The Impact of Deregulation of the
Electric Supply Industry on
Renewable Power Generation Projects

by

Cherie Miot Abbanat
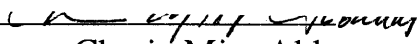
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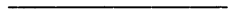
Signature of Author: _____

Cherie Miot Abbanat
Department of Urban Studies and Planning
June 6, 1997

Certified by:_____

Paul F. Levy
Adjunct Professor of Environmental Policy
Thesis Supervisor

Accepted by:_____

J. Mark Schuster
Associate Professor of Urban Studies and Planning
Chair, MCP Program

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ABSTRACT

Deregulation of the electric supply market is under consideration across the country. This change is intended to bring cheaper electric rates to customers by allowing customers to choose among electricity suppliers. However, deregulation may make it more difficult for cleaner renewable "green" energy sources such as wind powered generation to gain a foothold and to compete in the electric supply market than was possible in a regulated environment. This thesis has two objectives. First, an assessment of whether wind power could be competitive in a deregulated New England electric supply market is made. This thesis concludes that wind power will not be able to compete. Secondly, in light of this conclusion and assuming policy makers believe that renewable power is in the public interest, the roles and policies government should consider adopting in promoting wind technologies is explored.

Thesis Supervisor: Paul F. Levy
Title: Adjunct Professor of Environmental Policy

Acknowledgments

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Chapter I

Introduction

The generation of electricity from renewable power technologies, such as wind turbines and other non-fossil generation sources, promises cleaner air, a hedge against oil and gas price spikes, reduced relief from dependence on foreign oil, and a path to a more sustainable energy future. The production of electricity using wind turbines, however, is not cheap. Wind projects tend to be capital intensive, requiring large up-front capital investments in site assessment, zoning and equipment. Because wind projects may be located on mountains or in rural parts of the country, construction of transmission lines to these remote areas add to already-high costs. In addition, environmental permitting and impact assessments required for construction of such projects further add to the cost of these projects. The combination of the benefits of cleaner power and the costs makes generation by wind desirable but difficult to justify given that, on a relative cost per kilowatt hour (kWh) of production, wind power is more expensive than traditional sources of power.[1]

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[1] While the generation of electricity using wind power remains costly, the costs have been declining over the last decade. According to one news release, "costs have plummeted by more than 80 percent since the early 1980s," global sales of [wind] turbines reached $1.5 billion in 1995, and total installed capacity worldwide is reaching 5,000 MW. American Wind Energy Association, Statement of Randall Swisher, Executive Director, American Wind Energy Association, News Release, May 30, 1996.

In order to promote renewable technologies, federal and state governments have used a variety of subsidies, set-asides, and tax incentives. The Public Utility Regulatory Policies Act of 1978 (PURPA) and state integrated resource planning (IRP) programs provided regulatory processes by which electricity generated through the use renewable resources, could obtain a share of the electricity generation market.[2] PURPA and IRP programs created subsidies for renewable resources through set-asides, the use of low discount factors (opportunity cost), and the use of eternality adders. Set-asides provided direct subsidies to renewable resources while low discount factors or the use of externality adders improved the competitiveness of renewable resources vis a vis traditional coal, oil or gas generation units by making renewable investments less risky or less costly than they otherwise would be. Regulatory support for renewables was possible because ratepayers, the captive customer base, were employed to provide a steady stream of funds from rates that could be raised or lowered depending on what was "in the public interest." Tax and accounting incentives were also made available. Federal and state tax credits and accelerated depreciation of renewable equipment were designed to make renewable investments cost-competitive.[3]

In addition to subsidies, set asides and externality adders, the combination of regulatory decisions about resource mix and rate levels allowed regulators to provide a stable revenue stream for renewable projects. Once a power purchase contract between a renewable facility operator and a utility was approved by regulators, the contract costs were included in the utility's revenue requirement and funded through electricity rates. This guaranteed revenue stream provided renewable facility operators with a way to secure financing for projects, even if utility

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[2] See generally, Part 292 -- Regulations under sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production and Cogeneration, Subpart C. See also, Massachusetts Department of Public Utilities, Docket 96-47, Massachusetts Electric Company "Green RFP" filing.

[3] According to one study, "By 1992, most renewable energy projects were eligible for several federal tax incentives including a 10% business investment tax credit, a 15% business energy investment tax credit, and five-year accelerated depreciation. The 1996 Tax Reform Act reduced the federal tax incentives available...and many of the most significant tax incentives were eliminated over time. In 1992, some of the federal tax incentives were restored through Sections 1914 and 1916 of the Energy Policy Act (EPAct) which provided a ten-year, 1.5cent/kWh production tax credit for wind and closed-loop biomass and a permanent extension to the 10% business energy investment tax credit (ITC) for solar and geothermal facilities." Ryan H. Wiser, *Evaluating the Impacts of State Renewable Policies on Federal Tax Credit Programs,* Lawrence Berkeley National Laboratory, Prepared for California Energy Commission Renewable Program Committee, December, 1996.

rates had to be increased to do so. With the risk of projects shared between investors and ratepayers, the guaranteed revenue stream could be used as leverage to obtain cheaper start-up capital for projects. These federal and state renewable policies by no means erased the barriers that renewable projects faced. However, they dramatically shifted part of the risk of such projects to ratepayers and taxpayers, providing access to cheaper capital and ensuring that renewable projects would gain consideration in utility decision making processes.

Restructuring of the electric generation industry is being implemented in a number of states across the country and under consideration in many more. Competition, it is believed, will help bring choice and lower electricity rates to customers as they decide which company will supply their electricity needs. In a restructured electricity market, the generation supplies of regulated utilities would, in essence, be split from the distribution and transmission portion of utility operations. The generation of electricity would then operate as a deregulated entity selling electricity at wholesale and retail rates directly to customers. Generation suppliers will compete against each other in a newly created competitive electric supply market. In a deregulated electric supply market, only the transmission and distribution portion of electric companies would remain subject to regulatory oversight.

Deregulation of the electric generation market promises to change the way electricity is provided to customers and new projects are financed. In a deregulated electric generation market, the owners of power plants will bear the risk of generation projects. No longer will projects be guaranteed a captive customer market, a revenue stream or a reasonable rate of return. No longer will regulators have a direct say in what gets built and how much will be charged to end users. Instead, the market will dictate price, type, quality and quantity of electricity offered for sale. [4]

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[4] Under traditional rate of return regulation, regulators made the actual decision about what types of generation plant got built. For example, the Vermont Public Service Board recently approved a 6 megawatt (MW) wind farm under traditional rate of return regulation for Green Mountain Power. As part of its Order approving the project, the Board recognized the trend toward electric industry restructuring, but concluded: "...the economic analysis of this project, by itself, makes this a marginal project. However, when balanced with the many positive aspects of this project, in particular its environmental benefits and research value, we conclude that it serves the interests of the State of Vermont, its citizens, and GMP's ratepayers to allow this project to be constructed. The future is always uncertain. Given the small size of this project, its uniqueness as an alternative to traditional supply projects, and the potential for significant benefits if this project proves worthwhile, we conclude that the risks are appropriate and worth

In this brave new world of competition, each electricity supplier will have to decide how to secure customers for its products. The electricity supplier that wins the customer will (1) price its power lower than its competition; and/or (2) be able to differentiate its power from its competitors' power. Electricity suppliers will need to convince customers, not regulators, that their power is of superior price, quality of service, or performance.

The radical changes in the generation market likely to result from the approaching competition important questions arise: How will renewable suppliers, which tend to be more expensive, fare in the new competitive market absent government support? How will the increased risk of building generation facilities affect the generation resource mix? How will the cost of capital required by lenders and investors change in response to increased risk? Will customers be willing to pay a premium for cleaner technologies and if so how much? Will such a premium be enough to help these projects go forward?

This thesis investigates whether electricity generated from wind projects will be able to compete in a deregulated electric generation market. Success will largely be measured by the price of power from wind generators, since embedded in the price are factors reflecting assumptions about the risk of wind generation (cost of capital, capital structure) and reliability (wind patterns, likely demand for wind and expected cash flow). This price must, of course, be compared to the likely price of electricity generation in a deregulated market. In addition, customer willingness to pay a premium for green power, will be addressed. It is important to note, that this thesis focuses on the price of generating power. Not included in this thesis are the prices customers will pay for transmission and distribution of electricity to their homes.

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taking." The Board stated "In addition, any direct benefits from this project, including but not limited to the future savings in the costs of electricity from this project, the value of the research information generated by this project, and the expansion of this project or construction of additional wind projects by GMP or its subsidiaries shall flow to GMP's ratepayers. It is the ratepayers, not GMP's shareholders, who are assuming the risk that this supply resource will provide electricity at or below the cost of alternative resources over the life of the project." Petition of Green Mountain Power Corporation for a certificate of public good to for authority to construct a 6 Mw wind generation facility and associated line extensions in Searsburg, Vermont, State of Vermont Public Service Board, Docket No. 5823, May 16, 1996.

Chapter II is the heart of the thesis; the financial case for a Hypothetical Cape Cod wind project. Demand for electricity in the New England market will be examined with particular emphasis on whether a wind project located on Cape Cod will be available to respond to customer demands during peak periods. This requires consideration of wind resource availability and how well expected wind output correlates with demand for electricity within the Region. Wind resources, output, revenue stream, costs, capital structure and financing are examined from the perspective of an investor to gain an understanding of how changes in, or variability of these factors impart risk. This analysis requires the development and analysis of a financial model for the hypothetical Cape Cod wind project in order to determine project net present value (NPV) and the cost per kilowatt-hour (kWh) of electricity as measures of feasibility.

Chapter III centers on a discussion of the likely price of electricity in a deregulated market. This discussion is important because it provides a benchmark against which the likely cost of wind, determined in Chapter II, can be measured. If the cost for wind power is substantially higher than the market price of electricity, this provides a key indicator of the feasibility of wind projects.

The question of whether customers will be willing to pay a premium for clean energy is central to the question of whether wind projects will be viable in a competitive energy market and will be discussed in Chapter IV. If a wind energy producer can sell electricity at a price higher than the market price because customers value its environmental attributes, its "greenness," the risk of these types of projects may not be as great. In the absence of a cost advantage or a customer-perceived value difference, renewable energy sources will find it more difficult to gain a foothold and compete in the deregulated electricity supply market than was possible in a regulated environment. This suggests that, if policy makers continue to value renewable resources of power, regulators working within the confines of a deregulated electric supply market, will need to create mechanisms in order to ensure that renewable sources of energy continue to be considered in the future supply of electricity.

The final chapter, Chapter V, is an examination of how a portion of the risk of renewable projects could be shifted to ratepayers through three subsidy mechanisms: long-term loans, price

supports, or by instituting public/private renewable project joint ventures. Next, a discussion of the importance of minimizing ownership or geographical boundary restrictions, ensuring that subsidies are used to bring renewable power to the market and making long-term policy commitments is emphasized. Chapter V concludes with a summary of the major findings of the thesis.

Chapter II

The Financial Case for A Wind Power Project

We may want more wind power because it does not pollute the air, it provides a hedge against energy price spikes, or it reduces our reliance on foreign oil. While renewable resource projects may be good public policy, are they good financial investments? Will a corporation willingly tie up millions of dollars of scarce capital resources in a wind generation project when that same corporation could invest in other, less risky projects? In general, if wind power cannot provide investors with a reasonable return on investment, investors will invest in other more lucrative projects. If corporations are not willing to take a chance on renewable energy projects, customers may be left with fewer, instead of more, choices of electricity supply options.

The answer to the question of whether corporations will invest is -- it depends. It depends on a variety of factors including how much risk investors are willing to accept, the expected return on the investment, and the level of confidence that tax laws and public policies will continue to provide support to renewable projects. It also depends on the types and number of investments competing for the same capital resources. In short, investors rely on a different set of measurements than do policy makers in determining whether a project is a good deal. These measurements include assessments of potential site locations, the market for the product, and a financial analysis. In order to determine whether a wind project would be financially feasible in a deregulated electric supply market, we will analyze a wind project from an investor's point of view using these measurements. Specifically, we will make (A) an

assessment of the wind resources at a specific location; (B) an examination of the correlation between electricity demand patterns and the potential patterns of production of electricity from a wind project; and (C) an accounting of expected costs, revenues, cash flow and overall net present value.

A. Assessment of Wind Resource

Determining wind speed and availability of a potential wind farm site are critical first steps to determining whether developing a wind project at a particular site is worth further investigation. Table 1 shows a breakdown of the different classes of winds and their corresponding wind densities and speeds. In order for a potential site to be considered for development, wind speeds should average at least 15 mph, which translates into a Class 3 wind. Cape Cod may be an ideal location for wind projects. Class 5 winds, averaging approximately 17.5 mph, were recorded in Nantucket during 1994 and 1995.[5]

Assessing the wind resource of a given location begins with an understanding of how much power can be captured and converted into electricity by a wind turbine. Slight variations in wind speeds can change the quantity of electricity generated by a wind turbine. As power in the wind is generally calculated:

$P = (d*U^3*A)/2$
where:
P = the power in the wind
U = the wind speed
d = the air density
A = area perpendicular to the wind direction

Because wind power is a direct function of the air density, the wind swept area of the turbine blades intercepting the wind, and the wind speed, increasing any one of these factors increases the power available from the wind. For example:

- Power is a cubic function of wind speed. If the wind speed doubles, the power increases by a factor of eight.

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[5] Renewable Energy Feasibility Study Nantucket Site, Phase III, Final Options Report, February 29, 1996, Prepared for the Massachusetts Division of Energy Resources, Appendix A.

- Power is proportional to the area intercepted by the wind turbine. Double the area swept by a wind turbine blade and the power generated doubles.

- Power is not significantly affected by air density because air density does not change much except for at sites with extreme temperatures or above 3000 feet in elevation.[6]

Chart 1 translates wind speed at the Nantucket site into expected energy output from a Vestas-44 wind turbine based on the frequency of wind speeds monitored at the Nantucket site during 1994 and 1995. As shown in Chart 1, at 15 mph, the six Vestas V-44 wind turbines have the ability to produce 720 kWhs. At speeds of 18 mph,

Wind Speed Classification Table I		
Wind Power Class	Wind Power Density (W/m2)	Wind Speed (mph) **
1	0-200	0-12.5
2	200-300	12.5-14.3
3	300-400	14.3-15.7
4	400-500	15.7-16.8
5	500-600	16.8-17.9
6	600-800	17.9-19.7
7	800-2000	19.7-26.6

** Vertical extrapolation of wind speed based on the 1/7 power law. Mean wind speed is based on Raleigh speed distribution of equivalent mean wind power density. Wind speed is for standard sea-level conventions.
Assumes 50 meters height.

Source: Reconstructed chart from Planning Your First Wind Power Project: A Primer for Utilities, EPRI Report TR-104398

total expected energy jumps to 1,274 kWhs.[7] Using average wind speeds for each hour of a year, the expected power output for the entire Nantucket project is approximately 11,000,000 kWhs.[8] We will return to a detailed analysis of how this factor can be translated into a revenue stream for the project financial analysis discussed below.

B. Correlation between Wind Speed Patterns and Electricity Demand Patterns

An important part of assessing a wind project site is to compare wind speed patterns to the timing of the demand for electricity. This assessment can help determine the likely revenue

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[6] Planning Your First Wind Power Project, A Primer for Utilities, EPRI Report TR-104398, citing Paul Gipe, *Wind Power for Home & Business, 1993*

[7] Production levels off at approximately 3,600 kWhs at wind speeds that are over 34 mph because the wind turbine is incapable of turning any faster.

[8] This figure does not account for the variability of wind speeds for different years. This factors will be taken into account in a later section.

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Chart 1

Expected Energy Output for Given Wind Speeds
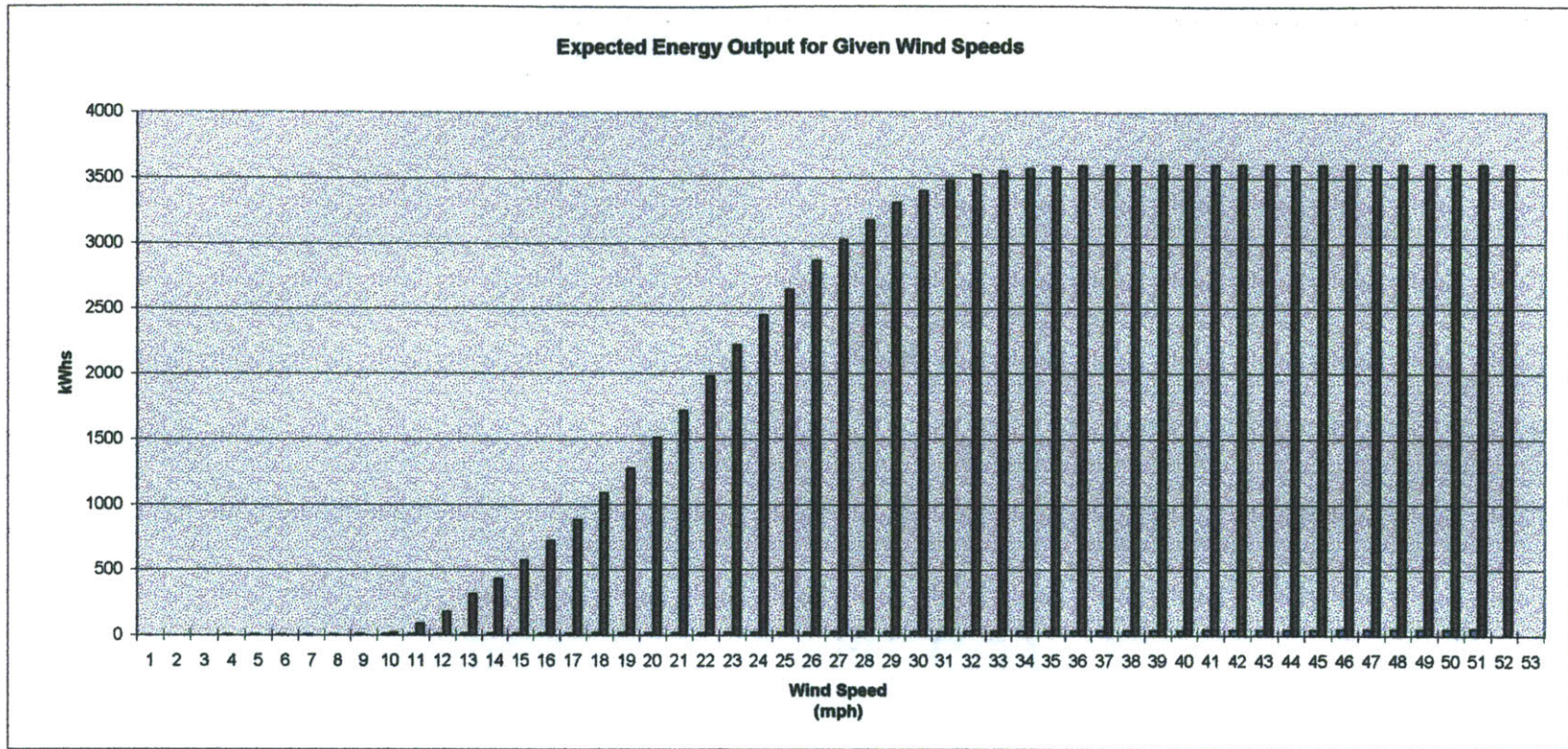
stream for the project. Wind speeds and peak demand periods must match fairly well in order to ensure that the maximum revenue for the project will be produced and the project revenue stream will cover the costs of the project. For example, if wind speeds consistently reach 30 mph at the wind site at 2:00 a.m. when customer demand is low, power generated at the wind farm would need to be priced well below cost in order to compete with lower-priced "baseload" units. By contrast, during peak demand periods more expensive generation units are dispatched which will drive the price of power up. A wind project that is able to produce electricity during peak demand periods will be able to sell its output higher prices and ensure a better revenue stream. Without a good correlation between wind availability and peak demand for electricity, a wind project will fail.

However, there is uncertainty about how demand patterns for power will change in a restructured electricity market. If high electricity demand leads to higher prices, customers may respond to these higher prices by decreasing their consumption levels or shifting their consumption of electricity to off-peak time periods. This could cause the peak periods to smooth out over time as customers adjust to these price signals. This makes it difficult to forecast whether peak periods will remain the same, shift, or decrease in a deregulated electric supply market. For purposes of this analysis, it is assumed that the demand patterns, will be similar to historical demand patterns. Using this assumption, our next step in assessing the feasibility of a wind project is to determine how well monthly and hourly wind speeds match with historic monthly and hourly New England demand for electricity.

Chart 2, Average Monthly Wind Speed, shows average Nantucket wind speeds for August 1994 through July 1995.[9] Winds tend to be highest in the winter months (November through February) and then taper off through the spring and into the summer months. Chart 3, Average Monthly kWh Production is a similar chart that translates the wind speeds from Chart 2 into expected kWh production from six turbines located at the Nantucket site. Chart 2 shows

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[9] Ideally, there would be multiple years' worth of data. Wind speeds can be greatly influenced by the number and severity of winter storms. Therefore, one year's worth of data must viewed in light of this limitation.

Chart 2
Average Monthly Wind Speed
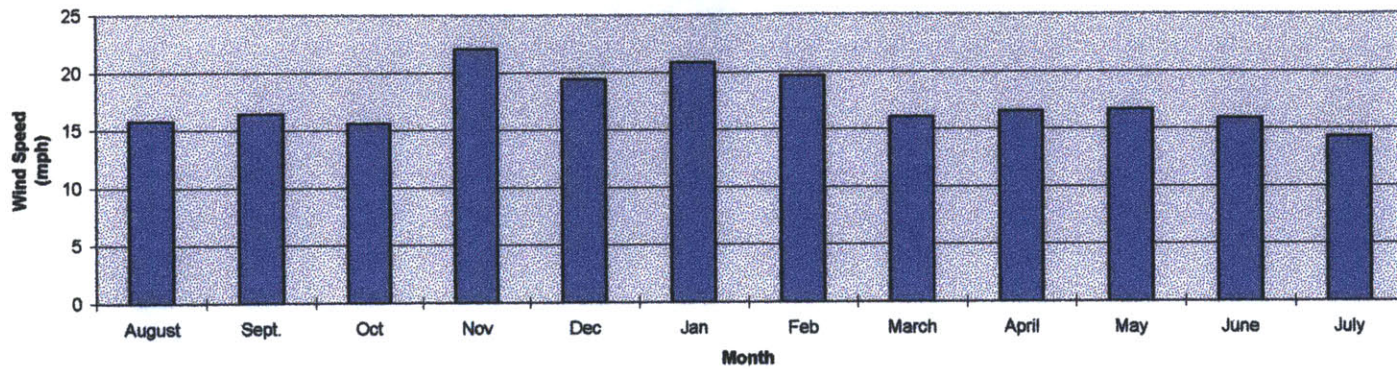
Chart 3
Average Monthly kWh Production
August 1994 - July 1995
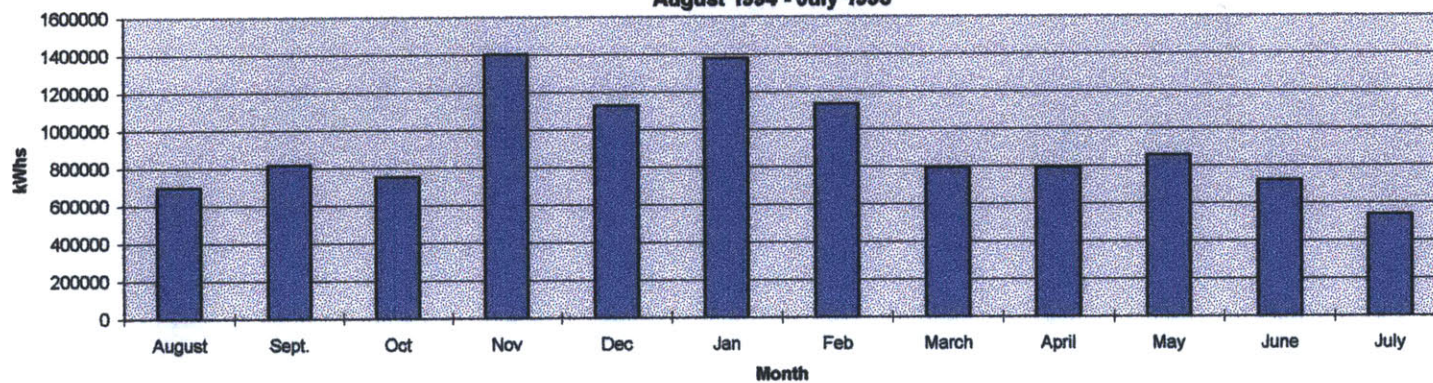
Source: Renewable Energy Study, Nantucket Site, Phase III, Final Development Options Report,
February 29, 1995.

how many kWhs the wind power plant will be able to sell into the market during different times of the year.

To complete the picture, New England Power Pool (NEPOOL) monthly peak demand data is provided in Chart 4, NEPOOL Monthly Peak Load Distribution, 1989 through 1995. As shown in this chart, demand for electricity is highest in the summer and winter months, with the spring and fall months requiring considerably less electricity. The New England summer months tend to peak slightly higher than the winter months.

When comparing Charts 3 and 4, it becomes evident that during the winter months wind output and demand for electricity is matched fairly well. Winter storms help contribute to the level and intensity of the winds on Cape Cod during these months. Demand increases as heaters are turned on, people spend more time indoors, and lights are kept on longer because of the shorter period of daylight. Unfortunately, wind speeds do not correlate well with the demand for electricity in the summer months. During these months when the electricity is in high demand, wind speeds, while not zero, are not sufficient to allow the turbines to operate at peak output levels.

We will use these charts in our analysis below to determine if, over the year, a sufficiently good correlation between wind speeds and the demand for energy exists to produce positive financial results.

C. Accounting of Expected Costs, Quantity of Output and Projecting Project Success

A financial analysis of a project is a projection or forecast of the likely costs, revenues, expenses, and taxes for a given project. It is a test used by investors to gauge the likely success of a given project as measured by project net present value (NPV) -- the extent, to which, if any, the present value of after-tax revenues exceeds the equity investment in the project. [10] Financial analyses account for costs, revenues, the opportunity cost of capital, and level of risk. Revenues are measured by price of the product multiplied times the quantity produced. Costs are measured

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[10] Brueggerman and Fisher, Real Estate Finance and Investments, Ninth Edition, 1993.

Chart 4
NEPOOL Monthly Peak Load Distribution
1989 to 1995
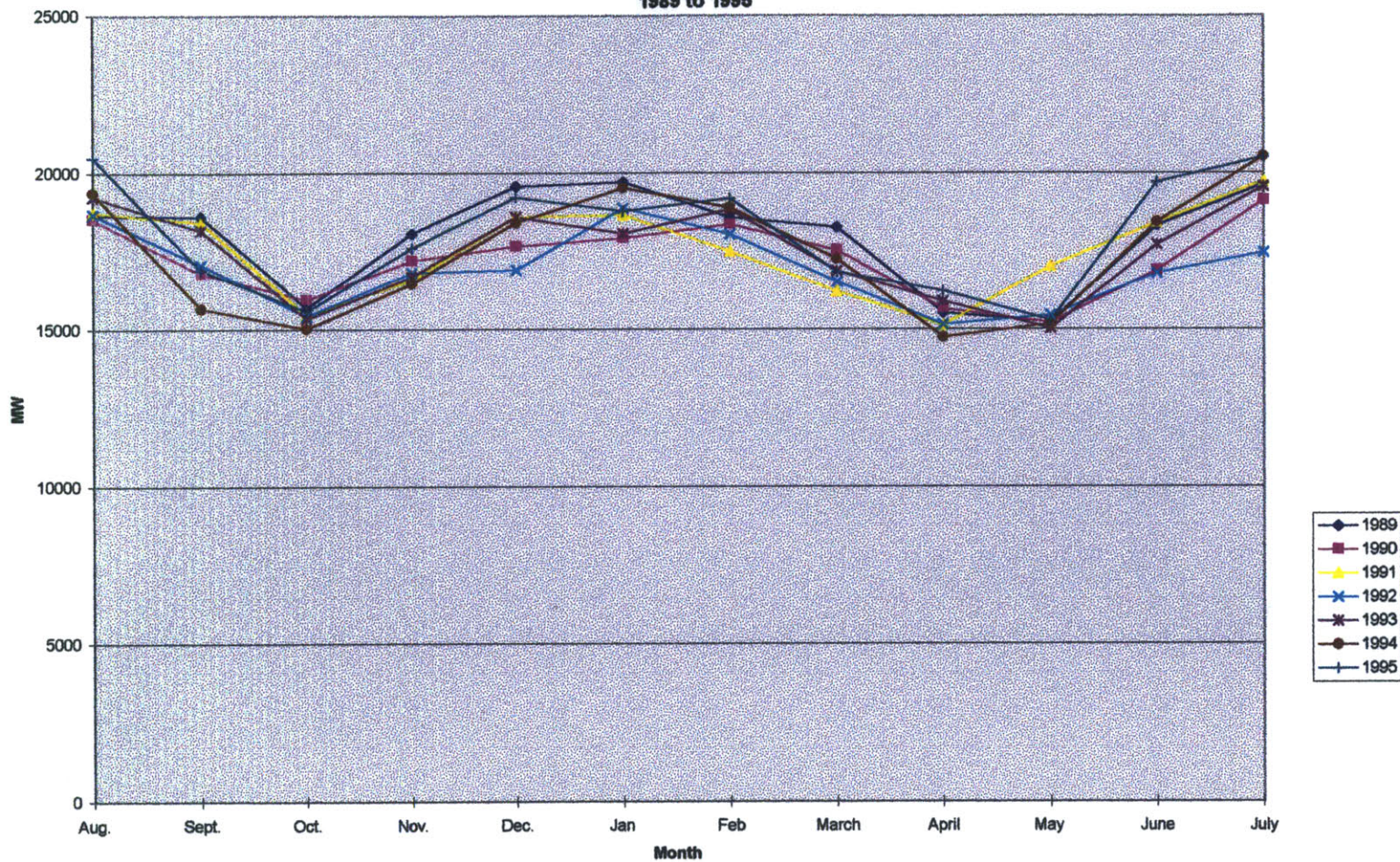
by level of expenses, including amortization of the initial capital-intensive start-up costs of an operation. Risk is reflected in the necessary capital rates demanded by debt and equity holders. These revenue and cost projections must also include a number of general assumptions about inflationary expectations, capital structure, revenue and cost increases, among many others.

The financial model developed for this thesis is for a Hypothetical Cape Cod wind project. The model employs a basic cash-flow analysis that projects the likely revenue stream, expenses, depreciation and taxes over a 20-year period. A standard cash-flow model was chosen in an attempt to replicate the process that a potential investor would use in evaluating this kind of project. The capital costs, operating costs and revenue stream represent a composite of a variety of wind projects reviewed in New England.

Overall feasibility is measured by the project's NPV, which depends on the discount rate (required return on equity or opportunity cost) assumed for the project.[11] NPV is an indication of whether a project will yield a sufficient return to debt and equity investors to justify the investment of scarce capital and resources given other investment alternatives. Assuming the correct interest and discount rates have been incorporated into the analysis, a

Table 2 Assumptions of the Financial Model	
Cost/Size Assumptions:	
Wind Farm Size	3.6 MW
Cost/kW of Capacity	$1,200/kW
O&M Expense per kWh	$0.0151/kWh
Total Projected Costs	$3,970,000
Land Value	$350,000
Combined Tax Rate	40%
Financing Assumptions:	
Equity Contribution (30%)	$1,296,000
Discount Rate	20%
Debt Amount (70%)	$3,024,000
Interest Rate on Debt	7.36%
Loan Term	10 yrs.
Amortization Term	10 yrs.
Annual Payment	$222,611
Production Tax Credit	$0.015
Depreciable Life	5 yrs.

positive NPV suggests that the project could attract the capital required for the investment. A negative NPV suggests that investors would choose to invest capital elsewhere to ensure adequate return in exchange for the risk associated with their investment.[12]

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[11] Brueggerman and Fisher, Real Estate Finance and Investments, Ninth Edition, 1993.
[12] Brealey and Myers, Chapter 5, 1997 edition.

Table 2 provides a summary of the project specifications and assumptions to be discussed below. First, a description of the hypothetical Cape Cod wind project including size, location, fixed costs and operating costs of the project are discussed. These specifications are based on wind projects proposed or located within the New England region.

A discussion of the financial assumptions will follow the description of the project specifications. Financing costs are likely to change in a deregulated electricity market. For example, the cost of equity is likely to increase as investors are no longer able share the risk of such projects with ratepayers.

An overall assessment of project feasibility will be tested using an NPV analysis. Price, cost and financing changes will be analyzed in order to show the sensitivity of the model to the various assumptions included. Next, because the price of electricity is likely to vary on an hourly basis based on demand and supply in decisions in a deregulated electric supply market, a discussion of how changes in price affect the revenue stream of the project is included.

1. Balance Sheet Financing

The underlying assumption of the financial model we employ is that the project would be financed by a large corporation through balance sheet financing. Balance sheet financing assumes that the debt/equity ratio is similar to that of the corporation and that debt is available to the project at the company's cost of debt. The return on equity is set according to internal corporate policy and measure of risk.

In a regulated environment, project financing, not balance sheet financing, would have been the norm for non-utility renewable generation projects. According to Brealey and Myers Project, project financing is when a corporation takes a private loan that is "tied as far as possible to the fortunes of a particular project and that minimizes the exposure of the parent."[13] Under PURPA as implemented in many states, utilities bought power from independent power producers under contract arrangements.[14] Utilities offered these contracts as a result of state policies and because they were guaranteed by rates charged to ratepayers. Many independent and

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[13] Brealey and Myers, Principals of Corporate Finance, Fourth Edition, 1991 at 608-609.
[14] Brealey and Myers, Principals of Corporate Finance, Fourth Edition, 1991, at 610.

renewable power projects used these long-term contracts to reduce the riskiness of the project and to set up off-balance sheet or project financing arrangements. The long-term power purchase contracts provided security for the debt that was issued for the project. As a result, some power projects were as much as 90 percent debt financed.[15] According to Brealey and Myers:

> Such extremely high debt ratios must rest on the utility's creditworthiness. In a sense, the utility has borrowed money "off balance sheet," since the contract to purchase power is a fixed, debt-like, long-term commitment. Other things equal, including the amount of on-balance-sheet debt, this fixed commitment should act as financial leverage and increase the volatility of utility earnings and shareholder returns. [16]

In a deregulated environment, power purchase contracts are unlikely to be available and balance sheet financing will become the norm for renewable projects. There are reasons for this. First, the absence of long-term power purchase contracts that allowed non-utility generators to lock-in prices for power across extended terms will mean that power producers will no longer have access to a guaranteed revenue stream to secure necessary long-term financing. Project sponsors will need to be large enough to have access to equity resources to invest in renewable projects, to secure debt financing, and to take advantage of the tax benefits associated with renewable projects. Renewable projects generate tax losses in the early years of operation that can be used to shield or offset taxable income. However, only an entity that has taxable income from other investments will be able to use these tax losses in the years in which they are incurred and worth the most. Because renewable projects are characterized by high capital costs in the fist few years of operation, these projects have no income against which to assign losses until later years in the project. In fact, an independent renewable project may actually have to pay taxes to comply with the alternative minimum tax law regardless of whether it generates income. This law requires even companies generating losses to calculate income using an alternative method to ensure that such companies pay at least some taxes.[17] These factors make it more likely that only large, diverse entities will invest in renewable projects.

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[15] Brealey and Myers, Principals of Corporate Finance, Fourth Edition, 1991 at 610.

[16] Brealey and Myers at 610, footnote 45.

[17] Windpower 1993 Proceedings, *Making Sense of the Federal Tax Code: Incentives for Windfarm Development*, Edwin T.C. Ing, at 43.

Additionally, renewable resources offer a large power producer a way to diversify fuel risk, promote company image and offer a greater variety of electricity products to consumers. While product diversification is not likely to the primary factor in the decision to invest in a renewable project, at least in the near term, it may become more important as suppliers attempt to differentiate themselves from the competition in a restructured electricity market.

By assuming that the hypothetical Cape Cod project would be developed by a large corporation, we also assume that the corporation has experience in power generation (siting, building and operating), access to cost information, consumer information, and wind data. We attempt thereby to eliminate concerns about inexperience that could further increase the risk of the project to an investor. Instead we focusing on the variations in interest rates, cost of capital, and the price of energy that will occur as a result of the competition. It is important to note however, while the analysis assumes that renewable projects would be developed by a large corporation, it also assumes the project would need to compete for capital against other projects within the company.

For these reasons, this thesis assumes balance sheet financing for the hypothetical Cape Cod wind project by a company with a debt/equity ratio of 70/30.

2. Project Capital Costs

Wind projects are capital intensive. As shown in Table 3, the installed costs per kilowatt of capacity can range from $1102 to $1681.[18] Most of these costs are related to equipment, construction and infrastructure costs. This is because the areas suitable for wind projects tend to

Table 3
Capital Costs per Kilowatt of Capacity
Of Actual Wind Project

Project	Capital Costs	Cost/kW
Vermont	$10 M	$1681
Cape Winds	$3.6 M	$1270
Nantucket	$3.9 M	$1102
Hyp. Cape	**$4.3 M**	**$1200**

Sources: Renewable Energy Feasibility Study Nantucket Site, Phase III.
Vermont Docket No. 5823, Testimony of John Zimmerman on Behalf of Green Mountain Power Corporation, JLZ Exhibit 7
The Cape Winds Project, A Proposal From the Commonwealth of Massachusetts Division of Energy Resources and Endless Energy Corporation to the U.S. Department of Energy Commercialization Ventures Program, August 29, 1996.

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[18] Significantly larger projects that employ numerous turbines, may have lower per kilowatt capital costs. For example, one article indicated that for 100 Vestas V39-500kW turbines, the cost per turbine would be approximately $930.00 per kW of capacity. Jensen, Oscar H., Poulsen, Egon V. , White, Paul T. "Project Performance" Vestas-American Wind Technology, Inc., White Paper, Conference Proceedings, Windpower '94/American Wind Energy Association, U.S. Department of Energy, Solar Energy Research Institute, Organizing sponsors, with support from Electric Power Research Institute.

be remote (*e.g.*, the Island of Nantucket, a ridge top). Transporting turbines to the site, preparing the site and, constructing the site tend to increase the farther these sites are from cities. For example, for the Nantucket project, the cost of transportation equipment (including a crane) and materials via ferry was estimated to be approximately $118,000.[19] Other capital costs related to rural locations include installing transmission lines to interconnect a wind generation facility to the utility transmission grid.[20]

Table 4 Vermont Wind Project	
Capital Cost Categories	Percent of Total Costs
Project Management	3%
Permitting	3%
Wind Resource Assessment	1%
Design and Engineering	4%
Equipment Procurement	42%
Construction	48%
Source: Exhibit JLZ, Vermont Docket 5823.	

Table 4 breaks down the categories of capital costs and the percentage of total capital costs each represents for the Vermont project.[21] As shown in this table, construction (including infrastructure additions) represents almost half of the total capital costs.

The high capital costs translate into high risk for a potential investor. More financial resources must be invested in the project "up front" before the project begins to generate revenue. High up-front costs combined with cash flow uncertainty for the years of operation, makes it more difficult for wind projects to "get off the ground."

As shown in Table 3, for purposes of the hypothetical Cape Cod project the capital costs the installed cost of the wind farm is assumed to be $1,200/kW of capacity for a total fixed costs of $4.3 million. This estimate is based on the range of costs of the three New England projects reviewed and discussions with wind project developers.[22]

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[19] Letter to Second Wind, Inc. from Vestas -- American Wind Technology, Inc., December 2, 1994, Renewable Energy Feasibility Study Nantucket Site, Phase III, Final Development Operations Report, Prepared for the Massachusetts Division of Energy Resources, February 29, 1996, at Appendix C.

[20] Depending on the voltage required and the distance a wind farm is from the electricity grid, cost to install transmission lines can range from $125,000 to $800,000 per mile. Energy Information Administration, Renewable Energy Annual, December, 1995 at 88.

[21] Some believe that the Vermont project may include higher than normal costs because of the high level of DOE/EPRI funds used to subsidize the project.

[22] Interview with Harley Lee, President of Endless Energy, Inc.

3. Operation and Maintenance Costs

Operation and maintenance (O&M) costs for wind projects include costs of the personnel who operate and maintain the wind project. O&M costs tend to be relatively low compared to more traditional forms of electricity generation. This is because wind projects are not dependent on fuel, which makes up the bulk of costs for more traditional power plants. As shown in Table 5, O&M costs can range from a low of $0.008 per kWh to $.025 per kWh. Operation and maintenance costs associated with the hypothetical Cape Cod wind project are assumed to be $.015 per kWh. This figure is based on a review of the O&M costs of the three New England projects.[23]

4. Cost of Equity

The cost of capital in a competitive market reflects investor's perception of the risk inherent in the project. As the risk of a project increases, the cost of capital likewise increases to compensate investors (both debt and equity) for the added risk associated with the project. As discussed above, factors that contribute to the measure of risk include certainty of the revenue, weather, technology, and credit.

The overall cost of capital is the weighted average cost of debt and the equity return required by investors in the project. Debt is the loan that a company takes to finance operations while equity is the amount of capital put in by project owners or the partners of the project. Interest on the debt is usually lower than interest paid on equity because it is more secure. Debt service typically has first claim on any revenue realized by

Table 5
Operation and Maintenance Costs for Three New England Projects

Vermont	$.0114
Cape Winds	$.025
Nantucket	$.008
Average	**$.015**

Sources:
Renewable Energy Feasibility Study Nantucket Site, Phase III.
Vermont Docket No. 5823, Testimony of John Zimmerman on Behalf of Green Mountain Power Corporation, JLZ Exhibit 7
The Cape Winds Project, A Proposal From the Commonwealth of Massachusetts Division of Energy Resources and Endless Energy Corporation to the U.S. Department of Energy Commercialization Ventures Program, August 29, 1996.

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[23] For larger projects, O&M costs may be significantly lower. In a recent article, the O&M costs for a 50 MW project were approximately $.012/kWh. Jensen, Oscar H., Poulsen, Egon V. , White, Paul T. "Project Performance" Vestas-American Wind Technology, Inc., White Paper, Conference Proceedings, Windpower '94/American Wind Energy Association, U.S. Department of Energy, Solar Energy Research Institute, Organizing sponsors, with support from Electric Power Research Institute.

the project and is secured by collateral. By contrast, those providing equity contributions as part

owners of the project, make money only after all outstanding debt and expenses have been paid.

This makes equity investments less secure, and the cost of equity higher than the cost of debt.

Equity is distinct from debt, too, in that it provides investors with the potential for unlimited "up-

side" or profit potential. For this reason, the investors are willing to take on more risk than are

debt holders who are only entitled to a fixed return on investment (the interest rate demanded).

In our analysis, return on equity is expressed as a discount rate. Table 6 shows how risk

may translate into a different discount rates required by equity investors. Because firms may

value risk differently, the discount rates shown in Table 6 will not be correct for all firms.[24]

For example, a discount rate of 10%
may correspond to equipment improvements
that employ known technologies. The low
discount rate may reflect the fact that the
company has experience with similar cost
improvements and that the company knows
the cost of the equipment and can estimate
the time that the plant will be off-line.
Because of known factors, in this example,
the risk to the company of such an investment

Table 6	
Category	Typical Cost of Equity or Discount Rate(%)
Speculative Ventures	30%
New Products	20%
Expansion of Existing Bus. (Co. cost of capital)	15 %
Cost Improvements (known tech.)	10%
Source: Brealey and Myers at 182.	

is low and the return is set at a rate close to a rate at which the company can borrow money, *i.e.*,

10%.

By contrast, a discount rate of 20%, corresponds to products that have yet to be tested in a

market setting. The firm may have experience selling a similar product but no experience with

the new product line. The 20% return required by investors is twice that of a relatively secure

investment to compensate investors for the fact that the product may not perform at expected

levels. Because we assume that the hypothetical Cape Cod project would be a new product for a

large corporation, the cost of equity is assumed to be 20%. This assumption recognizes that the

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[24] See, Brealey and Myers, at 182

corporation has experience with other ventures but reflects the fact that a new product, renewable energy, is to brought on-line. [25]

5. Cost of Debt

As discussed above, debt service has first claim on revenues generated by a project and is not entitled to profits that may result from the project. In the hypothetical Cape Cod project, we assume that a corporation will embark on the wind project through use of balance sheet financing, in essence relying on the corporation's entire portfolio of "projects" to service the debt. Debt is most likely to be in the form of bonds or direct loans from financial institutions. In balance sheet financing, payment of the loan is guaranteed by the corporation, not by the revenue stream of the project. In the event

Table 7 Yield Comparisons Corporate High Quality Bonds				
Maturity	4/23/97	4/24/97	52 Week High	Low
10-plus year	7.66%	7.69%	7.83%	6.89%
52 Week Average:			**7.36%**	

Source: The Wall Street Journal, Friday April 25, 1997, Section C19.

that the project is technically infeasible, or if revenues cannot cover expenses, the corporation assumes the responsibility to make payments on the loan.

As shown in Table 7, the financial section of the Wall Street Journal reported that corporate bonds of high quality, with a 10 plus year maturity, recorded a 52 week low of 6.89% and a high of 7.83%.[26] For our purposes, the 52 week average rate of 7.36% is assumed to be the rate at which debt will be made available to the parent corporation for its hypothetical Cape Cod project.

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[25] In a regulated environment, the discount rate is lower to reflect the fact that ratepayers share a large portion of the risk. For example, in the Vermont wind project, the financial analysis assumes an equity discount rate for GMP of only 9.41%. Docket No. 5823, Testimony of John Zimmerman on Behalf of Green Mountain Power Corporation, JLZ Exhibit 7, at 1. Similarly, in a green request for proposals ("Green RFP") submitted to the Rhode Island Department of Public Utilities in 1994, New England Electric Systems included a discount rate of 7.96% for its proposed wind project in Maine.

[26] The Wall Street Journal, Friday, April 25, 1997, Section C19

6. Expected Power Output

One of the most challenging tasks is determining the likely revenue stream as a function of expected power output for the project. Assuming all generated output is sold into the market, revenue is usually determined by a simple calculation of quantity of output multiplied by the price charged per unit of output. As discussed in Section A, Assessment of Wind Resources, determining the likely quantity of output from a wind farm is anything but certain. Minor wind changes due to weather pattern shifts can reduce the energy output for a wind turbine from expected levels drastically. Historical weather conditions are probably the best indicator of future weather patterns, yet cannot predict precisely what will happen at any given time because annual winter storm activity varies widely. Even with the best wind speed data, expected electricity output can be only a ballpark estimate.

The following analysis will provide an estimate of the likely output from the Hypothetical Cape Cod wind farm using wind speed data from Nantucket for the twelve month period August, 1994 through July, 1995 will be used.[27] In addition, five years of wind speed data from a site in Western Massachusetts is reviewed in order to determine annual variations in wind output. This analysis is less than ideal given that Western Massachusetts wind speed variability may not be indicative of Cape Cod wind speed variability. However, because of a lack of Cape Cod data, and given that the Cape Cod data for the twelve month period between July 1994 and August 1995 are unlikely to provide the correct output level for the next 20 years, we believe that the use of the Western Massachusetts data is reasonable. Charts 1 through 4 discussed earlier and additional information will be used as the basis of this analysis.

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[27] Nantucket Phase III Report, at 2-5.

As shown in Chart 1, wind electricity output will vary based on (1) hourly wind speed, (2) wind speed frequency and distribution, and (3) the size and number of wind turbines. The wind data provide enough detail to make a variety assumptions about what is a reasonable output level to assume for the Hypothetical Cape Cod project.

Wind speeds for the Nantucket site averaged approximately 17.4 mph for the twelve month period August, 1994 to July, 1995. As shown in Table 8, an analysis of the Nantucket wind speed data reveals that approximately 11.0 million kWh would have been generated in the 1994-1995 period using six Vestas V-44 turbines. Table 8 shows that more electricity will be generated during the winter months because of seasonal changes in wind patterns. (See Chart 3.)

This estimate of electrical output is subject to variations in seasonal and annual weather patterns. In order to determine the variability of wind speeds for the hypothetical Cape Cod project, wind speed data recorded from the Western Massachusetts ridge top was used as an indicator. In Table 9, these data show that average wind speed ranged between 16.62 mph to 18.44 mph over the five year period. The calculated standard deviation of the wind speed in a given year was plus or minus approximately 6.5 mph.

Table 8
Expected Electricity Output by Season for the Hypothetical Cape Cod Project
August 1994 - July 1995

Season	Kilowatt Hours
Winter	3,644,813
Spring	2,442,163
Summer	1,959,549
Fall	2,969,005
Total	**11,015,530**

Source: Calculations based on wind -speed and power curve data provided in the Nantucket Phase III Report.

Table 9
Wind Speeds at A Western Massachusetts Ridge Top
(MPH)

	Average Wind Speed	Standard Deviation
1987	18.19	6.90
1988	18.44	6.99
1989	16.62	6.18
1990	17.04	6.20
1991	16.85	6.41

Source: Wind Speed Data provided by the MIT Energy Lab.

Assuming these data are indicative of Cape Cod wind variability, we can expect electric output and the resultant revenue stream to vary according similarly. As shown in Table 10, these wind speed assumptions translate into expected electrical outputs that range from a low of 9.3 million kWh per year to a high of 12.1 million kWh per year- - a difference of approximately 3 million kWhr.

On average, output will be approximately 10.59 million kWhr annually plus or minus 1.2 million kWhs. For purposes of the NPV analysis, we assume this average output level, with the understanding that in some years output.

Table 10 Annual Wind Speed Variability	
	kWhr
1987	12,079513
1988	11,707,649
1989	9,360,286
1990	10,049,837
1991	9,752,716
Average:	10,590,000

Sources: Calculations based on wind -speed and power curve data provided in the Nantucket Phase III Report and Wind Speed Data provided by the MIT Energy Lab.

7. NPV Analysis

Tables 11 and 12 (attached) are spreadsheets that provide the input assumptions (discussed above) and the results of the financial model, respectively. As shown in Table 12, the break-even point of the project, *i.e.*, the point at which the NPV is greater than or equal to zero, occurs when electricity from the project is priced at 6.5 cents per kWh ($0.06486).

Table 13 Wind Project Sensitivity to Price per kWh	
Price/kWh	NPV
$.035	($1,353,244)
$.040	($1,122,975)
$.045	($892,707)
$.05	($662,506)
$.058	($305,872)
$.064861	**$0**
$.065	$24,015
$.07	$299,079

The model is extremely sensitive to the price at which electricity is sold. Table 13 shows how changes in the price of electricity could translate into financial disaster for the project. For example when the price of electricity drops from 6.5 cents to 5.8 cents per kWh, the project NPV plummets to a negative $305,872. If the price drops even further, for example, to 4.5 cents per kWh, the project NPV falls to a negative $892,707. Therefore, in order for company to invest in this project, the company would want to be confident that electricity from the project could be sold for at least 6.5 cents per kWh.

TABLE 11		
Hypothetical Cape Wind Project		
Input Variables:		
Wind Farm Capacity (kWs)		3600
Cost/kW of Capacity		$ 1,200.00
Project Costs		3,970,000
Land Value		$ 350,000
Total Cost		4,320,000
Equity Contribution (30%)		$ 1,296,000
Combined Tax Rate		40%
Going-out CAP Rate		17%
Debt Amount (70%) (fixed rate)		$ 3,024,000
Interest Rate (Corporate Bond Rate)		7.36%
Loan Term (months)		120
Amort Term (months)		120
Payment		$222,611
Depreciable Life (years)		5
Price of wind (cents/KWH)		$0.064861
Average O&M per KWH		$0.0151
Discount Rate (r)		20%
Annual Growth in Income (g)		3%
Production Tax Credit		0.015
Ann. Growth in Op. Exp.:		3%
Capacity Factor		29%
Annual Output		10,590,000

TABLE 12

		-	1	2	3	4	5	6	7	8	9
Year		1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
KWH			10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000
Revenue (Output * Price charged)			$ 686,881	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488
O & M Expenses											
	$ 0.0151		$ 159,909	$ 164,706	$ 169,647	$ 174,737	$ 179,979	$ 185,378	$ 190,940	$ 196,668	$ 202,568
NOI			$ 526,972	$ 542,781	$ 537,840	$ 532,751	$ 527,509	$ 522,109	$ 516,548	$ 510,820	$ 504,920
Debt Service Expense											
	Interest		$ 222,566	$ 206,729	$ 189,727	$ 171,473	$ 151,876	$ 130,836	$ 108,248	$ 83,997	$ 57,961
	Principal		$ 44	$ 15,881	$ 32,884	$ 51,138	$ 70,735	$ 91,775	$ 114,363	$ 138,614	$ 164,650
BTCF			$ 304,361	$ 320,171	$ 315,229	$ 310,140	$ 304,898	$ 299,499	$ 293,937	$ 288,209	$ 282,309
Taxes											
	Interest Expense		$ 222,566	$ 206,729	$ 189,727	$ 171,473	$ 151,876	$ 130,836	$ 108,248	$ 83,997	$ 57,961
	Depreciation (5 yr. MACRS)		$ 794,000	$ 1,270,400	$ 762,240	$ 457,344	$ 457,344	$ 228,672			
	Taxable Income (NOI - Taxes)		$ (489,594)	$ (934,348)	$ (414,127)	$ (96,066)	$ (81,711)	$ 162,601	$ 408,300	$ 426,823	$ 446,959
	Taxes		$ (197,600)	$ (377,103)	$ (167,142)	$ (38,772)	$ (32,979)	$ 65,626	$ 164,790	$ 172,266	$ 180,393
	Tax Loss Taken by Parent		$ (197,600)	$ (377,103)	$ (167,142)	$ (38,772)	$ (32,979)	$ -	$ -	$ -	$ -
	Accum. 1.5 cent Production Tax Credit		$ 158,850	$ 158,850	$ 158,850	$ 158,850	$ 158,850	$ 158,850	$ 158,850	$ 158,850	$ 158,850
	Tax Benefits		$ 0.0217	$ 0.0278	$ 0.0207	$ 0.0163	$ 0.0161	$ 0.0150	$ 0.0150	$ 0.0150	$ 0.0150
			$ 0.0081								
ATCF		$ (1,296,000)	$ 304,361	$ 320,171	$ 315,229	$ 310,140	$ 304,898	$ 233,873	$ 129,147	$ 115,843	$ 101,916
Discounted ATCF		$ (1,296,000)	$ 253,635	$ 222,341	$ 182,424	$ 149,566	$ 122,532	$ 78,323	$ 36,043	$ 26,965	$ 19,752
NPV	$ (0)										
IRR	0.00%										
Price of wind	$0.064861	$0.064861									

	10	11	12	13	14	15	16	17	18	19	20		
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017		
	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000	10,590,000		
$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488	$ 707,488		
$ 208,645	$ 214,904	$ 221,351	$ 227,992	$ 234,832	$ 241,877	$ 249,133	$ 256,607	$ 264,305	$ 272,234	$ 280,401		
$ 498,843	$ 492,583	$ 486,136	$ 479,496	$ 472,656	$ 465,611	$ 458,355	$ 450,881	$ 443,182	$ 435,253	$ 427,086		
$ 30,009	$ -	0	0	0	0	0	0	0	0	0		
$ 192,602	$ -	0	0	0	0	0	0	0	0	0		
$ 276,232	$ 492,583	$ 486,136	$ 479,496	$ 472,656	$ 465,611	$ 458,355	$ 450,881	$ 443,182	$ 435,253	$ 427,086		
$ 30,009	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
$ 468,833	$ 492,583	$ 486,136	$ 479,496	$ 472,656	$ 465,611	$ 458,355	$ 450,881	$ 443,182	$ 435,253	$ 427,086		
$ 189,221	$ 198,807	$ 196,205	$ 193,524	$ 190,764	$ 187,921	$ 184,992	$ 181,975	$ 178,868	$ 175,668	$ 172,372		
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
$ 87,011	$ 293,777	$ 289,932	$ 285,971	$ 281,892	$ 277,690	$ 273,363	$ 268,905	$ 264,314	$ 259,585	$ 254,714		
$ 14,053	$ 39,539	$ 32,518	$ 26,728	$ 21,956	$ 18,024	$ 14,786	$ 12,120	$ 9,928	$ 8,125	$ 6,644		

Reversion - Accounting for the sale of the property

Sales Price	$ 2,937,640
BT Reversion	$ 2,937,640
Taxes	0
(equipment fully depreciated)	
AT Reversion	$ 2,937,640

Changes in the required equity returns, the level of output, or the initial capital costs of the project could result in a negative NPV. Tables 14-16 show the project's sensitivity to changes in these variables assuming the price for electricity is 6.5 cents per kWh. As shown in Table 14, if project investors require a 25% or 30% return on equity instead of a 20% return, the project becomes unprofitable.

Table 14 Model Sensitivity to Required Equity Returns	
ROE	NPV
20%	$0
25%	($220,158)
30%	($375,521)

As discussed above, the level of electrical output from a wind project is critical because it translates directly into a revenue stream in the financial analysis. If, on average, the energy output of the turbines is less than 10.5 million kWhs calculated for the project, the project is not likely to be a good investment.

Table 15 Model Sensitivity to Level of Electrical Output	
Output	NPV
9,500,000	($221,719)
10,590,000	$0
11,500,000	$185,104

In addition, as the initial fixed costs and construction costs increase or decrease for the project, the financial viability of the project can change. In general, fixed costs have been on a downward trend due to technological advances in the development of wind turbines. At the same time, future costs for a wind project construction could increase if the location of the project is in a sufficiently rural location. Rural locations require the construction of transmission lines and infrastructure that add to the overall start-up cost equation. Table 16 shows what can be expected in term of changes to NPV, in the event that initial project fixed costs change.

Table 16 Model Sensitivity to Fixed Costs	
Fixed Costs	NPV
$3.0M	$462,122
$3.5M	$234,065
$3.7M	$134463
$3.97 M	**$0**
$4.0M	($14,940)
$4.2	($114,543)

8. Conclusion

The financial analysis shows that, given the assumptions of the model, electricity would need to be priced at a minimum of 6.5 cents per kWh in order for the project to break even.[28] This estimate is subject to a number of assumptions that, if changed, can substantially increase or decrease the profitability of the project. More importantly, this analysis ignores the fact that, in a deregulated market, the price of electricity will not be set by any one company, but rather by the conditions extant in the market. Accordingly, the 6.5 cent per kWh break-even price must be compared to the expected price of electricity in the market in order to determine whether the hypothetical Cape Cod wind project is likely to be profitable.

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[28] Currently, wind projects constructed before 1999 are allowed a 1.5 cent production credit and accelerated depreciation of equipment. Assuming the hypothetical Cape Cod wind project were built before 1999, these tax benefits amount to approximately 1 cent ($0.008) per kWh over the life of the project. Thus, the price of electricity from the wind project would be approximately $0.0568 instead of $0.0648.

Chapter III

What Will be the Price of Electricity in a Competitive Market?

Predicting the price at which goods and services will sell in a given market is like predicting the weather. No matter how sophisticated the predictive model, study, or data set, actual prices fluctuate. Prices in a competitive market reflect the hundreds of thousands of consumer and supplier decisions occurring simultaneously. The dynamic forces that drive these decisions vary by time of day, region and weather, among many other factors.

The price of electricity in the market will be a function of supply and demand at any given point.[29] In

Figure 1
Demand and Supply Curves

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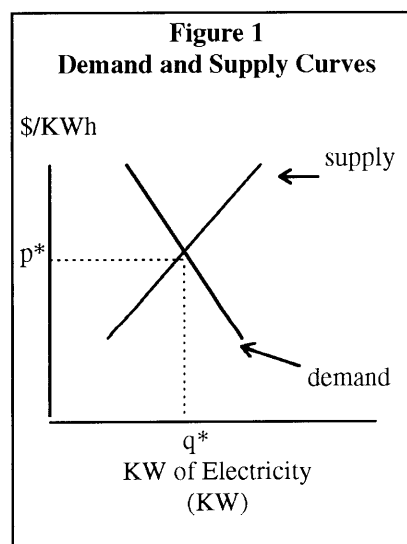
[29] For the purposes of this thesis, the market is defined as electricity customers in the New England Region encompassing the service territories of members to the New England Power Pool (NEPOOL).

Figure 1, the horizontal axis represents the quantity of electricity in the market; quantity increases to the right along the horizontal axis. The vertical axis represents the price of electricity in the market; price increases along the vertical axis.

For each price in the market, the supply curve shows what quantity of electricity will be sold. For example, at price p* per kWh, suppliers will be willing to offer q* megawatt hours of electricity to the market. The negative slope of the demand curve shows that as the price for electricity decreases, customers are willing to purchase more electricity. Similarly, the supply curve shows that as the price for electricity increases, suppliers are generally willing to provide more power to customers. Where demand for electricity intersects with the supply of electricity, the market price can be found.

Because demand and supply are not static, there is no one price point that will be said to be "the market price for electricity" as suggested in Figure 1. Demand for electricity fluctuates daily with the weather and temperatures changes and consumer work and weekend schedules. Demand also changes with the changing seasons; August and January tend to be high electricity consumption months, while Spring and Fall tend to be low consumption months. These changes produce a range of prices along the demand curve that will dictate where the market price for electricity will be in any given period of the day.

Figure 2
Price Increase Due to a
Shift in Demand
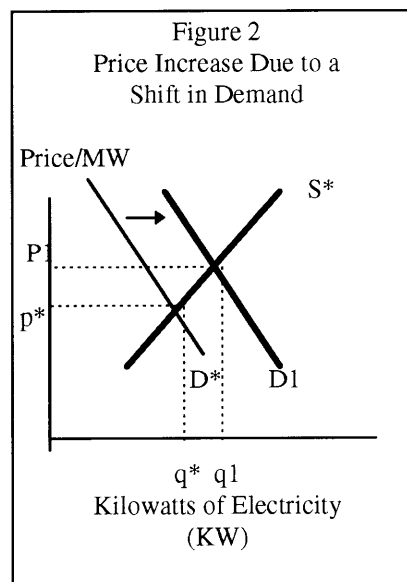
Even if we could predict the fluctuations on a daily and seasonal basis, other changes in demand and will keep us guessing as to the price of electricity in a deregulated market. As tastes change, or new products are introduced, e.g., electric vehicles, the demand curve is likely to shift. A shift of the demand curve either to the right or to the left has implications for the price of electricity. As shown in Figure 2, as new products are introduced and demand for electricity increases, a shift to the right (D1) results in a higher market price for electricity (p1).

Similarly, the supply side of the equation can be elusive. The supply of electricity in the market is a function of the number, type and capacity of the power generating units. Supply is affected by planned and unplanned plant outages, strikes, changes in fuel prices, among other factors, that affect the level and cost of output of the generating units in the system. Changes in the level of kWh generated in the market are reflected as a movement along the existing supply curve (Figure 1). In a deregulated market, in order to predict how the supply

Figure 3
Price Decrease Due to a
Shift in Supply

Price/KWh

S^*

S1

p^*
$p1$

D^*

q^* $q1$
Kilowatts of Electricity
(KW)

curve will look, total capacity available and the bid price of each supplier would need to be known.
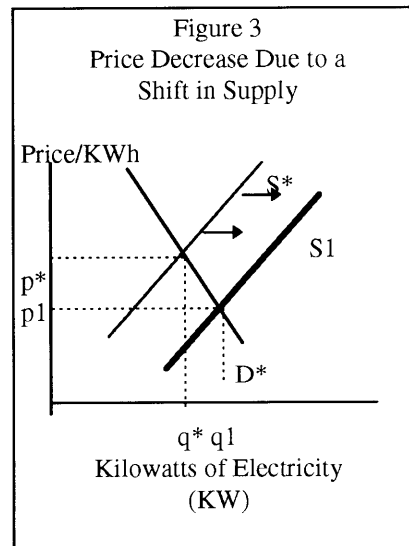
Shifts in the supply curve can occur as the cost of producing power changes (Figure 3). For example, if technological innovation in generating units advances and the cost of generating power becomes cheaper, producers will be able to produce more power at the same price (a shift to the right). For example, combined cycle natural gas units are making the cost of producing electricity cheaper than ever. As shown in Figure 3, assuming no change in capacity, cheaper sources of power could beat out older, outdated, oil generators.

If, however, producing power were to become more expensive, a shift of the supply curve to the left could occur. This could happen if outdated or cost inefficient baseload units are retired and replacement units encounter difficulties in obtaining siting approval. Currently, certain of the nuclear units that provided much of the base generating load for the New England region have been shut down or have been taken off-line as regulators investigate safety and compliance issues. This change could cause a significant change in the cost of generating power.

While predicting a precise price of electricity at any given moment in a competitive market is next to impossible, it may be possible to forecast a range of electricity prices based on (1) current short-run marginal costs, (2) trends in demand and supply of electricity and their impact on current short-run marginal costs, and (3) the contribution to fixed costs power

producers will need to add to short-run marginal cost to price at long-run marginal cost. These components, adjusted short-run marginal cost and contribution to fixed costs provide the likely long-run marginal cost of power in a deregulated market. This analysis relies on historical short-run marginal cost data, hourly demand data, supply data, and the fixed cost component of a combined-cycle natural gas unit as a proxy for market rate contribution to capital.

## A. Short-Run Marginal Cost of and Demand for Electricity in the New England Market

The historic short-run marginal cost of generating electricity in the New England market is a good starting point for forecasting the range of prices for power in a deregulated market. Marginal cost is measured in cents per kWh and reflects the running cost of the last generating unit dispatched in the system to meet demand. Historic short-run marginal costs reflect the demand and supply conditions of the market, albeit a regulated market. Short-run marginal costs as calculated by NEPOOL are:

> approximated by each unit's heat rate multiplied by the fuel costs for the unit, plus the variable operation and maintenance costs (non-fuel) for the unit...[as well as] the transmission penalty factors associated with each unit at the specified hour.[30]

Chart 5 shows how the short-run marginal cost of electricity follows changes in demand over a single twenty-four hour period. As demand increases over the day, generating units with different running costs are dispatched to serve the demand. This will result in changes in the short-run marginal cost of power. At 4 a.m., the demand for electricity was approximately 9,000,000 kWh. At this time period, the marginal cost per kWh was approximately 1.4 cents ($14/MWh). By contrast, at 9 a.m., when most people were at work, the demand for electricity jumped to 13,000,000 kWh (13,000 MWH) and the marginal cost paid for that hour increased to 1.77 cents/kWh ($17.70/megawatt hour).

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[30] Tabors Caramanis & Associates with Charles River Associates, *Market Power in New England: The Competitive Implications of Restructuring*, Prepared for the Attorney General of the Commonwealth of Massachusetts, April 1996, at 7.

Chart 5
Demand for and Marginal Cost of Electricity on
April 1, 1994
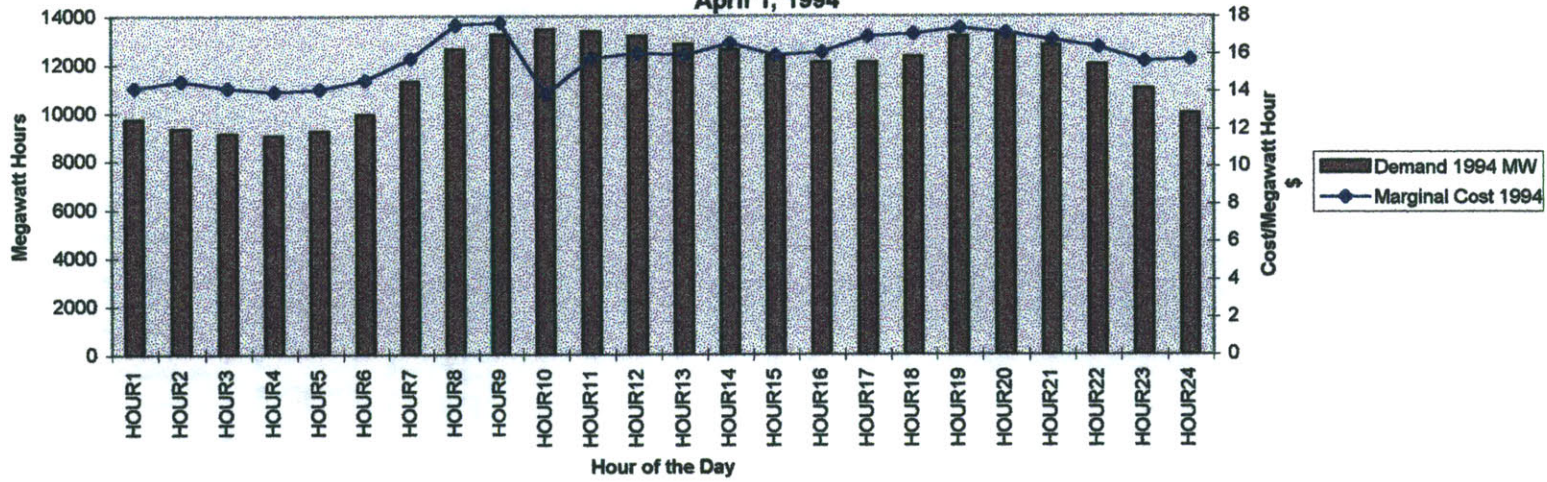
Source: FERC 714 Data.

While these changes reflect the workings of the regulated market, they are instructive and provide a base short-run marginal cost estimate for determining the price of electricity in a deregulated market. Charts 6A and 6B provide an indication of the change in quantity of electricity demanded for each hour of the year in 1993 and 1994. Charts 7A and 7B are similar charts that show the change in the short-run marginal cost, or "cost spikes," of electricity for each hour of the same period of time. These charts show the range of quantities and prices over these time periods and also provide an indication of how quantity and price vary on an annual basis. These changes combined with the unpredictability of output due to wind speed changes adds to the difficulty of predicting whether or not a wind farm is likely to succeed. We use these data as the basis of determining the range of short-run marginal costs per kWh we can expect in a deregulated market.
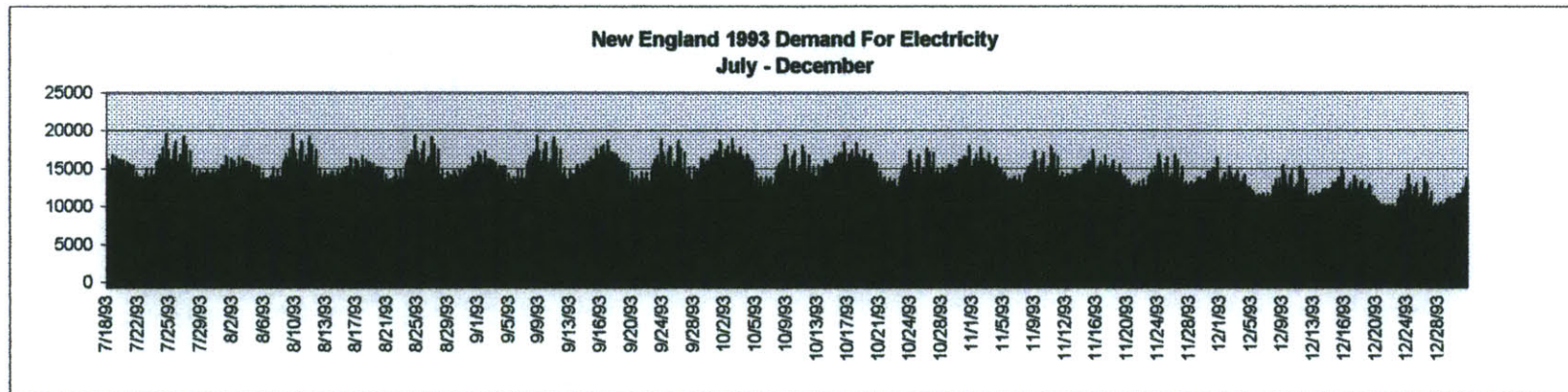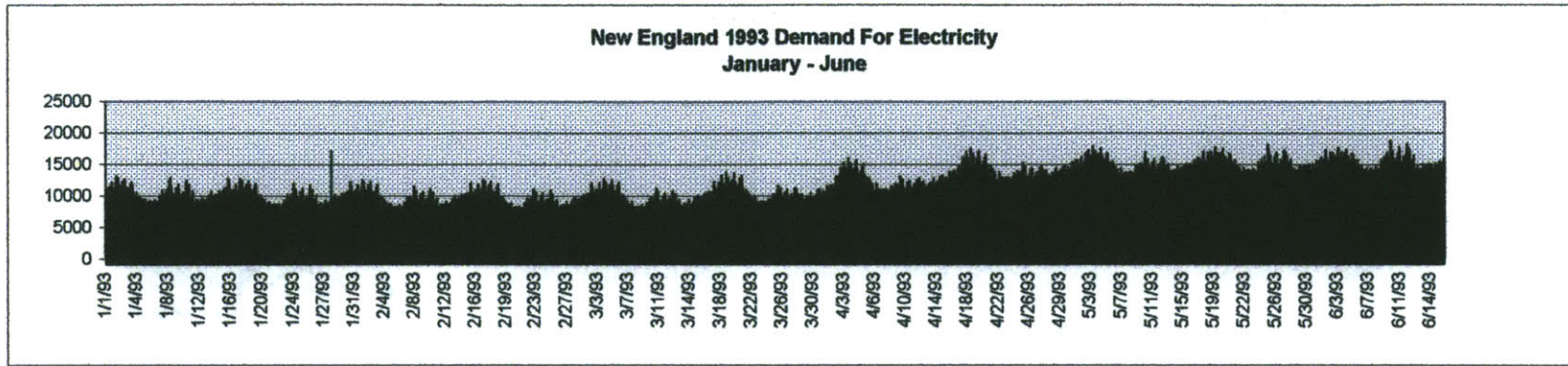
Chart 8 and Chart 9 are a histograms that show the distribution of demand and short-term marginal costs in 1993 and 1994. As shown in these Charts, system short-term costs were relatively low. Short-run costs range from about 1.2 cents per kWh ($12 per MWH) to approximately 2.8 cents per kWh ($28 per MWH) in 1993. As shown in Table 17, on average, cost was 2.02 cents per kWh (MWH was $20) plus or minus approximately .404 cents per kWh ($4 per MWH). Marginal costs covered a broader range of prices in 1994, ranging from 1.2 cents per kWh ($12 per MWH) to 3.5 cents per kWh ($35 per MWH). As shown in Table 17 above, average short-run costs were lower in 1994 at a total of 1.96 cents per kWh ($19.6 per MWH) plus or minus approximately .46 cents per kWh ($4.6 per MWH). In both years, almost 70% of the power was priced below 2.1 cents per kWh ($21 per MWH).

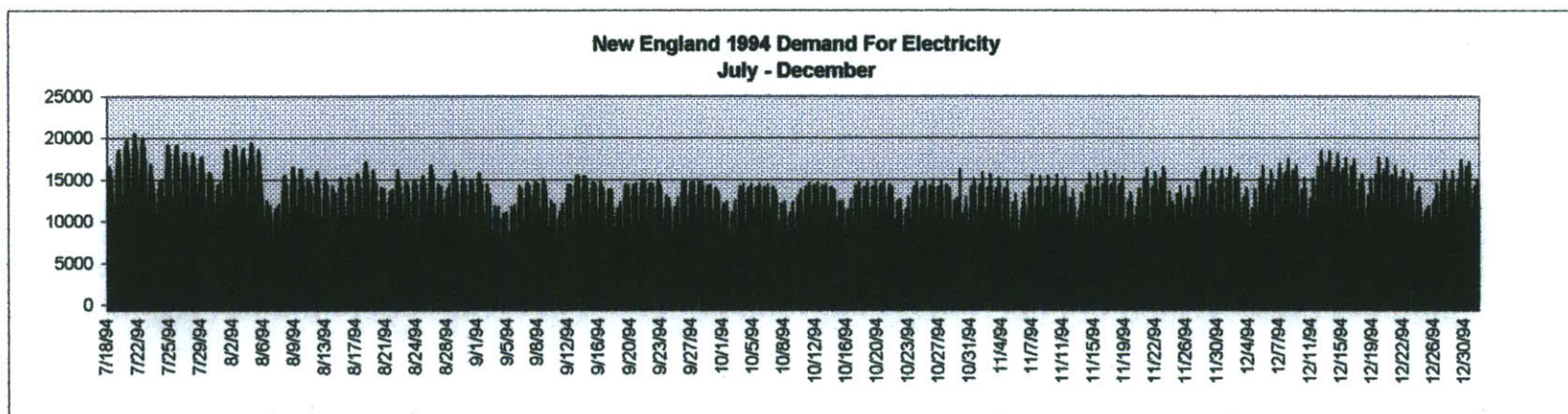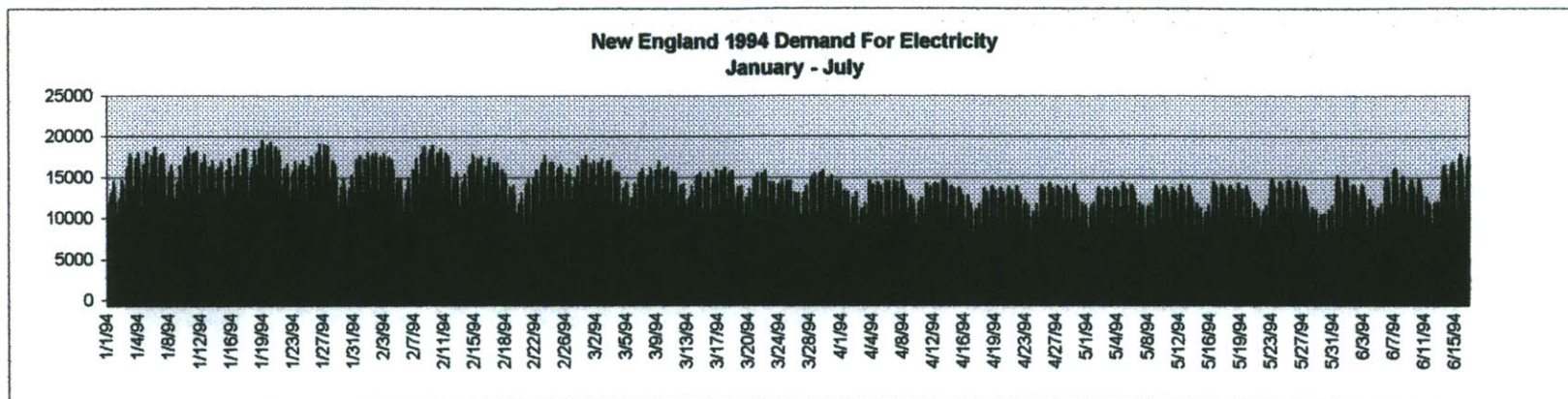| Table 17		
Average Cost per kWh		
	Average (cents/kWh)	Standard Deviation (cents/kWh)
1993	2.029	.404
1994	1.957	.464
Source: Federal Energy Regulatory Commission, Form 714		

These charts suggest that the short-run marginal cost of electricity was between 1.2 cents per kWh and 3.5 cents per kWh during these time periods. But, can we expect power to be similarly priced in a market situation? The answer to this question depends largely on whether (1) the overall demand for power will increase in the

Chart 6A

New England 1993 Demand For Electricity
January - June

New England 1993 Demand For Electricity
July - December

Source: FERC 714, 715 Data.

Chart 6B

New England 1994 Demand For Electricity
January - July

New England 1994 Demand For Electricity
July - December

Source: FERC 714, 715 Data.

Chart 7A

Marginal Cost Spikes 1993
January - June

Marginal Cost Spikes 1993
June - December
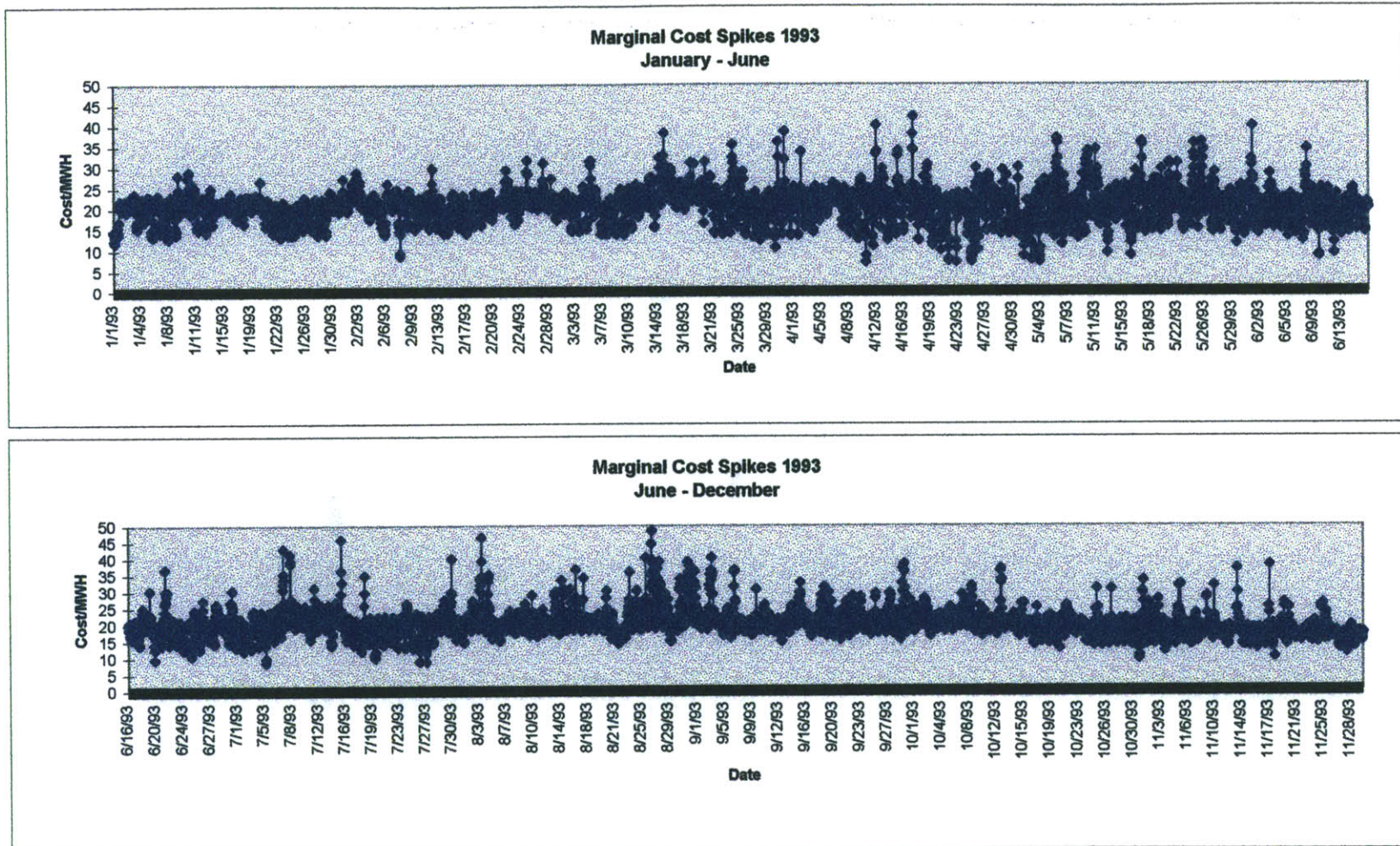
Source: FERC 714 and 715 Data

Chart 7B

Short-Run Marginal Cost Spikes
January - June 1994

Short-Run Marginal Cost Spikes
June - December 1994
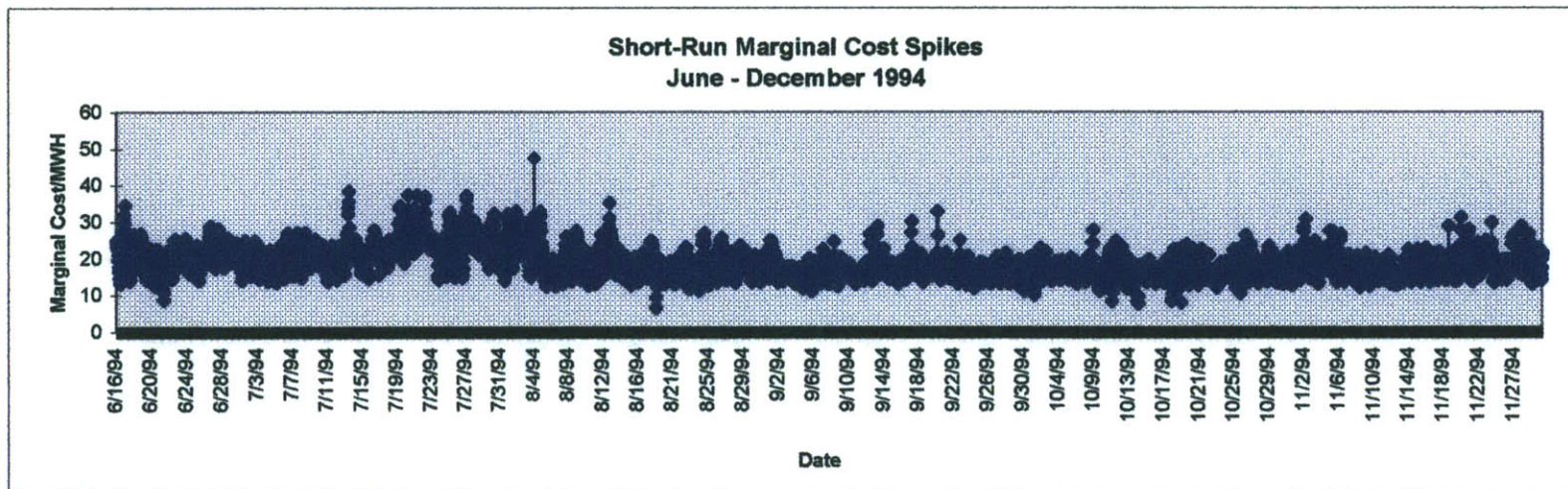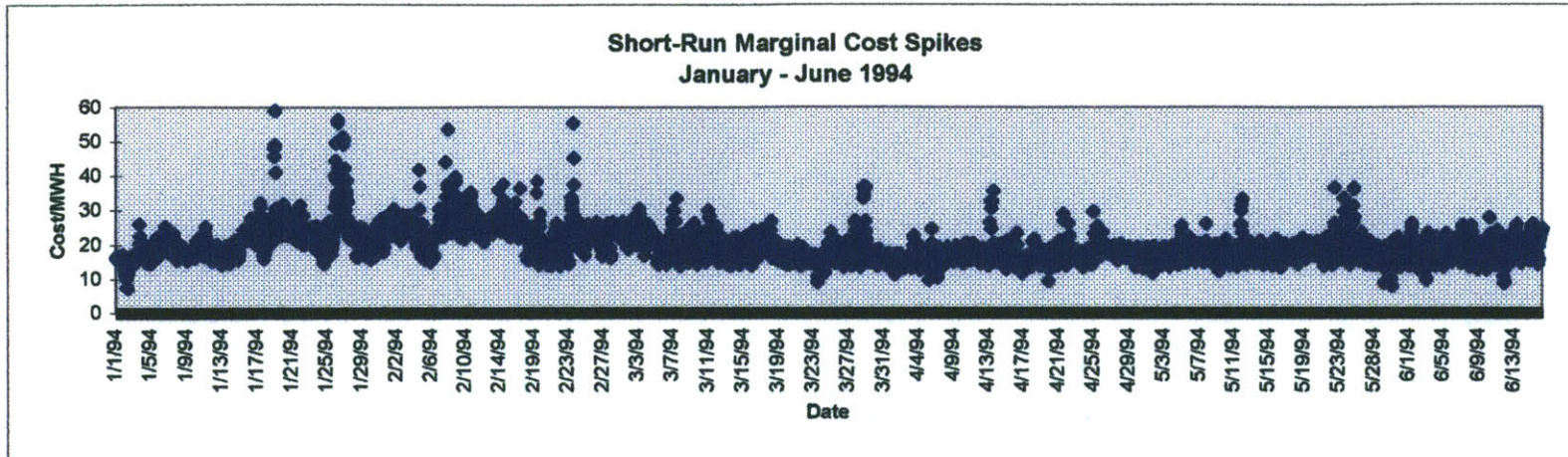
Source: FERC Form 714 and 715, 1994

Chart 8

Histogram of Distribution of Demand for Electricity in 1993

Megawatt Hours

Histogram of Distribution of Marginal Cost of Electricity in 1993

Marginal Cost per Megawatt Hour

Source: FERC 714 Data.

Histogram of Distribution of Marginal Cost of Electricity in 1994

Marginal Cost per Megawatt Hour

Hours in Year

Legend: Cumulative % ; Frequency

X-axis values: $57.56, $54.74, $51.91, $49.09, $46.26, $43.43, $40.61, $37.78, $34.95, $32.13, $29.30, $26.47, $23.65, $20.82, $18.00, $15.17, $12.34, $9.52, $6.69

Left Y-axis: 100%, 90%, 80%, 70%, 60%, 50%, 40%, 30%, 20%, 10%, 0%

Right Y-axis: 600, 500, 400, 300, 200, 100, 0

Histogram of Distribution of Demand for Electricity in 1994

Megawatt hours

Hours in a Year

Legend: Cumulative % ; Frequency

X-axis values: 20,089, 19,373, 18,657, 17,941, 17,225, 16,509, 15,793, 15,077, 14,361, 13,645, 12,929, 12,213, 11,496, 10,780, 10,064, 9,348, 8,632, 7,916, 7,200

Left Y-axis: 100%, 90%, 80%, 70%, 60%, 50%, 40%, 30%, 20%, 10%, 0%

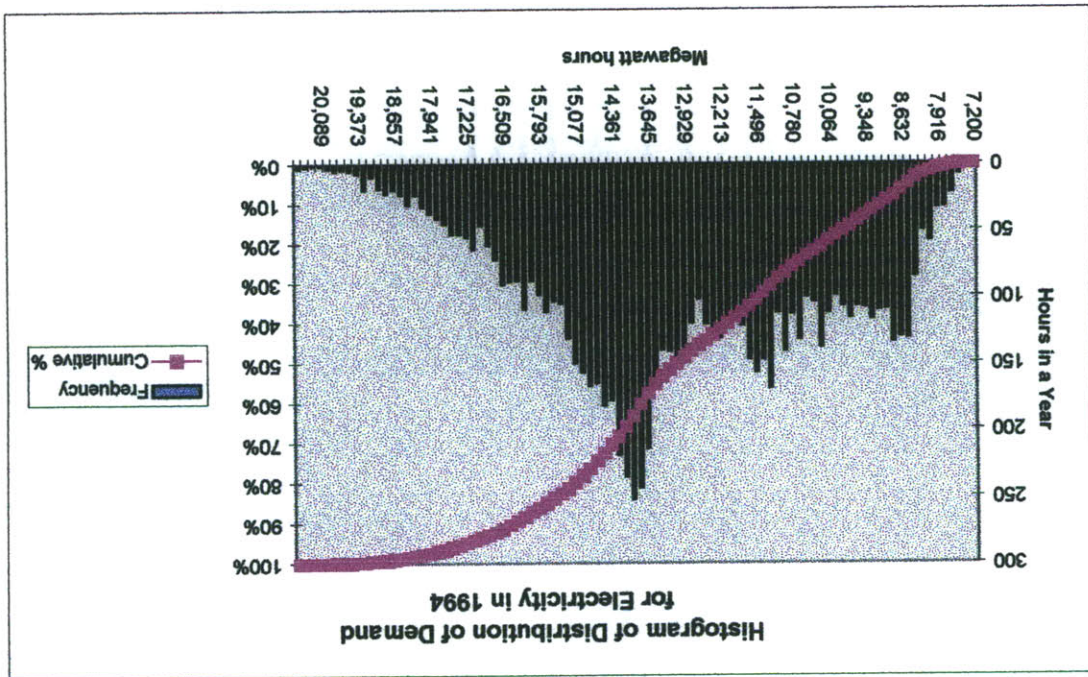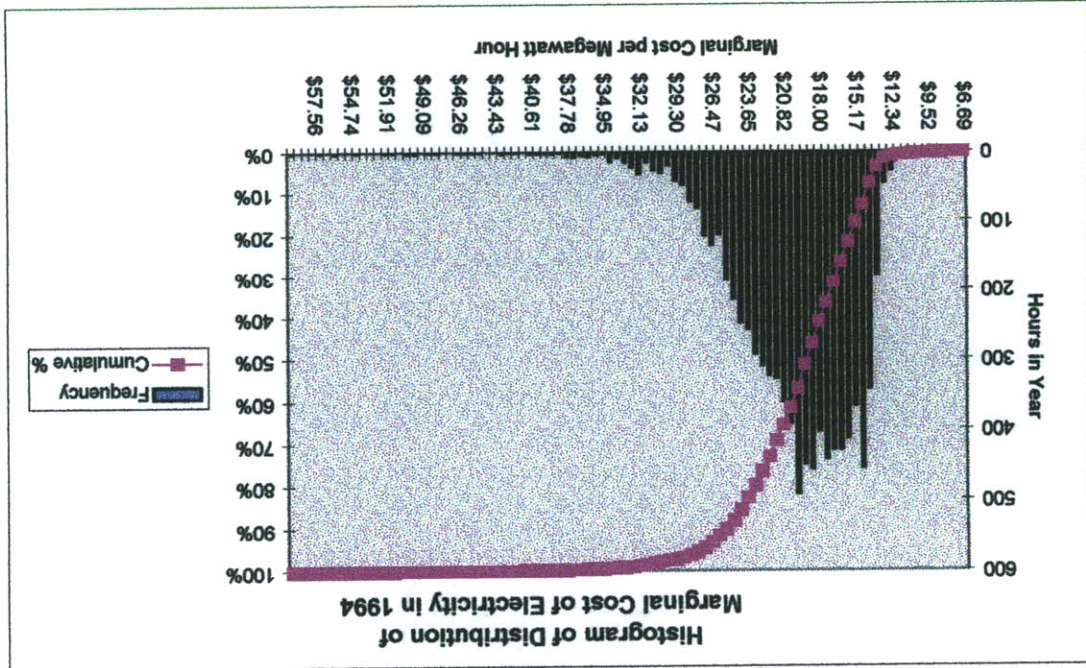Right Y-axis: 300, 250, 200, 150, 100, 50, 0

Chart 9

near future, (2) the supply of electricity will increase, and (3) whether companies will price above short-run costs on average in order to recover a portion of fixed costs.

1. The Effect of Projected Annual Energy Demand Changes on the Short-run Marginal Cost of Electricity in the New England Market

Annual Increases in demand in New England affects the short-run marginal cost of electricity over the course of the year (see Chart 5, 6 and 7. The historic and projected changes in demand for electricity are shown in Table 18 and 19 in gigawatt hours (GWH).[31] As shown in Table 18, there was a sharp decrease in demand for electricity between the years 1990 and 1994. It was not until 1994 that required energy demand levels reached their previous 1989 levels.

During the 1990s, when energy demand was low, the short-run marginal cost of electricity was also low as fewer high-cost generating units were dispatched. This means that cheaper nuclear and hydroelectric facilities could meet demand, hence the lower short-run marginal costs during this time period.

Recent projections, provided in Table 19, show demand growth through the year 2011 at a rate of 1.3% annually. In a regulated market, this projected increase in demand might suggest that in the near future we could expect the average short-run marginal cost of power to increase as more expensive short-run generating units are run more frequently to serve increased overall demand. If we assume that new units

Table 18 Energy Demand Levels 1989-1995		
Year	Demand (GWH)	Percent Change
1989	111,983	
1990	109,762	-2%
1991	108,682	-1%
1992	108,824	0%
1993	110,538	2%
1994	112,187	1%
1995	112,844	1%

Source: New England Power Pool Annual Reports, 1993-1995

Table 19 Projected Energy Demand Levels 1995-2011		
Year	Demand (GWH)	Percent Change
1996	113,302	
1997	114,092	0%
1998	116,102	1%
1999	118,115	2%
2000	119,924	2%
2001	121,763	2%
2002	123,226	2%
2003	124,633	1%
2004	126,074	1%
2005	127,672	1%
2006	129,475	1%
2007	131,212	1%
2008	132,936	1%

Source: New England Power Pool Forecast Report of Capacity, Energy, Loads and Transmission, 1996-2011, Prepared April 1, 1996

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[31] one gigawatt hour (GWH) is equivalent to 1 million kWhs

brought on line to serve demand have short-run costs of approximately 3.5 cents, versus the average 2.0 cents per kWh of the baseload nuclear and hydro units, we could expect average short-run marginal cost of electricity, to increase from an average of approximately 2.0 to 2.1 cents per kWh over the next several years.[32]

As discussed above, this 2.1 cent per kWh is not likely to be the price of power in a deregulated market. If power producers are to recover a portion of their fixed costs of production in the prices at which they offer power for sale within the market, power bidding, average power bids will likely be at the long-run marginal cost level, not the short-run marginal cost level. Thus, the 2.1 cent short-run marginal cost figure represents a base cost number that would need to be adjusted to account for the recovery of fixed costs.

2. The Effect of Changes in Supply on the Marginal Cost of Electricity in a Deregulated Market

The above analysis assumes, not only a regulated market, but that all existing capacity would remain running while additions to supply would be added to serve new demand. But this is not the case. Many of the existing generating plants, the nuclear units including Maine Yankee, Millstone 1,2,3, and Connecticut Yankee have been taken off-line because of safety problems. In fact, approximately 30,000 GWH in generation capacity in the New England region will not be available through at least the end of 1997.[33] As a result, NEPOOL is concerned about a potential capacity shortage situation as early as August of this year (1997).

With fewer baseload units available to serve demand, other higher-priced units will need to be dispatched in order to serve demand. These supply constraints will likely increase the short-run marginal cost of power. However, without recent marginal cost data, it is difficult to gauge the precise short-run marginal cost increase that will result from these constraints. It is also difficult to predict when the nuclear units will be back on-line. Table 20 provides a projection of the short-run marginal cost of power between 1997 and 2008 given three price

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[32] This estimate is a weighted average based on NEPOOL projected demand levels from 1996 to 2005. This analysis assumes that all power up to 112,844 GWHs costs 2 cents per kilowatt hour and all additional power over this level is priced at 3.5 cents per kilowatt hour.

[33] This estimate assumes a capacity factor of approximately 85% for these nuclear units.

scenarios -- low, medium, and high. The low scenario, assumes that once the nuclear units are back on line in 1998, their short-run marginal costs remain unchanged at 2.0 cents per kWh. Scenario 2, medium case, assumes that nuclear units that come back on-line will be priced at 2.5 cents to recover the costs of new operating and maintenance procedures as may be required by the Nuclear Regulatory Commission. The third scenario assumes that the nuclear marginal costs increase to 3 cents per kWh due to O&M increases.[34] This analysis estimates that the short-run marginal cost of power in New England will range, on average could be as low as 2.3 cents or as high as 2.5 cents per kWh plus or minus 0.4 cents per kWh.

B. Contribution to Fixed costs

Thus far, this analysis has focused on the short-run marginal cost of generating electricity as a basis for the price for electricity in a competitive market setting. But is it reasonable to assume that companies will be able to stay in business if they

Table 20 The Marginal Cost of Power: Three Scenarios			
	Low	Medium	High
Nuc. cents/kWh	2.0	2.5	3.0
New Demand cents/kWh	3.5	3.5	3.5
1997	2.0	2.0	2.0
1998	2.1	2.2	2.3
1999	2.2	2.3	2.4
2000	2.2	2.3	2.4
2001	2.3	2.4	2.5
2002	2.3	2.4	2.5
2003	2.3	2.4	2.5
2004	2.4	2.5	2.6
2005	2.4	2.5	2.6
2006	2.4	2.5	2.6
2007	2.5	2.6	2.7
2008	2.5	2.6	2.7
Weighted Average	2.3	2.4	2.5

Assumptions:
1. NRC regulations have no affect on marginal costs of plants not taken off-line
2. Connecticut Yankee is retired
3. Certain nuclear units off-line between 1996 and 1998. All assumed on-line by 1998.
4. Marginal costs for demand for power pre-1996 are assumed constant at 2.0 cents per kWh.

Sources: Federal Regulatory Energy Commission Form 1 Reports.

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[34] All scenarios assume the marginal cost of the first 112,000 GWHs remain priced at an average of 2 cents per kWh (1993-1994 rates) while all new demand for energy is priced at 3.5 cents per kWh.

price electricity at their short-run costs? System short-run marginal costs reported by NEPOOL are largely related to fuel costs.[35] These costs do not consider costs unrelated to fuel, such as labor, plant costs, and capital additions. Because companies will need to recover these costs in order to stay in business, energy providers will need to price on average closer to long-run marginal cost than short-run average cost. Long-run marginal cost recognizes the fact that companies will need to price power such that, on average, some contribution to these fixed costs is included in the market price for power.[36]

The mark up that companies will be able to charge, on average, to cover their fixed costs of production is, again, difficult to estimate. For purposes of this analysis, we used as a proxy the fixed costs associated with combined cycle natural gas units. It is assumed that combined-cycle units will be the most cost-efficient power production units in a deregulated market and that the mark-up of these units over short-run marginal costs will set the trend in a deregulated market. As shown in Table 21, the average capital cost recovery of these units is approximately 2.35 cents per kWh.

Given this fixed cost assumption, Table 22 provides a summary of the likely cost of electricity in a deregulated market that

Table 21
Combine Cycle Natural Gas Unit Fixed Cost Contribution

Installed Cost $/KW	Fixed Cost Cents/kWh
1000	3.1
900	2.8
800	2.5
700	2.2
600	1.9
500	1.6

Average 2.35

Assumes a capacity factor of 80%,70/30 D/E ratio, 15 yr. dep. life, 10% cost of debt, 20% cost of equity, annual fixed charge rate of .219 and fuel cost of $2.55/MMBtu. and does not include fuel costs.

Table 22
Estimated Market Price per kWh in a Competitive Electric Supply Market

Component	cents /kWh	cents /kWh	Cents /kWh
Marginal Cost of Generation	2.1	2.3	2.5
Contribution to Capital Costs	2.3	2.3	2.3
Market Price of Electricity	**4.4**	**4.6**	**4.8**
Average 4.6 cents/kWh			

[35] Interview with Henry Yoshimura of LaCapra Associates, April 16, 1997.
[36] This analysis recognizes that power producer bids will fluctuate on an hourly basis around short-run and long-run marginal cost. However, on average prices will need to be set closer to long-run marginal costs in order for producers to stay in business.

includes short-run marginal cost plus a contribution to fixed costs. According to this analysis, market prices will range from approximately 4.4 cents per kWh to 4.8 cents per kWh.

C. *Wind Energy in a Bidding System*

Wind energy will need to compete against other sources of energy in the deregulated market. As discussed in Chapter I, in an energy market, generation units will be dispatched into the system based on the price of energy bid by the energy producer. Units are ranked in order of price bid and dispatched as needed. The last unit brought on line to serve the demand for energy will set the marginal price for that hour.

While running costs for wind turbines tend to be very low, fixed costs tend to be relatively high. Thus, fixed cost recovery is of the utmost importance if wind projects are to stay in business. Furthermore, wind is a non-dispatchable source of power; wind turbines operate only when the wind blows regardless of the demand for power. These two factors, high fixed costs and non-dispatchability, put wind at a disadvantage relative to other more traditional forms of electric generation in a deregulated market bidding system. The high fixed costs provide the incentive to include large fixed costs in the price bid of energy especially in times of high winds and high demand -- the winter season. The lack of dispatchability provides an incentive to bid low at all times to ensure power will be sold whenever the wind blows. Wind power producers will need to find the balance between these competing goals in order to compete in a deregulated market.

The survival of wind projects will largely depend on the market of price of power. The lower the price of power in the market, the more difficult it will be for a wind project to stay afloat based on price alone in a competitive market. At a projected price of between 4.4 cents and 4.8 cents per kWh, a wind project with costs of approximately 6.5 cents per kWh will not be able to stay in business in a competitive market situation.

Chapter IV

Will Customers Pay for Green Electricity?

In many product markets, in countries around the world, industry is beginning to test the waters to find out if the "greeness" of a product, or how environmentally benign a product may be, will help sell products and services to customers. Just as product labels list ingredients or warn us of the hazards of tobacco or alcohol, labels that tell us how "green" a product may be are finding a way to the store shelves. Green labels try to persuade us that one product is superior because of how environmentally friendly its pieces and parts are; containers are recyclable, recycled materials are used in producing their products, or the product is "biodegradable," "all natural" or "organic." For example, Ben and Jerry's Rainforest Crunch ice cream touts the fact that Brazil nuts are among the ingredients. The nuts are bought from producers in the Brazilian Rainforest in an effort to promote the harvesting of nuts from the trees as a substitute for harvesting the trees themselves. By adding a touch of "green," companies bet that consumers will use their purchases to vote and in some cases pay more for products that may be environmentally friendly. One study that tracked green marketing efforts and showed that "green" products made up only 0.5% of all new products introduced in the United States in 1985, but made up approximately 9.2% of all new products that were marketed in the first half of 1990 -- an increase of almost twenty fold.[37,38]

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[37] Environmental Labeling in OECD Countries, Organization for Economic Co-Operation and Development, citing Green Marketing Alert, October, 1990.

Green labeling may be the latest advertising craze for selected consumer products and services, but will being green pay in the electricity market? Up to this point, this thesis has focused on the question of what electricity generated from a wind farm will cost and at what price it will be sold absent any marketing advantage. This analysis has assumed that the energy supplier with the cheapest electricity will win the customer. This analysis has yet to consider whether price will be the *only* factor on which consumers will base their electricity buying decisions. In other words, will customers make choices about electricity suppliers based on price alone or will, as may be the case in other markets, the "greenness" of the product be a significant factor in customer purchasing decisions? Also, how much customers might be willing to pay for "green" electricity needs to be determined. Even if customers would prefer "green" power, will they be willing to pay a premium for it, and if so, how much?

The answers to these questions are critical to renewable project investors trying to predict future revenue streams. If renewable power is more valuable to customers than other sources of power, the premium prices charged for renewable power could help make a project successful. In order to factor in a price mark-up for a wind project, convincing evidence that can show potential investors that projected revenue streams will be higher than would otherwise be expected is necessary. Therefore, in order to explore the question of willingness to pay, and determine whether a higher revenue stream can be assumed for the hypothetical Cape Cod project, recent studies about customer preferences and experience are reviewed below.

A. *Customer Willingness to Pay for Renewables - Public Opinion Surveys*

Much work on willingness to pay for renewables has been done by Barbara Farhar of the National Renewable Energy Laboratory (NREL). One study tracked the changing public perception of the cleanliness of the environment, customer preference for environmental regulation, and customer preference for alternative energy options over an eighteen-year period

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[38] While interesting, it is difficult to discern whether these results show (1) a change in the types of products that are being manufactured, or (2) a change in advertising slant of existing products.

by examining data from over 700 public opinion polls. According to the study, approximately 56% to 80% of respondents to recent national surveys say they would pay a premium for environmental protection or renewable electricity.[39] The author cautions, however, that:

> National evidence suggests that customers will notice and favor environmentally friendly electricity generation, whether [or not] they themselves participate in such programs. However, the specific percentages actually willing to participate in a given utility service territory should be defined by local-area market research and experience.[40]

The poll data in the study also show that approximately 59% to 78% responded that they would be willing to pay more taxes to protect the environment. While not specific to renewable energy, the author interpreted this result as significant given that "the word 'taxes' in a question almost always evokes a negative response."[41] Regarding renewable energy, the same study found that "60% of those surveyed in 1994 said they would be willing to pay more than $6 each month than they currently were paying for environmentally benign electricity."[42] And, as shown in Table 23, "...if given a choice between a utility company using coal to generate electricity and one using 'cleaner, but slightly more expensive renewables, three quarters said they would pay something more for renewable electricity; the amount selected most frequently was up to 5%."

Table 23 Willingness to Pay More for Renewable Electricity 1995	
Response	%
No more	24
up to 2%/month	23
up to 5%	26
Up to 10%	19
Up to 20%	5
More than 20%	3

Source: Farhar, Barbara C., *Energy and the Environment: The Public View*, Renewable Energy Policy Project, Issue Brief No. 3, October 1996, Table 9

The study addressed the discrepancy between those *willing to say they will pay* and those *actually willing to pay* for green electricity, recognizing the fact that until people actually write a check for renewable energy programs, it is difficult to be sure they would actually spend the money. The study found a striking difference between the numbers of people who say they

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[39] Ibid, at 3.
[40] Ibid, at 7.
[41] Ibid, at 7.
[42] Ibid, at 8.

would pay for renewables and the numbers of people actually signing up for utility-sponsored renewable programs. Utility market surveys that show that "at the inception of a green-pricing program, fewer than 10% (and often only 1% to 2%) initially sign up."[43] The author suggests two categories of factors as possible explanations for low participation rates: (1) utility failure to communicate effectively with customers, and (2) customer difficulty comprehending material and trusting the material that is presented.[44] The author suggests that customers are more likely to participate if they perceive the programs to be:

- Effective in actually producing clean electricity
- Advantageous through paying relatively small amount for value-added, avoiding resource depletion, planning for the future, or receiving a return (as in net metering);
- Reducing individual risk by keeping utility rates stable for long periods and customer ability to cancel, renew, or transfer participation; and
- Easy to understand.[45]

Finally, low participation rates, according the author, could be explained by the fact that it takes time for renewable programs to mature and penetrate the market.[46]

The author concludes from the study that there is "strong and consistent" public preferences for renewables and energy efficiency for the past eighteen years. This interest translates into opportunities for industry and government to develop products, services, programs and policies that customers and taxpayers want.[47]

B. *Traverse City Light and Power's Wind Project*

The Traverse City Light and Power Company (TCL&P) in Michigan had success selling wind power at a premium price to its customers. TCL&P asked its customers to help support a

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[43] Ibid at 10.
[44] Ibid at 10-11.
[45] Ibid at 11.
[46] Ibid at 11.
[47] Ibid at 11-12.

single 600 kW wind turbine.[48] Since its inception, approximately 145 residential customers and 20 industrial customers out of 8000 (roughly 2%) agreed to pay a premium of about $7.50 per month for power for wind generated power and approximately 80 customers remain on the waiting list to sign up for the wind energy program.[49] This translates into 1.58 cents per kilowatt hour above current rates.

According to the Company, with a customer subsidy and the federal tax incentives, the project was economical. The Company stated:

> With the federal production incentive of 1.5 cents per kW-hr. and the customer premium of 1.58 cents/kW-hr. this makes the cost of the electricity from the wind turbine the same as the other power purchased by the utility on a wholesale basis. One can say that the environmental costs are accounted for with the premium and fed subsidy so they have essentially "internalized" the environmental costs of making electricity. It is a back-door approach to solving this economic/environmental problem--while demonstrating that many consumers, if given a choice, are intelligent enough to do the right thing. They just never get a choice.[50]

However, the Company indicated that the rates charged to customers participating in the wind project were on the low side. The Company stated that the rate for wind power "is lower than the standard rate for many electric utilities in Michigan."[51]

The TCL&P findings are consistent with the Farhar study in terms of a 1% to 2% participation rate level. However, while this green power program shows that customers are willing to pay TCL&P's relatively "low" rates for green power, it is difficult to determine how these "low" rates compare to rates that will be set by the market and whether customers would *still* be willing to pay a premium for green power above market rates. This means that all we can

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[48] Traverse City Light and Power's WIND GENERATOR web page. See http://kermit.traverse.com/wind/ (March 20, 1997).
[49] Ibid. See also, Wind Energy Weekly, Volume 15, No. 720, October 28, 1996, at 5, citing Barbara Farhar and Ashley Houston, Willingness to pay for Electricity from Renewable Energy, National Renewable Energy Laboratory.
[50]Traverse City Light and Power's WIND GENERATOR web page. See http://kermit.traverse.com/wind/ (March 20, 1997).
[51] Ibid.

say about the Traverse Michigan green pricing program is that approximately 2% of customers are willing to pay something for green power, given already low prices.

C. The New Hampshire Pilot Program

A pilot program designed to simulate a competitive electric generation market is in progress in New Hampshire. Under this pilot program, power companies have gained experience competing against each other to win electricity customers. Approximately 17,000 customers were eligible to participate in the pilot program involving approximately 3% of New Hampshire's residential customers.

Power companies offered a variety of power pricing programs that included claims of renewable "green" power. The three companies offering power from renewable resources were Green Mountain Energy Partners, Northfield Mountain Energy and Working Assets Green Power. One paper, Green Power Disclosure and Certification: An Exploration of Issues and Options summarized these "green" power programs:

- Green Mountain Energy Partners offers predominantly hydro energy from a partnership with Quebec Hydro and states that it is 97.5 percent free of greenhouse gases. Price: 2.66 cents per kWh.

- Northfield Mountain Energy describes its pumped storage hydro project at a beautiful recreational area, but "where you see a breathtaking vista, we see megawatts.... Water is pumped up the mountain at night and flows down during the day to generate low-cost power." Price 3.11 cents per kWh.

- Working Assets Green Power lists the resources it does not use: nuclear , coal or Hydro-Quebec power. Price 3.5 cents per kWh.[52]

The author explains that these "green" programs may not be as green as they may have appeared indicating that "Hydro Quebec projects have been criticized for their destructiveness of Native American lands; the pumped storage may rely on nuclear power to pump the water back

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[52] Green Power Disclosure and Certification: An Exploration of Issues and Options, Renewable Energy Policy Project, December 4, 1996

to the top of the hill; and it is not clear how Working Assets, which buys power from New England Power Company, can avoid the power produced from New England Power's coal plants."[53]

Still, given the limitations of the green power options, it is important to ask: How many customers chose each of the options available?, and How many consumers found these options persuasive? The answer to the first question is unclear. Results of how many customers chose which option have yet to be published.

In a report announcing the New Hampshire Pilot program, generation prices

Table 24 Estimated and Actual Green Option Pilot Prices Offered to New Hampshire Consumers		
	Cents/kWh	
Estimated Rates	Res.	Bus.
	3.5	3.1
Actual Green Option Pilot Prices		
Green Mountain	2.66	
Northfield Mountain	3.11	
Working Assets	3.5	
Source: Green Power Disclosure and Certification: An Exploration of Issues and Options, Renewable Energy Policy Project, December 4, 1996		

for residential and large business customers were projected to be approximately 3.5 cents and 3.1 cents, respectively in a competitive market.[54] As shown in Table 24, these estimated rates are much higher than the rates offered to New Hampshire pilot customers for green and non-green products. It is difficult to determine why green option pilot program's generation rates are so low. It is possible that lower rates were offered to customers by electric supply companies in an attempt to gain market share or experience before the entire market is opened to competition. Thus, even if the results were available, it may be difficult to determine what the results actually mean about customer willingness to pay for green power.

The answer to the second question, how many customers found green options persuasive, can be answered in part by examining the results of a survey commissioned by the New Hampshire Public Utilities Commission. The survey asked customers participating in the pilot program to name the most important factor in choosing a competitive power supply company.[55]

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[53] Ibid.
[54] Electricity Competition and The New Hampshire Pilot Program, Sarah P. Voll, May 1, 1996
[55] Survey questions were also designed to find out, (1) how customers found out about the pilot program, (2) whether customers understand the program, (3) how many switched to a new power provider, (4) whether customers were

According to the results of the survey, customers overwhelmingly chose price as a determining factor in selecting a supplier.[56] Approximately 71% of the 231 customers surveyed stated that this factor was of strong influence; 15.2% indicated that this factor had no influence on their power buying decision. A company's environmental message or image had a strong affect on only 19.5% of the respondents; a majority of 54.1% indicated that this factor had no influence on their decision making process. When asked whether the choice of which supplier to use was influenced "by whether a power supplier offered electricity from a renewable source of energy" only 16.9% indicated that this factor was of strong influence, while 65.8% indicated that this factor had no influence on their decision making.[57]

These results suggest that, while environmental considerations may be a deciding factor for some when choosing a power company, contrary to the results reported in the opinion poll study, for the majority of consumers price is the most important factor.

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satisfied with the program, and (5) what entity should be responsible for educating consumers. UNH Survey Center, Retail Competition Pilot Program Survey Results, New Hampshire Public Utility Commission Web Site.

[56] The surveyors asked "As you probably know, there are different reasons consumers might choose one power supplier over another. Please tell me whether your decision to choose a new power supplier was influenced by each of the following:

Was your decision influenced by the *services* offered in addition to the energy supply, such as energy conservation services?

Was your decision influenced by the *environmental messages* or *environmental image* of the power supplier?

Was your decision influenced by the *gifts* offered in addition to the energy supply, such as a cash bonus or some other gift?

Was your decision influenced by the *total price* of electricity offered by the power supplier?

Was your decision influenced by the *reputation* of the power supplier?

Was your decision influenced by the *familiarity* with the power supplier before the Pilot Program started?

Was your decision influenced by the way *in which you signed up* with a power supplier, such as form or registration card?

Was your decision influenced by whether a power supplier offered electricity from a renewable source of energy?

Was your decision influenced by the sales personnel?

UNH Survey Center, Retail Competition Pilot Program Survey Results, New Hampshire Public Utility Commission Web Page

[57] UNH Survey Center, Retail Competition Pilot Program Survey Results, New Hampshire Public Utility Commission Web Page

D. The Massachusetts Electric Company Pilot Program

Massachusetts is also experimenting with competition in the electric supply market. Currently, Massachusetts Electric Company is running a pilot program designed to gain information about customer choice in a deregulated electric supply market. The

Table 25					
Factors Influencing New Hampshire Consumer Choice of a Power Company					
Factor	Level of Influence				
	Strong	Moderate	Weak	None	Total
Environmental Msg./Image	19.5%	17.7%	10.0%	58.0%	100%
Gifts	3.5	9.1	10.4	77.1	100%
Total Price	**70.6**	**13.0**	**1.3**	**15.2**	**100%**
Additional Services	14.3	17.7	10.0	58.0	100%
Reputation	27.3	21.6	7.8	43.3	100%
Familiarity w/supplier	18.2	15.2	6.5	60.2	100%
Method of sign up	7.8	10.0	9.1	73.2	100%
Renewable Energy	**16.9**	**12.6**	**4.8**	**65.8**	**100%**
Sales personnel	4.8	8.7	4.3	82.3	100%
If GAC, Town's evaluation	21.3	11.1	1.9	65.7	100%

Source: University of New Hampshire, Survey Report of Retail Competition Pilot Program Prepared for the New Hampshire Public Utilities Commission, Institute for Policy and Social Science Research, January 31, 1997.

program was implemented in September of 1996 and will run for one year. Customers can choose among a variety of electricity suppliers offering a number of electricity options. Electricity options include low-priced alternatives, green alternatives, as well as community service options.

Residential and small business customers from four Massachusetts towns, Lawrence, Lynn, Northhampton, and Worcester, are eligible to participate in the pilot program. Residential customers were invited to choose from three price options, four "green" options and two "other" options that included a combination of incentives. Small business customers were offered three price options (see Table 26), three green options and two "other options." The green options are summarized in the same article that reviewed the New Hampshire pilot. The article states:

- Northfield Mountain Energy will offer 100 percent hydropower (no pumped storage) from its parent company Northeast Utilities, $30 worth of energy conservation products, a mail-in home energy survey, donations to local community green projects, and a donation to the American Lung Association.

- Working Assets will offer... no-nuclear, no-coal, no-Hydro Quebec product purchased from New England Electric Power, but with specific generating plant commitments to avoid coal. Working Assets will also donate one percent of gross revenues to Massachusetts environmental groups and will give customers a $25 gift certificate for energy efficiency products after six months.

Table 26 Massachusetts Pilot Green Energy Option Base Prices (1) (cents)		
	Res.	Bus.
Non-Pilot Price of Power (2)	3.5	3.6-4.5
AllEnergy	3.01-3.4	3.0-3.4
Enova Energy	2.5	3.1
Northfield Mount.	2.6	2.8-2.6
Working Assets	3.3	n/a

Note:
(1) Rates do not account for the value of gifts, certificates, donations, etc..
(2) Non-pilot price of power estimated by Massachusetts Electric in the Customer Participation Information.
(3) na: not applicable
Source: Customer Participation Information, Massachusetts Electric Company.

- AllEnergy will offer power from the supply mix of its affiliate, New England Power Company; permanent retirement of SO2 emissions allowances, and community-based solar.

- Enova Energy (San Diego Gas & Electric) will offer New England power supply (presumably a mix of New England Power Pool), an energy/environmental survey, quarterly energy use reports and rewards, matched donations to environmental projects, and a raffle for electric vehicles.

Unlike the New Hampshire pilot program, data related to customer participation and option selection were made publicly available.[58]

The pilot was open to all customers in each of the towns selected to participate in the Massachusetts Electric Pilot. There were approximately 16,830 eligible residential customers and 125,300 eligible business customers. However, according to the rules of the pilot program, total subscription would be capped at 10,000 residence and 10,000

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[58] Massachusetts Electric Company, Choice: New England, Report on Pilot Program Enrollment, Presented to The Massachusetts Department of Public Utilities by Environmental Futures, Inc., Pilot Administrator, January 6, 1997.

business customers. By November 30, 1996, the residential portion of the pilot program lacked participants. Overall, of the 10,000 participant slots, only half that amount, 5292, were filled. According to the program report, by October 31, 1996,

> the residential portion of the Pilot had significant room remaining... [c]onsequently, throughout November Massachusetts Electric Company and Environmental Futures made a concerted effort to implement an additional extensive outreach campaign targeted at residences in the four communities.[59]

For purposes of this analysis, we will use as our basis of comparison, the total number of those eligible to participate in the program, approximately 16,830 residence customers and 125,300 business customers.[60]

As shown in Table 27, approximately 4% of residence (4,745) and 3% of business (547) customers that were eligible to participate in the program chose to do so. The highest participation residence and business rates were found in the town of Northhampton and the lowest participation residential and business rates were found in the town of Lawrence (see Table 28).

Table 27 shows that price was the determining factor for most participants. Approximately 2.6% and 3.1% of and eligible residential and business customers, respectively, elected a pricing option over a green option. Only 1.2% of residence customers and 0.1% of business customers chose a green option.

The winner in terms of green offerings were Working Assets which signed up 0.62% of eligible residential customers and Northfield which signed up 0.10% of eligible small business customers (Working Assets did not offer a small business green option). In terms of price, the Northeast Utility (NU) price offering won hands down attracting the most residence (0.8%) and business (2.3%) customers.

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[59] Massachusetts Electric Company, Choice: New England, Report on Pilot Program Enrollment, Presented to: Massachusetts Department of Public Utilities, Presented By: Environmental Futures, Inc., Pilot Administrator, January 6, 1997 at 1.
[60]Because the business portion of the pilot program was fully subscribed, some businesses that may have wanted to signed up were unable to participate in the program.

The results of the Massachusetts pilot program, while interesting, may not be the best indicator of customer willingness to pay for renewable power. First, while there are a variety of "green" options provided to customers, only Northfield Mountain will provide power from a renewable resource-- hydroelectric power. No power supplier actually tested the market for customer willingness to purchase power from resources such as wind or solar. Therefore, all we can say is that certain customers may be willing to buy some kind of green power.

Secondly, like the New Hampshire pilot program, all options, including green options, are priced below the current regulated power prices. This means that while customers may be willing to forego some savings when choosing a green

Table 27 Massachusetts Pilot Program Green Participation Rates		
PROGRAM	Residence	Business
GREEN		
All Energy	0.06%	0.01%
Enova	0.10%	0.01%
Northfield	0.38%	0.10%
Working Assets	0.62%	n/a
PRICE		
All Energy	0.10%	0.01%
Enova	1.64%	0.29%
NU Price	0.78%	2.26%
WEPCO price	0.10%	0.56%
WEPCO other	0.01%	0.01%
==		
Total Eligible Cust.	**16,830**	**125,300**
Total Participation	**4%**	**3%**
==		
Percent Choosing **Green Options**	**1.2%**	**0.1%**
Percent Choosing **Price Options**	**2.6%**	**3.1%**

Source: Massachusetts Electric Company, Choice: New England,
Report on Pilot Program Enrollment, Presented to: Massachusetts
Department of Public Utilities, Presented By: Environmental Futures,
Inc., Pilot Administrator, January 6, 1997.

option, these customers still pay less than they would have otherwise. Thus, the results of the Massachusetts pilot program can only tell us about customer willingness to forego savings and not whether customers would be willing to pay more for green energy. If power from renewable resources such as wind, solar, geothermal, or biomass is priced higher than current power costs, it is unclear whether or how many consumers would still choose a higher-priced green product.

E. Conclusion

The results of the public opinion polls are significant because they show that the public has a strong interest in the environment and environmental programs. This is good news for the environment because these results carry a strong message to national policy makers. But, what do customers mean when they say they are willing to pay for green sources of energy? Do they mean they would be willing to pay higher taxes? Do they mean they are willing to write tax deductible checks to environmental organizations? The results of the opinion polls that show that approximately 60% of

Table 28 Participation Rates by Town and Customer Class					
	Lawrence	Lynn	Worcester	Northhampton	Total
Residence					
Participants	414	813	2,361	1,157	4,745
Eligible	21,717	30,852	61,176	11,555	125,300
Partic. Rate	**2%**	**3%**	**4%**	**10%**	**4%**
Small Business					
Participants	46	99	234	168	547
Eligible	2,956	3,903	7,932	2,039	16,830
Partic. Rate	**2%**	**3%**	**3%**	**8%**	**3%**

Source: Massachusetts Electric Company, Choice: New England, Report on Pilot Program Enrollment, Presented to The Massachusetts Department of Public Utilities, by Environmental Futures, Inc., Pilot Administrator, January 6, 1997.

customers are willing to pay a premium for renewables are hard to interpret. Moreover, these results are not supported by the findings in Michigan, New Hampshire and Massachusetts where only 1% to 2% of customers actually signed up for green electricity pricing programs. Price, not greenness, appeared to be the governing factor in choosing a supply company. What people say they are willing to pay and what people actually pay appear to be inconsistent. As suggested by Barbara Farhar, there may be a number of reasons for this difference including problems with utility marketing efforts, lack of understanding by customers, or insufficient time for market penetration. Yet, in Massachusetts, even with a "concerted [residential marketing] effort" made by utilities and non-utilities, to educate and enroll customers in the pilot, participation rates fell short of expectations.

Could the lack of residential interest in the Massachusetts' pilot suggest that customers are just not interested in choosing power suppliers. Perhaps customers not only lack understanding, but also lack of time and effort to deal with all the telemarketers who call every night at dinner not only to sell electricity services, but also to sell telephone services, carpet cleaning services, among many others. Perhaps choosing a power supplier is just one more decision that customers feel does not make a big difference in household budgets and lives. Whatever the reason, one thing is clear, participation rates are lower than expected and, thus far, no more than 1% to 2% of customers can be expected to sign up for green pricing options.

Probably, as discussed in Section B, the most interesting experiment is the Traverse City Michigan wind power offering because (1) its participation rate, 1% to 2% of customers, is consistent with the findings in other service territories, and (2) its customers actually paid 1.58 cents per kilowatt higher rates than other customers opting for non-renewable power offerings, even though rates were below the electricity rates in the surrounding region. Perhaps these findings support the observations of Barbara Farhar, discussed in Section A, that customers may be more willing to pay for renewables when projects are, among other things, actually effective in producing clean electricity, easy to understand, and offered by municipal or non-utility suppliers with a reputation for stewardship. It is hard to draw conclusions from a single experimental program. This project provides one example where renewable power could be sold for more 3.5 cents per kilowatt hour when customers had a choice between two options.

It seems reasonable to expect 1% to 2% of customers to sign up for green electricity options. But, as discussed above, there is minimal evidence that more than 1% to 2% of customers would be willing to sign up for green electricity options regardless of price. As discussed above, rates offered for green pricing programs in New Hampshire, Massachusetts, and Michigan (to a lesser extent) were all below the power rates generally offered in the regions. This makes it hard to conclude that even if prices were above general power rates in the region, customers would still be willing to sign up for green offerings. Until there is more information, these findings suggest that price is the underlying factor in choosing a power supplier and a

provider of power from renewable resource cannot expect to be able to sell power at higher than market prices.

Chapter V

What Renewable Policy Options are Appropriate for a Deregulated Electric Supply Market?

It is clear that without set-asides, subsidies and/or guaranteed long-term support, renewable projects are unlikely to be attractive investments in a deregulated market. High capital costs, uncertain cash flows, weather fluctuations, and the availability of cheaper energy alternatives conspire to make investing in renewables untouchable for many investors. Other barriers include siting, permitting, and the cost of constructing transmission lines and other infrastructure.

According to the financial analysis, wind power would need to priced at approximately 6.5 cents per kWh for a project to break even -- roughly 1.5 to 2 cents higher than the estimated price of electricity in a deregulated market. If policy makers remain convinced that the benefits derived from renewable resources justify public investment in such projects, some assistance in the range of 1.5 to 2 cents per kWh will need to be provided to renewable projects.

Yet, as a general matter, subsidies distort market prices, cause the subsidized good to be over-consumed, and can adversely affect the behavior of firms. Assuming that competitive markets deliver goods efficiently, the ideal renewable policy will be designed such that it interferes as little as possible with the workings of the market.

The following sections focus on three policy options that could be considered as a means of ensuring that renewable power projects can compete against traditional generation facilities in a deregulated electric supply market. These mechanisms include (1) providing low interest loans to renewable power providers, (2) providing price supports to renewable projects, and (3)establishing state/company joint renewable venture projects. A final section provides general suggestions about minimizing the restrictions on renewable projects eligible for funding, the importance of making long-term policy commitments, and ensuring that the renewable fund is used to promote projects that actually deliver renewable power to New England.

A. *Low Interest Loans*

Renewable power projects tend to be highly risky in the early phases of the project because of high up-front capital expenditures, siting and permitting requirements, and uncertain revenue streams. As discussed above, many costs will be incurred well before the project will begin to generate revenue. For example, Green Mountain Power spent $4 million on project management, permitting, wind resource assessment and design and engineering for its wind farm before the company could begin construction. In total $9.6 million was spent before the project began to generate a revenue stream for the company.[61] These high up-front investments translate into high risk and make it likely that projects will fail in the initial stages of development, which could be a significant barrier to development.

Providing low interest long-term loans through a revolving loan fund is one mechanism that could be used to reduce the cost of these projects. This mechanism would encourage investment in renewable projects by making capital accessible at lower overall cost for these types of projects. At the same time, a revolving loan fund would allow the renewable fund to be replenished as loans are paid back. The renewable fund would continue to grow, and funds could be funneled into new renewable projects over time. Because the loans would need to be paid back to the renewable fund, potential investors would be responsible for cost overruns due to

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[61] Vermont Docket 5823, Exhibit JLZ-5, at 3.

delays in project construction and would still need to invest a substantial amount of capital to cover up-front preconstruction and construction costs associated with the project. This means that investors would continue to share in the risks of renewable projects.

A loan mechanism, however, is not without its disadvantages. First of all, subsidizing the cost of debt may provide an incentive for companies to overconsume debt because it is artificially cheap. This could provide those companies that have the ability to take on more debt to have an advantage than others in developing renewable projects. Next, if, as argued above, renewable projects are likely to be balance sheet, rather than project financed, it may be difficult to target debt subsidies to the renewable projects we are attempting to support. Debt within a corporation is fungible and millions of dollars in subsidies may not affect a corporation's cost of debt significantly. Because all assets are treated as part of the larger corporation it would be difficult to affect the overall cost of debt for renewable projects. Furthermore, tracking the funds through the corporation could be difficult.

Finally, providing long-term loan financing to companies would require a fair amount of administrative work. A loan advisory board would need to be set up to review loan applications. This advisory board would need to include a bank to manage the fund and to make loans. Once loans are made, the loans would need to be maintained by a banking staff familiar with loan servicing. In addition, the regulatory agency would need to oversee the technical aspects of the projects that are proposed for funding and to order audits, as necessary.

Direct loans may be more appropriate for projects that are financed "off-balance sheet." When project finance or "off-balance sheet" financing is employed, lowering the cost of debt is easy and more effective. Low interest loans are better able to affect the cost of capital, making renewable projects cheaper and more competitive. Still, problems such as the over-consumption of debt and administrative burden would remain. However, because it is more likely that renewable projects will be balance sheet financed, low interest loans may make little or no real difference in the competitiveness of renewable projects.

B. Price Supports

A price support mechanism is a direct payment to a wind power producer for each kWh that is produced. It is a way to use ratepayer funds to make up the difference between the cost of generating electricity using renewable resources and the price of electricity in a market setting. Price supports would allow a company to reach a break-even point on renewable projects; the projects would cover their costs of production and would be able to pay returns to their equity investors. Price supports of approximately 1.5 to 2 cents per kWh could ensure that renewable projects are attractive to investors.

Price supports would be most effective if introduced in the early years of a renewable project's operations. During this time, expenses associated with supporting the underlying investment will be at their peak and this may be the best time to provide these projects with a boost to get them through these difficult years. Price supports could provide these projects with just enough of a jump-start to help the project remain in the competitive market game.

The problem with a price support mechanism is that it could discourage innovation. If investors know that they will be paid per kWh of production, there may be less of an incentive to find ways to reduce costs or adopt more efficient technologies. In fact, depending on the level of subsidy, investors may over build at a high cost in order to receive as much revenue as possible. Price supports could hinder, instead of help, renewable technologies achieve a competitive standing in the long-run.

Also, unlike a low interest loan mechanism, a renewable fund used for price supports would not be replenished over time. Once funding is provided to renewable project investors, it is gone. Ratepayer money cannot be reused to promote additional projects or leveraged in a capital structure. Unlike loans where funds that are paid back can be funneled into new projects, with price supports the total amount of funding available to renewable projects would be limited to the amount authorized by the state in each year.

Price supports may be a good short-term solution to funding renewable projects, but are unlikely to help such projects become self-sustaining. Price supports are likely to be more of a

Band-Aid that props renewable projects up just long enough to get them through the early years of operations. If the renewable fund is used to provide price supports, the timing and level of the supports would need to be carefully considered.

C. Public/Private Joint Ventures

Another option may be to set up a renewable public/private partnership. The goal of the partnership would be to produce renewable electricity and to sell the electricity at a price that would provide a return to its investor owners -- ratepayers and private investors. The partnership would need to market its product, control costs and report to its owners on the success/failure of the project. Both partners would contribute capital to the project and would share in the risk and rewards of the joint venture.

As an owner of the project, the state could agree to a lower rate of return on its investment as a way of jump-starting the project.[62] Access to cheap capital would reduce the capital costs of a project by shifting a portion of the construction risk from the developer to the ratepayers. State assistance would make the project less risky for potential investors which could translate into an overall reduction in the capital costs of the project. This type of partnership would be advantageous to a private investor because in addition to a return on equity, all tax benefits could be funneled to the private investor to offset other taxable income.

A joint venture between the state and a corporation would help ensure that renewable power is delivered to the market and that the renewable fund continues to grow. Any state return on the investment from the renewable partnership could be funneled back into the renewable fund which could then be used to make cheap capital available to other projects. Also, as projects become successful, the state could elect to sell its share in the joint venture at which

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[62] Joint ventures are not unprecedented. Recently, DOER and Endless Energy submitted a joint venture proposal to the U.S. Federal DOE for grant money to assist in a wind energy project. The joint venture was for a 3 MW wind farm. DOER was responsible for administrative oversight of the project and agreed to contribute approximately $225,000 to the project. The Cape Winds Project, A Proposal From the Commonwealth of Massachusetts Division of Energy Resources and Endless Energy Corporation to the U.S. Department of Energy Commercialization Ventures Program, August 29, 1996.

point proceeds from the sale would be returned to the renewable fund. Other arrangements could also be made to guarantee the sale of power. For example, the joint venture could offer a contract for power to the state procurement office thereby providing the project with even greater stability.

The problem with joint ventures is that they provide an incentive to increase the level of equity in the project over that which might otherwise be required. If the state makes equity cheap, potential investors will want as much capital as possible. As the level of state-owned equity increases, the more risk the state would hold and the less likely these projects will ever be self-sustaining.

Another problem with providing cheap capital is that, while it is a good solution to the high up-front capital cost problem, once the money is spent, it is hard to get it back. Assuming the private partner would manage the project, it may be difficult for the state to ascertain whether projected costs, construction scheduling and revenue estimates are reasonable and whether the project makes good investment sense. This type of understanding would require expertise that the state may not have. Because of the high risks of renewable projects, there is the danger that the business could fail at which point ratepayers are left with no renewable fund and no renewable projects.

However, with all subsidy options, ratepayer funds will be at risk. Provided that the duties, risks and rewards are carefully portioned between each partner, a joint venture could be provide one option for the state to deliver renewable power customers in a way that works with, instead of counter to a competitive energy market. The partnership would need to act as a business entrepreneurs and share in the risks and returns of a venture, will need to compete against other providers in a competitive market, and will have to play by the same rules as all other providers. A joint venture between the state and a company could allow the state to deliver renewable power with minimal intervention in the market.

D. General Subsidy Program Criteria

Regardless of the type of subsidy program a state might choose to implement, there are other issues that must be considered by policy makers. These are the importance of (1) minimizing restrictions on ownership and geographic location of projects, (2) committing to renewable policies for no less than ten years, and (3) funding only those projects that actually deliver renewable power to consumers. We focus, in particular, on Massachusetts, but these issues will arise in other states as well.

1. Restrictions on ownership and geographic boundaries of renewable projects that will be eligible for funding should be minimized.

If Massachusetts ratepayers are to be funding renewable projects, it could be argued that any projects funded must directly benefit Massachusetts customers. The phrase "directly benefit" could mean that power from renewable projects should be produced in Massachusetts by Massachusetts companies and sold to Massachusetts customers. After all, the more renewable power produced in Massachusetts, the less dirty power that needs to be produced within the Commonwealth. This means that direct benefits of cleaner air will fall to Massachusetts consumers.

Secondly, renewable power projects mean economic development opportunities for the Commonwealth and its cities and towns. By requiring that all projects be Massachusetts-based, companies will need to own and/or lease offices and site space within the Commonwealth, and workers will need to be hired through all phases of the project and on a permanent basis. Development translates into construction jobs, company jobs, and property tax and income tax revenues for the cities and towns and the Commonwealth of Massachusetts.

While a pro-Massachusetts development policy may be attractive to many policy makers, it could decrease the likelihood that renewable power projects are built. Hard and fast boundary requirements and restrictions on ownership, location and purchase and sales agreements severely limits development options for a number of different reasons. First of all, there are technical

problems with boundaries. As discussed in Chapter II, very few sites within Massachusetts are suitable for wind projects (i.e., only the Cape and Islands and Western Massachusetts). Factors such as winds speeds, site size requirements, distance from residential and commercial developments are restrictions on development projects and need to be taken into account. Furthermore, access to utility transmission and distribution systems needs to be considered. Also, as with many projects, even if sites are suitable for wind projects, it is often difficult to find a community willing to accept renewable projects within its boundaries.[63] Because of the variety of technical limitations, drawing boundaries around where development can and cannot occur will serve to limit the number of renewable development options.

Ownership restrictions or requirements that specify that a company be based in Massachusetts would play a limiting role in the development of renewable projects. First of all, the term "ownership" would need to be defined by the regulator agency. Would ownership refer to where a company was incorporated, or whether a company was registered to do business in the state of Massachusetts? If companies are required to be incorporated in the Commonwealth, would companies be willing to "jump through so many hoops" just to apply for funding from the renewable fund? Furthermore, these types of restrictions may provide an incentive for companies to try to set up shell organizations in order to get around restrictions. In general, ownership restrictions may only serve to create a more difficult review process for the regulatory agency, an additional barrier to the development or renewable power projects and increase the cost of renewable power.

Finally, once ownership restrictions are implemented, they would need to be enforced by the regulatory agency. As renewable companies are bought, sold, taken over or merged with other companies, ownership restrictions would, presumably still apply. Companies would need to file reports, provide evidence of income tax or property tax payments, or some other measure of compliance in order to continue to receive the benefits the renewable fund may offer. This type of administrative work would be burdensome on a regulatory agency. Trying to understand

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[63] There is a proposal by the Town of Nantucket to construct six wind turbines at a landfill site on Nantucket. Since this proposal was made there have been numerous articles written for and against (mostly against) such a project in the local newspaper, the Nantucket Beacon.

and trace corporate structure and then, if violations occur, impose fines, and call back funds may not be worth the effort in time and money.

In general, restrictions are complicated, do not always produce the outcome desired and will most likely raise the cost of doing business as companies attempt to meet the terms of the restrictions. The situation becomes even more complicated for companies that wish to develop wind projects in more than one state. If every state operates according to its own rules, the task of delivering renewable power and cleaner air to New England consumers becomes even more difficult.

2. State renewable policies should be set for a minimum of ten years in order to ensure certainty in the market and to provide renewable power with a stable planning horizon.

Uncertainty in the market place drives up the cost of capital for companies and makes financial forecasting difficult. The more uncertain a company's assumptions about inflation, capital costs, revenue streams, tax status, weather, political climate, etc., the more difficult it is for that company to convince potential investors to supply capital needed to get projects off the ground. While not much can be done about changes in the weather or inflation, state policy makers can take action to provide some stability to companies in the form of long term commitments to policies.

Because companies make decisions based on ten or twenty year planning horizons, the better companies can predict what might happen during this timeframe the lower the riskiness of the project. Regulatory policies can work for or against company's long-term planning efforts. Regulatory policies that are in place for ten years or more, can provide companies with a type of insurance against at least one variable in their calculations. This certainty lowers risk which can be translated into lower capital costs and a lower price of power.

Regulatory policy makers need to recognize the negative effect that shorter-term policies can have on companies. In Massachusetts, the Department of Public Utilities states that "After three years of implementation [of the renewable fund], the Department will review the results achieved and will reevaluate that need for and appropriate level of funding to support

commercialization of renewables."[64] Clearly, this statement puts companies on notice that the renewable fund may or may not exist at the end of the first three years of their renewable projects. A company, considering investing in a renewable projects today, may find that it makes no sense to include support from the renewable fund in its financial calculations given that by the time a site is planned and constructed, the renewable fund may no longer exist.[65] It could be argued that it may be better to have no policy than to implement a policy that may not exist within the planning horizon.

States should consider adopting renewable support policies for no less than a ten year time period. Just as regulatory bodies expect companies to make commitments to providing renewable power within the Region, states need to commit to policies that provide long-term support for such companies. Ten years is a long enough period for companies to count on subsidies and policies when developing proposals for potential investors. Ten years is also enough time for regulatory bodies to review and track the success/failure of these policies. This is not to suggest that regulators should not be able to correct aspects of the policies during the time that they are implemented, only that a commitment be made to support these policies over at least a ten year time period.

3. Only those projects that produce renewable power should be eligible for funding.

The renewable fund should be used only to fund projects that produce renewable energy. As the Massachusetts Department of Public Utilities stated in its proposed rules:

> the most efficient use of the fund is to reduce the price of renewables, which will, in turn, enhance the ability of renewable energy producers to overcome the non-price barriers they face and pursue increased production opportunities. Therefore, at this time we do not intend to sanction use of the renewables fund to support pilot projects or any other initiatives not consistent with our Model Rules.[66]

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[64] Commonwealth of Massachusetts Department of Public Utilities, Electric Industry Restructuring Plan: Model Rules and Legislative Proposal, D.P.U. 96-100, at 178.

[65] The Vermont project preconstruction and construction phases took 3 years to complete. In fact, the study of the site took from 1993 until 1995.

[66] Commonwealth of Massachusetts Department of Public Utilities, Electric Industry Restructuring Plan: Model Rules and Legislative Proposal, D.P.U. 96-100 at, 179.

Renewable energy projects will provide cleaner air, increased choice among energy options, and lower cost renewable power and jobs. These benefits can be measured, tracked, reported by the media over the life of the renewable fund. Without evidence of these types of benefits, it will be difficult to retain the support from ratepayers and other stakeholders to justify the continued use of ratepayer funds for renewable projects. Renewable energy projects will provide a sense of legitimacy for policy makers who will need to justify the use of ratepayer funds. Ratepayers, the Legislature, the Governor, the Attorney General, among others, will need results they can point to as evidence that funds are being put to productive use.

Renewable research and studies do not produce renewable energy and should be encouraged to seek funds available from other sources. There are a number of entities, both public and private, that provide grants or funding for studies and pilot projects that investigate renewable technologies. For example, a number of universities, including the Massachusetts Institute of Technology, fund research studies and projects related to environmental technologies and public policy. In addition, a number of states have programs such as the Stretegic Envirotechnology Partnership (STEP) funded by the Massachusetts Executive Office of Environmental Affairs, that are designed to help enterprising companies test, certify and deliver new environmental technologies to the commercial market. Other agencies such as DOE and the National Renewable Energy Laboratory (NREL) and private institutions such as Edison Electric Institute (EEI) and Electric Power Research Institute (EPRI), issue studies ad nausium on renewable technologies, policies, and market research. Given the number of entities that are engaged in the study of renewables, it makes little sense to spend ratepayer money on additional studies that may or may not provide results.

E. Conclusion

This thesis has analyzed the technical, marketing and financial aspects of a hypothetical wind project on Cape Cod. There are three major findings. First, from a wind resource assessment, there appears to be a good correlation between wind speeds and demand for

electricity in New England especially in the winter months. This suggests that from a technical standpoint, wind power projects would be feasible. However, energy produced from a wind farm is unlikely to be able to compete on a price basis in a competitive market. This conclusion is based on the financial model that compares the break-even price of wind power, 6.5 cents/kWh, to the estimated price of electricity in a deregulated market, 4.4 to 4.8 cents/kWh.

Next, this thesis shows that an investor could not, at this time, expect customers to pay premium prices for electricity that will be high enough to make up the difference between the cost of wind power and the market price of power. In the long-run, as customers begin to understand and become used to and educated about green power and the deregulation of the electric power market, the number of customers willing to support these projects may increase. For now, however, there is no evidence that would allow a wind power project investor to "bank on" these long-run expectations. Therefore, this thesis concludes that approximately a 1.5 to 2 cent/kWh subsidy will be required in order to ensure that wind power projects are financially viable in a deregulated market.

If regulators believe that promoting renewable resources is in the public interest, a subsidy program will be need to be designed in order for renewable resources to compete in a deregulated market. Three subsidy mechanisms have been proposed: direct loans, price supports, and a public/private partnership. Each option would help deliver renewable power to the market by reducing project costs and risks for potential investors. Yet, each policy has a number of drawbacks. The best option may be to set up public/private partnerships. These arrangements would reduce the cost of capital for wind power projects, allow ratepayers to share in not only the risks, but also the successes of such projects, and work within the confines of a deregulated electric supply market. Public/private partnerships, however, require long-term involvement and commitment on the part of the Commonwealth. While no mechanism is right or wrong each has its drawbacks and needs to be designed to minimize market distortions, encourage innovation, control costs, and deliver renewable power at market prices.

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