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Cash Crop on the Wind Farm:

A New Mexico Case Study of the Cost, Price, and Value of Wind-Generated Electricity

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Western Governors' Association
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Preface

Severe energy-related problems are emerging in the United States on a number of fronts. They show up as serious breakdowns in the system from time to time – ranging from volatile and rising natural gas prices, to security issues associated with rising oil imports, to electricity blackouts that have affected vast regions sporadically since the late 1990s. At no time since the first energy crisis in 1973 has there been such a set of vulnerabilities that has emerged simultaneously. Moreover, the energy system is now pushing up against problems not experienced before. A long drought in the West is creating more intense concerns and conflicts over water, and thermal power plants are a huge water consumer. A large number of combined cycle power plants fueled with natural gas have been built in the past few years, but they are being affected by high and volatile natural gas prices. This same problem is affecting the chemical industry, which uses natural gas a feedstock to make basic materials for the U.S. economy.

The United States has not had an energy policy in place since the Carter administration, unless leaving it to large energy companies to supply whatever demand might arise is to be called an energy policy. Whatever the problems and defects of the Energy Plan published by the Task Force led by Vice-President Cheney, it did have the merit of putting the energy issue in the center of the national political debate in the first part of 2001. But, a variety of factors, including the terrorist attacks of September 11, 2001, and the Iraq war, as well as domestic differences over what the right policies might be, have so far resulted in an impasse. There have been many words and much effort but not an energy policy.

There is no single or simple answer to solve energy problems. Solutions must be coordinated on a number of fronts technically, geographically, economically, and politically. Many including IEER, have covered these issues.[1] Efficiency, including mileage standards for cars, is one key. Transmission infrastructure is another. And so far as supply is concerned, it appears clear that renewables sources of energy are a central part of the answer. Among these wind-generated electricity is possibly the most important for the short and medium term, because its costs have come down greatly and are now comparable, overall, to conventional generation (even without attributing the costs associated with climate change or nuclear proliferation to those sources).

The U.S. wind energy resource is huge – about two-and-a-half times the total electricity generation of the United States, without taking into account off-shore resources. The annual potential is the same order of magnitude as the total oil production of all the members of the Organization of Petroleum Exporting Countries. But of course, wind is not predictable. The costs associated with this are central to consideration of the value of wind-generated electricity to customers of electricity. There is a considerable literature on the *costs* of wind energy. Here we add to such considerations by assessing the spot-market and regulated market sales of wind-generated electricity and the *prices* it could fetch, given the uncertainty of future wind speed. We also consider how water conservation, reduction of natural gas price volatility, and reduction of carbon dioxide emissions might add up to enhance the value of wind energy.

We have focused this study on cost, price, and value comparisons. Since the costs of transmission are well known and understood, even for wind-generated electricity, we have not considered these in detail, other than to take them into account and to note that building transmission infrastructure is central to the realization of the potential of wind energy. The narrow focus on costs, prices, and

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[1] For IEER's report see Arjun Makhijani, *Securing the Energy Future of the United States*, Institute for Energy and Environmental Research, Takoma Park, Maryland 2001.

that show the kinds of economic circumstances in which much faster wind power development can take place.

We have received a great deal of help in preparing this report, which has been much improved as a result, but the authors, of course, take full responsibility for its contents and conclusions. This study was conceptualized last fall and it has been an immense and cooperative effort to get it done. Peter Bickel conceptualized and developed the spot-market statistical model; Aiyou Chen did the computations; Brice Smith worked with me on the study of the Chino Building in Santa Fe (Chapter 4) and did the final computations. Richard Simon and David Matson were our meteorological consultants and used the wind data for the five New Mexico sites to compute ten-minute and monthly average capacity factors that were central to our New Mexico case study.

This study would not have been possible without the full cooperation of the State of New Mexico. Governor Bill Richardson gave us a letter of support (reproduced here); Craig O'Hare and Michael McDiarmid provided us with information, contacts, wind energy data and insights; Daniel Hagen supplied us with the electricity use and billing data for the Chino building where he and Craig and Michael work, so we could make a detailed case study of a real building using recent price data. Ned Farquhar, in the Governor's office, was our liaison with the North American Energy Summit. Prasad Potturi graciously shared his vast knowledge of the New Mexico transmission network so I could orient myself to the problem. Soll Sussman, Doug Larson, and Richard Halvey gave me useful pointers as regards the North American Energy Summit.

My New Mexican friends have been enthusiastic about this study, among them Kimi Green. Ben Paulos, Katie McCormack, Warren Byrne, Roger Hamilton, and Ron Lehr helped me narrow the focus of the study to its present form, so that it would complement other work that has been done. Ben Luce and Ken Freese helped with insights, data, and contacts. Travis Coleman helped me understand the utility perspective. Amory Lovins gave me some initial comments on the proposal, as did Hal Harvey. Yih-Huei Wan, Brian Parsons, and Ruth Baranowski sent literature and data, and Brian also shared some important insights. I got many useful review comments, including detailed ones from Eric Hirst, Ron Lehr, Roger Hamilton, and Craig O'Hare. Jane Collins did a great job of collecting a large amount of data. Daily electricity and gas price data were provided to IEER courtesy of Platts. Lois Chalmers was, as usual, our able bibliographer, researcher and fact checker, and Annie Makhijani did the block diagrams in Chapter 4 and thought of the title.

No such effort is possible without funds, which were generously provided by the Livingry Foundation, the New Cycle Foundation, the Energy Foundation, the McCune Charitable Foundation and the New Mexico Community Foundation.

But when all is said and done, this study would have been impossible without Gay Dillingham. She made this a personal effort, believed in it, and treated this as her very own project. I know she wants her home state, New Mexico, to have a great role in getting all of us to a more secure and environmentally sound energy future and, through this project, I have come to share that goal. Even for one who has grown old and bald doing research and writing reports over more than three decades, this collaboration with Gay has been a privilege and a very extraordinary experience.

Arjun Makhijani
Takoma Park, Maryland
13 April 2004

State of New Mexico

Office of the Governor

Bill Richardson
Governor

January 23, 2003

Gay Dillingham, Director
CNS Communications
535 Camino Militar
Santa Fe, NM 87501

Dear Ms. ~~Dillingham~~ Gay:

As many New Mexicans are aware, I am a strong supporter of the development of wind energy in our state. I am pleased that a new wind production facility, producing over 200 MW, has recently opened in eastern New Mexico.

Thus I am writing to support your proposal for a wind energy study that will help define the economic feasibility of wind in New Mexico, and help identify some of the obstacles to further wind development. This is the kind of information that our agencies will benefit from in helping me fashion and further my Administration's aggressive clean energy goals.

Arjun Makhijani of the Institute for Energy and Environmental Research is a respected scholar and advocate who will identify important issues and get us information we can use.

While the envisioned study focuses on a specific location in NM to obtain a "real world" sense of the integration concept's feasibility, it's clear such a study would have national and even international implications for the viability of wind power.

Again, let me express my strong support for the study, and we are appreciative that Mr. Makhijani chose New Mexico to perform the study. The State of New Mexico stands ready to assist with the project in any way it can.

Sincerely,

Bill Richardson

Bill Richardson, Governor

cc: Joanna Prukop, Secretary
Energy, Minerals, and Natural Resources Department

Main Findings and Recommendations

Main findings

1. **Wind electricity generated at very favorable locations in large wind farms is economical today.** Consumers would not see increases in electricity bills with far greater use of wind-generated electricity, even without taking any credit for avoided water use orgreenhouse gas emissions.

2. **U.S. wind energy resources are enormous and can accommodate much faster growth in wind-generated electricity.** The United States has the physical wind resource base, with much of it concentrated in the region of the Western Governors' Association, to achieve high and economical penetration of wind capacity. The wind energy potential in the twelve windiest states of the continental United States, most of them members of the Western Governors' Association, is equal to about two-and-a-half times the entire electricity generation in the United States in 2003.

3. **A policy mandate is essential if high levels of wind integration are to be achieved in a reasonable time**. Three regions in Europe (one in Denmark, one in Germany, and one in Spain) have already achieved 27% penetration of wind capacity. This is in part because there is a strong political and policy consensus in Europe, including from industry, that reduction of greenhouse gas emissions and increasing renewable energy use are essential. Three western states (California, Nevada, and New Mexico) have also moved in this direction. But, in the absence of an economic and political mandate, such as a Renewable Portfolio Standard, wind energy development in the United States will lag far behind its potential.

4. **The transmission and institutional infrastructure needed for large-scale wind energy development is inadequate**. Wind energy development in the United States is lagging far behind Europe mainly because the transmission infrastructure and the economic and policy consensus to develop exists it in Europe to a far greater degree than in the United States.

5. **Prices of wind energy in typical Power Purchase Agreements (PPAs) appear to be considerably lower than the price that the same electricity would fetch if sold to the final consumer.** The average price of wind-generated electricity in many PPAs is in the $25 to $30 per MWh range. However, the price that the final consumer could pay, *without an increase in electricity bills*, is considerably higher. In other words, the implicit final price of wind (after taking into account transmission and distribution costs and grid integration costs) is considerably higher than wind developers are receiving. This gap between final price and wind developer revenue increases the need for tax credits. If wind developers could actually recover the implicit price being charged, development of wind power could be greatly accelerated.

6. **With the right policies and with investments in wind and efficiency, a large reduction in greenhouse gas emissions is economically feasible.** Since wind energy does not emit carbon dioxide, and since it is economical today, given the right conditions and policies, it follows that a large reduction in CO_2 emissions is possible without increases in electricity cost. This is currently being achieved in Europe. While credits for CO_2 reductions play a role these are modest.

7. **Federal and State Production tax credits are essential under present conditions.** In the absence of a national or uniform regional mandate and adequate transmission and other infrastructure for wind integration, federal and/or state production tax credits are essential for continued wind energy development.

8. **Given natural gas prices of $5 per million Btu or more wind energy can economically displace natural gas generation on a marginal avoided cost basis**. The cost of wind-generated electricity at favorable locations, including $3 per MWh for grid integration, ranges from $38 to about $45 per MWh for five New Mexico sites we looked at. The marginal avoided cost of natural gas in terms of fuel cost alone for combined cycle plants is about $38 to $40 per MWh. Wind also provides the benefit of avoided water use (a few dollars per MWh) and as a hedge against natural gas price volatility (also a few dollars per MWh). Wind-generated electricity can displace duct fired combined cycle electricity or peaking electricity from single-stage gas turbines even more economically, since the avoided costs in these cases are about $50 and $60 per MWh, respectively.

9. **Wind-generated electricity should get some credit for capacity and not only electricity generation**. Statistical methods can be used to commit wind energy in advance: Wind is not completely unpredictable. It can be estimated, with some error, on an hour-ahead, day-ahead, or seasonal basis. Statistical analyses can be used to plan wind capacity's availability in the grid. The size of the error, and hence costs can be reduced by (i) improved forecasting, (ii) diverse sources of wind energy supply geographically separated by large distance being integrated into the same grid, (iii) a transmission infrastructure and grid integration arrangements. Greater capacity credit for a given level of cost and reliability can be achieved if new wind capacity is planned so as to reduce natural gas use for electricity generation

10. **The economics of wind energy would improve if wind developers could realize a reasonable capacity credit**. In the examples we have studied, wind capacity credits could amount to $2 or $3 a MWh, which is a significant portion of the gap between the price in a PPA and the cost of wind energy (the difference being made up today by tax credits). Such capacity credits are more appropriate and feasible if day-ahead forecasting has reduced errors.

11. **Integration of large amounts of wind energy without the extensive use of tax credits is feasible**. If the necessary policies are put into place, and the infrastructure is built, the West can achieve high penetrations of wind energy comparable to the highest levels in Europe. There is no inherent technical obstacle to this; nor is there a reason to anticipate significant increases in cost of electricity. The following are needed to accomplish this goal:
    - **regional transmission infrastructure** with wind integrated into it
    - **geographic diversity in wind development** so as to reduce uncertainty and increase capacity credit
    - **equitable rules for grid integration and transmission access**
    - **systematic connection of wind energy development with reducing natural gas use in power plants**
    - **reasonable capacity credit for wind power plants**

12. **Wind-generated electricity can be used to make natural gas available for vehicles (indirectly)**. Earth source heat pumps, combined heat and power systems, and wind energy can be joined to eliminate the need for using natural gas for space and water heating in buildings. This natural gas, in turn, can be used in vehicles as compressed natural gas to displace gasoline and reduce oil imports. This type of arrangement would lead to significant CO_2 reductions both in buildings and in cars, as well as lower urban air pollution.

13. **Integrating fuel cells into the renewable energy mix will require improvements in fuel cell and hydrogen production efficiency as well as reduction in fuel cell costs.** Integrating hydrogen production and fuel cells into the electricity system as part of a strategy to increase renewable energy can help increase the capacity credit for wind. It is, however, not economical today due to high fuel cell costs and low overall efficiency of converting wind-generated electricity into hydrogen and fuel cell electricity. Optimization via use of combined heat and power systems and efficiency improvements can also help reduce costs.

Recommendations:

1. **The Western Governors' Association should formally adopt a renewable energy goal of 20 percent of electricity supply for the region.** Given that wind energy is both plentiful and, in the right circumstances, economical, a decision to get 20 percent of the region's electricity from renewables, with an emphasis on wind energy penetration, is highly desirable for reasons discussed in the findings. The Operational Rules Committee of the Western Renewable Energy Generation Information System has already produced draft rules for tracking renewable energy generation. Ten to fifteen years would be a reasonable time frame to achieve such a goal. Each state would, of course, set its own regulations for enacting and achieving the 20 percent Renewable Portfolio Standard. The WGA should urge the National Governors' Association and the federal government to adopt the same Renewable Portfolio Standard.

2. **Wind energy development should be integrated with planning for reduction of natural gas price volatility.** Since wind-generated electricity costs at favorable sites are often lower than avoided costs of natural gas at current prices, regulatory bodies and independent system operators should examine the benefits of using wind-generated electricity to displace single stage gas turbine peaking unit use including having some of the same units as standby units, as part of an overall approach for achieving high wind capacity penetration at modest cost. A regulatory framework for such integration needs to be created.

3. **The WGA should charge the Western Interstate Energy Board to examine large scale wind energy integration in the entire region.** A committee, created as part of the Wind Evaluation Team of the WEIB, should be set up to examine the technical and economic requirements of large-scale wind energy development in the Western Interconnect region (20 to 40 percent penetration), including:

- **diversity of supply and demand** that can be accomplished via integration of wind source in different states onto a single grid, as well as the reduction in cost of wind-generated electricity via increased capacity credit that geographic and demand diversity can bring
- **the cost and financing of regional transmission lines** designed to serve large-scale wind energy development, including HVDC lines
- **enhancing existing meteorological capabilities** to serve the purpose of reducing errors in wind forecasts, thereby increasing the value of wind power plants
- **ways in which some of the benefits** to the economy in terms of saving water can be realized by wind farm operators
- **creation of financing mechanisms for infrastructure** that will allow bundling to reduce financial risk and reduce cost at the same time.
- **integration of wind energy development** with reduction of natural gas use in power plants (relatively)
- **policies that would result in cost internalization for CO_2 emissions and water** use so that the collateral benefits of wind energy to society can be reflected in the marketplace.

4. **New regulations are needed for equitable access to final consumers.** In states where electricity is regulated, rules to enable utilities to recover reasonable costs (including return on investment) can be created as part of the implementation of a Renewable Energy Standard. We estimate that if wind energy is developed at suitable sites, this is not likely to significantly affect the final cost of electricity to consumers.

5. **Harmonized internalization of water and greenhouse gas emission costs should be carried out throughout the region.** Today, states are in the leadership of renewable energy as well as in the area of reduction of greenhouse gas emissions. An approach to cost internalization for CO_2 emissions and water use by thermal power plants would accelerate the development of wind power considerably. The price of wind-generated electricity in typical PPAs might increase on the order of $5 per MWh as a result.

6. **New Mexico should create a demonstration project to combine wind, fuel cells, solar photovoltaics, efficiency, and the use of compressed natural gas in motor vehicles.** This combination of measures holds large potential for both environmental and security benefits, but is not economical today. A demonstration project in which the benefits could be carefully assessed, along with the costs, would be of immense value in evaluating the prospects and difficulties of the road to a renewable energy future in which hydrogen, natural gas, and renewables are the main energy sources, while the use of oil is much reduced. While we did not study the question, it may be desirable to integrate some direct use of solar photovoltaic electricity into such a demonstration project, to assess reduction in peak loads on the grid and increased capacity credit for wind. New Mexico is well placed to provide leadership for such a project in the WGA and also the entire country since it has excellent scientific and technical resources available in the form of national laboratories, and NASA (at White Sands), and a state government that has already made the policy commitment to renewables and has much of the legal infrastructure in place.

Chapter 1: The Wind Energy Resource: An Introduction

There is now general agreement that emissions of carbon dioxide and other greenhouse gases due to human activities are playing a significant role in climate change. Conflicts over control of oil have been rife in the world for nearly a century; they continue. But in the last decade-and-a-half a major new resource, greater than the oil that transformed the economy of the twentieth century has become economically viable – energy from wind. The global land-based wind energy resource is several times the world's total electricity generation. The offshore resource potential may be even greater. The United States is also well endowed with wind energy in areas where it is developable. The top 12 states (of the lower 48) with high wind energy in areas with large farms and lands on which wind turbines can be built have a total potential of about 10 billion megawatt-hours, equivalent to roughly 2.6 times the total electricity generation of the U.S. Table 1.1 shows the details for these twelve states. This excludes offshore wind energy. Seventy percent of the wind potential in these twelve windiest states is from states belonging to the Western Governors' Association. The potential of the other members of the WGA, Alaska, Hawaii, California, Oregon, Washington, Idaho, Arizona, Nevada, Utah, and Pacific U.S. territories, is in addition to that listed in Table 1.1. This is, of course, a statement of the resource base. A great deal of investment, not only in wind farms, but also in infrastructure, especially transmission infrastructure, will be required before even a fraction of this physical resource base can be turned into a technical and economic reality in the U.S. energy system.

There are a number of ways to compare the size of the wind energy resource and its relations to environmental, energy, economic, and security problems. For an environmental perspective, the developable U.S. wind energy resource (i.e., excluding populated areas, national parks, etc.) can help greatly reduce U.S. greenhouse emissions arising from the use of fossil fuels, when combined with improving efficiency of energy use, and other measures. In addition, the use of wind energy can have a positive impact on water conservation (see Chapter 5).

Another way to look at it is that the annual amount of wind energy that can be generated is the same order of magnitude as the entire annual oil output of all countries belonging to the Organization of Petroleum Exporting States in physical terms. About two percent of the wind resource in the twelve most windy states would, over 40 years, be equivalent to the entire oil reserves of the Arctic National Wildlife Refuge, assuming they are as high as 10 billion barrels. Of course, the wind energy potential would still be available after that, while the oil reserves of ANWR would be exhausted. North Dakota, Texas, and South Dakota together (or any three of the top five states together) have enough wind energy to displace all U.S. oil imports, which at present stand at 11 million barrels per day. We will discuss how wind energy and efficiency initiatives can indirectly help reduce oil consumption in cars, even without the development of fuel cells cheap enough to power the cars themselves.

The New Mexico wind energy resource is the same order of magnitude as US oil imports from the Persian Gulf region. As noted above, these comparisons give a broad picture of the magnitudes of energy involved (rather than an exact technical equivalence). Of course, translating this potential into an actual reduction in oil imports to realize the positive impact on security will be a complex and costly matter.

When considering the economics of wind as compared to fossil fuels, it is important to recall the actual magnitude of the investment associated with oil and natural gas production. In 2003, the International Energy Agency estimated that the world investment in oil and gas between 2001 and 2030 will equal nearly $6.1 trillion. Almost $3.9 trillion of that expenditure is expected to be in exploration and development costs alone. The U.S. and Canadian investment in oil and natural gas over this time period is predicted to be more than one-fourth of the global total.[2] Looking just at the two largest U.S. oil companies, Chevron-Texaco and Exxon-Mobil, we note that between 2000 and 2002 they spent a combined total of $31.3 billion on exploration and production while their net output actually dropped by just over 2% per year over that same time.[3] Energy is a costly business, and a vital one. Huge energy-related investments in the supply, transport, and demand sectors are inescapable for a modern economy. A central question is whether and under what circumstances these investments make economic sense. But there are also other factors – climate change and security issues, in particular, are problems associated increasingly with greater use of petroleum.

Wind energy development has been proceeding rapidly in the past few years. It is the fastest growing source of electricity. But this is from a small base. Total installed wind capacity in the United States at the end of 2003 was 6,370 MW.[4] This is far lower than the 28,440 megawatts of capacity in the European Union at the end of 2003, equivalent to the electricity consumption of 35 million people in the European Union and providing 2.4% of the total EU electricity consumption.[5] In 2002 and again in 2003 Europe added almost as much wind capacity as the entire U.S. installed capacity.[6] Wind energy meets less than half a percent of U.S. electricity demand. The present low level of U.S. use of wind is in stark contrast with its immense potential in economic, environmental and security terms.

There are several reasons for the gap between promise and reality: the lack of transmission infrastructure, rules for transmission and for integration of wind power into the electricity market that do not provide a level playing field for wind, and the pricing structure for wind electricity. This study is focused on the last issue. However, we will make some comments in the policy section drawing on the literature, such as the work of the Seams Steering Group – Western Interconnect (SSG-WI),[7] whose goal is to create a seamless grid in the Western Interconnect region. This is because the large-scale development of wind energy will not be possible without

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[2] Claude Mandil. "World Energy Investment Outlook: North American Energy Investment Challenges: 2003 Insights." [Paris]: International Energy Agency. Online at http://www.csis.org/energy/031112_mandil.pdf

[3] Matthew R. Simmons. "Energy Infrastructure: The World's Arterial and Circulatory System." Presented at the Sixth Annual Rice Global Forum, Rice University, Houston, Texas, September 8, 2003. [Houston]: Simmons & Company International, 2003. Online at http://www.simmonsco-intl.com/files/Rice%20Global%20Forum.pdf.

[4] "Boom: 2003 Close to the Best Year Ever for New Wind Installations – Bust: Expiration of Key Incentive Lowers Hope for 2004: AWEA Urges Quick Renewal of Production Tax Credit to Build on Market Momentum" American Wind Energy Association press release, January 22, 2004, at http://www.awea.org/news/news040122r03.html, viewed on Feb. 13, 2004.

[5] "Wind power installed in the Europe by the end of 2003," European Wind Energy Association, January 4, 2004, http://www.ewea.org/documents/europe_data_jan04_final.pdf.

[6] "Wind Power Expands 23% in Europe but Still Only a 3-Member State Story" EWEA New Release, Brussels, 3 February 2004, www.ewea.org.

[7] Seams Steering Group – Western Interconnect (SSG-WI). Online at www.ssg-wi.com.

addressing the financial, institutional, regulatory, and other issues associated with the construction of a suitable infrastructure for transmission of wind-generated electricity.

The price of wind energy received by wind farm developers is based on the way that the value of wind energy is computed by its purchasers. Related to this issue is the division of the revenues actually derived from wind electricity sales between wholesale purchasers who resell it to final consumers and the developer of wind energy. Under current pricing formulas, discussed below, wind energy developers often cannot meet their costs based on revenues from wind energy sales alone. The difference is made up by the federal tax credit and, in some states like New Mexico, a state tax credit. When the federal tax credit expires, as it did on December 31, 2003, development of new large-scale wind energy projects can grind to a halt. This is damaging to the industry, to the environment and to security.

For large-scale wind electricity potential to be developed to a level that substantially affects oil imports or greenhouse gas emissions, ways must be found to reduce the gap between the low price and cost of wind energy. The average value of wind energy at the time of generation is at present far above the price it commands. Technological development to lower the cost of wind energy is, obviously, one way to realize that. But wind-generated electricity in large wind farms is already quite comparable in terms of average cost to other major electricity sources. This study examines whether a higher price realization by the wind developer is reasonable given the various issues, like uncertainty in future wind and the costs of integrating wind-generated electricity with electricity grids.

Table 1.1: Physical Wind Resource Base in the Top 12 States (contiguous United States)

State	Annual electricity generation potential, billion kWhe	Percent of total U.S. electricity generation, 2003[a]	Comments
North Dakota	1,210	31.5	WGA member
Texas	1,190	30.8	WGA member
Kansas	1,070	27.8	WGA member
South Dakota	1,030	26.8	WGA member
Montana	1,020	26.5	WGA member
Nebraska	868	22.6	WGA member
Wyoming	747	19.4	WGA member
Oklahoma	725	18.9	
Minnesota	657	17.1	
Iowa	551	14.3	
Colorado	481	12.5	WGA member
New Mexico	435	11.3	WGA member
Total, top twelve	**9,984**	**259.6**	
Total ERCOT (Texas)	~1,000[b]		reliability region mainly including the Texas grid
Total Western Interconnect	~3,000[b]		Reliability region up to approximately the Montana-New Mexico North-South line
Total Eastern Interconnect	~6,000[b]		Reliability region covering rest of the lower 48 states (i.e., generally including states in the East, South, and Midwest, 4 of which are WGA members)

Source: *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States* Pacific Northwest Laboratory, 1991, as cited by American Wind Energy Association, online at http://www.awea.org/pubs/factsheets/WindEnergyAnUntappedResource.pdf.

Notes:
(a) Electricity generation in 2003 = 3846 billion kWh (kilowatt-hours) . Source EIA.
(b) The totals for the interconnected regions are approximate since the regions do not correspond exactly to state borders. ERCOT (Electric Reliability Council of Texas) includes most of Texas, but excludes a part of the Texas panhandle. Transmission is currently coordinated within the Interconnect regions.

Chapter 2: Wind Electricity Costs and Present Prices

As wind energy has become more economical in the past decade-and-a-half, studies have focused on how it can be integrated into the grid, and the costs of such integration. There has also been a considerable effort on the transmission infrastructure that will be needed if wind energy is to become a significant part of the electricity supply. Transmission bottlenecks are, in any case, a serious problem in some parts of the country.[8] We will summarize here various aspects of the cost of wind generated electricity and compare that to a few cases of the prices that are actually realized by developers of large-scale wind farms. This sets the stage for considerations of what the wind energy might actually be worth to purchasers, so that potential prices might be compared with the costs of wind-generated electricity.

A. Assessing the cost of wind-generated electricity – general considerations

The costs of wind energy installations are dominated by the capital costs of the turbines and the construction of the plant at the site. The main variable in the construction relates to the location and the infrastructure at the wind site. These issues are well-known and well-understood and we will not consider them in this report. Rather, we will use a typical cost of one million dollars per megawatt as the capital cost for the installed capacity on a large wind farm in a suitably windy site – such as those that are widely available in many states, including, of course, the 12 states shown in Table 1 above (in Chapter 1).

At rates of interest and return on investment comparable to coal-fired power plants, the main cost determinant is the capacity factor – that is the ratio of the actual annual power output to the maximum power output were the wind turbines operating at full capacity throughout the year. Capacity factors at good wind sites are typically above 30%. They are far higher at especially good sites.

Higher financing costs for wind compared to other energy sources also play a role. In the mid-1990s, investors typically demanded a 50% greater return on investment from wind power plants, compared to natural gas fired combined cycle power plants (18% versus 12%).[9] This differential has decreased with time, because volatile natural gas prices and climate change concerns have created new uncertainties for fossil fuels. However, the intermittent nature of wind and, in some cases, issues associated with transmission still result in higher relative yields being demanded for wind power projects.

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[8] For a summary studies assessing the costs of wind integration into the grid, see Brian Parsons et al., "Grid Impacts of Wind Power, A Summary of Recent Studies in the United States," draft of paper presented to the European Wind Energy Conference, Madrid, Spain, June 2003, Online at http://www.nrel.gov/wind/pdfs/grid_integration_studies_draft.pdf. For a survey of transmission-related issues, including investments needed to accommodate capacity growth, and various scenarios relating to wind-generated electricity in the West, see Jeffrey Miller, "Planning Bulk Transmission for Wind Generation," California Independent System Operator, February 26, 2004. Online at http://www.nationalwind.org/events/transmission/western/2004/presentations/Miller.pdf.

[9] Ryan Wiser and Edward Kahn, "Alternative Windpower Ownership Structures; Financing Terms and Project Costs," LBL-38921. (Berkeley, CA: Lawrence Berkeley Laboratory, May 1996). Online at http://eetd.lbl.gov/ea/EMS/reports/38921.pdf, Table ES-1, item on equity cost.

The availability of wind power plants is typically very high – typically above 98 percent.[10] Maintenance-related costs are typically modest – about $5 per MWh.

B. Grid Integration Costs

The realization of delivered energy from wind turbines depends, of course, on whether the wind is blowing and what the wind speed is relative to the speed at which the maximum power output is achieved. Since the existence of wind at any specific future moment, say on a minute to minute basis, cannot be predicted, wind energy is "non-dispatchable" – that is, the power plant can deliver energy into the grid, but its availability cannot be relied upon in advance for a specific future period. Wind power plant capacity may be scheduled or sold ahead of time, say on a day-ahead basis, or an hour-ahead basis, but there are costs associated with misestimation of future power generation. It is important, therefore, to consider the various time-scales of operation of a power system grid, so as to understand and assess the nature of the costs associated with integrating wind power plants into the grid. A survey (published by the National Renewable Energy Laboratory) of studies of the impact and cost of the integration of wind energy into the grid has described them succinctly:

> Balancing the power system occurs over several time frames. Years in advance, for example, enough generation has to be planned and built so that there is sufficient capacity available to meet load requirements. Closer to real time, system operators forecast day-ahead load requirements and select which available generators can reliably meet the expected requirements at the lowest cost. Obtaining accurate forecasts from individual loads and generators is important, but only because collectively they constitute the aggregate forecast within a control area….
>
> Forecasting errors result in costs either because the system operator knows the forecast is unreliable and includes additional reserves in the mix of committed generation or because unforeseen errors result in the need to adjust the generation mix at the last minute. In either case, the resulting generation mix will be sub-optimal.[11]

Wind energy has two advantages in the longest time frame, which relates to adding capacity. Wind projects can be built relatively quickly and the incremental capacity additions can be kept small. Since power plants long-term future load forecasts can be in error by large amounts, the long lead times (many years) for construction that are typical of coal and nuclear plants create risks that can be avoided by wind power plants. However, there are two provisos to this statement. First, wind power cannot provide baseload capacity without costly energy storage,

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[10] Chris Tuttle. *Renewable Energy: Wind Power.* Presented at the Rural Utilities Service Electric Engineering Seminar, March 5-6, 2002, Dallas, TX. p.8. Online at http://www.usda.gov/rus/electric/engineering/sem2002/tuttle.pdf.

[11] Brian Parsons, Michael Milligan, Bob Zavadil, Daniel Brooks, Brendan Kirby. Ken Dragoon. Jim Caldwell. *Grid Impacts of Wind Power: A Summary of Recent Studies in the United States*. Draft of paper presented at the European Wind Energy Conference, June, 2003. Madrid, Spain. (Golden, CO: National Renewable Energy Laboratory, 2003).

which could negate the advantage of short lead times.[12] Second, wind capacity additions can be made rapidly to the grid only if there is a well-developed transmission structure that connects high wind areas where the wind power plants are to be built with a regional grid, which should also have enough capacity to carry the power. This second constraint is often a crucial one. With these two provisos, adding wind power plants to the grid can reduce risks from errors in long-term electricity forecasts.

There are three other time frames of interest:[13]

1. Regulation: The scale of this time frame is seconds to about 10 minutes. Adjustments in the power system in this time frame are made automatically by computer, in order to meet rapid fluctuations in demand, which are typically small relative to total demand. Rising demand in this time frame is met by generating units that are online but not running at full capacity and by spinning reserve.
2. Load following: The scale of this time frame is ten minutes to several hours. This is the period over which significant changes to load can occur and must be met by the power system. Regulated utilities, which manage their own generation, transmission and distribution, have an integrated operation to ensure that there is sufficient capacity available to meet changing demand. Rising demand in this time frame is met by generating units that are online but not running at full capacity, by spinning reserve, and by units that can be started up quickly, if necessary – typically single stage natural gas turbines or hydropower plants.
3. Unit commitment: This time frame involves commitment of specific units that require a relatively long time to start up and/or shut down (several hours, and sometimes longer). Since variations in electricity demand over a day and between seasons follow predictable patterns, unit commitment times are on the order of a day, several days, and according to season (so that maintenance of large units can be scheduled).

When wind constitutes a small fraction of the total system capacity, regulation costs of adding wind power plants to the grid appear to be low. There are load following costs as well as unit commitment costs associated with integrating wind power plants into the grid that arise directly from the unpredictability of future wind. These costs have been estimated in several studies in the past few years, by Electrotek Concepts for the Utility Wind Interest Group, the PacifiCorp, Eric Hirst, and others, which are summarized in Parsons et al., 2003. Note that these are costs to the utility or independent power producer of integrating with the grid. These costs are incurred because the wind energy is non-dispatchable. In a well-integrated grid that can be regarded as a single control area, possible in the case of large areas in Europe, the control area of interest can be very large, and the costs of grid integration of wind may be correspondingly lower.[14]

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[12] Spatial diversity of wind power plants over very long distances connected on the same grid can alleviate a portion of this problem. Of course, this has its own issues with respect to large transmission investments and grid integration. See Chapter 3.

[13] Parsons et al., 2003, *op. cit*., p. 3.

[14] In Western Europe, the introduction of wind-generated electricity is occurring very rapidly with far greater penetration (2.4 percent of electricity already). There is little utility resistance because wind-generated electricity is part of the mandate to reduce carbon dioxide emissions about which there is strong and general consensus in Western Europe. Personal telephone communication with Brian Parsons, National Renewable Energy Laboratory, 7 April 2003; cited with permission. See also Chapter 5.

Several key studies have been summarized by Smith *et al.* in a paper published by the National Renewable Energy Laboratory. The results of these studies show that the cost of integrating wind power plants into electricity grids are quite modest when the amount of wind capacity is small relative to the total; they rise as the capacity increases.[15] The table below, summarizing costs of wind energy integration with the grid is from that study:

Table 2.1: Results from representative studies examining grid integration costs for wind generated power at various levels of total wind capacity.

Study	Wind capacity, % penetration	Integration Element	Integration Cost $/MWh
Hirst	0.06 to 0.12	all except unit commitment	$0.81 to $3.22
UWIG/Xcel	3.5	all	$1.85
Pacific Corp/IRP	20	all	$5.50
We Energies I	4	all	$1.90
We Energies II	29	all	$2.92
Great River II	16.6	all	$4.53

Source: Adapted from J. Charles Smith, Edgar A. DeMeo, Brian Parsons, and Michael Milligan. *Wind Power Impacts on ElectricPower System Operating Costs: Summary and Perspective on Work to Date*. To be presented at the 2004 Global WINDPOWER Conference, Chicago, Illinois, March 29-31, 2004. Preprint. NREL/CP-500-35946. (Golden, CO: National Renewable Energy Laboratory, March 2004). p. 8.

Large-scale wind energy imposes costs on the electric system because of short-term fluctuations in wind. Since power varies as the cube of the wind speed, these variations are magnified when it comes to power output. Eric Hirst, an independent consultant on wind energy and other electricity system technical and economic issues, has assessed the costs of integrating wind-generated electricity into the grid at somewhere between $2 and $5 per MWh.[16] The other studies cited in Table 2.1 above are broadly in agreement with this range. Transmission costs for wind energy are also higher than for a typical baseload plant. Since wind power plants do generate the maximum amount of power for some of the time, the transmission capacity must be capable of handling this amount. But since the overall capacity factor is far below that of baseload plants, the utilization of transmission capacity is also correspondingly lower. Hirst has estimated transmission costs of $4 to $9 per MWh for a wind power plant with an annual capacity factor of 33%.[17]

[15] Hirst and Hild have shown that when wind power become a very large fraction of the generating capacity of a utility, the costs to it in terms of reduced realized revenues can be very large. See Eric Hirst and Jeffrey Hild, *Integrating Large Amounts of Wind Energy with a Small Electric Power-System*, April 2004. Online at http://www.ehirst.com/PDF/WindIntegrationReport.pdf. The penetration level of 40 percent for wind capacity in this study is not generally a concern for wind development, since the overall current level in the country is under 1 percent and the largest penetration just over 10 percent. This may, however, be a concern to specific parties seeking to develop wind in a particular area.

[16] Eric Hirst, letter to Dick Watson, summarizing key points from a workshop "Wind Energy and Electric Power Systems," December 13, 2003. See also Eric Hirst, *Integrating Wind Energy with Electric Systems*, December 2003.

[17] Hirst December 2003, op cit.

B. Selection of the site for this methodological study

There are several criteria that are important in selecting a site for large-scale wind energy development:

- Wind speed and energy – annual average and seasonal averages
- Price that can be obtained per unit of wind energy by the developer
- Other infrastructure, such as roads and rail
- Terms on which financing can be obtained
- Transmission-line availability – infrastructure as well as available capacity
- Ownership of land and potential related constraints on wind energy development
- Regulatory considerations affecting wind site development.

The main technical goal of this study is to develop a method for computing a practical value of wind energy that will enable wind developers to improve upon the avoided marginal cost pricing typical of large-scale wind farm power purchase agreements. Transmission line availability, potential development of transmission infrastructure, costs and rules under which transmission lines are made available to wind-generated electricity, and methods for evaluating the costs that an intermittent source like wind impose on a specific grid are all factors affecting site selection. In this study, we select a site that will enable us to focus on the main problem we have set out to solve: assessing how much value wind-generated electricity can have over and above avoided marginal cost. We therefore have selected a site where:

- there are favorable winds
- transmission corridors and infrastructure exist (without assessing its actual availability, since this is a methodological study rather than a study aimed at actual development of a particular site)[18]
- road and rail infrastructure exist
- the state government is favorable to wind energy development.

This last factor is a consideration, since state level policies can provide a crucial stimulus to wind power development, especially at a time when the federal level uncertainties are considerable. With these factors in mind, we focused on the State of New Mexico. The state has publicly available ten-minute wind data, which were made available for this study free of charge. The state also provided other non-material support and information.

Table 2.2 shows the average capacity factors for five sites in New Mexico. Wind data were collected by the State of New Mexico, and analyzed for IEER by meteorological consultants, Richard Simon and David Matson. The capacity factors in Table 2.2 were calculated using the turbine characteristics of a General Electric 1.5 megawatt wind turbine, of the type used in the 204 MW New Mexico Wind Energy Center that was commissioned in October 2003. The power

[18] We recognize that, in New Mexico, as elsewhere, transmission line capacity will need to be added for large-scale development of wind power. The policy considerations related to this are beyond the scope of this report. We have added reasonable transmission costs for transmission of wind-generated electricity, which include capital costs of the lines and take into account transmission losses.

output of this turbine versus wind speed is shown in Figure 2.1. This is a commercially available turbine that is typical of the large sizes that are used on land-based wind farms.[19]

There are two years of wind data available for these five sites, whose locations are shown in Figure 2.2. These are indicative of the expected performance and suffice for then purposes of site selection. The capacity factors range from a low of 35.7 percent for the Johnson Mesa site to 43.4 percent for the Redonda Mesa site. We did not select the latter for study, even though it has the highest capacity factor because it is remotely located and has poor transportation access. We focused our study on the San Juan site in New Mexico (Site 604), which is about 30 miles southwest of Portales, in eastern New Mexico. It has overall average capacity factor of 42.9 percent over the period for which data are available (July 1999 through June 2001). It also has good road and rail access and is about 50 miles from the transmission corridor at Clovis in eastern New Mexico.[20]

In considering spot market sales, we assume that the sales take place at the Four Corners hub in northwestern New Mexico, for which we have spot market data for the year 2003. We will assume transmission costs of $5 per MWh, i.e. at the low end of the range of $4 to $9 cited above, for Site 604 because of its favorable location and high capacity factor; for the same reason, we also assume a low value of $2 per MWh cost of integration of the wind farm with the grid. The levelized cost of wind-generated electricity at a hypothetical wind farm located at New Mexico Site 604 would be about $35 per MWh, including variable maintenance costs.[21] Grid integration raises the overall cost of electricity at the wind farm to $37 per MWh. The cost of power delivered to the Four Corners hub for sale there would be $42 per MWh, plus about $2 per MWh to account for transmission losses, bringing the total cost to $44 per MWh. We will consider a 100-turbine wind farm, with a maximum capacity of 150 MW.

Site 604 is, overall, the most favorable of the five sites in New Mexico for which we have wind data. To provide a range, we will also roughly estimate the cost of wind-generated electricity delivered to the Four Corners hub from the Johnson Mesa site (Site 601). This site has the lowest capacity factor of the five New Mexican sites considered. The cost of wind-generated electricity works out to about $42 per MWh. If we add the high end of grid integration costs ($5 per MWh) and the high end of transmission costs ($9), we get an upper limit estimate (among the five New Mexico sites for which we have data) of about $56 per MWh for costs of wind-generated electricity, delivered to the Four Corners hub. This gives us a range of costs of about $42 to $56 per MWh for the New Mexico sites. The high end of grid integration costs would apply in the case of far higher penetration of wind energy than is the case at present in the United States (though it varies greatly from one region to another). A reasonable range of costs of wind-generated electricity for these five sites, including grid integration and transmission to the Four Corners hub would be $42 to $52 per MWh.

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[19] For manufacturer information on the 1.5 megawatt turbine used for this study, see GE Energy. "1.5 MW Series Wind Turbine." (2004). Online at http://www.gepower.com/prod_serv/products/wind_turbines/en/15mw/index.htm

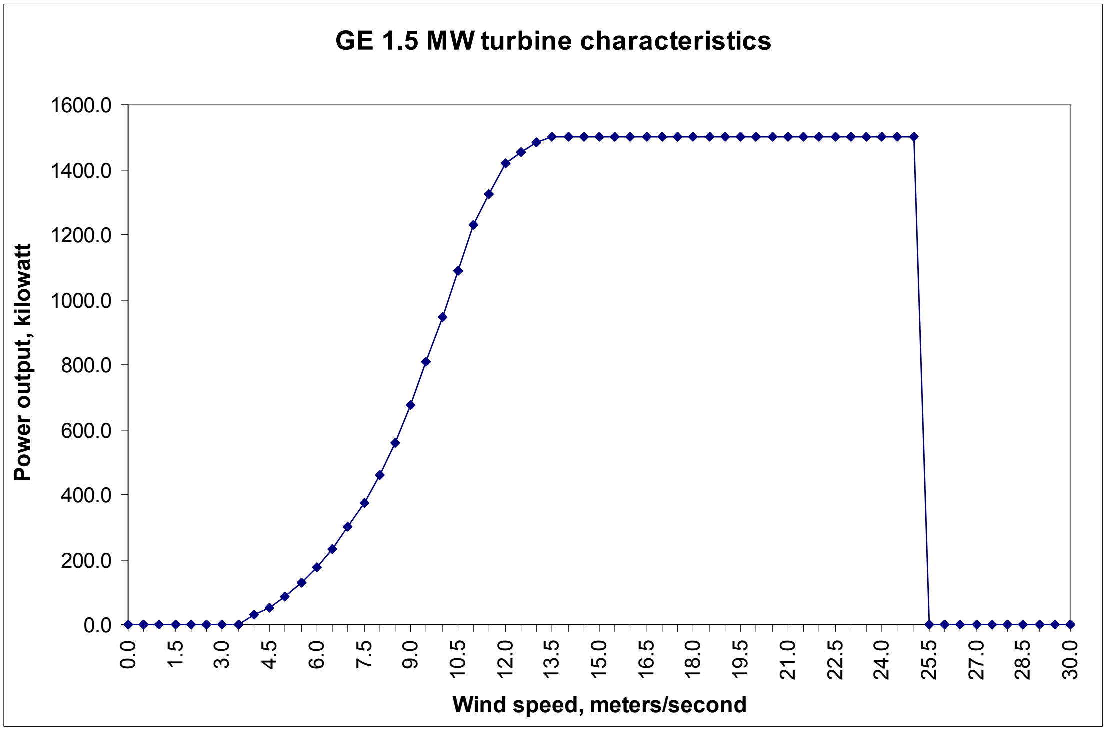
[20] We recognize that sufficient transmission capacity is an issue in New Mexico and elsewhere, for large scale development of wind-generated electricity.

[21] We use a capital recovery factor of 0.11 to compute the levelized cost. We use a variable maintenance cost of $5 per MWh.

Table 2.2: Capacity factors at five wind sites in New Mexico.

Month	Year	Site 601 Johnson Mesa	Site 602 Frio Draw	Site 603 Redonda Mesa	Site 604 San Juan Mesa	Site 605 Tatum
Jul	1999	31.0	30.0	48.5	33.6	30.7
Aug	1999	25.8	20.8	33.3	28.2	18.5
Sep	1999	28.2	30.0	37.6	36.9	29.8
Oct	1999	30.4	41.4	46.5	44.0	38.8
Nov	1999	27.6	35.1	38.5	39.1	38.4
Dec	1999	41.1	44.2	40.5	40.1	49.8
Jan	2000	39.2	49.8	45.2	51.7	49.4
Feb	2000	43.7	53.0	48.2	57.7	50.8
Mar	2000	40.3	50.6	48.6	58.8	51.0
Apr	2000	52.8	51.6	48.5	55.0	48.6
May	2000	46.0	47.2	47.6	49.8	47.6
Jun	2000	39.1	38.5	44.0	42.0	34.4
Jul	2000	27.1	28.0	39.1	33.7	32.4
Aug	2000	23.1	32.8	47.5	41.0	33.2
Sep	2000	33.4	39.2	46.2	45.4	36.8
Oct	2000	33.5	32.0	37.6	33.4	34.3
Nov	2000	no data	40.0	45.4	43.4	34.1
Dec	2000	36.7	48.2	47.7	52.1	41.5
Jan	2001	32.7	37.8	38.1	39.3	41.7
Feb	2001	39.5	47.3	46.9	47.8	42.9
Mar	2001	27.2	37.7	36.5	39.1	36.1
Apr	2001	53.7	57.1	49.0	47.6	49.9
May	2001	33.5	37.4	40.3	34.6	38.7
Jun	2001	36.6	35.8	39.9	35.9	41.4
Overall Average		35.7	40.2	43.4	42.9	39.6

Source: Data from Michael McDiarmid, P.E., of the New Mexico Energy Conservation and Management Division. Analysis by Richard Simon and David Matson, meteorological consultants. Wind density assumed = 1.08 kilograms per cubic meter. Turbine rotor/blade diameter = 77 meters.



Source: GE turbine data provided by Richard Simon, meteorological consultant. The output is designed to drop to zero at 26 meters/second and higher wind speeds to prevent damage to turbines in extremely heavy winds.

Figure 2.1: Power output from a General Electric 1.5 MW wind turbine as a function of wind speed.

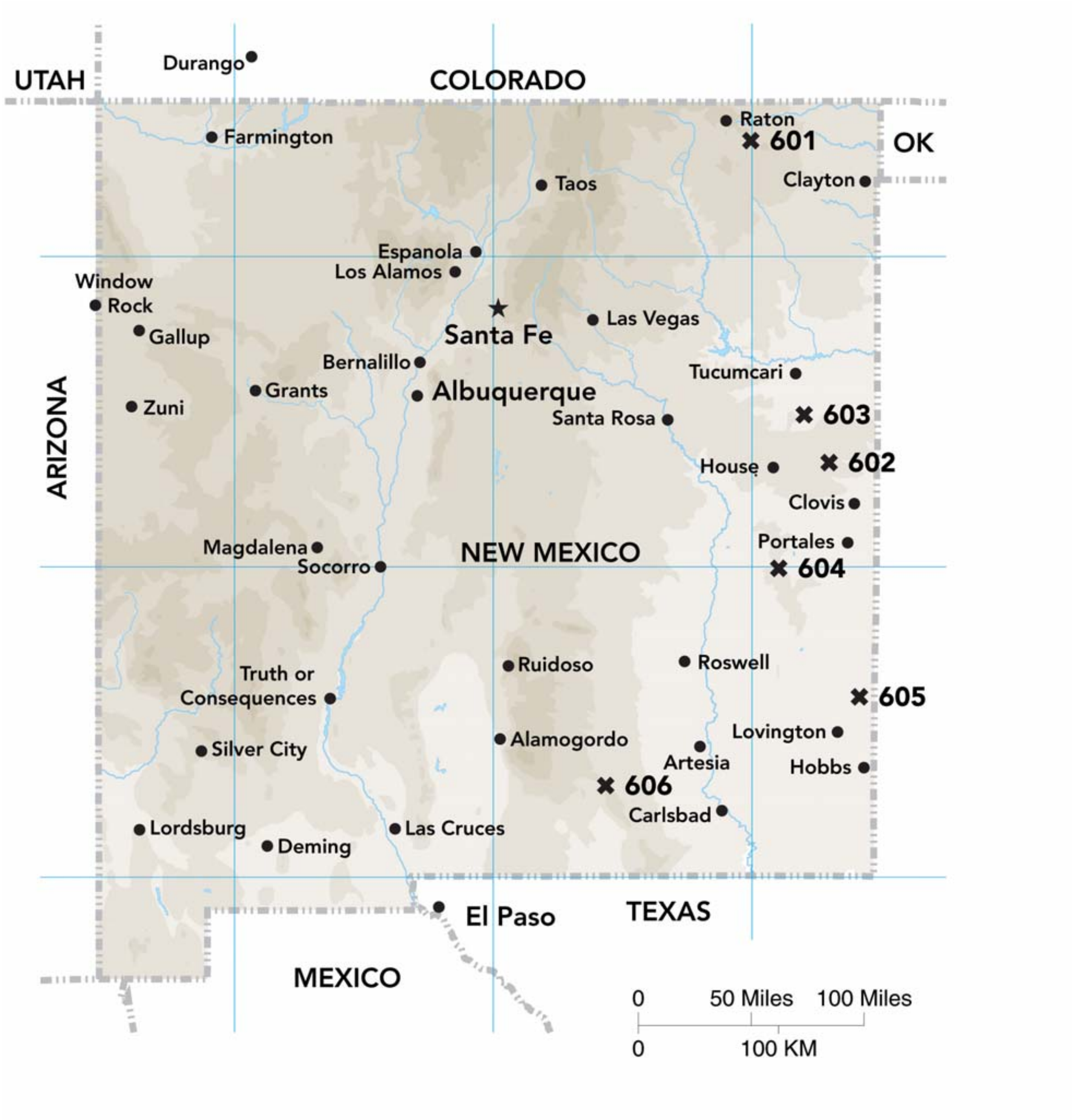


Figure 2.2: Locations of the five sites for which wind data are presented in this report. The map also shows House NM, the location of the FPL 204 MW Wind Energy Center.

We can also consider the cost of wind energy to the final consumer by adding typical transmission and distribution costs. These vary greatly, depending on whether the final consumer is a residential customer, who takes electricity in small amounts from a relatively costly distribution network, a medium-sized commercial customer, where distribution costs are lower, or a large customer, where there are no distribution costs. Table 2.3 shows the costs of wind electricity generated at the San Juan site (Site 604) in New Mexico at the site, at the Four Corners hub and at the Chino building in Santa Fe, New Mexico – a building we will look at more closely in Chapter 4.

Table 2.3: Cost of wind generated electricity from Site 604 at the wind farm, the Four Corners hub, and the Chino office building in Santa Fe New Mexico.

Location for cost estimation	Delivered cost, $/MWh	Mix of Grid Electricity
Wind farm: San Juan site (604), including grid integration (for present grid, average of generating stations)	$37	$35 to $40
Four Corners Hub	$44	variable
Chino Building, Santa Fe	$66	$64

As noted above, costs at less favorable sites will be higher. For the New Mexico sites we evaluated, the highest cost of electricity delivered to the Chino building in Santa Fe would be about $76 per MWh for Site 601.

C. Current Wind-generated Electricity Pricing: Avoided Cost

The term "avoided cost" came into use in the context of electricity pricing after the passage of a 1978 law known as the Public Utilities Regulatory Policy Act.[22] The trade association of independent power producers and marketers, Electric Power Supply Association (EPSA), defines avoided cost thus:

> Avoided cost is the cost the utility would have incurred had it supplied the power itself or obtained it from another source. Avoided cost is the price at which an electric utility purchases the output of a QF [qualifying electric power generator under PURPA].[23]

This cost can be computed in two broadly different ways. It can include the total cost of generation of a unit of electricity, including capital costs, other fixed costs, and variable fuel and maintenance costs. Such a price would apply if a seller of electricity can demonstrate that a utility would have to build a new power plant in order to supply all or part of the electricity that it, the independent producer, is marketing. A typical avoided cost on this basis for baseload coal power may be about $40 or $50 per MWh. Nuclear electricity prices are more variable, since capital costs of nuclear power plants, which dominate the total cost, have differed widely from one plant to the next. The full avoided cost can range from $40 to $70 per MWh, when capital costs are included. The cost of combined cycle natural gas fired power plants, which are also used as

[22] For information about PURPA, see for instance, the website of the merchant power generators and marketers at http://www.epsa.org/competition/faqs.cfm?what=245, as well as webpages following this.
[23] http://www.epsa.org/competition/faqs.cfm?what=249#answer

baseload plants (though not in preference to coal or nuclear power plants, when these have already been built, varies mainly according to the cost of fuel, which tends to dominate at prices above natural gas costs of $3 per million Btu.

Spot market prices as of this writing (April 2004) are above $5 per million Btu and are expected to stay at or above $5 for some time.[24] Avoided costs for combined cycle power plants are in the range of $30 to $50 or more, depending on natural gas prices. At current prices (March 2004), the full avoided costs for natural gas fired power plants are about $50 per MWh. These full avoided costs must be understood in the context of the ability of these plants to provide electricity that can be scheduled – that is, the generating units can be committed in advance by the Independent System Operators (apart from unforeseen and unscheduled outages, which are relatively rare). Wind energy cannot command full avoided costs because it is not dispatchable. We provide these costs here as a point of reference, as the hypothetical maxima, in case of perfect predictability of wind (as for instance, when wind-generated electricity is coupled with storage, which, of course, adds considerable cost to the system).

Moreover, the assumption that an independent producer, including wind farm developers, be able to command full avoided cost has never been true, but is even less true in the era of deregulated utilities and large-scale merchant power producers. Many utilities have surplus capacity themselves. They can also purchase power on the spot market that would at many times be priced lower than the full avoided cost that includes capital cost. They are therefore generally unwilling to enter into contracts for purchasing wind-generated electricity that is on par with full avoided cost. Variable avoided costs for coal and nuclear power plants are often on the order of $20 per MWh, though they vary by region, utility, season, and even time of day.

Further, there have been great changes in the structure of the electricity industry since PURPA was enacted in 1978. At that time, almost all electric power in the United States was sold by regulated utilities. Of the small fraction that was not, the vast majority was mainly power generated by large industries for their own use. Since 1992, there has been the emergence of large holding companies that own both unregulated merchant power plants in widely dispersed geographic areas as well as regulated utilities that sell power at prices overseen by state-level regulatory bodies. Utilities, therefore, tend to offer prices that correspond more to their variable costs, that is, fuel plus variable maintenance costs, though some capacity cost may also be factored in (see below). Variable costs depend on the time of day and on the season, because utilities typically have a mix of generating plants, and the avoided fuel and maintenance charges depend on when merchant power is actually made available.

We shall see that these factors result in Power Purchase Agreements that provide revenues that are lower than those that we derive from market considerations. Power Purchase Agreements also typically provide revenues to wind developers that are lower than the costs of production. The difference has been made up mainly by a federal tax credit, known as the Production Tax Credit, or PTC. In 2003, this credit amounted to 1.8 cents per kilowatt-hour ($18 per MWh); it is available for the first ten years following the commissioning of the wind power plant, after which it expires.[25] Some states, like New Mexico, also have a state-level production tax credit.

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[24] For spot prices of fuels, see the website of the Energy Information Administration, http://www.eia.doe.gov
[25] U.S. Energy Information Administration. "Annual Energy Outlook with Projections to 2025 - Issues in Focus - The Renewable Electricity Production Tax Credit." Online at http://www.eia.doe.gov/oiaf/aeo/issues_7.html.

The federal tax credit has, however, introduced its own uncertainties. It is subject to periodic renewal by Congress since it has been enacted for rather short periods of time. The structure of wind energy pricing at present makes it difficult or impossible for wind energy developers to get financing for power plants unless the tax credit is in place. This tax credit expired on December 31, 2003. The wind tax credit has wide support in Congress and is included in pending energy legislation. But the prospects for passage are uncertain at this writing, because the legislation contains many high cost and controversial subsidies to the fossil fuel and nuclear industries, at a time of high federal deficits. In states like New Mexico, the state tax credit can make up some of the difference. That may be enough to cover costs at the very best sites. The uncertainties around the federal tax credit, are a major issue when it comes to the rate of development of wind energy in the United States.

Table 2.4 shows some essential features of the purchase power agreements (PPAs) for four wind power projects. The varied nature of these agreements is evident. All of the pricing arrangements take the federal PTC into account. These prices are not sufficient to cover costs at even very favorable sites, especially given the unfavorable bond ratings for all the projects. For instance, wind power costs, exclusive of the federal PTC at the site that is examined in detail as our case study work out to about $35 per MWh, assuming favorable financing terms. They would be $40 per MWh or so with unfavorable financing. There would also be a demand for a higher return on equity by investors than for fossil fuel projects.[26] The unfavorable ratings are due to a mix of factors, some related to the company, but many related to how Wall Street evaluates wind power. If unfavorable financing terms are combined with sites with lower capacity factors, say about 35 percent as at Site 601, the costs of wind-generated electricity could rise to $45 per MWh, even before any grid integration and other costs are taken into account.

Table 2.4 shows four types of pricing arrangements arrived at by large-scale wind farm developers with wholesale purchasers of wind-generated electricity. Three of these projects had low bond ratings (at about BBB level), which result in higher financing costs. One project was not rated.

Table 2.4: Wind-generated electricity prices obtained by large-scale wind farm developers: four examples

Wind farm site	**Price(s) obtained by developer, $ per MWh (rounded)**
Project 1, Southwestern United States	27 flat rate
Project 2, Southwestern United States	33 peak 23 off-peak
Project 3, Midwestern United States	54 summer peak 30 summer off-peak 16 off-peak, rest of the year
Project 4: Western United States	29 escalating at 3% per year

[26] We will not discuss nuclear power project comparisons, because Wall Street has viewed these as risky and no new nuclear power plant has been ordered in the United States since 1978.

These examples show that wind energy prices received by developers generally tend in the direction of marginal avoided cost. As noted, all of them take the federal tax credit into account. In the first two cases, which are in the southwest, electricity supply is dominated by coal and nuclear. These are the closest to a flat avoided marginal cost basis, while the others are more nuanced, but still are clearly based on the avoided fuel and variable maintenance costs. While the overall costing of these projects is not available to us, even favorable financing would not have enabled the developers to cover their costs without the federal tax credit. None of the PPA's would result in revenues greater than the $35 per MWh cost of wind power production (including maintenance costs), even at very favorable sites. This indicates why the development of wind energy is currently dependent on the federal tax credit, and is likely to remain so, in the absence of substantial further reductions in cost, unless a better price, that is closer to the value realized for wind energy in final sales (i.e., a price that includes some credit for the capacity that wind farms add to the grid) can be recovered by wind developers.

Chapter 3: Wind-Generated Electricity – A Model for a Spot-Market Contract

We have outlined cost considerations relating to wind energy in the last chapter and estimated costs for a large wind farm at New Mexico Site 604 (the San Juan site), near Portales. We also briefly compared them to costs for wind sites at other locations in New Mexico. Finally, we saw that the costs of wind-generated electricity even at very favorable sites, like the San Juan, New Mexico site (604), are significantly higher than the prices that wind developers typically realize. This situation currently makes the federal production tax credit essential to the economic viability of wind farms.

In this and the next two chapters, we seek to answer a different question: *what price would different types of customers be willing to pay for wind-generated electricity*? We assume in these three chapters that the hypothetical customers in question do not attach any value to the environmental or other beneficial aspects of increasing the use of renewable energy sources. Some of these issues, such as the savings in water usage for power generation, will be briefly addressed in Chapter 5. But since it is very difficult for wind developers to actually realize any significant part of the value that these aspects of wind energy provide to society, we begin first by asking a market-oriented question: what kind of contract will a customer be willing to make with a wind energy developer, knowing that there are uncertainties attached to future wind supply? This allows us to get an idea of market prices for wind-generated electricity, which we can then compare to the costs we have discussed in the last chapter. We will address these questions for different types of hypothetical customers and then discuss some policy implications.

However, future wind energy can be forecast with some level of confidence, the specifics of which depend on:

- how far in advance the forecast of wind speed is being made
- the aggregate period of time for which the wind speed forecast is being made
- the level of confidence with which we want to make the forecast – that is, how big an error (under-prediction or over-prediction) we are willing to tolerate, which depends on the cost of being wrong, and
- the amount of wind speed data that exists for past time periods

For instance, it is essentially impossible to forecast average wind speed a year or even a month ahead for a specific hour on a future day. The uncertainties around the average value will tend to be very large. By contrast, it will often be possible to make an estimate of average wind speed, say in July, or even for peak hours (6 a.m. to 10 p.m.) and all off-peak hours (10 pm to 6 am) aggregated for that month with a reasonable degree of confidence, provided there are wind speed data that have been collected for a number of years. In the same way, since there is some correlation between wind speed in the present hour and that in the previous hour, we can make an estimate of wind energy production in the next hour with some confidence, though significant errors will still tend to occur from time to time.

A basic determinant of the economic value of future wind energy is the degree of precision with which the forecast can be made. In other words, there is a range of values of wind energy, with the lowest value being the case in which no estimate about future wind energy availability can be made and the highest value being when a perfect estimate of future wind speed for any period can be made for long periods of time (months, seasons, years). There will be a range of values at the low end that depend on the lowest marginal avoided cost of the electricity source that wind displaces. Similarly, there will be a range of values at the high end, depending on the period for which the aggregate future perfect wind energy estimate can be made and the gross avoided cost (possibly including a portion of or all of the capital cost) of alternate electricity sources available at that time. The actual value of wind energy will be somewhere in between these minima and maxima.

We will approach the problem of wind energy value by exploring how these maxima and minima of electricity values can be determined, and then present a statistical model for determining a practical actual value of wind energy, given the circumstances prevailing in a specific electricity market.

A. Evaluating the Degree of Market Development

There are a several ways in which one can compute values of wind-generated electricity in a market. The simplest, from a statistical point of view, is to assess the revenues that would be obtained if all of the wind energy could be sold in advance on an electricity spot market. This assumes that

(i) there is a well-developed spot market, and
(ii) the amount of wind energy being sold on the spot market at any time is small compared to the total amount on offer, so that the fact of offering wind-generated electricity on that market does not materially lower the price offered.

This approach can be applied to sales of wind-generated electricity at various levels of aggregation of time – hour-ahead sales, day-ahead sales, real-time sales, on-peak and off-peak sales, or seasonal sales. We have used data from the spot market at the Four Corners hub in Northwestern New Mexico. The Four Corners hub is a major electricity generation center but relatively little of this or other electricity is offered for spot-market sales on the Four Corners hub, as we will see below. We could have used prices in more developed spot markets, where electricity is deregulated, and the grid is managed by an Independent System Operator. We chose to use price data from the Four Corners hub since it is located in the same state as the site we are studying where a wind farm might be located in order to assess the annual spot market price that wind-generated electricity would fetch. [27]

Electricity sales to New Mexico consumers are regulated by the Public Regulation Commission. We will consider sales within this framework in the next chapter. The purpose of using spot market prices here is illustrative rather than an attempt to develop a precise estimate of spot market realization of wind-generated electricity prices. Our goal is to develop a market-oriented model of a contract between a spot market purchaser of wind-generated electricity and a seller of the same commodity.

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[27] This assumes that transmission line capacity exists to deliver the power to the hub. In New Mexico, as in many other places, investment in transmission lines will be required for large scale development of the wind energy resource. A detailed discussion of this issue, of which there is already considerable awareness, is beyond the scope of this report. Nonetheless, we address transmission issues briefly in the last chapter.

Consider a day on which the wind fluctuates a great deal at New Mexico Site 604, where our hypothetical 150 MW wind farm is located. Table 3.1 shows the hourly spot market prices of electricity at the Four Corners hub for April 1, 2003, along with the hypothetical wind farm output for wind data for the same date.[28] April tends to be a month with low spot market prices because the demand for electricity is low during this month. The table shows the average price, weighted by the size of the transaction, the lowest price and the highest price realized in each hour of the day for spot market sales. If all the conditions for real-time sales for wind-generated electricity list above were met, the average price over the day that the wind developer would realize would be about $39 per MWh. However, in this example, the conditions are not met.

Figure 3.1(a) shows the volume of electricity traded at each hour of the day, compared to the electricity that would be generated by a 150 MW wind farm at site 604 on that day. The first part of the day, until about 4 p.m. had high winds for the most part, with correspondingly high output. The volume of trades in much of this period was also at the high end (for that day). Yet for several hours, the wind power output actually exceeded the volume of trades, as can be clearly seen from Figure 3.1(a). Hence in this case, putting the output of a single wind farm on to the grid for sale at the Four Corners hub would have significantly lowered the price at that hub, making it more comparable to the low price, if it could be sold at all. Hence, the revenues in this case would be much lower than the average marginal avoided cost that wind-generated electricity typically fetches today as part of long term power purchase agreements. In the latter part of the day, when wind speeds and electricity output were low, the output could likely have been sold at the prevailing price, but the total revenue would, of course, be low, because of the low volume for sale.

Table 3.2 and Figure 3.1(b) show data for 29 July, roughly typical of July days for spot trading prices, when the demand for electricity is typically high, and the spot market prices for electricity were also higher than in April or May. The (weighted) average value of wind-generated electricity that would be realized for that day in case of a well developed market would be $51 per MWh. The electricity generated for much of the day in the hypothetical wind farm is considerably lower than that sold on the hub, though this is not true for all hours. And between 11 p.m. and midnight, no electricity was sold on the spot-market at all.

We might summarize the actual situation at Four Corners as follows. While the Four Corners hub transmits a great deal of power that is generated in the area (several thousand megawatts of power plant capacity exist there) as well as power that traverses the hub, almost all of it is sold under longer term contracts between individual buyers and sellers who are simply using the transmission corridor, instead of being sold on the spot market. Four Corners cannot serve as the hub for large-scale spot sales of wind-generated electricity unless there is a far more developed spot market there – i.e. unless the volume of hourly sales is considerably higher.

[28] All hourly data are actual hourly spot market electricity sales data for the Four Corners hub for 2003 compiled by Dow Jones, which IEER acquired from Dow Jones for this study. As noted above, we do not have wind speed data for the year 2003, the most recent complete year for which we can get spot prices of electricity. April 1 average peak and off-peak prices are typical for the spring months of April and May, when both heating and air-conditioning demand are low. We are assuming that the winds in 2003 were the same as for the year for which we have data, for the purposes of these illustrations. This use of the wind data does not affect the development of the methodology and the analysis at all. Of course, in a real case, when actual revenues were at stake, we would use the wind speed data for the year for which we were making evaluations of potential revenues.

Table 3.1: Hourly spot market prices of electricity at the Four Corners hub for April 1, 2003.

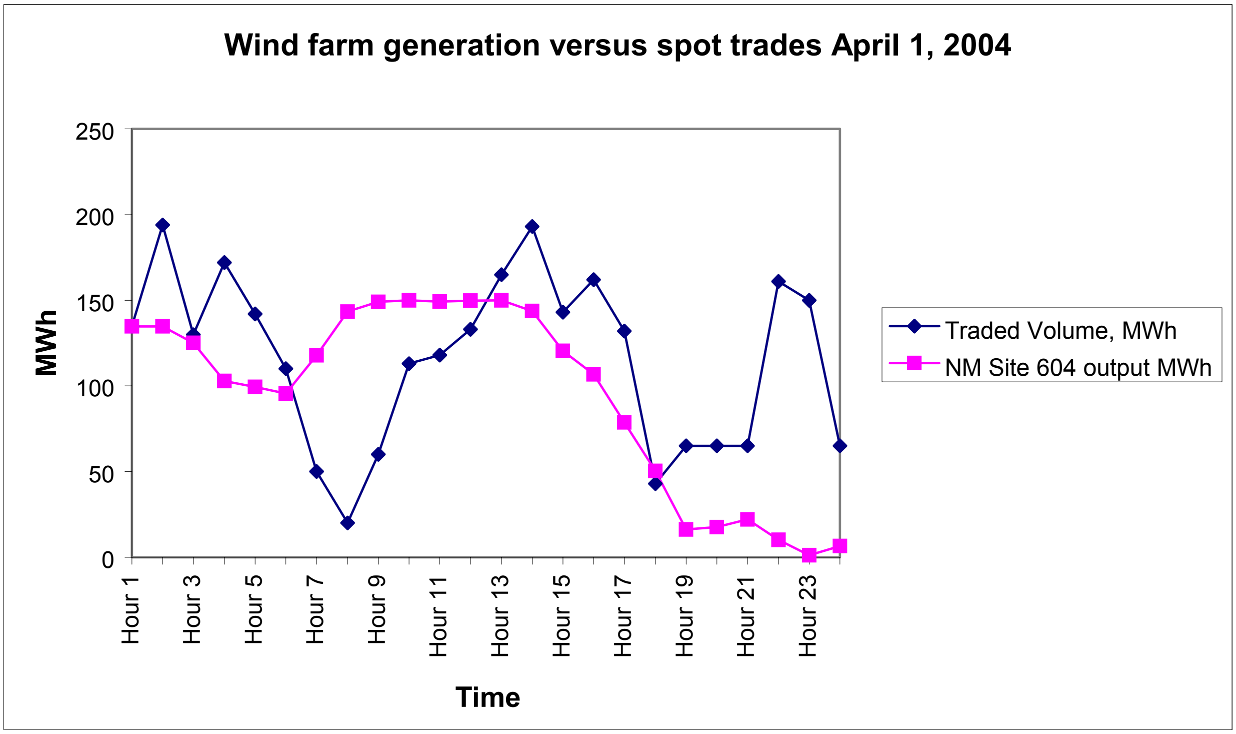
	Four Corners Hourly Index				
	Power Delivery Date:			**4/1/2003**	
Time	Price	Volume	High	Low	NM Site 604 Output (MWh)
Hour 1	$22.44	135	30	18	135
Hour 2	$21.24	194	25	16	135
Hour 3	$20.12	130	25	16	125
Hour 4	$19.83	172	25	16	103
Hour 5	$21.77	142	25	19	99
Hour 6	$21.73	110	25	19	96
Hour 7	$25.00	50	25	25	118
Hour 8	$35.00	20	35	35	143
Hour 9	$35.00	60	35	35	149
Hour 10	$35.94	113	41	15	150
Hour 11	$38.75	118	41	15	149
Hour 12	$39.21	133	43	15	150
Hour 13	$43.03	165	50	11	150
Hour 14	$38.38	193	50	11	144
Hour 15	$34.32	143	43	11	120
Hour 16	$39.30	162	51	11	107
Hour 17	$40.24	132	51	11	79
Hour 18	$73.26	43	75	50	50
Hour 19	$71.15	65	75	65	16
Hour 20	$71.15	65	75	65	18
Hour 21	$67.31	65	75	55	22
Hour 22	$43.17	161	75	30	10
Hour 23	$35.00	150	45	30	1
Hour 24	$23.77	65	27	13	7

Source: Dow Jones, for columns 1-5.

Table 3.2: Hourly spot market prices of electricity at the Four Corners hub for July 29, 2003.

	Four Corners Hourly Index				
	Power Delivery Date:			**7/29/2003**	
Time	Price	Volume	High	Low	NM Site 604 Output (MWh)
Hour 1	$34.00	100	34	34	91
Hour 2	$34.00	50	34	34	101
Hour 3	$30.86	70	34	23	79
Hour 4	$29.32	95	34	23	41
Hour 5	$26.57	175	36	25	4
Hour 6	$25.00	140	25	25	12
Hour 7	$25.00	100	25	25	1
Hour 8	$25.00	50	25	25	14
Hour 9	$60.00	13	60	60	27
Hour 10	$56.43	105	60	55	29
Hour 11	$55.00	125	55	55	44
Hour 12	$55.67	150	56	55	49
Hour 13	$55.00	200	57	53	45
Hour 14	$60.43	350	65	57	32
Hour 15	$61.17	450	65	57	29
Hour 16	$62.50	490	65	57	32
Hour 17	$64.42	638	68	62	30
Hour 18	$63.67	588	68	58	32
Hour 19	$61.26	380	65	58	51
Hour 20	$61.06	360	65	58	77
Hour 21	$60.18	450	68	55	107
Hour 22	$60.55	510	68	58	113
Hour 23	$60.00	200	60	60	140
Hour 24	$45.00	0	50	40	129

Source: Dow Jones, for columns 1-5.



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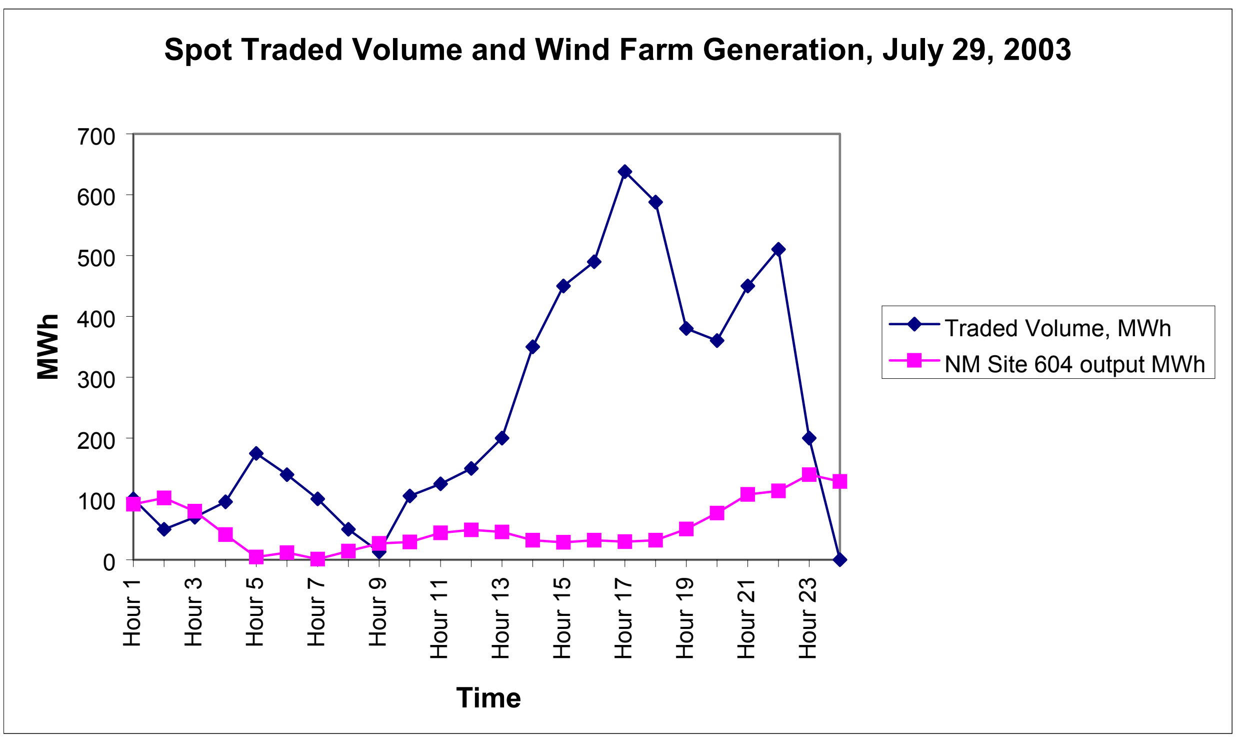

(b)

Figure 3.1: Spot Market data for the Four Corners hub are from Dow Jones, for two days. (a) April 1, 2003 and (b) July 29, 2003. Hour 1 is the hour between midnight and 1 am.

B. The Unpredictability Discount

A seller of wind-generated electricity would not realize the average spot market price, except in cases where the wind-generated electricity is sold in real time on a fully developed spot market and the amount on offer is small compared to the real-time sales of electricity.[29] We want to estimate the compensation that might be offered by a purchaser who would discount the offered price because of the uncertainty that the full amount offered would actually be delivered due to uncertainty in the future wind speed. From the point of view of the seller, we must consider the contractual arrangement that he is ready to make to compensate the purchaser in case of a shortfall.

The model assumes that a fully developed market exists in which customers would demand firm supply. The wind farm operator makes a day-ahead or hour-ahead offer of electricity. We assume that the revenue realized for these sales is the average spot market price for the period in question. We also assume that any shortfalls in supply are made up by purchasing electricity at the maximum spot market price for the same period. In practice, the purchaser would be compensated by the seller of wind farm power post facto by an amount equal to the shortfall multiplied by the spot market price. This implies that the wind farm is integrated with a grid, which is suitably regulated to provide sufficient reserve capacity. This, in turn, implies that the wind farm operator pays the costs of integration with the grid, including the cost of the reserve capacity that is needed corresponding to the level of wind penetration (See Chapter 2). This is a reasonable approach since the wind farm operator must bring the electricity to the marketplace (hypothesized to be the Four Corners hub in our example). The purchaser is only concerned about the price of the electricity and how his risks are to be covered. The seller assesses whether his costs are going to be covered by the realized net price. Hence, we can compare the price that the wind farm operator realizes in the market place (in this case, the spot market) and compare it to the total cost of producing wind-generated electricity. We have not taken detailed account of the value of surpluses in this report. We have computed this value on a notional basis by imputing to it the lowest spot market price for the period in question, for purposes of discussion.

The statistical problem from the point of view of the seller is to develop an optimal strategy for offering hour-ahead or day-ahead sales. How much should be offered for sale, given uncertainty in future wind speed? The autoregressive model, described in the Appendix, represents one reasonable strategy for optimization of sales on the spot market.[30] In this approach the seller

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[29] For a discussion of real-time operations and sales see Eric Hirst, *Interactions of Wind Farms with Bulk-Power Operations and Markets*, Oak Ridge, TN, prepared for Project for Sustainable FERC Energy Policy, Alexandria, Virginia, September 2001.

[30] While this model was independently developed, it is similar in its use of auto-regression to the model developed by Eric Hirst in 2001. Eric Hirst, *Interactions of Wind Farms with Bulk-Power Operations and Markets*, Oak Ridge, TN, prepared for Project for Sustainable FERC Energy Policy, Alexandria, Virginia, September 2001. However, our method for computing the value of wind energy is different in that we use average and maximum spot market prices to estimate the amount that should be offered for sale and loss produced by an error in that estimate. Hirst's approach is very useful in estimating the regulation costs that wind imposes on the system. The method here allows a market estimation of the value of wind energy based on spot market prices. Since this model was developed to illustrate the market approach, we have used an auto-regressive model of order 1 (AR1) for simplicity, in which the value of a variable in the previous period is used to estimate its value for the subsequent period.

offers the electricity at the average price for the period (hour or day) prevailing on the spot market, and compensates the seller at the maximum price for the same period, in case of a shortfall in generation. The seller's optimization strategy for estimating the amount to be offered is based on the ratio of the average price to the maximum price. If the ratio is close to one, he offers a large amount for sale, since the cost of being wrong is low. If the ratio is much less than one, he offers a small amount, since the cost of being wrong is high. We use the wind data for NM Site 604 and we use spot market data for 2003 for the Four Corners hub to illustrate the model. The mathematical approach and details of the calculations are shown in Appendix A.

The results of such a model can be interpreted as follows:

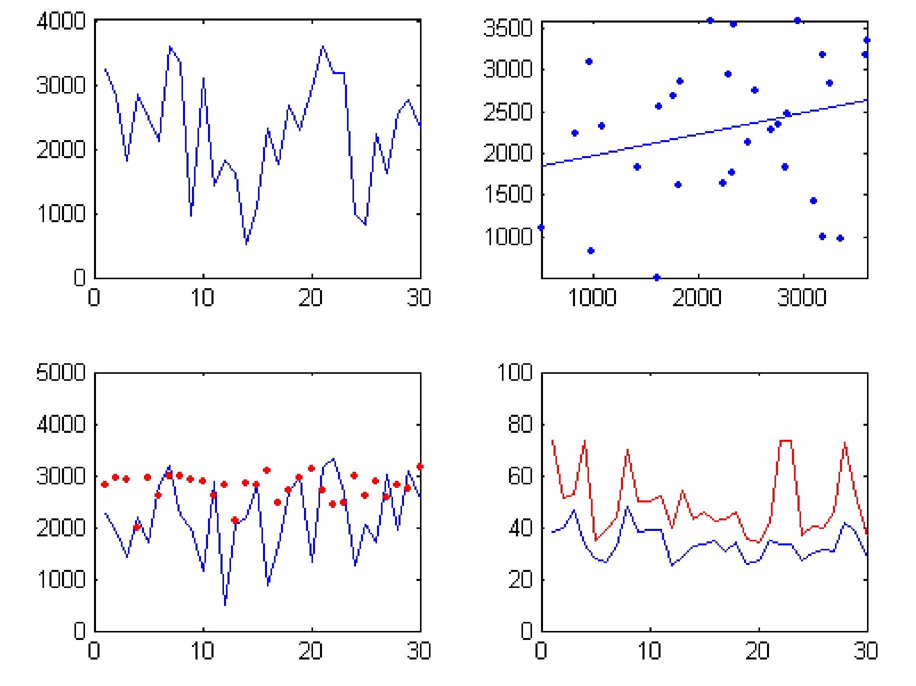
- They provide an estimate of the net revenues that can be expected from a wind farm, if the output is sold on the spot market, on a day-ahead or an hour-ahead basis.
- They provide estimates of the cost to the wind farm operator of intermittent wind output – hence they also give an indication of the value of increasing the precision of the wind forecast.

Figure 3.2(a) shows the results of the model for day-ahead sales of wind energy using wind data for April 2000. For the purposes of this illustration, we assume that wind data for 1999 through 2001, the period for which we have detailed data, can be joined with 2003 prices at the Four Corners hub. Our choice of 2003 price data, instead of data from the period for which we have wind data is influenced by the fact that market conditions have changed considerably in the past few years. Therefore, a realistic illustration requires more recent price data. Figure 3.3(a) shows the results for hour-ahead sales, aggregated to show daily revenues. Figures 3.2(b) and 3.3(b) show the residues – that is the amounts by which the actual generation is in excess of or falls short of the contracted sale. The day-ahead residues are much bigger that the hour-ahead residues, which is also evident from the scatter plot. This is because the prior hour's wind speed is a much better predictor of wind in the current hour than is the case for the prior day and the current day (the "current" period being the one for which the sales are being considered). Thus, in terms of price per megawatt-hour, the hour-ahead contract yields a better price than the day-ahead contract. In the case of April 2000 wind data, the day-ahead average price realization is $28.52 per MWh; the hour-ahead price realization is $31.46. In both cases, the price realized is much less than the $42/MWh cost of generating the electricity and bringing it to the Four Corners hub.

What matters, of course, is not the price in any particular month, but the average over a year or a few years. Table 3.3 shows the hour-ahead prices realized for wind-generated electricity (still for the San Juan New Mexico, Site 604) for a 14-month period. Figure 3.4(a) compares the realized price to the average spot market price for the same period. Again, the average realized price of $31.70/MWh is less than the cost of $44. This is also true of the average spot market price for 2003. Note that the value of the surplus is not integrated into the realized price, but this is small and would not change the conclusion.

Figure 3.4(b) shows the realized price, the cost, and the realized price plus the $10 per MWh New Mexico production tax credit. With the New Mexico production tax credit, the price realized is a little lower than the average cost. This shows that, in the example we have considered, wind energy sales may be able to realize nearly full cost on a spot market basis with the New Mexico production tax credit, but without the federal tax credit (which has expired as of this writing).

This provides one indication that development of wind energy is still possible even without relying on the federal production tax credit, provided suitable markets exist. Of course, as we have seen, the Four Corners hub is not a suitable market as yet. We will consider sales of wind energy, in the context of a large commercial customer in New Mexico, where sales are regulated, in the next chapter.



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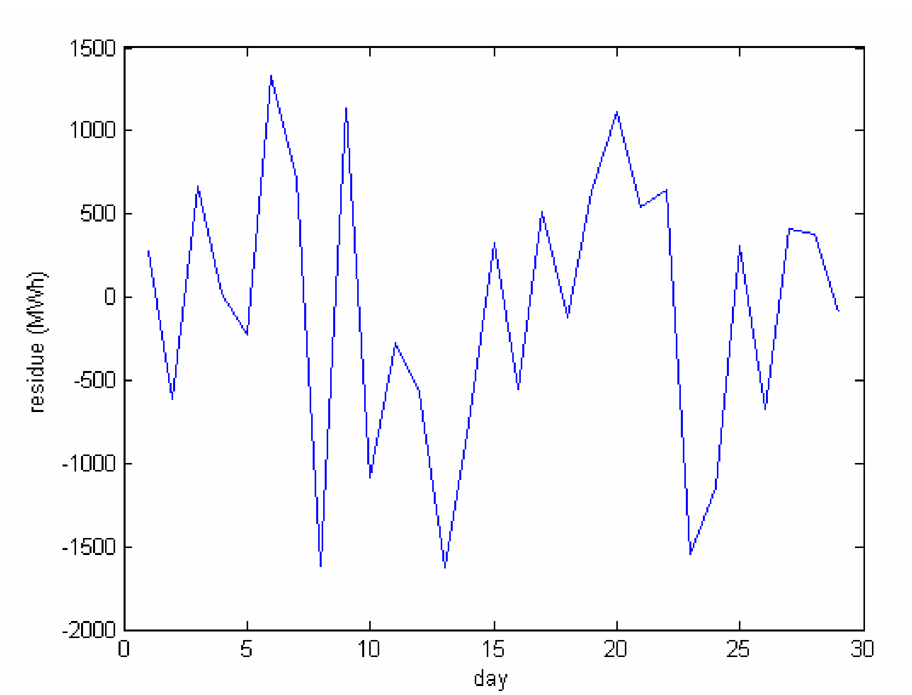
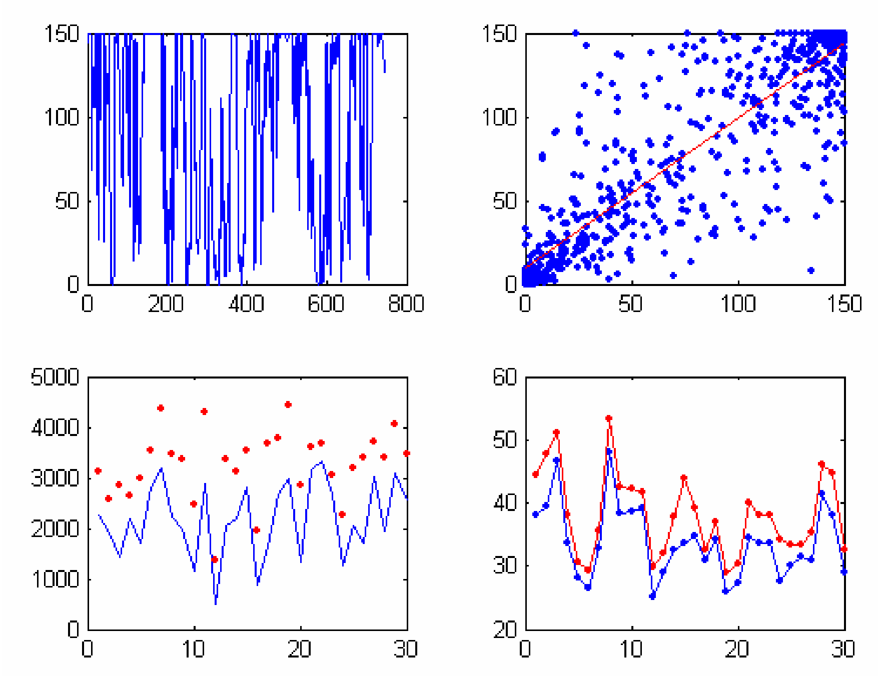
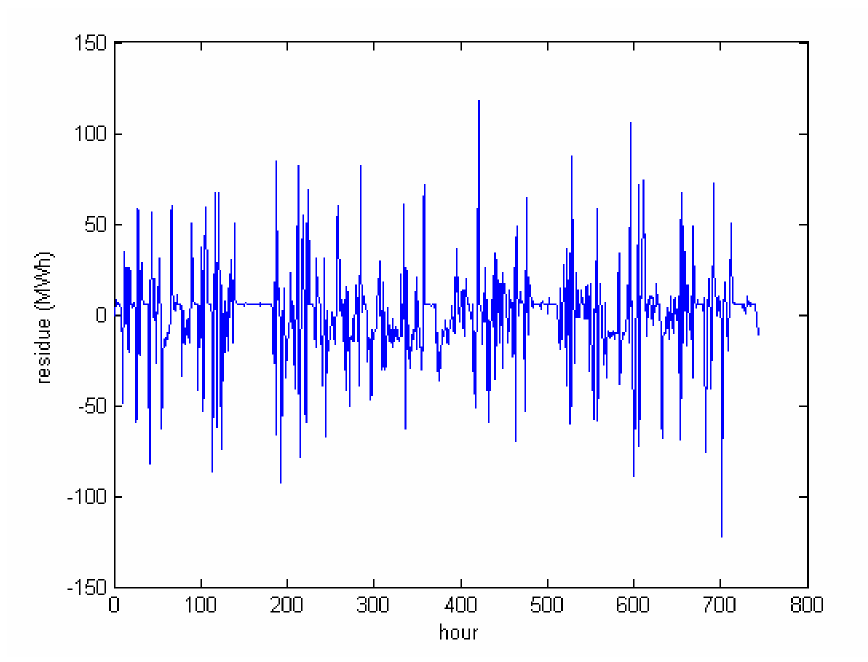


(b)

Figure 3.2: (a) Daily analysis for April 2000: the upper left box plots March's daily output and the upper right plots the above daily AR model fitting, the lower left plots April's daily output and predicted sale (red points), and the lower right plots the average and maximal spot price in April 2003. (b) Daily AR(1) residue plots for March 2000.



(a)



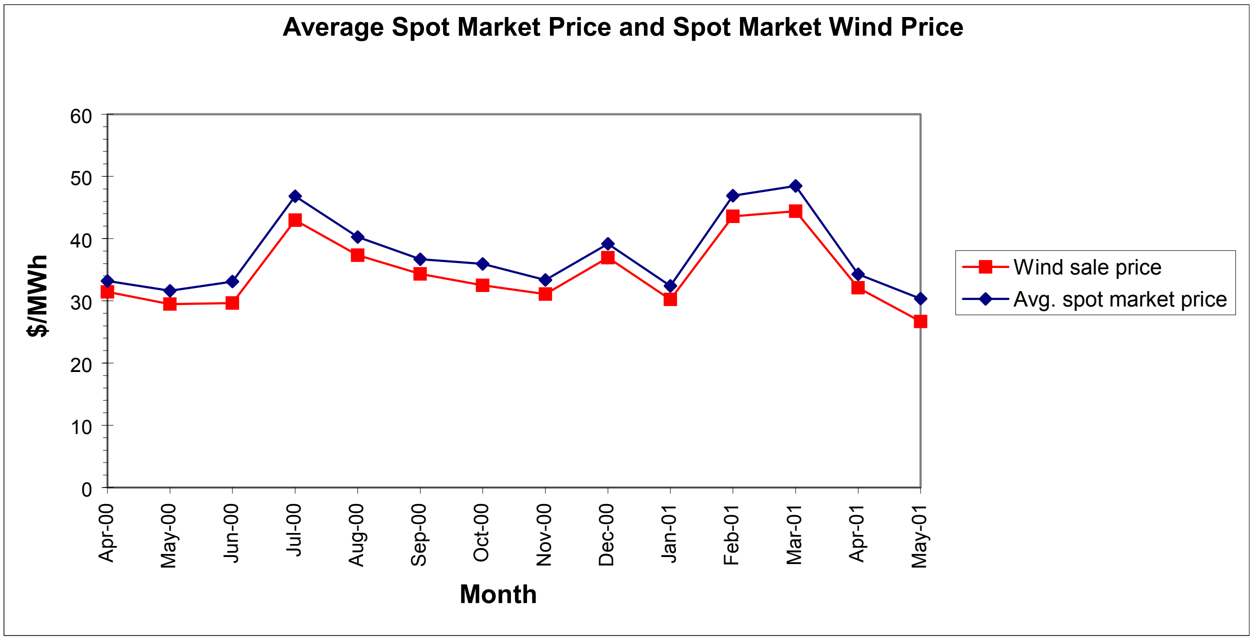
(b)

Figure 3.3: (a) Hourly analysis for April 2000: the upper left plots March's hourly output and the upper right plots the above AR model fitting, the lower left plots April's daily output and daily sale (red points, i.e. sum of 24 hours' output sale), and the lower right plots the average and maximal spot price in April 2003. (b) Hourly AR(1) residue plots for March 2000.

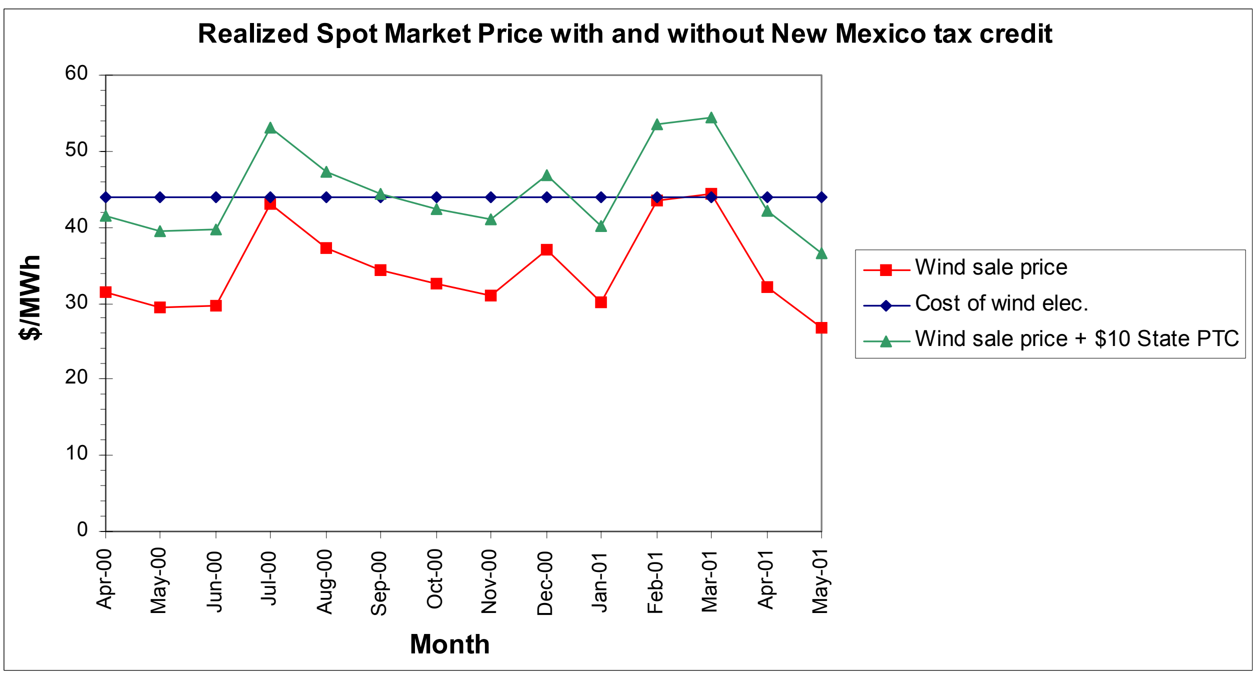
Table 3.3: Hour-ahead prices realized for wind-generated electricity from the San Juan, New Mexico site for a 14-month period between April 2000 and May 2001.

Month	**Actual Revenue**	**Actual output**	**Value of actual output**	**Average sale price**	**Oracle average sale price**	**Unsold actual output**	**Nominal value of unsold actual output**
	($*1K)	(MWh*1K)	($*1K)	($/MWh)	($/MWh)	(MWh*1K)	($*1K)
April, 00	2, 059.48	65.47	2, 172.86	31.46	33.19	1.76	43.71
May, 00	1, 811.80	61.50	1, 944.89	29.46	31.62	1.75	48.47
June, 00	1, 483.36	50.01	1, 655.72	29.66	33.11	2.41	62.05
July, 00	1, 815.07	42.23	1, 977.37	42.98	46.82	1.17	46.59
Aug., 00	1, 872.89	50.17	2, 021.02	37.33	40.28	1.37	43.78
Sept., 00	1, 865.94	54.36	1, 995.11	34.33	36.70	1.54	46.37
Oct., 00	1, 371.26	42.20	1, 516.29	32.49	35.93	1.34	37.37
Nov., 00	1, 755.01	56.48	1, 884.03	31.07	33.36	1.83	48.55
Dec., 00	2, 428.72	65.75	2, 529.51	36.93	39.19	1.66	50.36
Jan., 01	1, 524.89	50.26	1, 657.95	30.22	32.40	1.32	27.84
Feb., 01	2, 349.80	53.93	2, 532.76	43.57	46.88	2.18	78.65
Mar., 01	2, 159.16	48.68	2, 332.30	44.41	48.46	1.38	45.31
April, 01	1, 761.38	54.90	1, 882.57	32.09	34.29	1.75	47.23
May, 01	1, 204.58	45.15	1, 369.77	26.68	30.34	1.99	55.85

Notes:
1. Price data are for Four Corners hub, 2003. Data from Dow Jones.
2. Notional value of unsold output is calculated by using the low spot market price for the hour. This revenue is not included in the "actual revenue" column.
3. The term "oracle average sale price" refers to the case when there are no errors in prediction of future wind speed.



(a)



(b)

Figure 3.4: Hypothetical realized prices from hour-ahead spot sales of wind-generated electricity on the Four Corners Hub, 2003 price data, 2000 and 2001 wind data.

C. Credit for wind capacity

1. Improving wind forecasts

Before going to the example of the regulated market, let us first consider the issue of a capacity credit for wind. As we have noted electric power grids require dispatchable capacity to be on line so that the generation can follow the changes in load over periods of minutes or hours. Since wind is not completely unpredictable on a day-ahead basis, it is possible for some wind capacity to be scheduled on such a basis. The prior day's wind or the prior hour's wind can be used to estimate the wind speed, and hence capacity available for the next period. Errors in forecasting create an imbalance between the amount of capacity that is assigned to wind for the next day (say) and the actual output. This imposes a cost on the system because such imbalance require that other, more reliable reserves be available within short periods (several minutes) to compensate and maintain system reliability.

Evidently improvements in wind forecasting can reduce the error and, hence, the cost of adding wind capacity to a grid at a given level of penetration. Another way of stating the same thing is that a larger wind capacity penetration can be achieved at about the same cost per MWh of electricity if wind prediction is improved. Figure 3.5 shows the reduction in imbalance at various levels of wind penetration into an electric system corresponding to 20 and 40 percent improvements in reliability. The results are from an Iowa study, which used data from California,[31] to assess the impact of improving the accuracy of wind forecasts. The conclusion was as follows:

> The relationship between the curves is nonlinear, which implies that larger quantities of wind will have a larger impact on imbalance. The other two curves are based on 20% and 40% improvements to wind forecasting, respectively. If a utility were to set aside enough reserves to cover 3 standard deviations of hourly imbalances, wind's share would be approximately 3 x 68 = 204 MW in the persistence case, with 1600 MW of installed wind. This represents just under 13% of the installed capacity of the wind plant.[32]

The reserve estimate of 204 MW applies to the standard reference case for wind forecasting (the top curve, diamonds in Figure 3.5). If the forecast for the next day is 204 MW or less (about 13 percent capacity factor for a 1,600 MW plant), no capacity credit can be given to wind for that period. If the forecast capacity factor for the next period is say 30 percent, or 480 MW, the percentage reserve to compensate for the uncertainty in wind would have to be 204 MW, which is 42.5 percent of the forecast capacity. In this case the wind plant could get a capacity credit of 57.5 percent of forecast capacity. For the same circumstances, but 40 percent improved forecasting (bottom curve, squares in Figure 3.5), the reserve required is only 3*30 = 90 MW. In this case the reserve required is about 19 percent, and the capacity credit that can be allocated to wind is over 80 percent (the maximum case examined in Chapter 4).

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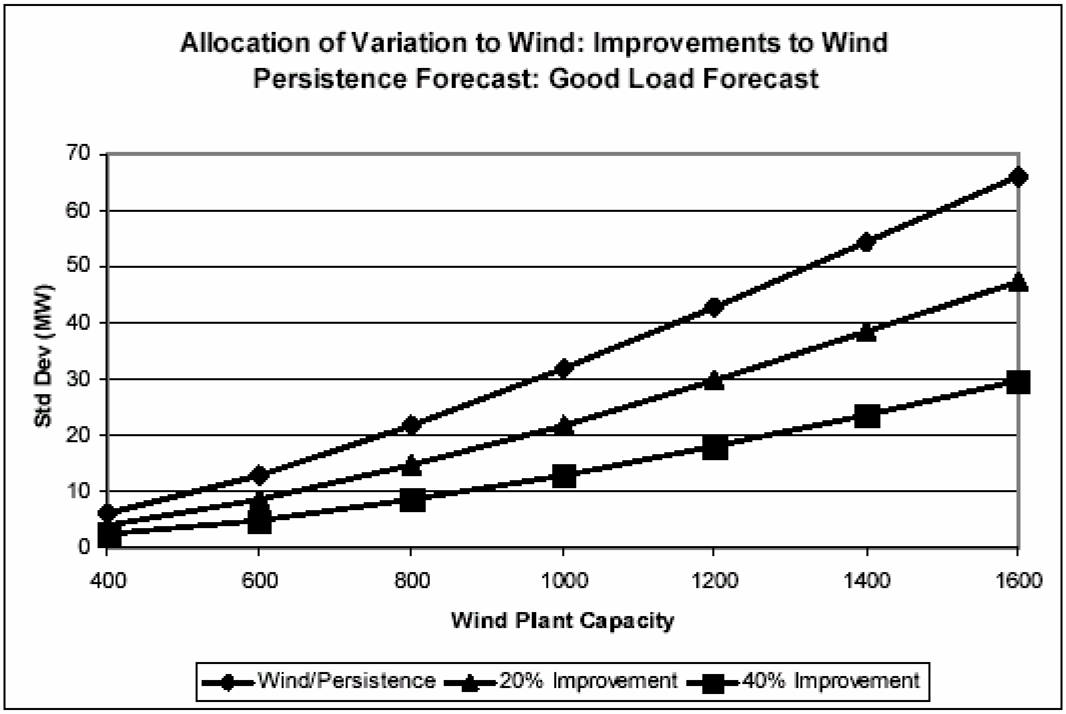
[31] Such hybridization of data for the purposes of illustration is common in wind power studies, since different systems have different kinds of data available and accessible.

[32] Results of the Iowa study as described by Parsons et al., 2003, op. cit., p. 8.



Source: Reproduced from Parsons et al. 2003, Figure 6, p. 18

Figure 3.5: Imbalance in MW due to wind energy for three levels of wind speed forecast precision

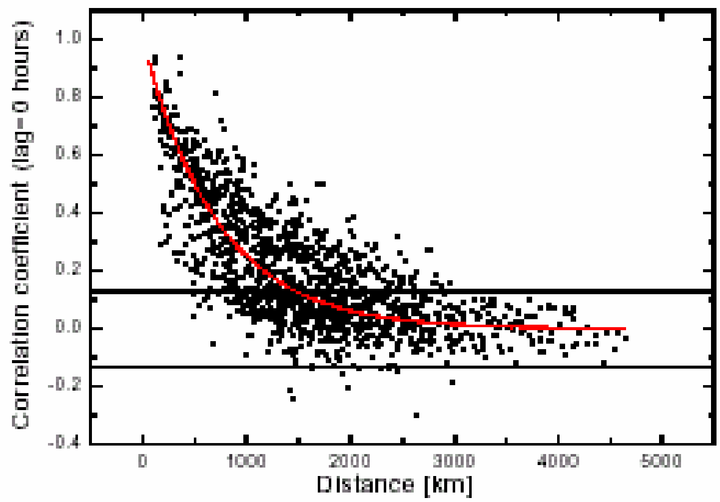
Over the year, a significant fraction of capacity credit can be given to wind, with the actual credit depending on the forecast accuracy, among other factors (see below). A capacity credit that is built into the revenue structure of the developer of a wind power plant could increase revenues considerably. Evidently, the amount would depend on how the capacity is credited in the rate structure. In New Mexico, final consumers of medium size (such as the Chino building analyzed in the next chapter) pay capacity charges that may vary from about $3,840 per MW per month in the case of PNM, which also has peak and off-peak energy charges, to over $10,000 per MW per month and a flat, low energy rate. For a wind power plant of 150 MW and a 42.9 percent annual average capacity factor (New Mexico Site 604), an 80 percent credit for capacity that is explicitly built into the revenues of a wind developer could increase those revenues significantly (possibly from about 15 to 40 percent, if the energy revenue alone is assumed to be $25 per MWh), with the percentage depending on the other features of the power purchase agreement.

2. Improving geographic diversity

Credit for capacity can also be increased by geographic diversity and a sturdy transmission system. A European study[33] that examined the correlation of winds and their effect on the grid

[33] Gregor Giebel, Niels Gylling Mortensen, and Gregor Czisch, *Effects of Large-Scale Distribution of Wind Energy in and Around Europe*, undated, but appears to be have been published in 2003. Online at http://www.iset.uni-kassel.de/abt/w3-w/projekte/Risoe200305.pdf and the associated Power Point presentation delivered at the Risø International Energy Conference: Energy Technologies for post Kyoto targets in the medium term, held at Risø National Laboratory, Denmark, 19 - 21 May 2003, online at http://www.risoe.dk/konferencer/energyconf/presentations/giebel.pdf.

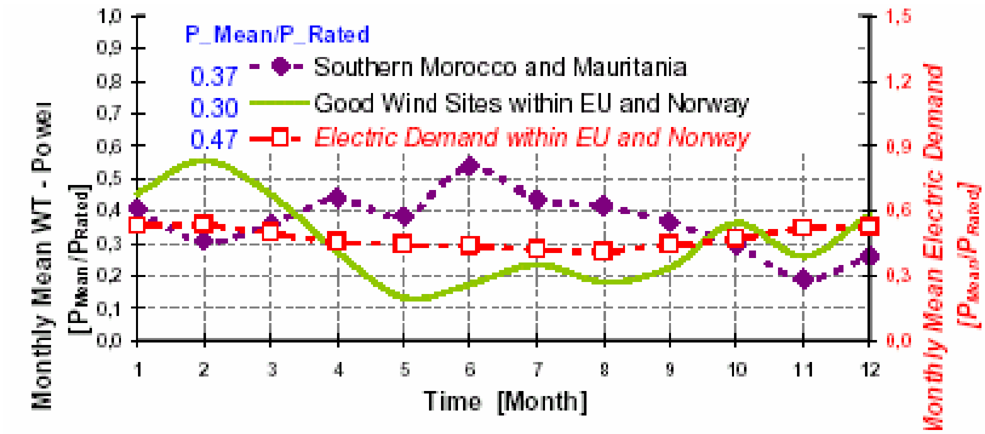
found that that the correlations decreased “more or less exponentially” by 63% in a distance of about 700 kilometers (about 430 miles) as shown in Figure 3.6. For wind farms separated by a distance of 2,500 kilometers, there was no correlation between the outputs. Highly correlated wind speed means that the output will tend to be low or high simultaneously. This creates a greater cost of wind integration because it tends to increase the amount of non-wind reserve capacity need, all other things being equal. Conversely, uncorrelated wind speed output between wind farms means that there is a higher chance that wind will be blowing in one place when it not in another, reducing the amount of non-wind reserve capacity that would be needed.



Source: Giebel, Mortensen & Czisch 2003 presentation, p. 8.

Figure 3.6: Correlation factors for wind availability at 60 wind farm sites located throughout Europe and the UK.

The specific characteristic distances over which the output of wind farms becomes uncorrelated will, of course, depend on the locations that are being paired. In the study cited above, European wind farms were paired with Moroccan wind farms (see Figure 3.7). However, the study indicates that with sufficient geographic diversity, and a transmission system linking wind power plants (in this case a high voltage DC line was studied), that wind capacity can be reliably integrated into the grid. In this case development of wind separated by large distances and a sturdy transmission system replace the need for reserve capacity.



Source: Giebel, Mortensen & Czisch 2003 presentation, p. 14

Figure 3.7: Average monthly production of wind generated electricity at certain favorable land based sites in the EU and Norway (smoothed line) as well as in Morocco and Mauritania (diamonds) showing the lack of correlation in available power. The average monthly electricity demand for the EU and Norway is also shown (squares).

3. Transmission lines and wind integration

We have already mentioned that transmission line capacity is a very major factor determining whether and how much wind can be developed in favorable areas. There is however more to it than that. The existence of a dense transmission system with sufficient capacity can increase the degree of wind penetration for a given integration cost. Even a strong distribution system can help. Much of Denmark's land-based wind capacity does not go through a high voltage transmission system, but feeds directly into the distribution system, lowering losses and costs[34]. Wind already supplies 2.4% of Europe's electricity supply. Three regions in Europe have a penetration as high as 27 percent of capacity (Schleswig-Holstein in Germany, Jutland-Funen in Denmark, and Navarra in Spain).[35] While we know of no detailed overall cost studies that have been done of this level of wind energy penetration – European utilities are in agreement with the political and social mandates that high wind energy is necessary to meet the goals of reducing of CO_2 emissions. Cost estimates for future wind integration on top of this are not high. For instance, the contribution to electricity cost of a High Voltage DC transmission line from southern Morocco to central Europe is estimated at 15 euros per MWh. The wind energy cost is estimated at 30 euros per MWh or less.[36]

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[34] Brian Parsons, telephone conversation, 7 April 2004.
[35] Giebel, Mortensen & Czisch 2003 presentation, op. cit.
[36] Giebel, Mortensen & Czisch 2003, main report and also the presentation. For capital costs and other details on North Africa-Europe HVDC see "Transferring Electricity," on the Sahara Wind website at http://www.saharawind.com/HVDCenergytransfer.htm. The estimate of capital cost of an HVDC line dedicated to large-scale wind energy transmission is 70 euros per kilowatt per 1000 kilometers of line for an aerial line. The dollar-euro exchange rate is about 1.20 dollars per euro as of this writing. The exchange rate has fluctuated a great deal since the introduction of the euro. The approximate purchasing power equivalent exchange rate is about 1 dollar per euro.

D. Conclusions

Large distances between areas with high wind potential – a description that fits the states in the region of the Western Governors' Association – can create very significant economic and reliability benefits. An assessment of the coordinated development of wind power on a large scale in the region of the WGA, including considerations of geographic diversity, capacity credit, and transmission line infrastructure, would be very useful in highlighting the areas where interstate cooperation might be particularly beneficial. Specifically, a study examining the construction of High Voltage DC transmission lines though the region dedicated to wind energy, with branches going to major consumption centers, should be studied carefully. Such a study would have great added value if it considered various ways in which wind-generated electricity could be used to alleviate emerging problems related to natural gas supply and volatility (See Chapter 5). Further, integration of the spatial diversity in wind energy supply could not only bring about smoothing in wind power output, it also means more diversity in demand. This would reduce the overall need for capacity, because system coincident peak can be reduced for the same overall total load.

Chapter 4: Integrating wind energy into a distributed grid system with fuel cells and purchased power

New Mexico is served by a number of regulated utilities, the largest of which is PNM, followed by Xcel Energy (formerly Southwestern Public Service). There are also publicly owned utilities and cooperatives, some of considerable size, for example the Los Alamos County-owned utility and the Lea County Electric Coop. New Mexico exports electricity westward, for the most part. The Four Corners area, where major generation facilities are located is also a hub for transmitting electricity out of the state and the location of a spot market as we have discussed.

This chapter will examine the sale of wind generated electricity in a regulated market to a large commercial customer. We will use the example of a single office building to illustrate the assessment of wind energy's value at the retail level. The top curve in Figure 4.1 (triangles) shows the monthly electricity demand in 2003 for the Chino building in Santa Fe, which is used by the State of New Mexico as an office building. The building is heated by resistance heating and has had an update on its air-conditioning system. It was built in the 1980s.[37]

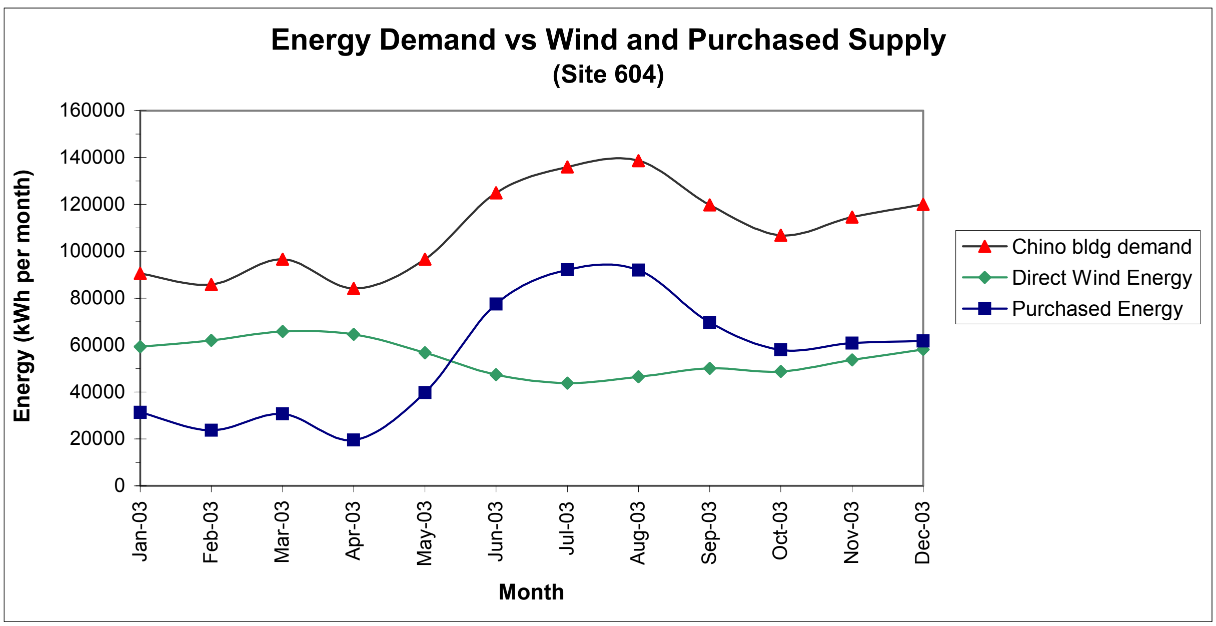

Figure 4.1 : Energy demand for the Chino building in Santa Fe owned by the state of New Mexico (triangles) as well as the postulated energy purchases from a 188 kW wind farm located at site 604 (diamonds) and the power purchased from other sources (squares). The average wind power purchased over the year is equal to 50% of the total annual demand.

The curves in Figure 4.1 also shows the purchase of energy from a wind farm located at New Mexico Site 604. We assume that the average monthly capacity factors for July 1999 through June 2001 (diamonds) are the values for the wind farm for the year for which we are doing the calculations. The contract with the wind farm is arranged so that the wind farm supplies half the yearly total electricity used by the Chino building on a supply schedule that corresponds to the wind farm's monthly capacity factors. That is, the Chino building operators purchase a larger

[37] Data for this building were kindly provided by Daniel Hagen

amount of electricity in the months of higher wind electricity generation and vice versa. Purchased power makes up the difference.

The electricity rate structure of the building consists of a demand charge of $3.84 per kilowatt of maximum demand per month (with a minimum of 50 kW). Then there are peak and off peak energy charges. We were provided with the building electricity use details for 2003 and the corresponding electricity by Daniel Hagen, who is responsible for the utilities in the building. We did not have a breakdown of transmission and distribution charges separately broken out in the electricity bill. We therefore used the rates for transmission and distribution charged by another of New Mexico's regulated utilities, Southwestern Public Service (now Xcel Energy), for the same category of electric service. These amount to about $25 per MWh for the General Service category, which applies to the Chino building.

Using transmission and distribution losses of 7 percent and a grid integration charge of $2 per MWh, we compute the total cost of generating wind electricity and delivering it to the Chino building to be about $66 per MWh. This is lower than the average price of $73 per MWh paid by the Chino building user (the State of New Mexico). However, since the high use of wind energy in the building results in a proportionally greater percentage of the peak demand being met by purchased power, the actual cost of using wind to the building is somewhat higher. Another way to state this is that the comparable cost of electricity to the Chino building user would be about $64 per MWh, exclusive of demand charges and the higher charges for electricity at peak times. As noted in Figure 4.1, the installed capacity required at the wind farm to supply half the electricity usage of the Chino building in this way would be about 188 kilowatts. Hence, with the present rate structure, the cost of electric utilities to the Chino building would not increase, even if half its electricity were supplied from wind farms, and without any decrease in costs being achieved by production tax credits.

The assessment of the costs of getting a large proportion of electricity from wind depends in large measure on whether and how much capacity credit is attributed to the 188 kW wind farm capacity that would be needed. If no credit is given for the capacity, there would be a slight increase in the electricity bill (less than one percent). If there is an 80 percent credit for capacity (a very high upper limit), there would be a net savings of about two percent.

These estimates are somewhat artificial because they assume that the rate structure will not change even if a large amount of wind-generated electricity is introduced into the system. This assumption especially important in case the investments have not been made in transmission, meteorology, and other aspects of the system to reduce wind integration costs at high penetration. The reason is that in our example of the Chino building, the rate structure recovers peak electricity costs partly through peak energy charges and partly through a relatively low demand charge of $3.84 per kilowatt per month. For instance, if the demand charge were increased for the portion of electricity that is purchased, the savings would be reduced or would disappear, depending on how rates for the energy charge were adjusted.

For comparison, we have done the same type of calculation for Site 601 in New Mexico, which has the lowest average capacity factor of the five sites. We assume for simplicity that all other costs are the same. The lower capacity factor means that the installed capacity at Site 601 would have to be somewhat greater than that needed at Site 604 to supply the same amount of electricity.

Figure 4.2 shows the monthly distribution of energy consumption from a wind farm with 229 kW of installed capacity at site 601 (diamonds) as well as the purchased power (squares) and total demand for the Chino building (triangles). The wind pattern from this site is not very favorably matched to the Chino building demand, since it has a very high capacity factor in April, a month of low demand. The user could expect additional demand charges under such circumstances. However, if various sites with different seasonal wind patterns were integrated, as discussed in Chapter 3, this problem would be considerably ameliorated.

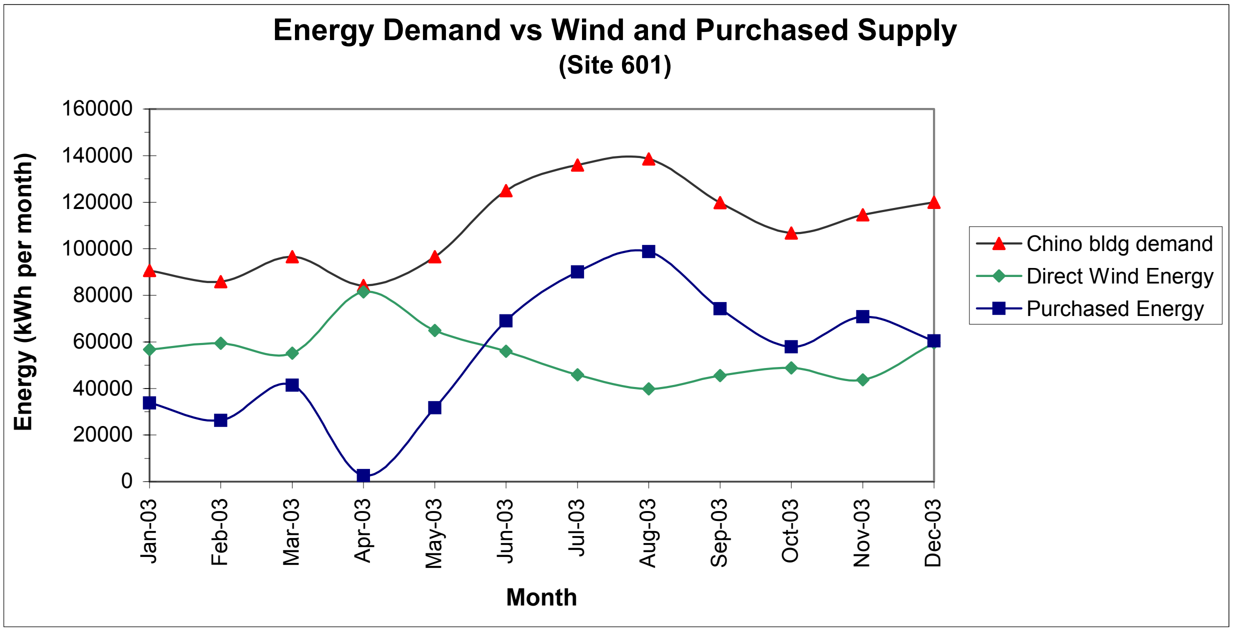

Figure 4.2 : Energy demand for the Chino building (triangles) as well as the postulated energy purchases from a 229 kW wind farm located at site 601 (diamonds) and the power purchased from other sources (squares). The average wind power purchased over the year is equal to 50% of the total annual demand.

Using the existing rate structure, the Chino building user would increase their annual electricity bill by about $2,000 to $4,800 for the year. We also did a sensitivity calculation assuming that the wind farm operator pays a grid integration charge of $5 per MWh instead of $2, corresponding to roughly a 20 percent penetration rate for wind. In that case, there is a net increase in the electricity charge of $4,100 to $6,900 for the year (a change of 4% to 7%). As noted above, the cost of the wind-purchased power combination would be higher, since the demand charges would likely be increased relative to the energy charge.

If we look at the example from a system perspective, the costs associated with adding wind capacity are considerably lower, because different end users make heavy demands on the system at different times – that is, there is a diversity in the demand. If diversity in demand is coupled to geographic diversity in wind electricity generation, the costs of large scale integration of wind energy can be considerably reduced. In other words, such diversity, which requires a sound transmission infrastructure to achieve, is a crucial factor in allowing a significant credit for wind power plant capacity.

Conclusion: Whether and how much high penetration rates of wind energy increase costs depends a great deal on:

- the capacity factor of the wind site selected for development
- how well the profile of the winds corresponds with the load
- the costs of grid integration at high penetration levels.

There are ways in which the cost of wind penetration can be considerably reduced, especially if wind energy development is linked to reduction of natural gas use in power plants. While we discuss this in the next chapter to assess the costs and benefits, we note here that a very low cost of back up capacity can be provided for wind, if its development is coupled explicitly and through contracts to displace natural gas use at peak times in single stage gas turbines (where the avoided cost for generation and maintenance alone is on the order of $60 per MWh) and even in combined cycle power plants, where the avoided costs are on the order of $40 per MWh.

Specifically, if wind is used to displace high fuel cost natural gas generation, reserve arrangements can be specified as part of the contracts, so that wind development does not have to be accompanied by the development of new reserve capacity and its attendant costs. At the same time, the capacity credit for wind can be increased without reducing reliability.

A. Reduction of greenhouse gas emissions

Another aspect of these results is that the state could reduce the CO_2 emissions associated with supplying electricity to the Chino building by roughly 50% and still not significantly increase the building's energy bill. This is because emissions of CO_2 attributable to the Chino building would come entirely from the use of fossil fuels that are used to generate the electricity purchased from the grid. As a first approximation, the reduction of purchased power by 50% would reduce the corresponding greenhouse gas emissions by about 50% also, since New Mexico electricity generation is mainly from coal-fired power plants. A more refined calculation may show a somewhat lower or higher reduction, depending on the actual mix of fuels that supplied the Chino building at various times in the year. If wind displaces nuclear generated electricity for part of the time, while increasing the relative share of fossil fuel generation in the purchased power mix, the CO_2 reduction would be less than 50%. If it displace coal preferentially, and increases the share of hydro and nuclear, then the reduction would be larger than 50%. But in any event, it would be very substantial, and far greater than the amounts required under the Kyoto Protocol to be achieved by about 2010.

We can impute an economic benefit to this, if carbon dioxide credits were traded in the United States, as they are in Europe. For every dollar of value assumed per metric ton of avoided CO_2 emissions, the corresponding value of wind-generated electricity amounts to about 9 cents per MWh, assuming it displaces coal-fired power plants. It would be about 3 cents per MWh in case of natural gas fired combined cycle power plants.

The Congressional Budget Office has analyzed a trading value of $25 to $50 per metric ton of carbon emitted in one of its evaluations of methods for reducing greenhouse emissions.[38] This yields a value for wind-generated electricity of $2.25 to $4.50 per MWh in the case of displacing coal fired power plants and $0.75 to $1.50 in the case of natural gas fired combined cycle power plants.

B. A distributed grid example

Large scale wind energy use can be integrated into the electricity system in a number of ways, if the problem of energy storage could be overcome. Much attention has been centered on the use of fuel cells in vehicles. However, the operational and cost considerations in transportation applications are very severe, as the National Research Council has recently pointed out.[39] In this section, we consider the application of fuel cells for stationary applications with wind energy being used to generate the hydrogen. A conceptual block diagram for the system is shown in Figure 4.3.

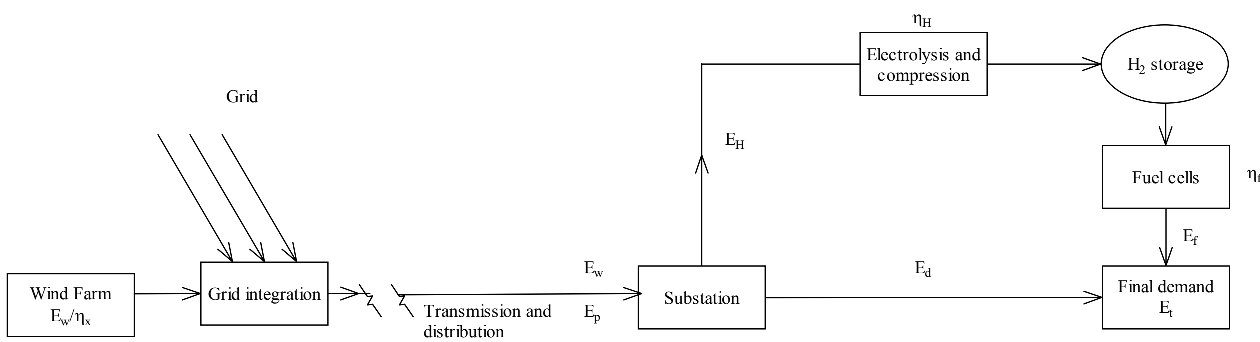

Figure 4.3 : Components of a distributed grid system using large-scale wind energy, purchased power, and fuel cells.

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[38] U.S. Congressional Budget Office. *Shifting the Cost Burden of a Carbon Cap-and-Trade Program*. A CBO Paper. Washington, DC, July 2003. Online at http://www.cbo.gov/showdoc.cfm?index=4401&sequence=0.

[39] National Academy of Engineering, Board on Energy and Environmental Systems. *The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs* (Washington, DC: National Academies Press, 2004). Executive Summary online at http://books.nap.edu/books/0309091632/html/1.html.

In this system, wind energy is integrated into the grid up front and then a portion of that energy is used directly as electricity while the remaining amount is used to make hydrogen for fuel cells. In the case that the fraction of energy used to produce hydrogen goes to zero, we recover the example described in a previous section of this chapter. For illustration purposes in this section, we set the fraction of wind energy used to generate hydrogen for the fuel cells at 50%. This fraction describes a representative case that takes into account both the final electricity cost and the overall system functionality. A few days of hydrogen storage capacity (compressed hydrogen at about 500 atmospheres) is considered to be a part of the system to allow the fuel cell usage to stabilize the net power contribution from wind relative to short term fluctuations. In this example, the fuel cells are assumed to produce electricity with 50% efficiency. We also assume that the hydrogen is generated using electrolysis with 65% efficiency, and that it is stored and used on site. This obviates the need to postulate the development of a hydrogen energy infrastructure in the form of pipelines or modifications of the internal aspects of buildings. For simplicity, we ignore any possible use of waste heat from the fuel cell for building heating purposes.

Figure 4.4 shows again the total energy demand of the Chino building (triangles) as well as the amount of wind energy used directly (diamonds), the amount of energy output from the fuel cells (crosses), and the amount of purchased power (squares). This data is for a 284 kW wind farm located at site 604 and a fuel cell bank with a 25 kW installed capacity and a 90% capacity factor. Again this illustration is set up so that half of the energy demand for the building is met by purchased power while the other half is met by direct wind energy usage and the fuel cell output.

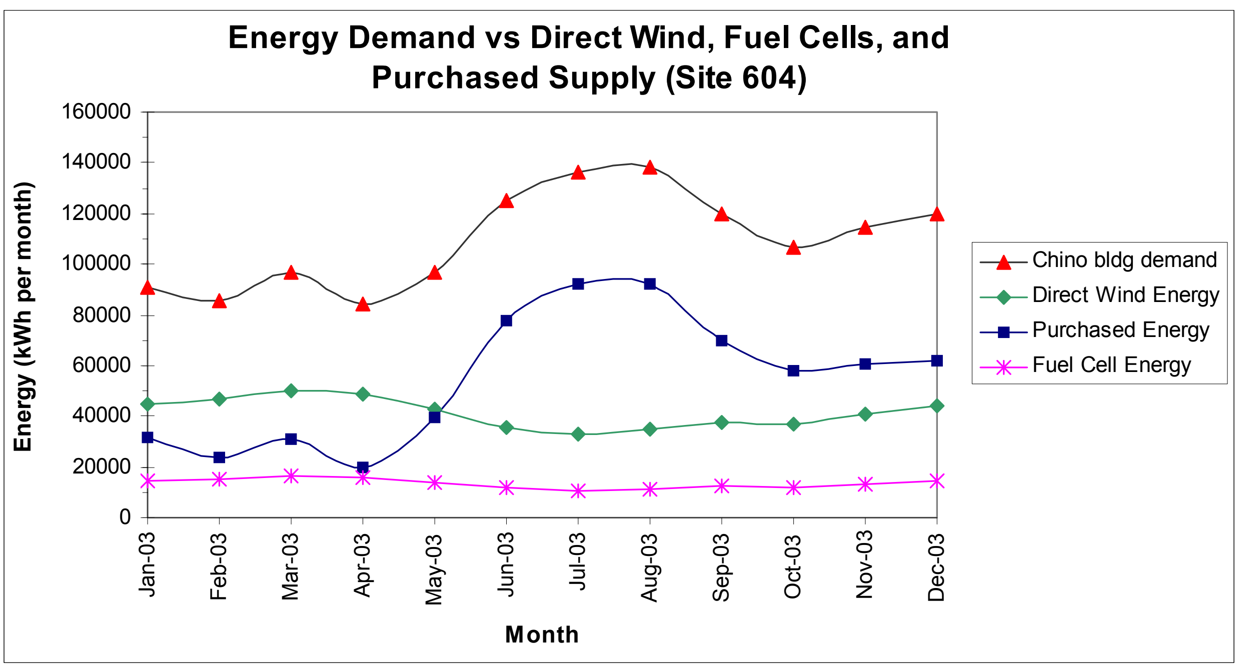

Figure 4.4 : Energy demand for the Chino building in Santa Fe (triangles) as well as the postulated direct energy usage from a 284 kW wind farm located at site 604 (diamonds), the energy output from 25 kilowatts of fuel cell supplied with hydrogen by 50% of the purchased wind power (crosses), and the power acquired from other sources (squares). The average power purchased over the year from non-wind sources is equal to 50% of the total annual demand.

Because the monthly fuel cell output tracks that of the wind farm (since we assume only limited hydrogen storage), the annual average for the effective capacity of the fuel cells is reduced to about 20.5 kW. This fuel cell power, however, is still equivalent to more than 32% of the direct wind energy used or an annual average of 12% of the total energy requirements for the Chino building. Thus, the fuel cells provide a substantial ability to stabilize the effective use of wind power for the consumer, and open up options for cost optimization not explored in this example such as running them at full power during peak demand times and refilling the hydrogen reserves during off-peak hours.

In order to determine the costs of this system, we assumed that the fuel cell system capital cost was $4 million per megawatt, including a few days of storage and the electrolytic cells needed to create the hydrogen. With this assumption, the costs of supply the Chino building go up substantially – by over one-third for wind-generated electricity from Site 604 and by about half for electricity from Site 601.

These cost estimates assume that the rate structure remains the same, which is a more realistic assumption in the case of the wind-hydrogen-fuel-cell system combined with purchased power than in the previous two examples, especially if even a moderate capacity credit is attributed to a portion of the wind-generated electricity used directly (i.e., not via hydrogen).

C. Displacement of natural gas for use in transportation

As noted, the Chino building is an all electric building due to its use of resistive heating. In many areas of the country, however, most commercial and residential buildings are heated by natural gas. Gas is a commodity that is vital and whose price is increasing, in large measure due to the increase of power plants that use it as a fuel (see Chapter 5). One can apply the scheme developed above for the Chino building and combine with a highly efficient electric heating system driven by a device variously known as an "earth source heat pump" or a "geothermal heat pump." It is also possible to conceive of a fuel-cell combined heat and power system in which the heat output could be used to heat buildings and thereby reduce the use of natural gas.

Detailed consideration of such schemes is beyond the scope of this report, but they would be central to optimizing the combined wind power fuel cell system considered above. They could also provide one important way in which wind energy combined with fuel cells and efficiency could be used to diminish the insecurities and problems associated with the present large scale of oil imports well before fuel cells become cheap enough for use in automobiles. Fuel cell prices must come down to 50 to 100 dollars per kilowatt for use in vehicles, but they can be roughly ten times that for effective use in stationary applications. Moreover, the severe fuel storage and space constraints do not apply to stationary systems, though they are still a major consideration. But the success of such a system will also depend on improvements in efficiency of hydrogen production and storage, and of effective combined heat and power systems based on fuel cells.

Preliminary calculations indicate that schemes in which wind, fuel cell combined heat and power systems, and highly efficient earth source heat pumps are optimized (along with other building efficiency improvements) have the potential to entirely displace the use of natural gas for heating at least in commercial buildings that are similar in size to or larger than the Chino building. The natural gas could then be used in vehicles to reduce the use of gasoline, which would reduce oil imports. The use of compressed natural gas as a substitute for gasoline or diesel fuel has long been established as a commercial technology for fleets. In the past decade or so it has come into widespread use in many countries in the world.

Alternatively, the freeing up of natural gas from space and water heating, which are among the most inefficient uses of this fuel (as measured by the second law of thermodynamics),[40] would help reduce natural gas price volatility. System wide electricity planning in which wind power also displaced some use of gas for electricity generation could help in a transition to a U.S. energy system that has far less carbon dioxide emissions, far less air pollution and significantly less oil imports. Figure 4.5 shows the schematic of such a transformation from an electricity-natural gas heating system with oil transport, to an all-electric, highly efficient building powered by a mix of conventional power plants, wind-generated electricity, and fuel cells that run on hydrogen made from wind-generated electricity.

There is of course the possibility of simply installing earth source heat pumps and reducing the use of natural gas in buildings, and this should be pursued simultaneously with the development of wind energy. However, new power plants are mainly natural gas fired and natural gas prices are rising and volatile. The high prices of natural gas are, in turn, causing prospective builders of new power plants to consider coal. This will, of course, lead to even higher emissions of carbon dioxide, as Alan Nogee of the Union of Concerned Scientists has pointed out.[41] Vigorous development of wind energy is a sound approach to addressing such issues.

According to a detailed survey of energy use in commercial buildings in 1992, the use of natural gas in buildings over 10,000 square feet was nearly 2 trillion cubic feet. Total use in office buildings, educational and health care establishments, and hotels was about 1 trillion cubic feet.[42] Most such natural gas use is for space and water heating. The scheme shown in Figure 4.5, combining wind-generated electricity, fuel cells, combined heat and power, and earth source heat pumps can likely be applied to a significant numbers of these buildings. Existing schools, army housing, etc. have been backfitted with earth source heat pumps with significant reductions in energy use.

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[40] The high advertised efficiencies of space and water heating systems that use natural gas are based on the first law of thermodynamics, which does not take into account the quality (temperature) of the energy, but only its quantity. The second law takes the quality into account. It is possible with earth source heat pumps, which are commercially available, to reduce the use of energy in space heating by about a factor of four relative to natural gas or electric resistance heating. President George W. Bush has an earth source heat pump at his ranch in Crawford, Texas. See Claudia Feldman, "Welcome to Crawford," *Houston Chronicle*, February 11, 2004, http://www.chron.com/cs/CDA/evergreen.mpl/travel/tx/prairies/812351.

[41] Alan Nogee, "Hedging Against Climate Change," Union of Concerned Scientists, Power Point Presentation to the North American Energy Summit, Albuquerque, New Mexico, 15 April 2004.

[42] U.S. Energy Information Administration. *Commercial Buildings Energy Consumption and Expenditures in 1992*. DOE/EIA-0318(92) (Washington, D.C., 1995), Figure 3.1, page 23.

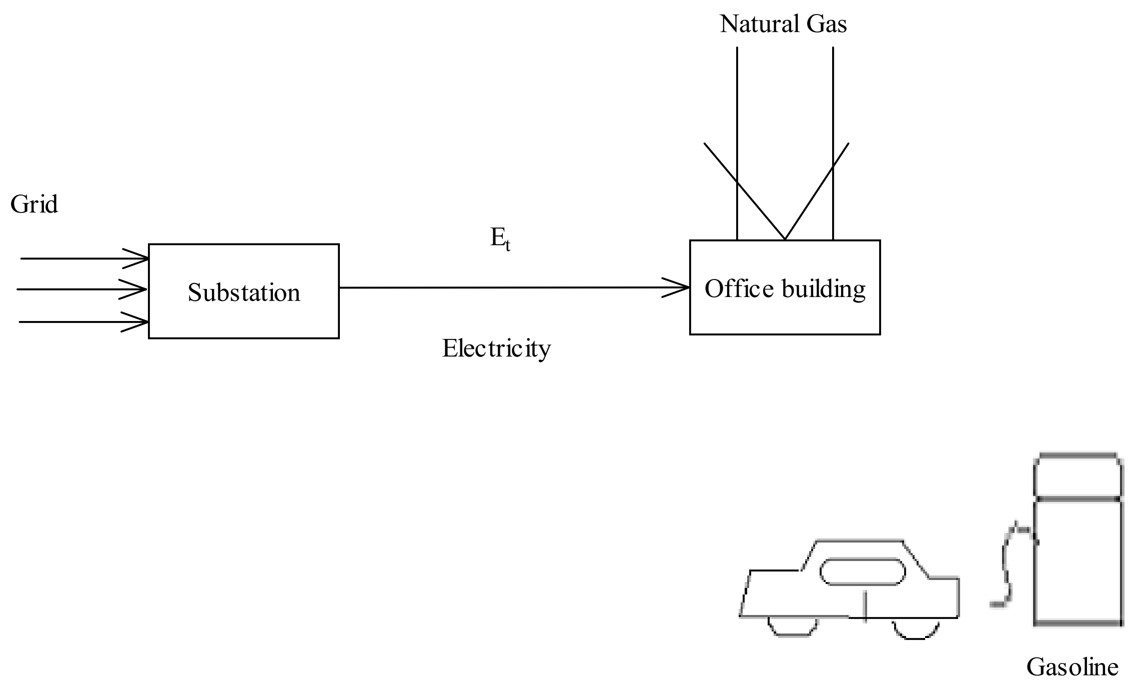


Figure 4.5 A: Schematic of present-day typical building and vehicular use

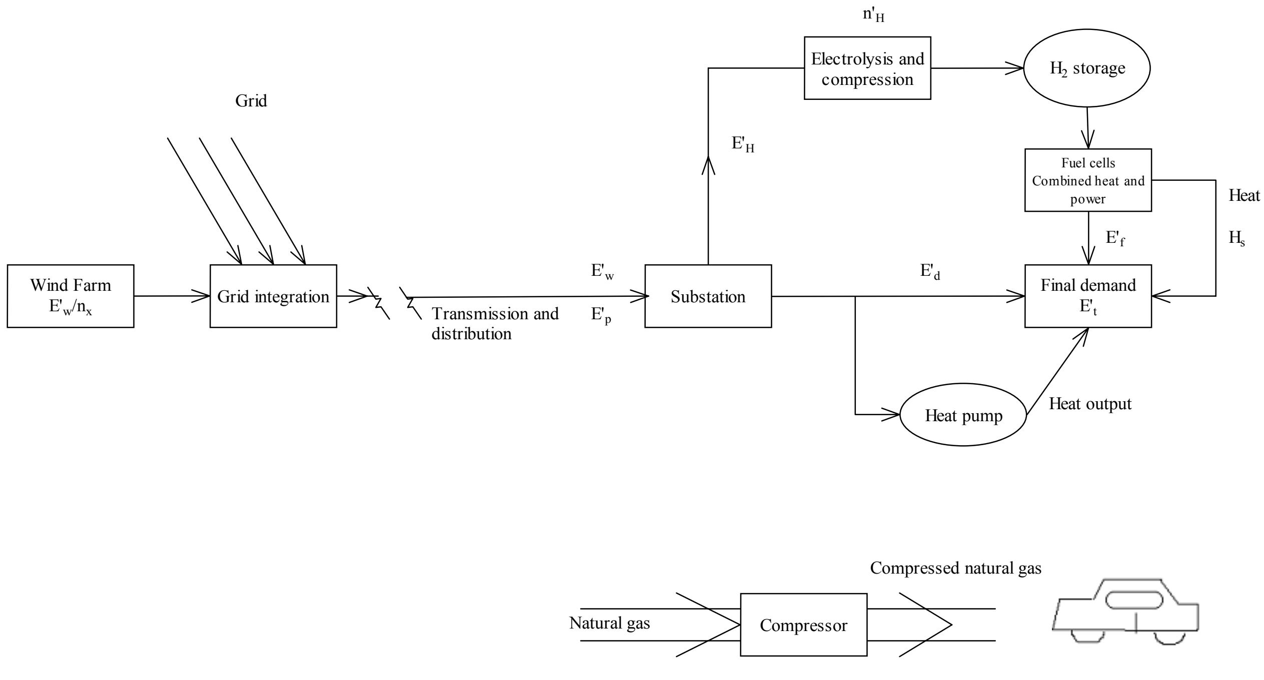


Figure 4.5 B : Components of a distributed grid system using large-scale wind energy, purchased power, and fuel cells with the intent of displacing natural gas from use in heating large commercial buildings.

By combining the various elements – wind, fuel cells, efficiency with earth source heat pumps and use of natural gas in cars – it will be possible to greatly reduce the use of natural gas for space and water heating in the commercial sector, freeing it up for use in transportation. Even a 1 percent transfer of natural gas from space heating to vehicles would result in a reduction of 80 million gallons of gasoline per year, equivalent to the annual use of gasoline by over 100,000 cars. This would correspond to a reduction of CO_2 emissions by over 300,000 metric tons per year, as well as reduction in urban air pollution, and the achievement of national security benefits from reduced oil imports.

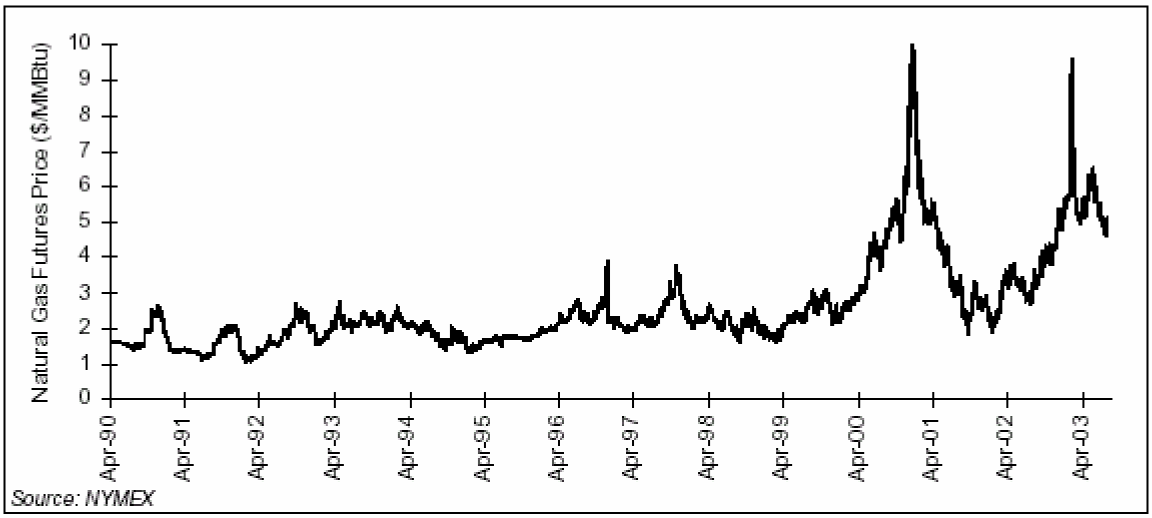
There is evidently a significant investment cost to such a scheme. We have not done a detailed feasibility study that would optimize the various factors. However, our study of the Chino building without optimization indicates that the cost of achieving these goals, including on the order of 50 percent reduction in building greenhouse gas emissions, would be modest if viewed as a fraction of present cost of the services that energy provides, like heating, cooling, and lighting.

We have not explicitly addressed the issue of solar photovoltaic cells in place of or as a complement to this system. In desertic areas, solar cells can complement wind energy, especially in cases when wind speeds are low at peak times. The cost of solar cells is about $4 million to $5 million per MW. Of course, unlike fuel cells, they do not require fuel, but their capacity factor is considerably lower. Their integration into the system would add broadly similar costs as fuel cells do today.

The analysis in the this and the previous section indicates that there are no real cost advantages to integrating fuel cells into the electricity system on a large scale at the present time. However, there are advantages to adopting policies that will integrate them first into the stationary power system and linking that to reducing gasoline imports for transportation and to improvements in the efficiency of heating buildings. Effective use of all renewable resources, including wind and solar energy and large reductions in CO_2 are likely to require fuel cells and hydrogen in the mix. Carrying out a demonstration project that includes the elements described in this section can be justified on those grounds, as well as on grounds relating to improved security that would be attendant upon reduced dependence on oil for transportation.

Chapter 5: Wind Energy and Natural Gas

Natural gas prices have risen over the past few years; in the same period they have also shown significant volatility. In the two year period 2000 to 2001, the spot price of natural gas varied from lows on the order of $2 per million Btu (about 1,000 cubic feet or 29 cubic meters) to highs of about $10. The spot market price as of this writing is above $5 per million Btu. The price of gas has drifted upward to $5 per million Btu since the latter part of 2002. Figure 5.1, reproduced from Bolinger, Wiser, and Golove,[43] shows the price of natural gas futures from 1990 to 2003, showing both the volatility as well as the recent rising trend.



Source: Bolinger, Wiser, and Golove, 2003, p. 4.

Figure 5.1: Natural gas futures prices from April 1990 through April 2003.

The trend towards rising and volatile natural gas demand is due, at least in part, to a large increase in the capacity of natural gas-fired combined cycle electric power plants. Bolinger, Wiser, and Golove have summarized the trend, which is expected to continue, as follows:

> For better or worse, natural gas has become the fuel of choice for new power plants being built across the United States. According to the EIA (2003), natural gas combined-cycle and combustion turbine power plants accounted for 96% (138 GW out of 144 GW total) of the total generating capacity added in the U.S. between 1999 and 2002. Looking ahead, gas-fired technology is expected to account for 80% of the 428 GW of new generating capacity projected to come on line through 2025….

[43] Mark Bolinger, Ryan Wiser, and William Golove. *Accounting for Fuel Price Risk: Using Forward Natural Gas Prices Instead of Natural Gas Price Forecasts to Compare Renewable to Natural Gas-Fired Generation: Executive Summary*, LBNL-53587 (Berkeley, CA: Lawrence Berkeley National Laboratory, August 2003), p. 4. Online at http://eetd.lbl.gov/ea/EMS/reports/53587_exsum.pdf

> With increasing competition for natural gas supplies, it is likely that gas prices will be as or more volatile than they have been in the past.[44]

The use of gas in power plants on a large scale combined with its use for residential and commercial heating as well as a fuel and feedstock in the chemical industry are factors that tend to make the demand relatively inelastic in the short and medium term. At the same time, the supply of natural gas is also inelastic over time periods of less than a few years because it takes time to build natural gas infrastructure. Specifically, imports from outside North America could provide a significant potential new source of natural gas. Large amounts of natural gas are routinely flared in oil exporting developing countries like Nigeria where the domestic infrastructure for using the gas has not been well developed, and where oil exports are a priority because they form a large part of governmental revenue.

Importing natural gas from other continents is a much more complex task than importing oil. Because natural gas at atmospheric pressure has very low energy content per unit volume relative to oil, it must be liquefied for tanker transport (unless it can be transported by pipeline, as is the case from North Africa into Europe). The tankers must be cooled to cryogenic temperatures to keep the gas liquid. Special offloading facilities for the handling and evaporation of the natural gas back into gaseous form for transport in pipelines is required in the importing country. The scale and lead time of such investments is long. Moreover, greatly increasing the imports of liquid natural gas from across the oceans raises similar security questions as oil and additional ones related to the fact that natural gas can explode under certain circumstances.

These factors – high and volatile natural gas prices, the long lead times for building natural gas infrastructure, and security issues associated with liquid natural gas imports – have raised the possibility that wind energy could be used to displace a part of the natural gas now used in electric generating plants. This can generate two several different kinds of economic benefits:

- For the utility that has combined cycle natural gas capacity, it could be profitable to displace a part of it by wind-generated electricity.
- It could be very profitable to displace single stage peaking gas turbines, which are typically operated only for a few hundred hours per year, with wind energy
- Wind capacity could provide a hedge against rising natural gas prices
- High wind penetration into an electricity system could displace enough natural gas to help stabilize prices.
- Wind energy, when combined with efficiency improvements in heating and air-conditioning systems (notably earth source heat pumps, as discussed in Chapter 4) could displace large amounts of natural gas in the long term to make it available for displacing some petroleum use in vehicles.

High natural gas prices have stimulated exploration, new production,[45] and the construction of plants for liquefying natural gas. However, due to the long lead time for increasing supply

[44] Bolinger, Wiser, and Golove, 2003, op. cit. p. 4.
[45] Exploration and new production always carries environmental penalties, of course. The environmental costs of coal bed methane have aroused special concern and controversy. Consideration of such issues is well beyond the scope of

significantly and the tight market, natural gas prices are expected to stay well above historical levels. Moreover, the tight supplies and inelastic demand in the short-term also raise the possibility that high volatility may affect certain markets from time to time.

The question arises then is how one might arrive at a contract price for future sale of natural gas on a monthly or seasonal basis. The following factors, not all of which would apply to every situation, are germane to this question:

- What are the costs (corresponding to risks) associated with uncertainty in wind when contracts are for a future month or season?
- What are the avoided costs when wind-generated electricity displaces either combined cycle or single stage peaking natural gas generation?
- What is the value of wind-generated electricity when used as a hedge against volatility in future natural gas prices?
- What is the value of wind-generated electricity when it saves water by displacing electricity from natural gas or coal-fired power plants? There is in addition a related question: What is the value of wind-generated electricity in the context of droughts that might result in the shut down of some thermal power plants due to lack of sufficient water in the reservoirs from which their cooling water is drawn?

We consider each of these factors below.

1. Wind uncertainty

Day head wind speeds are much more difficult to predict with accuracy than seasonal wind speeds averaged over a whole season or a significant part of a season because seasonal weather patterns are driven by predictable factors. If the contract is on an aggregate seasonal basis, the cost associated with advance contracting for wind-generated electricity should be low. Shortfalls over a season can be made up with purchases of electricity on the spot market at suitable times. Similarly, surpluses could be sold on the spot market. We assume, as a first approximation, that the risk in a contract for sale of wind-generated electricity over a season is low.

2. *Variable avoided costs*

We will use five dollars per million Btu as the base price of natural gas for this discussion of the potential of wind-generated electricity to displace natural gas use, especially in electricity generation. At this price, the avoided fuel cost alone for combined cycle-generation is $35 per MWh, while that for single stage peaking turbines would be about $55 per MWh.[46] This is exclusive of variable maintenance costs of several dollars per megawatt hour. Total variable avoided costs would be about $40 for combined cycle plants and about $60 per MWh for single stage gas turbines. For a range of natural gas prices from $3.50 to $7 per million Btu, the corresponding avoided costs would be about $29 to $54 per MWh for combined cycle plants and $43 to $82 for single stage natural gas turbines.

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this paper. In any case, use of wind energy to displace natural gas use will help reduce pressures but will not, of course, eliminate them.

[46] We assume a heat rate of 7,000 Btu per kWh for combined cycle plants (just under 50% efficiency) and 11,000 Btu per kWh for single stage gas turbine plants in estimating these values.

Since wind-generated electricity is now far superior to single stage natural gas turbines, its use at peak times can be integrated with putting existing single stage turbines in appropriate standby modes to support wind capacity. This could be a low cost way of improving capacity credit for wind, since it does not require new turbine capacity to be built. Similarly, duct firing of combined cycle plants uses about 25 percent more natural gas than normal combined cycle operation.[47] At $5 per million Btu of natural gas, the avoided fuel and variable cost for duct firing is about $50 per MWh, which is well within the economic range for wind-generated electricity.

3. Value of wind-generated electricity as a hedge

When a utility purchases wind-generated electricity for a price that is fixed for the long-term, there is an automatic hedge against natural gas price volatility, if the utility has natural gas generating capacity. Bolinger, Wiser, and Golove have attempted to assess the cost of natural gas price volatility to operators of combined cycle plants and concluded that it is very difficult to assess cost over periods comparable to typical long-term wind power contracts or even to develop a general assessment or rule of thumb for shorter periods. Over a period of a few years, the value of wind-generated electricity as a hedge against natural gas price volatility might be a few dollars per MWh.[48]

4. Water resource economy

The benefit of wind-generated electricity in a water scarce situation can be assessed indirectly by estimating the cost of occasional loss of generating capacity due to lack of water, or more reliably, by estimating the cost of using dry-cooling for thermal power plants (when the condenser is air-cooled rather than water cooled). There are a variety of estimates for the net cost of dry-cooling which depends on ambient temperatures and the cost of water, at least. For instance, a study done by the Clean Air Task Force and the Land and Water Fund of the Rockies of a hypothetical 700 MW combined cycle natural gas fired plant in Arizona, estimated the dry-cooling cost to be about $2.50 per MWh, .[49]

5. Other water-related considerations

Given that serous droughts have afflicted large part of the West for several years, and continue to do so in some areas, the value of water has become a much larger question that it already was prior to the drought. In 2001, for instance, the Corette power plant in Montana was shut for several days because water flow in the Yellowstone River was below the required threshold.[50] There are increasing conflicts between use of water for irrigation, electricity generation, protecting endangered species, and urban growth. It is possible that wind energy may be useful in alleviating

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[47] Northwest Power Planning Council, Natural Gas Combined-Cycle Turbien Power Plants, August 8, 2002, See Table 1. we use a heat rate of 9,200 Btu per kWh for duct firing in this calculation.
[48] Bolinger, Wiser, and Golove 2003, *op cit*.
[49] The Clean Air Task Force and the Land and Water Fund of the Rockies, *The Last Straw: Water Use by Power Plants in the Arid West*, study done for the Energy Foundation and the Hewlett Foundation, Hewlett Foundation Energy Series, April 2003, p. 12. Online at http://www.catf.us/publications/reports/The_Last_Straw.pdf.
[50] Clean Air Task Force and Water Fund of the Rockies, 2003, *op cit.*, p. 8.

some of these conflicts. For instance, where there are existing reservoirs, off-peak wind-generated electricity could be used to pump water that had been released for electricity generation back into the reservoirs for re-use for other purposes. Of course, large reservoirs raise their own issues. This issue and the value that it may add to wind-generated electricity is worth considering but it beyond the scope of this report.

5. Conclusions

We can summarize the value of using wind-generated electricity in place of combined cycle natural gas power plants in arid high-wind areas as shown in Table 5.1:

Table 5.1: Summary of the various additional values attributable to wind generated electricity for wind farms located in arid high-wind areas.

Item	Value attributed to wind-generated electricity, \$/MWh	Comments
Avoided variable costs of combined cycle plants (fuel plus variable maintenance)	\$40	Natural gas price \$5 per million Btu
Hedge against natural gas price variability	a few dollars	difficult to estimate
Water conservation by reducing thermal generation	\$2.50	variable depending on water prices and summer temperatures

This yields a total avoided cost on the order of \$45 per MWh for combined cycle plants for a cost of natural gas of \$5 per million Btu. This is comparable to the cost of generating wind power at favorable sites plus grid integration at penetrations of less than 10 percent. The main issue, however, is whether these economic benefits can be captured by wind developers. This is the same issue that affects the realization by the wind farm developer of the retail value of wind-generated electricity, as we saw in Chapter 4 in our case study of the Chino building in Santa Fe.

Appendix A: Assessment of the Cost of Intermittent Wind Output Using Spot-Market Prices

April 9, 2004

In this appendix, we develop a statistical model to assess the cost of intermittent wind energy output (other than minute to minute fluctuations, whose cost we simply add on to the cost of wind power generally), from day to day or hour to hour. We do this by assuming that a fully developed market exists in which customers would demand firm supply. The wind farm operator makes a day-ahead or hour-ahead offer of electricity. We assume that the revenue realized for these sales is the average spot market price for the period in question. We assume that any shortfalls in supply are made up by purchasing electricity at the maximum spot market price for the same period. Finally, we also assume that the wind farm is integrated with a grid, which is suitably regulated to provide sufficient reserve capacity. The cost of short falls in meeting supply commitment in such an arrangement would be reimbursed after the fact to the purchaser. We do not deal with surpluses in generation in this draft. These will be covered in the final version of the report. One option for assessing the value of surpluses is to assume that an arrangement can be made for off-take of any surpluses at the lowest spot market price by a customer with sufficiently large demand relative to anticipated surpluses. We used Dow Jones spot market data for 2003 for the Four Corner hum for these computations.

Under these assumptions, the model can be developed as one that devises an optimal strategy for offering hour-ahead or day-ahead sales. The model is developed below. Examples from the wind data for NM Site 604 for several months for both the day-ahead case and the hour-ahead case are provided. These are also summarized in the main body of the report. The model was developed by Professor Peter Bickel. The computations were done by Aiyou Chen.

A. Optimal Sale Policy of Wind energy Output for a Future Time Period (Day-ahead, hour-ahead)

We want to examine the value that past knowledge of wind speed or power production has on gross income to be expected from wind energy sales by a utility generating wind energy, which we will call the Wind Farm utility. We will apply the general model to a specific favorable wind location in New Mexico: Site 604, for which wind speed data are available (measured during 1999-2001). In conjunction with these wind data, we use the hourly spot market prices for electricity (in dollars per megawatt hour (MWh)) at the Four Corners hub for the year 2003. This hub is one of the major points of export of electricity westward from New Mexico. We do not have a long time series for wind data and assume, for the purposes of this illustration, that the wind data from the time period are sufficiently representative that they will not affect the broad quantitative conclusions of presented here.

The technical framework for the model is that a wind farm operator can commit to selling an amount of electricity in advance, based on his expectation of what the output of wind energy would be in the future period for which the commitment is being made and the cost of falling short. Any shortfalls in the commitment are met by purchases from the grid. This technical arrangement requires that an advance agreement be made that a wind farm operator will purchase grid electricity from some other entity that either has surplus capacity on line or is maintaining spinning reserve. This arrangement provides a form of insurance to the Wind Farm operator that he will be able to meet sales commitments even if the predicted wind does not materialize.

Let *Out* be the actual electricity output, *Avep* and *Maxp* be the average and maximal spot price for the period in question, and *Sale* be the amount of electricity committed for sale. Then the net revenue of the sale is

$$\textbf{Revenue(\textit{sale})} = Sale * Avep - (Sale - Out)_+ * Maxp\,. \quad \textbf{(1)}$$

where the "+" subscript indicates the larger of the expression and zero.

The generic assumption is that if the real electricity output is less than the output sale we claimed, we will have to buy extra electricity with prices *Maxp* higher than the market average price. Suppose that *Out* has a distribution, say *F,* which is to be interpreted as the distribution of *Out*, given the previous period's output. We want to maximize the expectation of Revenue, that is,

$$\textbf{Max \{Expectation of Revenue(\textit{sale})\},} \qquad \textbf{(2)}$$

We can obtain after some statistical analysis that the optimal sale amount depends on the empirical electricity output distribution ***F*** and is given by

$$\textbf{\textit{Sale}} = F^{-1}\left(\frac{Avep}{Maxp}\right). \qquad \textbf{(3)}$$

According to the above model, given the electricity output distribution, we can predict the optimal output sale for the next time period optimally in the sense of maximal expected net revenue. This model can be adapted in general situations, for example, the time period and location can be flexible as long as the output distribution ***F*** for that period and location can be estimated well. Although the spot price changes with time and spatially, the average and maximal daily price for the next time period can be assumed known. Thus the key problem is to estimate the electricity output distribution ***F***.

B. Autoregressive Models for Output

We need to estimate the distribution of daily electricity output. We used an auto-regressive (AR) scheme to model the daily output. This model is a first cut. It can undoubtedly be improved and would be, in real implementation. But we do not expect a better model would give qualitatively different results. Let O(t) be the electricity output for the t-th day. An autoregressive model based on the previous period's (hour or day) price (which we call an AR(1) model) can be expressed by

$$O(t+1) = \beta_0 + \beta_1 O(t) + e(t+1) \quad \textbf{(4)}$$

where e(t) represents the random difference between the best linear predictor based on O(t) and O(t+1). This random difference is supposed to be independent of O(t) and have a distribution which does not depend on t.

A. Daily analysis and Hourly analysis

In the following example we fit the AR(1) model of equation (4) to March 2000 data

(i) with time period, one day
(ii) with time period, one hour.

Having fitted the model, we now use it to predict respectively, daily, hourly output in April 2000. Note that we only use the March data to estimate the parameters β_0 and β_1 of the model. Predictions of output in period t+1 are based on these and the observed output in period t. Thus the output on April 2 would be based on the output of April 1. Sales commitments are then based on formula (3) and revenues (positive or negative) are calculated on the basis of the predicted day's (or hour's) max and average spot prices. Finally, total revenue for the month is calculated by adding up over days, respectively, hours for the month. These figures do not include any computation of revenue for excess production, (more than sale commitment). Details are given below.

C. Example: Sale Prediction for April 2000 at New Mexico site 604

Here we fitted two AR models from March 2000 output data based on daily output and hourly output, and then used the model and the formula (3) to make predictions.

3.1. Daily sale prediction:
The following AR model is thew best fit to the daily output data in March 2000 .Here O(t) is the t-th day's output (MW):

$$O(t+1) = \beta_0 + \beta_1 O(t) + e(t+1),$$

where $\beta_0 = 1.7272e+3$ and $\beta_1 = 0.2531$. Figure 1 provides the residual plots (from the second day to the 30th of March), whose empirical distribution will be used in implementing the formula (3).

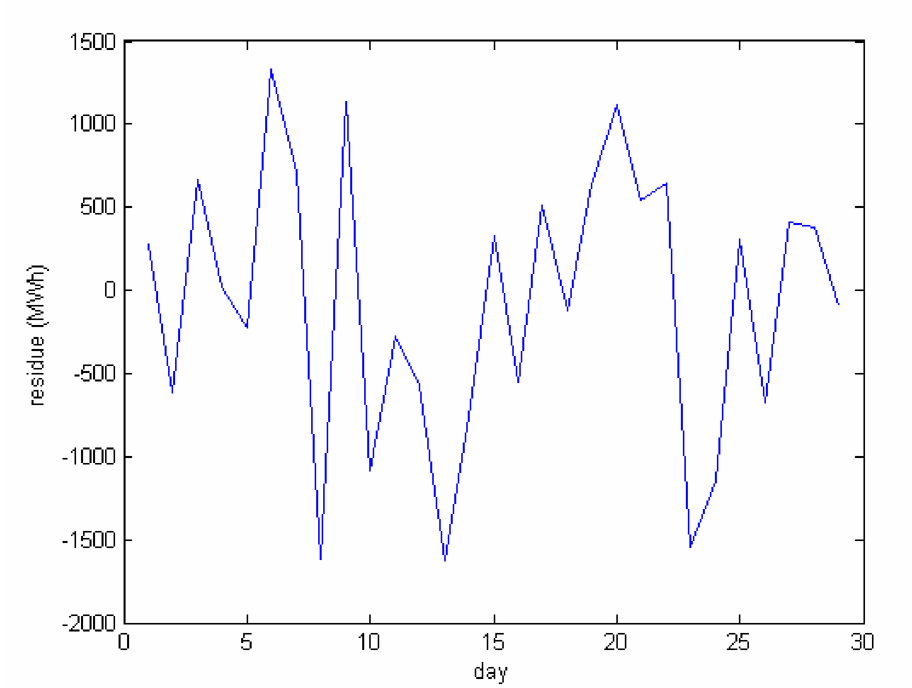

Figure 1: Daily AR(1) residue plots for March 2000

To predict the (t+1)-th day's output sale in April 2001, the following procedure is used, where Sale(t+1) is the predicted sale for the (t+1)th day, O(t) is the t-th day's output, and Avep(t+1), Maxp(t+1) are the average and maximal spot price for the (t+1)th day in April 2003:

$$Sale(t+1) = \beta_0 + \beta_1 O(t) + \hat{F}^{-1}\left(\frac{Avep(t+1)}{Maxp(t+1)}\right)$$

The prediction and real outputs for April 2000 are given in Figure 2.

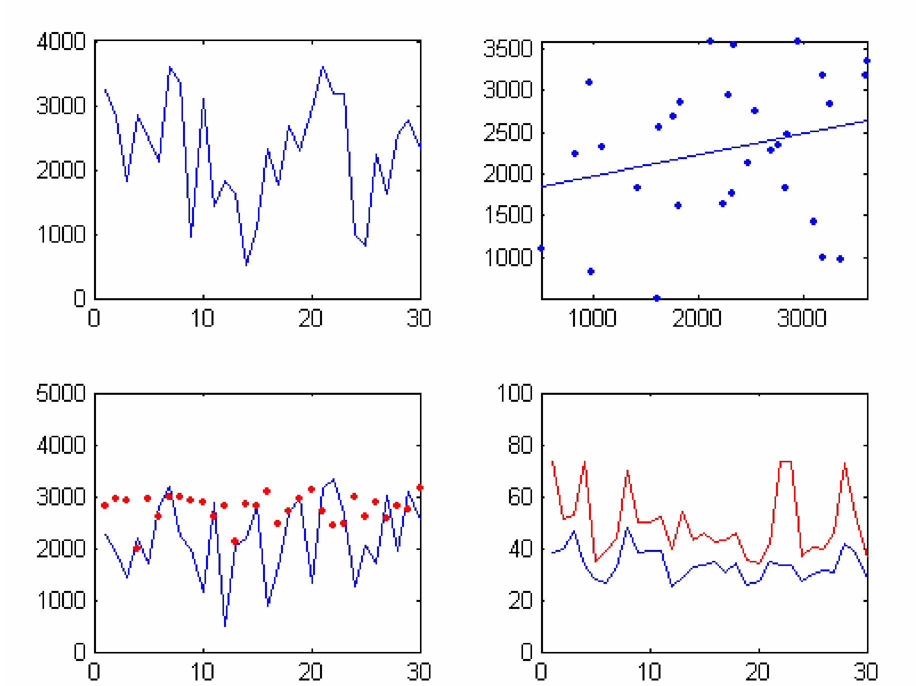

Figure 2: Daily analysis for April 2000: the upper left box plots March's daily output and the upper right plots the above daily AR model fitting, the lower left plots April's daily output and predicted sale (red points), and the lower right plots the average and maximal spot price in April 2003.

As we indicated the fit is not terribly good and the residuals show additional structure, but this is a reasonable first cut and we indicate an appropriate fix in our discussion of the hour to hour autoregression.

Table 1 in the following provides the detailed numbers for April 2000 which include the dates, real daily output, predicted daily sale, the value of the actual output if we had been able to forecast perfectly and actual revenues based on the use of our strategy.

Table 1: Daily Prediction Analysis summary for April 2000 in New Mexico site 604

Date	Actual Output	Output Sale	Difference*	Value of actual output*	actual revenue*
April 2000	(MWh *1K)		(MWh *1K)	($ *1K)	
1	2.3	2.8	-0.5	86.9	68.2
2	1.9	2.9	-1	75.8	64.0
3	1.4	2.9	-1.5	66.1	56.4
4	2.2	2.0	0.2	74.4	67.3
5	1.7	2.9	-1.2	47.7	39.8
6	2.8	2.6	0.2	74.0	68.3
7	3.2	3.0	0.2	104.1	98.0
8	2.2	3.0	-0.8	107.1	90.6
9	2.0	2.9	-0.9	76.1	65.4
10	1.1	2.9	-1.7	44.2	25.0
11	2.9	2.6	0.3	112.1	101.3
12	0.5	2.8	-2.3	12.6	-21.8
13	2.0	2.1	-0.1	58.7	56.3
14	2.2	2.8	-0.6	71.3	64.6
15	2.8	2.8	0	94.2	94.0
16	0.9	3.1	-2.2	29.9	11.9
17	1.6	2.5	-0.8	50.2	39.8
18	2.7	2.7	0	91.7	91.5
19	3.0	2.9	0	76.7	75.7
20	1.3	3.1	-1.8	36.3	24.7
21	3.1	2.7	0.4	108.5	94.0
22	3.3	2.4	0.9	112.9	82.0
23	2.7	2.5	0.2	89.7	83.7
24	1.3	3.0	-1.7	34.6	18.8
25	2.1	2.6	-0.5	61.8	56.3
26	1.7	2.9	-1.2	53.6	43.7
27	3.0	2.6	0.4	93.4	79.7
28	2.0	2.8	-0.8	81.2	54.7
29	3.1	2.8	0.3	118.4	105.0
30	2.5	3.2	-0.6	73.0	68.5
Total	65.5	82.8	-17.3	2, 217.3	1, 867.3
	(MWh *1K)		(MWh *1K)	($ *1K)	
Average price*				$33.87 per MW	$28.52 per MW

* Note of Table 1: **difference** in Column 4 of Table 1 is the difference between actual output and output sale, positive means excess output and negative means lack of output; **Value of actual output** for one day in Column 5 is that day's actual output multiplied by average spot price of the same day in 2003; **Actual revenue for one day** in Column 6 is calculated by formula (1) using that day's output sale, actual output, the average/maximal spot price of the same day in 2003; **Average price** in Column 5 is total Value of actual output of the month divided by the total actual output of the month; **Average price** in Column 6 is total actual revenue of the month divided by total actual output of the month.

5.2. Hourly sale prediction:

The following AR(1) model is the best fit to the hourly output data in March 2000 . O(t) is the t-the hour's output (MW):

$$O(t+1) = \beta_0 + \beta_1 O(t) + e(t+1),$$

where $\beta_0 = 96.3512$ and $\beta_1 = 0.8925$. The following figure provides the residual plots (from the second day to the 31th of March), whose empirical distribution will be used in implementing the formula (3).

The fit to the AR model at this scale is much better .Note that AR(1) at this scale implies a more complex model than AR(1) on the daily scale consistent with the poor fit we found.

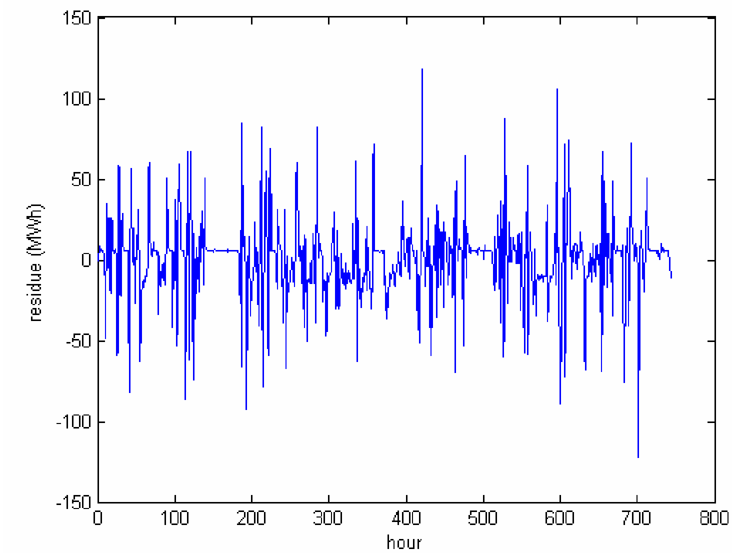

Figure 3: Hourly AR(1) residue plots for March 2000

To predict the (t+1)-th hour's output sale in April 2001, the following procedure is used. Now , Sale(t+1) is the predicted sale for the (t+1)th hour, O(t) is the t-th hour's output, and Avep(t+1), Maxp(t+1) are the average and maximal spot price for the day the (t+1)-th hour belongs to in April 2003:

$$Sale(t+1) = \beta_0 + \beta_1 O(t) + \hat{F}^{-1}\left(\frac{Avep(t+1)}{Maxp(t+1)}\right)$$

Once we have predicted all the hourly sales, then 24-hours summation gives daily sale prediction. The prediction and actual outputs for April 2000 are given Figure 4.

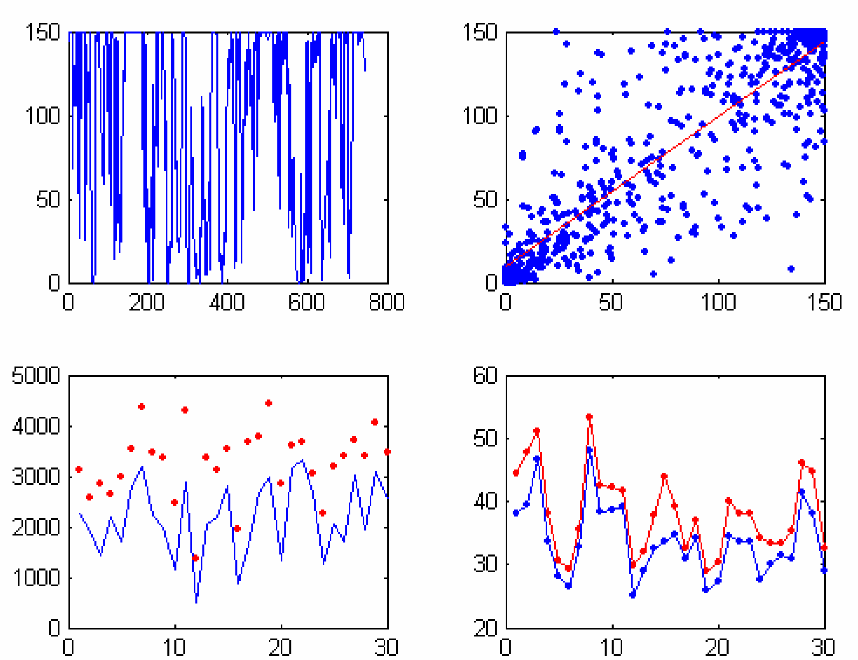

Figure 4: Hourly analysis for April 2000: the upper left plots March's hourly output and the upper right plots the above AR model fitting, the lower left plots April's daily actual output and daily sale (red points, i.e. summation of 24 hours' output sales of the day), and the lower right plots the daily average spot price (blue, i.e. average of each hour's average spot price of the day) and daily maximal spot price (red, i.e. average of each hour's maximal spot price of the day) in April 2003.

Table 2 the following provides the detailed numbers for April 2000 which includes the dates, actual output, output sale, value of actual output and actual revenue (see definitions in the notes below the Table).

Table 2: Hourly Prediction Analysis summary for April 2000 in New Mexico site 604

Date	Actual Output	Output Sale	Unsold actual output **	Value of actual output**	Actual Revenue**
April-00	(MWh *1K)		(MWh)	($ *1K)	
1	2.3	3.1	5.0	76.6	72.9
2	1.9	2.6	67.4	85.5	80.3
3	1.4	2.9	27.6	60.9	57.7
4	2.2	2.6	43.6	74.4	70.9
5	1.7	3.0	74.2	47.5	43.6
6	2.8	3.5	91.1	75.9	72.6
7	3.2	4.3	102.6	103.2	98.4
8	2.2	3.5	0.0	100.3	96.9
9	2.0	3.4	39.4	71.9	68.0
10	1.1	2.5	113.1	37.7	31.9
11	2.9	4.3	3.8	107.3	105.3
12	0.5	1.4	52.7	14.6	10.9
13	2.0	3.3	63.5	57.8	54.1
14	2.2	3.1	82.3	75.1	70.6
15	2.8	3.6	86.8	94.3	88.7
16	0.9	2.0	0.0	28.8	26.6
17	1.6	3.7	0.0	42.8	41.8
18	2.7	3.8	87.3	98.8	94.5
19	3.0	4.4	115	76.1	72.2
20	1.3	2.8	119	37.5	32.9
21	3.1	3.6	3.8	107.2	105.4
22	3.3	3.7	55.0	112.9	109.3
23	2.7	3.1	91.5	89.7	84.5
24	1.3	2.3	17.7	31.0	27.5
25	2.1	3.2	102.6	57.2	51.9
26	1.7	3.4	54.8	46.2	43.4
27	3.0	3.7	87.3	95.2	92.0
28	2.0	3.4	21.4	77.7	75.1
29	3.1	4.1	51.1	114.7	110.3
30	2.5	3.5	99.4	74.2	69.3
Total	65.5	97.5	1.8	2, 172.9	2, 059.5
	(MWh *1K)		(MWh *1K)	(thousand dollars)	
Average price**				$33.2 per MW	$31.5 per MW

** Note of Table 2: **Unsold actual output** in Column 4 is the summation of each hour's excess output of the day.
Value of actual output for one day based on hourly analysis in Column 5 is the summation of each hour's value of actual output in that day, where each hour's value is that hour's output multiplied by average spot price in the same month/day/hour in 2003; **Actual revenue** for each day in Column 6 is the summation of each hour's revenue in that day; **Average price** in Column 5 is total value of actual output of the month divided by total actual output of the month; **Average price** in Column 6 is total actual revenue of the month divided by total actual output of the month.

B. Computation of total revenues for 14 months incorporating a proposed accounting for excess production.

We now give a summary table for the 14 months of observations at site 604 based on hourly analysis. Revenues are always calculated using prediction parameters from the previous month. In addition, we show total actual monthly output and monthly excess output. We finally give a nominal value to the excess output, i.e., for each hour it is the excess output multiplied by that hour's minimal spot price, and we report the total for each month.

Table 3: Summary of Hourly analysis for 14 months at site 604

Month	Actual Revenue	Actual output	Value of actual output	Average sale price	Oracle Average sale price	Unsold actual output	Nominal value of unsold actual output
	($*1K)	(MWh*1K)	($*1K)	($/MWh)	($/MWh)	(MWh*1K)	($*1K)
April, 00	2, 059.48	65.47	2, 172.86	31.46	33.19	1.76	43.71
May, 00	1, 811.80	61.50	1, 944.89	29.46	31.62	1.75	48.47
June, 00	1, 483.36	50.01	1, 655.72	29.66	33.11	2.41	62.05
July, 00	1, 815.07	42.23	1, 977.37	42.98	46.82	1.17	46.59
Aug., 00	1, 872.89	50.17	2, 021.02	37.33	40.28	1.37	43.78
Sept., 00	1, 865.94	54.36	1, 995.11	34.33	36.70	1.54	46.37
Oct., 00	1, 371.26	42.20	1, 516.29	32.49	35.93	1.34	37.37
Nov., 00	1, 755.01	56.48	1, 884.03	31.07	33.36	1.83	48.55
Dec., 00	2, 428.72	65.75	2, 529.51	36.93	39.19	1.66	50.36
Jan., 01	1, 524.89	50.26	1, 657.95	30.22	32.40	1.32	27.84
Feb., 01	2, 349.80	53.93	2, 532.76	43.57	46.88	2.18	78.65
Mar., 01	2, 159.16	48.68	2, 332.30	44.41	48.46	1.38	45.31
April, 01	1, 761.38	54.90	1, 882.57	32.09	34.29	1.75	47.23
May, 01	1, 204.58	45.15	1, 369.77	26.68	30.34	1.99	55.85

Notes to Table 3:
Value of actual output for one month is the summation over the month of the value of each hour's actual output multiplied by the average spot price of the same month/day/hour in 2003;
Average sale price for one month is the actual revenue of the month divided by that month's actual output;
Oracle average sale price for one month is the value of actual output divided by total actual output;
Unsold actual output for one month is the summation of each hour's excess output in that month, where excess output for hour t = max(0, actual output in hour t minus output sale for hour t);
Nominal value of unsold actual output for one month is the summation of each hour's nominal value of unsold actual output in that month, where one hour's nominal value of unsold actual output is the unsold actual output in that hour multiplied by the minimal spot price in the same month/day/hour in 2003.