ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY
Environmental Energy Technologies Division
1 Cyclotron Rd., MS 90-4000, Berkeley, CA 94720

MEMORANDUM

From: **Mark Bolinger and Ryan Wiser, EETD**
Subject: **Analysis of Utility-Scale Wind Turbines and Projects in the US**
Date: **August 9, 2002**

Abstract

Utility-scale wind turbines are defined here as turbines over 50 kW in size used to supply electricity to wholesale electricity markets, typically through electricity sales to electric utilities. The market for utility-scale wind turbines in the US is potentially quite large, yet this market does not initially seem to be a promising fit for anticipated WindSail technology for a number of reasons:

- WindSail turbines are likely to be too small to compete (see Section 3.3).
- WindSail's anticipated maintenance benefits are not critical for this market segment (see Section 3.5).
- The current market is very competitive in terms of total costs and profitability (see Sections 3.6 and 3.10).
- Turbine manufacturers have been able to develop direct drive technology in a HAWT design (see Section 3.10).

One potential niche that WindSail might seek to exploit within this sector involves "infilling" at existing wind farms. It is not clear, however, what potential this strategy holds; we note that at least two other VAWT manufacturers (Wind Harvest Company and TMA) seem to be pursuing this approach, though few installations of this type have yet occurred.

3. Utility-Scale Wind Projects in the U.S.

This memo emphasizes utility-scale wind turbines used to supply power to wholesale electricity markets through power sales agreements with utilities or other electricity suppliers. This is the principal market for wind turbines in the United States and internationally. Though the cutoff point is somewhat arbitrary and will depend on the particular turbine's vintage (e.g., some of the early utility-scale turbines installed in California are now quite small by today's standards), utility-scale turbines can generally be defined as those that are greater than 50 kW of nameplate capacity. In today's market, however, where many turbine manufacturers no longer offer turbines <600 kW, any new utility-scale turbine will be substantially larger than 50 kW.

3.1 Market Size and Potential

Current Market Size

Figure 3-1 shows the current size of the utility-scale wind power market in the U.S., as well as historic growth over time. Over 4,000 MW are now installed. The spikes in installed capacity in 1999 and 2001 reflect the expiration of the federal production tax credit (1.8¢/kWh in 2002) in each of those years (more on the PTC below). For a state-specific breakout of current installed capacity and incremental growth in the past year-and-a-half, see Figure 2-3.

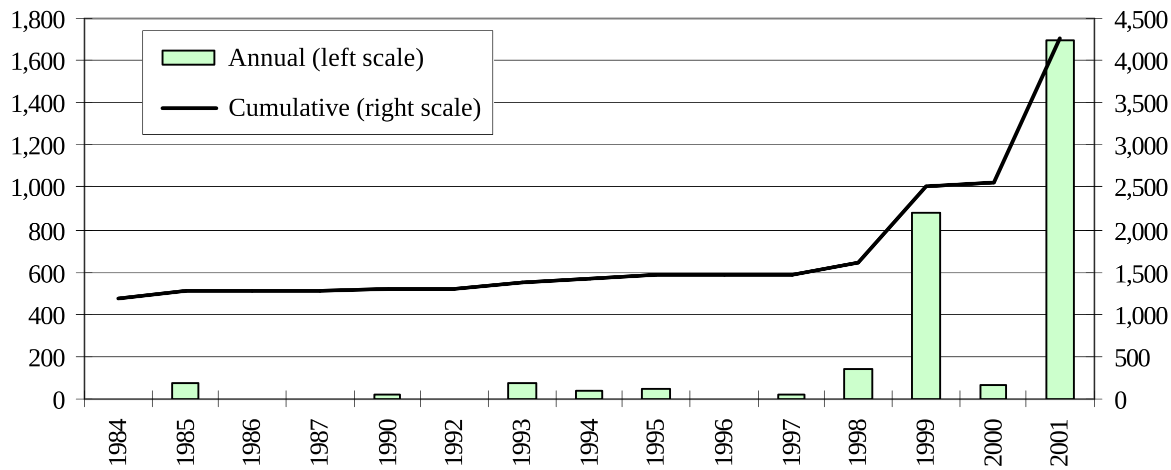

Figure 3-1. Installed Wind Capacity in the United States

Market Growth Prospects

It is unclear how much additional utility-scale wind turbine capacity will be added in the US in the future, though growth prospects are reasonably strong. Table 2-5 presented two forecasts of US utility-scale wind power growth through 2005: the EIA reference case forecasts that 2,530 MW will be added between 2002 and 2005, while BTM (2001) forecasts 3,400 MW of incremental capacity over this 4-year period. By 2020, the EIA reference case in Annual Energy Outlook 2002 (AEO 2002) forecasts 9,060 MW of installed wind capacity in the U.S., an annualized growth rate of 6.8% from 2000-2020 (note that this assumes no PTC extension beyond 2001). Assuming the PTC is extended through 2006, AEO 2002 forecasts 13,000 MW by 2020 (an increase of 4,000 MW due solely to the PTC extension). In a separate “High Renewable Energy Case,” AEO 2002 forecasts 8,720 MW of installed wind by 2010 and 25,270 MW by 2020. This represents a 12.4% annualized growth rate from 2000-2020.

3.2 Drivers of Utility-Scale Wind Development in the United States

The major drivers of utility-scale wind energy development in the US include the federal production tax credit, 5-year accelerated depreciation, renewable portfolio standards, system-benefits charges, green power demand, and, increasingly, economics. Each of these drivers is briefly described below.

The Federal Production Tax Credit (PTC) has been a major driver of wind activity in the US. Originally implemented in the Energy Policy Act of 1992 as 1.5¢/kWh for the first 10 years of a project's life, the PTC is indexed to inflation and currently stands at 1.8¢/kWh in 2002. The PTC can lower the cost of wind-generated electricity by nearly 2 cents/kWh. The PTC must periodically be re-authorized by Congress; the credit was allowed to expire at the end of 2001, but in March 2002 was re-instated retroactively through the end of 2003. Thus, any commercial wind project on line prior to 12/31/03 is guaranteed to receive the PTC for 10 years (whether or not the PTC is extended beyond that date). Meanwhile, the Senate Energy Bill currently in conference committee contains a PTC extension through 2005. The periodic expiration of the PTC has resulted in a boom/bust cycle for wind development in the U.S. (see the spikes in 1999 and 2001 in Figure 3-1 above), as developers rush to complete their projects ahead of these deadlines. Uncertainty over whether the PTC will be extended makes projecting wind installation trends into the future difficult.

5-Year Modified Accelerated Cost Recovery System (MACRS): The IRS tax code allows wind turbine equipment to be fully depreciated at an accelerated rate over a 5-year period. This rule provides an additional tax incentive to owners of wind power projects.

Renewable Portfolio Standard (RPS): An RPS requires all retail suppliers to include a minimum percentage (usually increasing over time) of eligible renewable energy in their products. In the U.S., 12 states have enacted some form of RPS policy (with varying effectiveness), and the Senate Energy Bill currently contains a federal RPS that ostensibly requires 10% of all electricity sold in 2020 to be source from renewable energy.[1] Since an RPS tends to favor the cheapest renewable energy technologies, wind power is a major beneficiary of this policy. This is evident in Texas, where an RPS that amounts to a 2000 MW renewable energy requirement by 2009 has triggered "the Texas wind rush": more than 900 MW of wind power were installed in Texas alone during 2001.

System-Benefits Charges (SBC): Fourteen states have enacted SBC funds devoted to renewable energy. More than $3 billion earmarked for renewable energy will be raised over the next decade through these small charges on electricity bills. Once collected, a number of states are using these funds to provide direct financial incentives to wind power projects. To date, wind power has been one of the primary recipients of these funds in California, Pennsylvania, New York, New Jersey, and Oregon. Much of the wind development in the mid-Atlantic states over the past few years would likely not have occurred without the support of SBC funds (along with green power demand and the prospect of RPS policies in New Jersey and elsewhere).

Consumer Green Power Demand: Experience in California, Pennsylvania, and elsewhere has shown that some consumers are willing to voluntarily pay a bit more for electricity generated from clean, renewable energy resources (so-called "green power"). Wind power has benefited from green power demand, particularly in the Mid-Atlantic region, where several wind farms in Pennsylvania are currently devoted to satisfying green power demand. Large customers (commercial, institutional, and governmental) have shown particularly strong interest in supporting green power, often the result of executive or legislative activity (in the case of governmental

[1] Recent LBNL analysis shows that this stated 10% standard by 2020 is effectively only a 4.5% standard, given certain exemptions and provisions contained in the bill.

purchases). Nonetheless, the total demand for wind-generated electricity from these voluntary green power markets on a nationwide basis does not yet exceed 500 MW.

Economics: Wind project development in the US is largely driven by federal tax incentive policies (PTC and accelerated depreciation), and state incentives (SBC) and mandates (RPS). Increasingly, however, wind power is able to compete (and occasionally win) head-to-head with other forms of generation on the basis of cost alone (including the impact of the PTC and accelerated depreciation). The economics of wind is detailed further in later sections of this memorandum. At a cost of as low as 2.5 ¢/kWh, however, wind power is now able to compete with natural gas generation in some parts of the US. This trend is likely to continue into the future, at least as long as the PTC remains in place.

3.3 Typical Project and Turbine Sizes

Typical Turbine Size

Table 1-2 showed that the average size of utility-scale turbines installed in the U.S. in 2000 was 686 kW, up from 327 kW in 1995. Data presented below in Table 3-1 suggests that this number increased to 893 kW in 2001. Half of all new installed capacity in 2001 featured MW-class turbines (see Table 3-1 below). This upscaling of turbine sizes is likely to continue, and many believe that onshore wind applications will in the future feature turbines with an average size of 1.5 MW each (offshore wind applications will utilize turbines in the 3-5 MW range). It is our understanding that WindSail would utilize much smaller turbines, which are generally not favored in utility-scale wind applications.

Typical Project Size

Table 3-1 lists 20 projects that came on line in 2001, totaling 1,670 MW. These projects represent 99% of all the wind capacity installed in the U.S. in 2001; the remaining 1% (<20 MW total) is comprised of a dozen or so “onesies” and “twosies” – small projects with just one or two turbines, most often installed in Minnesota to take advantage of a 1.5¢/kWh state production incentive for projects under 2 MW and sited on agricultural land. Excluding these small projects, the average project size installed in 2001 was 83.5 MW. While project sizes range considerably, there is a trend towards larger projects, especially in the Mid-Western and Western states where land constraints are less significant. Projects ranging from 20-100 MW in size are becoming standard.

Table 3-1. US Wind Projects Developed in 2001 ***(sorted by project size in descending order)***

Project Name	State	Project Size (MW)	# of Turbines	Turbine Size (MW)	Turbine Manufacturer
King Mountain	TX	278.2	214	1.3	Bonus
Stateline	WA, OR	262	397	0.66	Vestas
Desert Sky	TX	160.5	107	1.5	GE Wind
Woodward Mountain	TX	159.7	242	0.66	Vestas
Trent Mesa	TX	150	100	1.5	GE Wind
Gray County	KS	112.2	170	0.66	Vestas
Indian Mesa	TX	82.5	125	0.66	Vestas
Top of Iowa	IA	80.1	89	0.9	NEG Micon
Llano Estacado	TX	80	80	1	Mitsubishi
MountainView	CA	66.6	111	0.6	Mitsubishi
Rock River I	WY	50	50	1	Mitsubishi
Fenner	NY	30	20	1.5	GE Wind
Montfort	WI	30	20	1.5	GE Wind
Peetz Table	CO	29.7	33	0.9	Nordex
Condon	OR	24.6	41	0.6	Mitsubishi
Klondike	OR	24	16	1.5	GE Wind
Ruthton	MN	15.84	24	0.66	Vestas
Mill Run	PA	15	10	1.5	GE Wind
Ponnequin III	CO	9.9	15	0.66	Vestas
Somerset	PA	9	6	1.5	GE Wind
Total		**1,670 MW**	**1,870**	**0.893**	

3.4 Installed Costs

Data on Installed Costs of Wind Projects

The installed cost of utility-scale wind projects in the US has declined dramatically in the past twenty years. In the early 1980s, Kenetech reportedly installed 100 kW machines at Altamont at a price of $2,200/kW, and Zond's (later Enron Wind and now GE Wind) first project in 1981 was completed at an installed cost of $4,000/kW (EPRI 2001).

Today, a common rule of thumb is that utility-scale turbines (if installed as part of a larger wind farm) can be installed at a total cost of $1,000/kW. Of course, actual installed costs can vary significantly from project to project, depending on project size, strength of the dollar (most turbines are manufactured overseas), site terrain and location, ease of interconnection, and other factors. Thus, a range of installed costs is more appropriate. EPRI's Technical Assessment Guide (TAG) – a widely cited source for wind project cost data – identifies a range of installed costs from $1,600/kW for a single turbine project to $1,000/kW for projects over 50 MW, and notes that recent projects in the U.S. are towards the lower end of this range (EPRI 2001).

Data on actual installed costs for specific projects is hard to come by, but three sources are reported below: (1) TVP data, (2) wind plant sales prices, and (3) the Energy NorthWest wind project. These data generally support the $1,000/kW installed cost for larger wind projects in the US.

- **TVP Data.** DOE's Wind Turbine Verification Program (TVP) monitors the development and operation of six wind projects across the United States. Table 3-2 shows installed costs of five of these projects.

Table 3-2. Installed Costs from DOE Turbine Verification Program

Project	State	MW	$/kW	Year
Central & South West	TX	6.6	1,130	1995
Green Mountain	VT	6.05	1,800	1996
Wisconsin Low Wind Speed Turbine	WI	1.2	1,670	1998
Algona	IA	2.25	1,230	1998
Springview	NE	1.5	1,380	1998

Note that these are all small projects, and fairly old (in terms of how quickly the market is evolving). Even so, two of the projects stand out as being particularly expensive. The Green Mountain project's installed cost of $1,800/kW is reportedly the result of:

- higher-than-normal permitting costs (which would have been lower on a $/kW basis were the project larger)
- relatively high pre-construction costs (e.g., clearing trees and building roads)
- cold weather features made the turbines more expensive than normal
- this was Green Mountain's first wind project (learning curve)

At $1,670/kW, the Wisconsin Low Wind Speed Turbine project was expensive due to delays in the project caused primarily by two successive bankruptcies of turbine suppliers (as well as a learning curve – this was the utility's first wind project). The original turbine supplier, Kenetech, went bankrupt in 1996, and the replacement supplier, Tacke, went bankrupt in 1997 during construction. Enron Wind subsequently purchased Tacke and completed the project.

- **Wind Project Sales Prices.** In addition to the TVP data on actual project costs, we have data on the sales price of 4 projects that were built and sold in 2001. Table 3-3 summarizes this information. With the exception of the 15 MW Mill Run and 9 MW Somerset projects (sold jointly as a 24 MW project, but still much smaller than the other listed projects), the other projects' *sales prices* are approaching $1,000/kW. Note that these turnkey sales prices are likely to be higher (perhaps significantly so) than actual installed costs, as an operating project is not as risky as a project in development, and the developer will require adequate compensation for having taken on the development risk. Thus, while it's impossible to say for sure, it is likely that each project's installed cost is well below $1,000/kW.

Table 3-3. Sales Price of Four Projects Built and Sold in 2001

Project	State	MW	$/kW	Year
Top of Iowa	IA	80.1	1,125	2001
Mill Run and Somerset	PA	24	1,238	2001
Llano Estacado	TX	80	1,033	2001
Desert Sky	TX	160.5	1,094	2001

- **Energy NorthWest Project Cost.** We also have information on the projected installed costs of a 48.1 MW wind project currently under construction in Washington State. Energy NorthWest, the project owner, is a publicly owned utility that issued revenue bonds to finance the project. The bond prospectus reveals that the cost of the turbines and towers comes to $550/kW, the full EPC contract (i.e., turbine plus installation costs) comes to $877/kW, and the all-in costs (including EPC, contingencies, T&D and interconnections, Energy Northwest development and bond issuance costs, and indemnity contract cost) comes to $1,189/kW (Wiser 2001).

A final source of installed cost data comes from turbine orders. Many of the Vestas turbines (660 kW) installed last year (see Table 3-1 above) were purchased in bulk by wind developer and project owner Florida Power & Light (FPL). FPL reportedly placed a 700-turbine order with Vestas in 2000, and due to the sizable purchase received very low turbine prices. For example, the January 2001 issue of *WindPower Monthly* states: "Last month, Vestas of Denmark, the world's largest wind turbine manufacturer, quoted an option on additional machines for a large American order at a price a fraction above $447/kW. This implies complete wind farms can be built for around $650/kW, even if no further savings are made in balance of plant costs." Note that FPL reportedly sourced towers locally, instead of purchasing from Vestas; hence, the quoted price of $447/kW likely represents all turbine equipment except the tower.

In conclusion, to enter the utility-scale wind market in the US, all else equal, WindSail would need to offer total project costs of at or around $1000/kW. The wind turbines alone will likely need to be priced at or below $600/kW.

Breakdown of Installed Costs

Tables 3-4 and 3-5 estimate the percentage of total installed costs spent on various project elements. Table 3-4 reflects project-level categorizations, while Table 3-5 focuses more acutely on turbine components. Potential items of interest to WindSail (which is contemplating a "towerless", gearless turbine) include the fact that towers make up 10-13% of total installed costs, while gearboxes reportedly account for as much as 17% of installed costs.

Table 3-4. Typical Project Capital Cost Elements

	% of Total Investment Costs
Turbines	49%
Construction	22%
Towers (tubular steel)	10%
Interest During Construction	4%
Interconnect/Substation	4%
Development Activity	4%
Financing & Legal Fees	3%
Design & Engineering	2%
Land Transportation	2%
Total	100%

Source: EPRI 2001

Table 3-5. Typical Turbine Capital Cost Elements

	% of Total Investment Costs
Machine frame including ring	7%
Blades	14%
Hub including main shaft	6%
Gear including clutch	17%
Generator/controller	9%
Tower including painting	13%
Hydraulics including hoses	3%
Yaw gear	2%
Nacelle cover	4%
Insulation/cables, etc.	3%
Estimated assembly cost	3%
Total machine cost	**79%**
Civil works, infrastructure, and grid connection	**21%**
Total investment cost	100%

Source: Lako 2002

3.5 O&M Costs

O&M at the Project or Turbine Level

Just as $1,000/kW has become a rough rule of thumb for installed costs, 1¢/kWh has become a rule of thumb for utility-scale wind turbine O&M costs. As with installed costs, however, O&M costs vary from project to project due to a number of factors, perhaps most notably project size.

The 1997 version of EPRI's Technical Assessment Guide (TAG) estimates that – at that time – annual O&M costs ranged from **0.7¢-1.2¢/kWh** for a 25 MW project comprised of 500 kW turbines (EPRI 1997). A more recent update of EPRI TAG identifies O&M at $32.71/kW for a 1 MW wind plant and $19.32/kW for a 200 MW wind plant (EPRI 2001). At a 35% capacity factor these are equivalent to **1.0¢/kWh** and **0.63¢/kWh**, respectively.

A 1997 report from the National Wind Coordinating Committee estimates that maintenance costs for modern wind turbines are 1¢/kWh or less (Chapman 1997). Using a value of **0.9¢/kWh**, this document breaks O&M down as follows:

- unscheduled maintenance (0.68¢/kWh or 75% of total O&M),
- preventive maintenance (0.18¢/kWh or 20% of total O&M),
- major overhauls, on a levelized replacement cost basis (0.04¢/kWh or 5% of total O&M).

In contrast, a recent report presented at AWEA's WINDPOWER 2002 conference estimates that for projects consisting of large (2 MW) turbines, unscheduled maintenance accounts for only 52% of O&M costs, scheduled maintenance accounts for 39%, and the remaining 9% is for operations and reporting (Vachon 2002).

This same report estimates that O&M costs are roughly **1¢/kWh** when levelized over 20 years. Specifically, O&M starts off at roughly 0.6¢/kWh for the first 3 years (assuming 3-year warranty), and then increases more or less linearly to roughly 2¢/kWh by year 20. These numbers include both scheduled and unscheduled maintenance costs (both escalating at a 2.5% inflation rate), but neglect lost revenue opportunities, due to the fact that the wind industry has been able to achieve rapid repair times by swapping out parts rather than repairing or rebuilding on site. In addition, costly failures of mechanical components tend to occur slowly, thereby allowing time to plan component replacement during scheduled outages (Vachon 2002).

EPRI (2002) confirms this assertion, by noting that the availability of utility-scale turbines in California has only been marginally impacted by widely reported performance problems over the years, because industry has worked to minimize down time by swapping out parts. One potential implication of this approach for WindSail is that its anticipated low-maintenance attributes may not provide much of a competitive advantage in the utility-scale segment of the market.

Finally, the bond prospectus for Energy Northwest's 48 MW Nine Canyon wind project indicates relatively high O&M costs of 1.4¢/kWh by the project's third year of operation, as shown in Table 3-6. This may be due to a conservative estimate of O&M costs.

Table 3-6. Energy NorthWest Project O&M Costs ($/MWh)

Costs	**2004**	**2005**	**2006**	**2007**
Fixed Operating Costs	8.7	11.3	11.6	11.9
Variable Operating Costs	0.6	2.7	2.8	2.9
Total Operating Costs	**9.3**	**14.0**	**14.4**	**14.8**

Source: Wiser 2001

O&M at the Component Level

Tables 3-7, 3-8, and 3-9 provide a sense of which turbine components require the most O&M, both in terms of frequency of component failure (Table 3-7) and magnitude of maintenance or replacement cost (Tables 3-8 and 3-9). Note that Tables 3-8 and 3-9 are in year 2000 Euro-currency units; with the Euro now roughly at parity with the dollar, a direct one-to-one translation from Euros to dollars will give a rough idea of costs in dollar terms.

Table 3-7. Estimates of Mean Time Between Failure (MTBF) for Key Mechanical Components of Mature Turbines

Component	Components per Turbine	MTBF = Mean Life (Years)
Gearbox	1	18
Generator	1	15
Blade	3	40+
Yaw Drive Motor	2-4	22
Yaw Drive Pinions	2-4	13
Yaw Bearing/Sliders	1	25
Hydraulic Power Units	1	15
Hydraulic Actuators	1-3	13

Note: MTBF is assumed invariant with turbine size.

Source: Vachon 2002

Table 3-8. Replacement Cost for Major Components on 600 kW Turbines

	[Thousand €$_{2000}$]	[€$_{2000}$/kW]
Entire blade set	~100	~167
Individual blade	~36	~60
Gearbox	>50	>83
Generator	Up to 18	Up to 30

Source: Dresdner Kleinwort Wasserstein, January 2001 (based on data from Allianz).

Source: Lako 2002

Table 3-9 shows that gearbox maintenance is a major O&M expense, accounting for roughly a quarter of annual maintenance costs for a typical 600 kW turbine.

Table 3-9. Estimated Maintenance Cost Over 15 Years for a 600 kW Turbine

	Cost over 15 years [Thousand €$_{2000}$]	Annual costs [€$_{2000}$/kW/a]
Maintenance including consumables	54	6.0
Oil change	15	1.7
Blade maintenance	33	3.7
Gearbox maintenance	51	5.7
Generator maintenance	10	1.1
Other	23	2.6
Insurance	41	4.6
Total	228	25.0

Source: Dresdner Kleinwort Wasserstein, January 2001 (based on data from Allianz).

Source: Lako 2002

Vachon (2002) reports that crane costs account for nearly half of total unscheduled maintenance costs, and are a function of both height and lift. For 20-25 ton cranes, the estimated 4-day lease costs (in North America) are roughly $60,000 for a 50m lift height, increasing to $70,000 for a 60m lift height. For 60-65 ton cranes, estimated 4-day lease costs are $138,000 for a 62m lift height, increasing to $170,000 for an 82m lift height (Vachon 2002). Several turbine manufacturers are now incorporating cranes directly into their nacelles/towers to ease maintenance of large turbines, particularly at offshore sites.

3.6 Overall Costs and Power Sales Prices

Ultimately, the various factors described above – project and turbine size, installed costs, and O&M costs – will, along with expected return on investment and capacity factors, determine the revenue requirements of a project. This will, in turn, dictate the price of a power sales agreement that a project requires to make the project profitable.

Nearly all utility-scale wind projects in the US require 10-30 year power sales agreements that will provide an assured revenue stream for the project's output at a price dictated in advance. Table 3-10 presents the key terms of 22 power sales agreements totaling 1,390 MW. This represents half of the utility-scale wind power capacity installed between 1998 and 2001 in the US, and one-third of total installed wind capacity in the United States as of the end of 2001. The contracts are sorted by commercial operation date (actual or expected). The contracts provide critical information about the effective cost of wind power for a utility buyer, and the price that WindSail would need to be able to supply to be competitive in this market segment.

To compare contract prices on a normalized basis, we levelized the price stream of each contract over a 25-year period according to the following assumptions:

- Contracts with terms of less than 25 years earn a fixed $30/MWh for their output once the contract term has expired.
- Contracts with options for extension (controlled by the buyer) will not be extended, and the project will simply earn a fixed $30/MWh once the initial contract term has expired.
- 3% inflation rate (all prices are in nominal terms)
- 10% discount rate

Results are presented in the final column of Table 3-10. The normalized 25-year contract prices in this sample range from a low of $25.5/MWh to a high of $71.6/MWh, with the capacity-weighted average price at **$38.5/MWh**. Note that all of these projects receive the 10-year federal production tax credit (1.8¢/kWh in 2002), which in most cases is built into their contract price.

Table 3-10. Project Economics

Commercial Operation Date	Contract Term (Years)	Project Capacity (MW)	Project Capacity Factor	25-Year Levelized Price (nominal $/MWh)
Sep-98	30.0	~100	37.3%	31.5
Oct-98	30.0	~25	34.5%	59.5
May-99	25.0	~100	37.3%	30.7
Jun-99	33.0	~10	31.4%	49.4
Jun-99	15.0	~25	40.2%	42.3
Jun-99	20.0	~75	40.6%	28.3
Jun-99	20.0	~75	29.4%	50.4
Jun-99	20.0	~100	N/A	43.7
Oct-00	20.0	~25	41.9%	38.3
Dec-00	10.0	~25	27.4%	49.5
Jul-01	10.0	~25	23.0%	71.6
Sep-01	15.0	~25	26.9%	38.6
Oct-01	20.0	~10	30.4%	43.0
Oct-01	20.0	~10	33.5%	43.0
Oct-01	20.0	~50	36.9%	35.1
Oct-01	10.0	~75	38.3%	49.3
Nov-01	15.0	~75	37.8%	26.4
Dec-01	20.0	~50	25.6%	62.5
Dec-01	25.0	>100	34.1%	25.5
Aug-02	11.5	~50	N/A	47.6
Aug-02	11.5	~75	N/A	47.6
Dec-03	17.0	~75	30.7%	48.4
		Total=1,390		**Wgtd Avg=38.5**

With the PTC, it appears as if WindSail would need to be able to supply power at under 4¢/kWh in order to be competitive.

3.7 Capacity Factors and Project Performance

Based on the data presented above, project capacity factors – a function of wind resource – are revealed to be as low as 23% and as high as 42%, and are the major determinant of contract prices. (Of the remaining three variables shown in the table – commercial operation date, contract term, and project size – only project size exhibits a meaningful relationship with contract price; commercial operation date and contract term appear to have little bearing on price).

Though not shown in Table 3-10, turbine availability (i.e., the percentage of time that a turbine is *available* to generate electricity were the wind to be sufficient) is typically in the vicinity of 98%, and is generally guaranteed by the manufacturer to be at least 95% for the first 2-5 years of the turbine's life, depending on warranty arrangements (Dunlop 2001). This implies that utility-scale wind turbines in the US have very little "downtime," with scheduled and unscheduled maintenance typically occurring during times in which the wind is not blowing. WindSail's potential maintenance advantages may therefore not be deemed particularly important in the utility-scale market segment.

3.8 Cost Projections

Figure 3-2 shows NREL projections of future reductions in the levelized cost of electricity from utility-scale wind turbine technology (note that these estimates do not include the value of the 1.8¢/kWh federal production tax credit). According to this figure, wind is projected to become cost competitive – i.e., without any subsidy – with bulk power in the next 5-10 years. We note, however, that this projection appears aggressive. We estimate the current cost of wind power without the PTC to be ~5 cents/kWh, while NREL has pegged that number at ~4 cents/kWh.

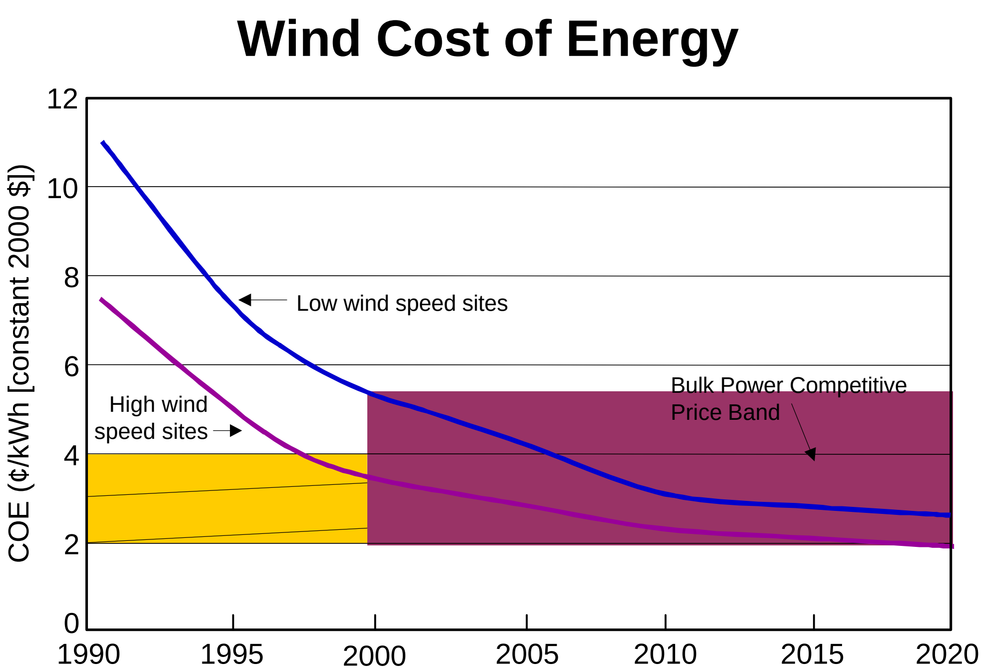

Figure 3-2. Projected Cost of Wind Energy *(Source: NREL January 2002)*

Dunlop (2001) estimates that the per-MW cost of wind turbines has declined by 3%-5% in recent years. He cites Moore's Law – a rule-of-thumb from the semiconductor industry that predicts that the performance/price ratio of computer chips doubles every 18 months – as potentially having an application to the wind turbine industry. In particular, since 1980 the size of turbines has doubled every four years, with every doubling in size bringing a 15% reduction in the per-kWh cost of the turbines (Dunlop 2001).

Lako (2002) looks at the implications of doubling cumulative installed capacity rather than turbine size. Cost reductions that are driven by improvements in manufacturing processes often proceed along a path known as a "learning curve". The "progress ratio" that describes the curve estimates the percentage cost decline for each doubling in manufactured capacity. For example, a progress ratio of 0.8 means that with each doubling of cumulative capacity, costs should decline by 1.0-0.80, or 20%.

While progress ratios for photovoltaics are often found to be on the order of 0.80, Lako (2002) observes that progress ratios for wind turbines tend to be higher, ranging from 0.90-0.98, depending on the turbine component. Perhaps not surprisingly, most potential for cost reductions comes from the rotor and nacelle (i.e., everything on top of the tower), which is estimated to have a progress ratio of 0.90. The progress ratio for the tower itself is 0.96, while "civil work, insfrastructure, and grid connection" is estimated to have a progress ratio of 0.98. Factors driving these rather high (i.e., modest potential for cost reduction) progress ratios are:

- the advanced state of current wind turbines with capacities 0.6 to 2.5 MW,
- limited potential for further up-scaling,
- limited cost reduction potential for towers (which are often sourced locally).

These three limiting factors (at least 2 of which do not apply to anticipated WindSail technology) suggest that future cost reductions for HAWTs may be somewhat more muted than they have been in the past (as consistent with Figure 3-2 above from NREL), or than Dunlop (2001) anticipates for the future. However, as a relatively immature technology, VAWTs are likely to have lower progress ratios than HAWTs, and therefore greater potential for future cost reductions through increased R&D and manufacturing volume.

3.9 Turbine Scaling Issues

The different cost trajectories pictured in Figure 3-3 reveal that cost reductions in HAWTs have been driven as much (or more) by upscaling of turbine size as they have by mass production. Specifically, the figure shows that larger turbines are far less costly than smaller ones, and that – within each turbine size category – cost reductions have occurred through time.

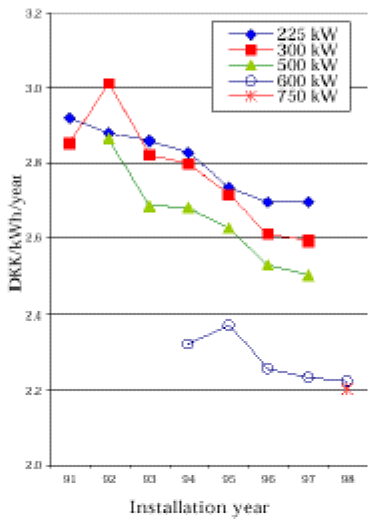

Figure 2.6 *Specific investment defined as ex-works Danish turbine price divided by annual production; roughness class 1; list prices of leading manufacturers (DKK$_{1999}$)*
Source: Wind power in Denmark. Technologies, policies and results. September 1999.

Source: Lako 2002

Figure 3-3. Cost Reductions Across Different Turbine Sizes

With 2+ MW turbines currently in production for on- and offshore wind projects, and 3+ MW turbines in near-term development for offshore applications (with 5 MW turbines in the planning stages), will this trend continue?

One of the main issues regarding further up-scaling of turbine size is the massive amount of weight that needs to be supported by ever-taller (= stronger = more expensive) towers. Lako (2002) examines the weight of the rotor and nacelle relative to turbine capacity and swept area for sub-MW- and MW-class turbines across six different turbine manufacturers who offer both classes. The average weight/capacity ratio (kg/kW) of sub-MW turbines is 53.7, compared to 56.2 for MW-class turbines. The respective weight/swept area ratios are 21.7 and 26.5.

While the 600-900 kW class of turbines exhibit the lowest weight/capacity and weight/swept area ratios, this does not automatically mean that this size range is optimal. A 1997 BTM Consult ApS document points out that higher towers usually translate into a better wind regime, while larger swept area equates to increased power output, meaning that on a weight/kWh basis, there is very little difference between sub-MW- and MW-class turbines (Ohlenschlaeger 1997). Although the cost/kW was slightly higher for the MW machines, the cost per generated kWh is almost the same as, or even less than, the smaller machines. Of course, the largest turbine examined in this document was only 1.65 MW (large at the time); whether this relationship holds for 3+ MW HAWTs remains to be seen.

Vachon (2002) reports that O&M costs for larger turbines (2 MW) are slightly lower (especially in later years) than for smaller turbines (600-750 kW). Even though cranes and parts are substantially more costly for large turbines, there are fewer total parts that fail (for a given project size). For example, there are only 10 generators that can fail in a 20 MW project consisting of 2 MW turbines, compared to 20 generators that can fail in a 20 MW project consisting of 1 MW turbines.

On the other hand, when a single generator fails in the former case, the project has lost 10% of its generating capacity, whereas when a single generator fails in the latter case, only 5% of total capacity is down. EPRI (2001) also points out that larger turbines have seen less operating experience, and are more challenging to erect in complex terrain and adverse weather conditions, perhaps making them riskier than time-tested smaller models (e.g., the Vestas 660 kW).

Overall, it is not clear when the current trend towards larger turbine sizes will stop. Many analysts believe that onshore applications are unlikely to trend towards turbines greater than 2 MW in size, if for no other reason than the challenges in transporting larger machines (and their massive towers) to project sites. Offshore turbine applications, meanwhile, may trend upwards of 5 MW.

3.10 The Competition: Turbine Manufacturers, Market Shares, Technology, and Profitability

Turbine Manufacturers Active in the US

The market for utility scale HAWTs is competitive. As shown in Table 3-11, six utility-scale turbine manufacturers were present in the US market over the past three years, with two in particular – Vestas and Enron Wind (now GE Wind) – dominating the market.

Table 3-11. Installed Capacity in US (1999-2001)

	MW	US Market Share
Vestas	822	31%
Enron/Zond	811	31%
NEG Micon	418	16%
Mitsubishi	281	11%
Bonus	278	11%
Nordex	24	1%
Total	2,634	100%

In addition to these stalwarts, other players to watch in the coming years include:

- **Gamesa Eólica –** The 2nd largest turbine manufacturer in the world, Gamesa turbines have so far been limited mostly to the Iberian Peninsula (the company is based is Spain) due to a restrictive licensing agreement with Vestas, who owned 40% of Gamesa. Within the past year, however, Vestas has sold its stake in Gamesa, thereby allowing Gamesa to look to other markets, including the U.S. (where it is rumored to be partnering with at least one developer).
- **The Wind Turbine Company –** With funding from the DOE and NREL, this Washington-based company has developed an innovative 2-blade downwind turbine that is light enough to be supported by very tall and lightweight towers (constructed from standard natural gas pipeline). This turbine has been extensively tested at NREL's wind test site, and a 500 kW commercial prototype is currently operating in southern California.
- **Lagerwey –** This Dutch company uses direct drive turbines (750 kW, 1.5 MW and 2 MW, see Figure 3-5), has just completed its first installation in North America (in Toronto), and is rumored to be mounting a challenge to GE Wind's patent on variable speed technology as it plans to enter the US market.

Technology

The major suppliers of utility-scale wind turbines in the US are all using the same basic turbine configuration: upwind, 3-bladed horizontal axis wind turbines. Variations in gearbox and generator configurations, however, are common. While details are not provided here, one point does deserve note: besides Lagerwey, at least 3 other European turbine manufacturers are developing direct drive technology for HAWTs. Enercon (from Germany) offers 4 different gearless turbines, ranging from 300 kW (see Figure 3-4) to 1.8 MW. Jeumont (from France, new to the wind industry) is testing a commercial prototype 750 kW direct drive turbine (see Figure 3-6). ABB has also been developing a direct drive generator for offshore use (Windformer), but has reportedly abandoned that effort. As illustrated by the figures below, the large-diameter generator necessitated by direct drive technology has led to unconventional nacelle configurations (though not necessarily unappealing – Enercon has marketed its characteristic egg-shaped nacelle as "organic" and in harmony with nature's sense of design).

Figure 3-4. Enercon 300 kW

Figure 3-5. Lagerwey 750 kW

Figure 3-6. Jeumont 750 kW (nacelle)

Profit Margins

The wind turbine manufacturing industry for utility-scale turbines appears to be very competitive with regard to price, with EBIT (Earnings Before Interest and Taxes) margins low and ranging from 4%-15% (Dunlop 2001). Where a company falls within this range seems to depend partly on its size: Vestas and Gamesa, the two largest wind turbine manufacturers in the world, enjoy EBIT margins of 11-15%, while smaller manufacturers like Nordex and NEG Micon have EBIT margins of only 4-6%. While no turbine manufacturer posts a price list, and there is anecdotal evidence that price discrimination among clients does occur, it appears that NEG Micon is selling turbines at a 15% discount to Vestas' turbines (the market leader), likely in an attempt to gain market share (particularly following its recent gearbox problems, which almost bankrupted the company). This could account for a portion of its lower operating margins relative to Vestas (Dunlop 2001).

3.11 Conclusions

The market for utility-scale wind turbines in the US is potentially quite large, yet is also quite competitive and perhaps unfriendly to newcomers utilizing new technology (witness the trials and tribulations of The Wind Turbine Company). This market does not in general seem to be a promising fit for anticipated WindSail technology for a number of reasons:

- WindSail turbines are likely to be too small to compete (see Section 3.3).
- WindSail's anticipated maintenance benefits are not critical for this market segment (see Section 3.5).
- The current market is very competitive in terms of total costs and profitability (see Sections 3.6 and 3.10).
- Turbine manufacturers have been able to develop direct drive technology in a HAWT design (see Section 3.10).

In addition, WindSail would need to overcome the stigma of VAWTs, which is perhaps more engrained within the utility-scale sector than in any other.

One potential niche that WindSail might seek to exploit within this sector involves "infilling" at existing wind farms by siting low-height VAWTs interspersed among the taller HAWTs to capture unused wind resources. The potential to take advantage of pre-existing infrastructure (e.g., sub-stations, transmission access, roads, etc.) as well as a proven wind resource (at least at 50 meters) is what makes this strategy potentially low-cost and somewhat intriguing. It is not clear, however, what potential this strategy holds, especially where land constraints do not hinder the use of larger and more cost-effective turbines. We note that at least two other VAWT manufacturers (Wind Harvest Company and TMA) seem to be pursuing this approach, though few installation of this type have yet occurred. Projects of this type are most likely in California, a state that is facing serious constraints on finding new wind sites, but projects would likely still need to compete with new MW-class wind turbines at 4¢/kWh or less.

3.12 Works Cited

California Renewable Technology Market and Benefits Assessment, EPRI, Palo Alto, CA and California Energy Commission, Sacramento, CA: 2001. 1001193.

Chapman, Jamie. 1997. "Wind Energy Costs." National Wind Coordinating Committee, January 1997.

Central and South West Wind Power Project Development: U.S. Department of Energy – EPRI Wind Turbine Verification Program. TR-107300. December 1996.

Dunlop, John. 2001. "Moulin Vert: Wind Power – It's Real and It's Growing." FBR International Limited, European Energy Research, October 30, 2001.

EPRI. 1997. *Renewable Energy Technology Characterizations*. TR-109496. December 1997.

Green Mountain Power Wind Power Project Development: U.S. Department of Energy – EPRI Wind Turbine Verification Program. TR-109061. December 1997.

Lako, P. 2002. "Learning and Diffusion for Wind and Solar Power Technologies." ECN-C—02-001. Netherlands

Ohlenschlaeger, Kell. 1997. "The Trend Toward Larger Wind Turbines", BTM Consult ApS, *Windstats – Autumn 1997*

Project Development Experience at the Iowa and Nebraska Distributed Wind Generation Projects: U.S. Department of Energy – EPRI Wind Turbine Verification Program. TR-112835, December 1999.

Vachon, William A. 2002. "Long-Term O&M Costs of Wind Turbines Based on Failure Rates and Repair Costs", Presented at Windpower 2002, June 2-5, 2002

Windpower Monthly News Magazine, January 2001 issue

Wisconsin Low Wind Speed Turbine Project Development: U.S. Department of Energy – EPRI Wind Turbine Verification Program. TR-111438. December 1998.

Wiser, Ryan. 2001. "Memorandum on Energy Northwest Bond Issuance for 48 MW Wind Project." Lawrence Berkeley National Laboratory: Berkeley, California.

Information about turbine manufacturers:
http://www.awea.org/directory/wtgmfgr.html

Information on direct drive turbines:
http://www.jxj.com/magsandj/rew/2001_02/turn_better.html