projects count the BETC and/or PTC towards the Energy Loan Program's required annual average debt service coverage ratio of 1.25, the BETC (both as a 5-year credit and a pass-through payment) triggers a PTC haircut, the BETC pass-through payment is considered taxable income, all tax-motivated corporate equity investors require an after-tax internal rate of return of 15%, all local investors require an after-tax internal rate of return of 10%, and the revenue requirements and benchmark power prices shown are fixed for 20 years and do not escalate.

[2] In this structure, the local contribution comes in the form of debt, not equity. See Section 6.6 for further explanation.

7. Conclusions

As described in this report, experience with community wind power development in both Europe and the United States demonstrates that community wind is possible if the right combination of policies and conditions exist. Above all else, revenue certainty is paramount to attracting community wind investors. Thus, policies that provide stability (and profitability) to community wind in Oregon will be essential.[139] If the past is any indication of the future, such policies are not likely to arise at the federal level; rather, specific *state* policies that *differentially* support community wind will be necessary to drive this form of development.

Along these lines, Oregon appears to be in a rather unique position. The state already has in place an aggressive Energy Loan Program and a valuable Business Energy Tax Credit, both of which are *potentially* (see below) accessible to each of the seven different community wind ownership structures examined in this report. The BETC in particular favors small over large projects, as eligible project costs against which the credit can be claimed are capped at $10 million.[140] Furthermore, the Oregon Public Utilities Commission is currently considering a favorable expansion of PURPA contract terms, which, if implemented, could prove to be a critical keystone for the development of community wind in Oregon. Finally, the Energy Trust of Oregon has both the interest and means to support community wind power development, and has commissioned this report as a first step in thinking about how it might do so.

The modeling results presented in this report suggest that certain ownership structures are more likely than others to be successful in Oregon. Specifically, those structures that can capture the PTC (or REPI) by selling power to an unrelated party – i.e., the *multiple local owner*, *Minnesota-* and *Wisconsin-style flip*, and the *town-owned* structures – all appear to be more competitive and/or attractive than structures that depend upon selling power to investors (i.e., *cooperative-owned*, *aggregate net metering*, and *on-site* projects).[141] Open questions remain regarding the viability, or even legality, of two of the more attractive structures, however – *Wisconsin-style flips* and *town-owned* projects. This leaves *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 with any modeling exercise, however, our results are only as good as our assumptions, and we note that several of our assumptions could – pending additional time, budget, and expertise – be refined with greater certainty. Since several of these assumptions are critical not only to our modeling results, but more importantly to the viability of those community wind projects that are already in development in Oregon, we recommend that among the Energy Trust's first steps in developing a community wind program should be to resolve the following outstanding questions:

[139] Such policies should also drive the development of a strong wind project construction and operations infrastructure to cost-effectively support such projects.

[140] This is one reason why our results show that 1.5 MW, or even 10.5 MW, community wind projects may require less incremental support than one might otherwise think, based on the level of additional support recently sought by much larger wind projects: the BETC is worth proportionally less to projects that cost in excess of $10 million.

[141] As shown in Table 16, *aggregate net metering* actually appears to be the *most competitive* structure. As noted in Section 6.8, however, this particular structure likely faces perhaps the most significant barrier to implementation – strong utility opposition – and as such, should perhaps be discounted.

1) Will taxable loans from the Energy Loan Program trigger the PTC's anti-double-dipping provisions? If so, then projects hoping to use the PTC will need to seek other sources of debt, most likely on less favorable terms (with respect to debt service coverage ratios, PTC/BETC monetization, and perhaps also interest rate).
2) Pending favorable resolution of the previous question, can the $20 million cap on the Energy Loan Program's ability to issue "private use" (taxable) bonds be increased to ensure that there is sufficient loan capacity to support an Energy Trust community wind program?
3) Does the BETC (both as a 5-year credit *and* pass-through payment) trigger the PTC's anti-double-dipping provisions?
4) Should the BETC pass-through payment be treated as taxable income, or as a reduction in depreciable basis (and if so, for Oregon purposes, Federal purposes, or both)?
5) Should Section 9006 USDA grants be treated as taxable income, or as a reduction in depreciable basis (and if so, for Oregon purposes, Federal purposes, or both)?
6) What requirements must be met to avoid having to register securities in Oregon? We have provided a layman's interpretation in this report, but a more detailed opinion on this matter from a lawyer knowledgeable in Oregon securities law is warranted.
7) Are municipalities in Oregon permitted to own wind projects? If so, under what conditions may they use their bonding authority to issue tax-exempt municipal debt to finance a wind project?
8) Does the Wisconsin-style flip structure pass muster with the IRS?
9) What role will the Energy Trust allow TRC's to play in providing an additional source of revenue to community wind projects?

Publicly resolving these specific questions will help reduce the transaction costs of developing a community wind project in Oregon. Furthermore, the answers to these questions could have major implications for both the relative and absolute competitiveness of various ownership structures, and therefore the amount of financial support the Energy Trust might ultimately need to provide. As such, we encourage the Energy Trust to pursue these questions, and to the extent that the correct answers to these questions are not consistent with our modeling assumptions, revise the model accordingly to reflect a more accurate picture of how community wind is likely to develop in Oregon.

More generally, a number of program design lessons arise from experience with community wind in both Europe and the United States, as well as our financial analysis of community wind in Oregon. Perhaps the most important of these is that community wind has thrived wherever there are long-term, stable policies that enable local investors to earn a reasonable rate of return while incurring minimal transaction costs. For example, feed-in tariffs in Denmark, Sweden, and Germany have enabled community wind to dominate in those three countries. Closer to home, community wind in Minnesota – the only state in the US where community wind can be considered to be thriving – has developed primarily under what equates to a feed-in tariff with Xcel Energy. These lessons underscore the importance of the current PURPA proceeding in Oregon: if the proceeding does not result in a long-term standard offer power purchase agreement (PPA) suitable for community wind, working with Pacific Power and PGE to establish such a tariff should become a high priority for the Energy Trust.[142]

Even with a long-term PPA, however, some sort of incremental state incentive may still be required to make community wind projects economically viable in Oregon. The question of whether, and if so how much, additional financial support (beyond the BETC and Energy Loan Program) is required can be addressed with financial modeling, as presented in this report. Under current Pacificorp tariffs, benchmark PPA prices provided by the Energy Trust, and our modeling assumptions, we find that on-site projects would require substantial incremental support, while several of the ownership structures that sell power to an unrelated party may not require much – if any – additional support.

Given the potentially limited need for ongoing, long-term financial support for some of these structures, the Energy Trust may wish to focus on supporting *near-term* projects that demonstrate *replicable* ownership models that can ultimately be applied at a scale sufficient to reduce transaction costs, lead to infrastructure development, and minimize possible diseconomies of scale. In supporting this first wave of "groundbreaking" projects, the Energy Trust should recognize that such projects are, by design, perhaps likely to incur higher costs than the hypothetical projects modeled in this report.

Specific efforts targeted at building infrastructure to minimize transaction costs and bring community wind up to scale may also be warranted. For example, Wisconsin began by developing a community wind business plan, while Illinois funded a 3-year wind resource monitoring program targeted at sites suitable for community wind. Massachusetts has gone even farther by retaining a stable of consultants to provide developmental assistance, and a pool of "preferred partners" to reduce transaction costs during the construction phase. The Energy Trust should consider what types of infrastructure-building activities are appropriate (i.e., in addition to this report, as well as the anemometer loan program). At a minimum, the Energy Trust should continue to offer its anemometer loan program (and consider expanding its range to include areas outside of Pacific Power and PGE service territories), and should endeavor to answer the nine tax and legal questions listed above. More aggressive steps might include proactive efforts to reduce construction costs by, for example, attracting new local entrants into the crane business (which should reduce mobilization fees), perhaps through an Energy Trust guarantee of some minimal amount of business. Similarly, as an organization in tune with the evolving status and schedule of most wind projects in the Northwest (large and small), the Energy Trust may be in a unique position to help community wind projects to "piggyback" on top of larger commercial wind projects (even when not sited contiguously) in order to capitalize on lower turbine costs (i.e., through bulk purchases) or shared crane mobilization fees.

Finally, a few other near-term activities should also be considered. Recognizing that the availability of USDA grants may reduce the need for incremental financial support, the Energy Trust should work to connect potential projects to possible USDA funds, through workshops, referrals, or other forms of information dissemination. The Energy Trust may also wish to open a dialogue with RECs and BPA in the hopes of attaining reasonable wheeling tariffs for

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[142] Since our financial modeling shows that even attractive on-site tariffs may not be sufficient to justify on-site wind in Oregon, working to establish reasonable on-site tariffs should be relegated to a second-tier priority.

community wind projects located in REC service territories. And, given that several of the ownership structures modeled in this report can become significantly more or less attractive depending on possible changes to policies (particularly changes involving the PTC and REPI), the Energy Trust would be well-served to closely monitor the policy arena and be prepared to adapt its program to a changing policy environment.

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