Arnold Schwarzenegger
Governor

WIND POWER GENERATION TRENDS

PIER INTERIM PROJECT REPORT

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Wind Power Generation Trends

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION

1.1 California Wind Energy Consortium

The importance of wind energy has long been recognized by the California Energy Commission (ENERGY COMMISSION), which supports research and development in renewable energy including wind through its Public Interest Energy Research (PIER) Program. Wind energy provides significant benefits in terms of improved air quality, increased diversity in electric energy sources, local and state revenues, and employment. Still, wind energy development in California faces a large number of minor and major impediments.

In an effort to foster additional development of wind energy in the state, the ENERGY COMMISSION created the California Wind Energy Consortium (CWEC), which is managed by the University of California at Davis. The mission statement of the California Wind Energy Consortium (the Consortium) is to support the development of safe, reliable, environmentally sound, and affordable wind electric generation capacity within the state of California. To fulfill this mission, the Consortium will manage a focused, statewide program of scientific research, technology development and deployment, and technical training. The effort is conducted in close cooperation with industry, state and federal agencies, and other institutions to maximize the benefits of wind energy resources in California for its citizens.

1.2 Wind Turbine Generator Optimization

One of the Consortium's first assignments was a series of white papers, whose purpose was to review the performance of wind turbines in typical operating environments. Wind turbine power generation characteristics are affected by a wide range of factors including: seasonal changes in air density, blade soiling (insect debris, dust, etc.), control system interactions with turbulent winds, maintenance procedures, and connection issues to the electrical transmission system. These factors impact both the cost and the value of wind power production. The goal of this effort is to evaluate performance issues and identify methods and procedures for maximizing wind energy generation and value.

Three topic areas were identified for the white papers: 1) daily wind power generation trends, 2) optimization of wind turbine peak capacities, and 3) transmission interconnection issues and standards. This report includes data evaluations, commentary, and review in the first two topic areas. The goal of this effort was to establish a sense for the variations in wind power generation in California and assess the change in these levels according to the time of day and the season of the year. Representative wind data was obtained and adjusted to standard air density. This data was then used to determine the power output of three representative 1 MW wind turbines with different rotor sizes: 50 meter diameter, 70 m diameter, and 90 meter diameter. The output from these turbines was compared against the statewide system electrical demand and trends were observed.

2.0 WIND TURBINE GENERATOR DESCRIPTION

2.1 Wind Generator Technology Overview

Worldwide wind power capacity has been expanding rapidly and by the end of 2001, the cumulative installed wind generating capacity was approximately 25,800 MW, with about 1667 MW located in California [1]. A combination of wind technology improvements, cost reductions, and government policy incentives have created a strong market for wind turbines and their components throughout the world. Design and manufacturing improvements continue to reduce the cost of wind energy and increase its reliability.

In the past twenty years, several varieties of wind turbine architectures were developed, installed, and tested with varying degrees of technical and economic success. Today the global wind industry is dominated by turbines that are mounted on a horizontal axis, with three blades, an upwind rotor, an active yaw drive system, and a freestanding tower. This generalized architecture now accounts for nearly all utility scale wind turbine installations and has become the de facto industry standard. Important design variations remain within the standard architecture related to power regulation, pitch adjustment, speed control, and yaw system design.

Most manufacturers are continuing to develop new turbine designs in the megawatt size range [2]. Current trends, however, suggest that turbine size in terrestrial sites may reach a stable design region in the general rotor size of 40 to 80 meters and rated power output of 500 to 2000 kW. Turbines on the small side of this range will have an advantage in complex terrain, because they can be transported and erected more easily. Turbines on the large side of the range will be preferred in densely populated regions because of reduced land use impact, and along accessible ridges, where heavy lift equipment can be operated during construction and installation.

For nearly twenty years, a continuing reduction in the cost of wind energy has come through increasing the size of the turbines. Additional major reductions in the cost of wind energy are unlikely to result from increased turbine scale alone. Improving cost effectiveness will increasingly rely on manufacturing efficiencies, design optimization for specific site conditions, and elimination of premature component failures. This represents a change in engineering approach and development philosophy, which has not been generally recognized by the industry.

Turbine optimization for specific wind regimes and climate conditions is becoming more common as the market expands and matures. Specific power is an important parameter governing the performance of a wind turbine system, and is defined as the rated power in watts divided by the swept area of its rotor in square meters (W/m^2). In general terms a turbine with a high specific power will be more economic in sites with higher wind speeds, while those with lower specific power are more suitable for low wind regimes. A summary of specific power for a number of selected utility scale wind turbines is provided in Table 2.1. This data shows that the specific power of existing, commercially available wind turbine generation equipment is within a range between 280 and 500 W/m^2.

Table 2.1 Specific Power of Selected Wind Turbines

Manufacturer	Rated Power (MW)	Rotor Diameter (m)	Specific Power (W/m2)
Vestas	0.660	47.0	380
Bonus	0.600	42.0	433
Nordex	0.600	43.0	413
Mitsubishi	0.600	44.0	395
NEG Micon	0.750	48.0	414
GE Wind	0.900	52.0	424
NEG Micon	0.900	52.0	424
Bonus	1.000	54.2	433
Nordex	1.000	54.0	437
Mitsubishi	1.000	54.0	437
Bonus	1.300	63.0	417
Nordex	1.300	60.0	460
GE Wind	1.500	70.5	384
GE Wind	1.500	77.0	322
NEG Micon	1.500	72.0	368
NEG Micon	1.500	82.0	284
Vestas	1.800	80.0	358
Bonus	2.000	76.0	441
NEG Micon	2.500	80.0	497
NEG Micon	2.750	92.0	414

Manufacturers are beginning to offer several different rotor sizes for a given wind turbine model. GE Wind Energy, NEG Micon, and other major wind turbine manufacturers are offering machines whose specific power can be better optimized to localized site conditions. There is also a trend toward development of turbines with relatively low specific power output. This trend has been pushed forward by the market in Germany, where large rotor designs are economically viable and high levels of installed wind capacity leave few remaining high wind energy resources for new construction.

2.2 Turbine Performance Model

For purposes of this study we evaluated the performance of several representative 1 MW wind turbines. Three different rotor diameters were studied (50 m, 70 m, and 90 m) as shown in Table 2.2 and Figures 2.1 and 2.2. The specific power of the first two model turbines brackets the existing range (509 to 260 W/m^2), while the third model explores a design region that is not commercially available at the present time.

Table 2.2 Specific Power of Model Wind Turbines

Rated Power (MW)	Rotor Diameter (m)	Specific Power (W/m2)
1.000	50.0	509
1.000	70.0	260
1.000	90.0	157

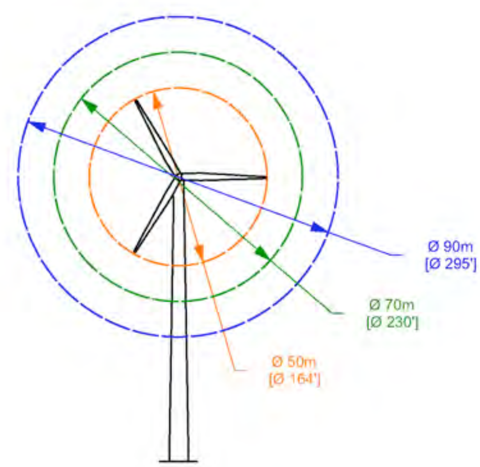

Figure 2.1 Rotor Diameter of Model Wind Turbines

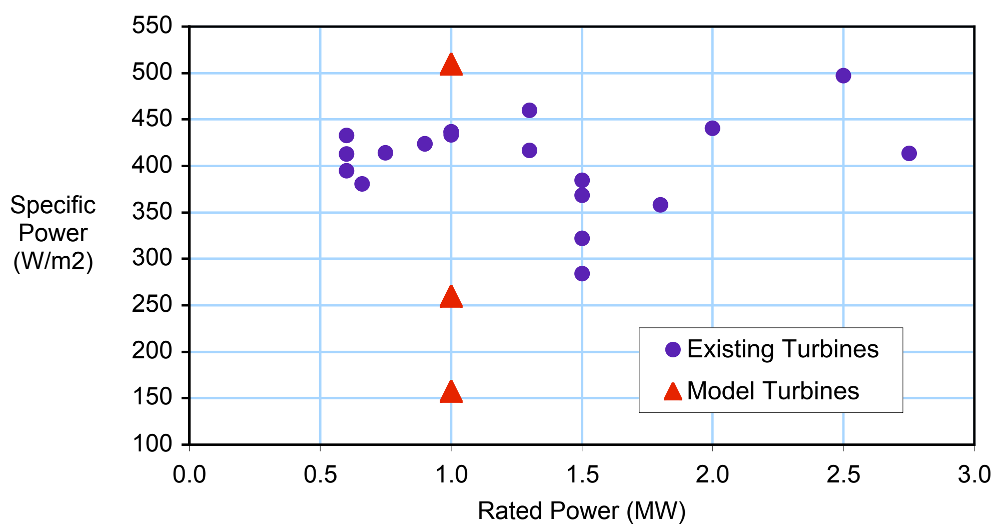

Figure 2.2 Specific Power as a Function of Rated Power for Existing Turbines and Model Turbines

The reference wind turbine blade planform characteristics were defined non-dimensionally as a function of the rotor radius, as shown in Table 2.3 and Figure 2.3 and the blade length was scaled as necessary to match each of three rotor sizes studied. The blade characteristics are representative of current technology.

Table 2.3 Blade Planform Definition

Radius Ratio	Chord Ratio	Twist Deg
5%	5.2%	29.5
15%	7.8%	19.5
25%	8.6%	13.0
35%	7.6%	8.8
45%	6.6%	6.2
55%	5.7%	4.4
65%	4.9%	3.1
75%	4.0%	1.9
85%	3.2%	0.8
95%	2.4%	0.0

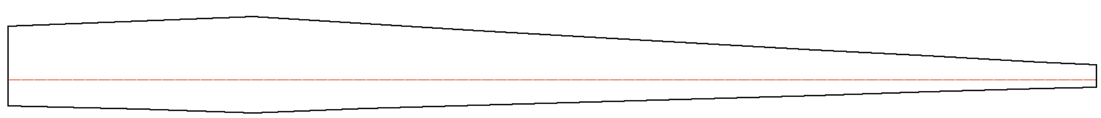

Figure 2.3 Blade Planform Drawing

The performance of the wind turbine rotor was calculated using blade element momentum theory and a summary of the non-dimensional rotor performance is provided in Table 2.4. The rotors were assumed to operate at constant speed, with peak power output limited by blade pitch adjustment.

Table 2.4 Summary of Rotor Non-Dimensional Performance

Tip Speed Ratio	Power Coeff. Cp	Thrust Coeff. Ct
18.00	0.002	1.096
15.00	0.244	1.022
13.00	0.361	0.966
12.00	0.409	0.937
11.00	0.452	0.907
10.00	0.485	0.872
9.00	0.502	0.829
8.00	0.498	0.773
7.50	0.485	0.737
7.00	0.470	0.699
6.50	0.453	0.659
6.00	0.430	0.611
5.50	0.389	0.548
5.00	0.316	0.460
4.50	0.240	0.375
4.25	0.201	0.333
4.00	0.165	0.294
3.75	0.138	0.261
3.50	0.113	0.232

Table 2.5 Summary of Turbine Rotor Properties

Rotor Diameter (m)	Rotor Speed (rpm)	Tip Speed (m/s)	Rated Wind (m/s)
50	28.6	75.0	13.2
70	16.4	60.0	10.5
90	10.6	50.0	9.0

Drive train efficiency was included in the performance model. Although the basic turbine rating was 1 MW, the gearbox and generator were assumed to have design ratings of 1.5 MW and 1.15 MW to provide sufficient margin for transient loads. The drive efficiencies were determined from the rotor input power, assuming the values provided in Table 2.6. Power curves were developed for each model variant and are shown graphically in Table 2.7 and Figure 2.4. The larger rotor turbines were assumed to shut-down earlier in high winds in order to limit peak operating loads on the equipment, and the power curves reflect this constraint on the upper operating range.

Table 2.6 Drive Train Efficiency Model

Input (MW)	Gearbox Efficiency	Generator Efficiency	Drive Train Efficiency	Output (MW)
0.000	1.0%	1.0%	0.0%	0.000
0.038	70.0%	31.9%	22.4%	0.008
0.075	80.0%	62.9%	50.3%	0.038
0.150	89.0%	86.8%	77.2%	0.116
0.300	94.0%	90.8%	85.3%	0.256
0.450	96.0%	91.5%	87.8%	0.395
0.600	97.0%	91.5%	88.8%	0.533
0.750	98.0%	91.1%	89.3%	0.670
1.500	98.0%	89.5%	87.7%	1.316

Table 2.7 Turbine Power Output as a Function of Wind Speed

Wind Speed (m/s)	50 m Rotor (MW)	70 m Rotor (MW)	90 m Rotor (MW)
0	0.000	0.000	0.000
1	0.000	0.000	0.000
2	0.000	0.000	0.000
3	0.000	0.000	0.002
4	0.000	0.005	0.049
5	0.005	0.077	0.194
6	0.054	0.204	0.370
7	0.151	0.355	0.570
8	0.261	0.523	0.796
9	0.387	0.712	1.000
10	0.521	0.911	1.000
11	0.671	1.000	1.000
12	0.829	1.000	1.000

Wind Speed (m/s)	50 m Rotor (MW)	70 m Rotor (MW)	90 m Rotor (MW)
13	0.983	1.000	1.000
14	1.000	1.000	1.000
15	1.000	1.000	1.000
16	1.000	1.000	0.500
17	1.000	1.000	0.000
18	1.000	1.000	0.000
19	1.000	0.500	0.000
20	1.000	0.000	0.000
21	1.000	0.000	0.000
22	1.000	0.000	0.000
23	1.000	0.000	0.000
24	0.500	0.000	0.000
25	0.000	0.000	0.000

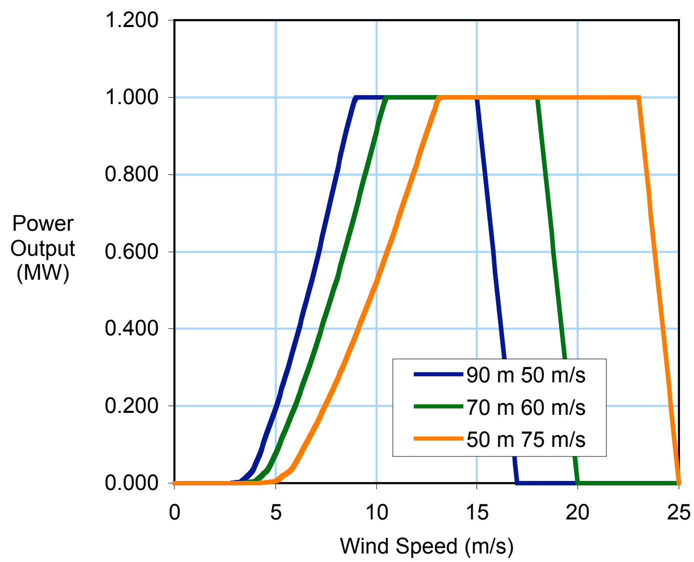

Figure 2.4 Turbine Power Curve Comparison

Although the power curves included turbine performance losses from control system interactions at shut-down, they do not include mechanical availability, wind plant array efficiency (wake losses), collection system efficiency, or losses due to blade soiling. Wind plant efficiency varies with specific site conditions and turbine layouts. Typically the total plant efficiency will be in a range from 85% to 95%.

3.0 POWER GENERATION AND DEMAND

3.1 Yearly Wind Power Generation

The power generation of a commercial wind turbine is time variant, but follows regular daily and seasonal patterns. One of the goals of this study was to review representative wind turbine generation as a function of time for a full year. Meteorological data was obtained from a commercial wind plant located in the Tehachapi Mountain resource area. This region has the largest installed wind capacity in the state [2] and leads the state in wind energy generation.

The meteorological data were recorded as ten minute averages and were corrected to standard atmospheric density using the IEC power performance methodology [3]. The wind speeds were then adjusted linearly to obtain average annual wind speeds of 6 m/s, 7 m/s, and 8 m/s. The resulting data were representative of the pattern of winds in Tehachapi region for 2001 over a broad range of average wind speeds. The wind data were used to estimate electrical output using the turbine power curves presented in Table 2.7 and Figure 2.4.

Power output is often characterized by the capacity factor, which is a non-dimensional representation of the power output as a fraction of the maximum, or rated, power of the generator. For a wind turbine rated at 1 MW, the power output in MW and the capacity factor are equal to one another. Representative time series of power generation capacity during each quarter of 2001 are provided in Figures 3.1 through 3.4 for the 70 meter diameter wind turbine operating at a 7 m/s reference site.

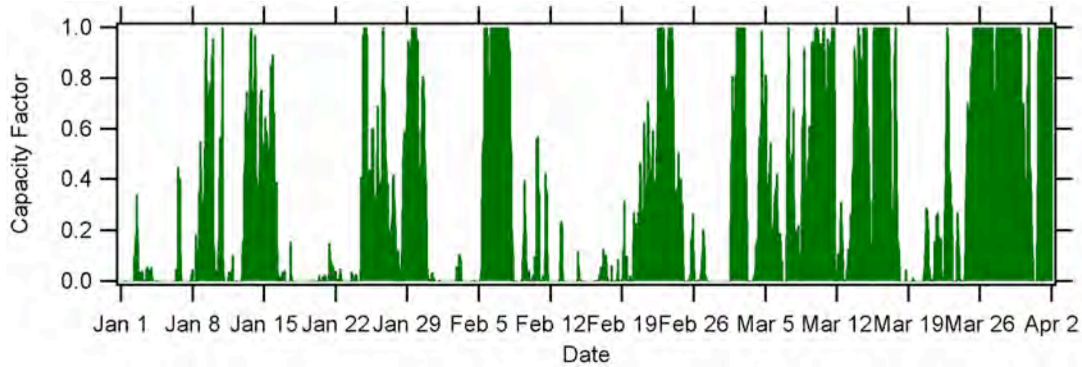

Figure 3.1 First Quarter 2001 Power Generation at the 7 m/s Site

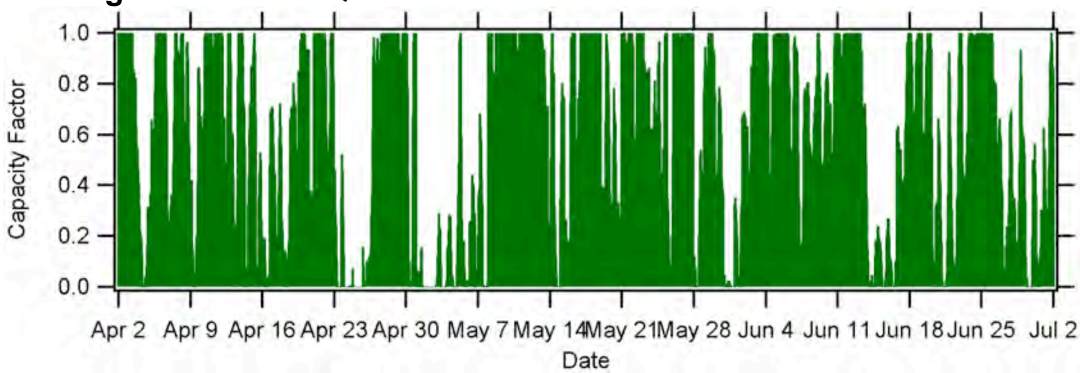

Figure 3.2 Second Quarter 2001 Power Generation at the 7 m/s Site

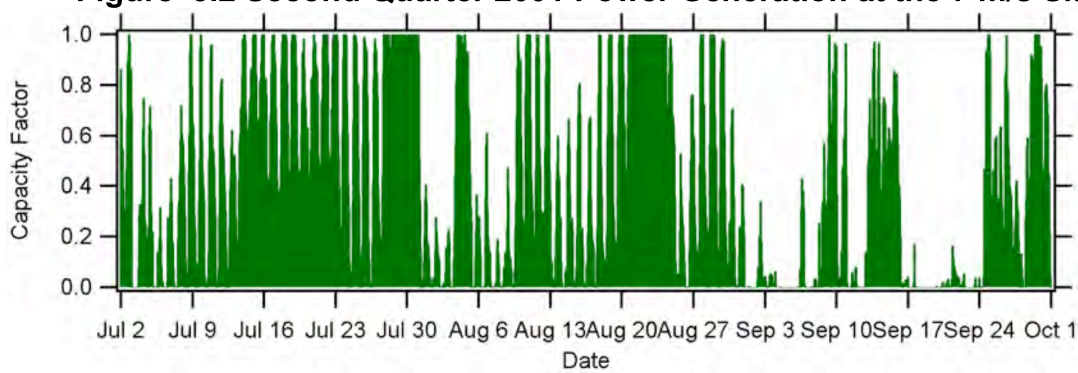

Figure 3.3 Third Quarter 2001 Power Generation at the 7 m/s Site

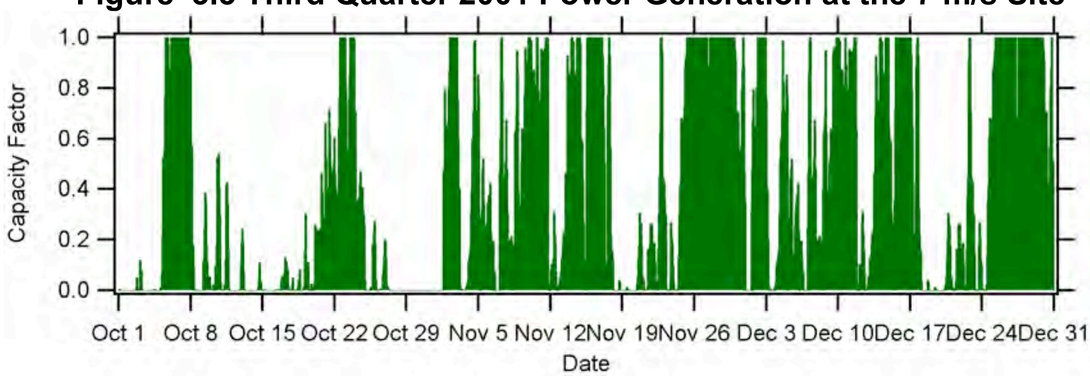

Figure 3.4 Fourth Quarter 2001 Power Generation at the 7 m/s Site

A summary of the average annual capacity is provided in Table 2.8 for each turbine size and reference wind speed. The data in this table are based upon an assumed 100% wind plant efficiency and actual capacities will be somewhat lower. The same capacity factor data is shown graphically in Figure 3.5. This chart shows the strong effect of rotor diameter on turbine capacity and the potential gains that can be made with large rotors. The graph also shows that restricting the upper operating ranges (as shown in Figure 2.4) has minimal impact on generation capacity for average wind speeds less than 7 m/s.

Table 2.8 Turbine Capacity Factor as a Function of Wind Speed

Wind Speed (m/s)	Annual Capacity Factor Rotor Diameter (m)		
	50 m	70 m	90 m
6	18.6%	31.0%	41.0%
7	27.0%	40.4%	48.5%
8	35.0%	47.4%	51.2%

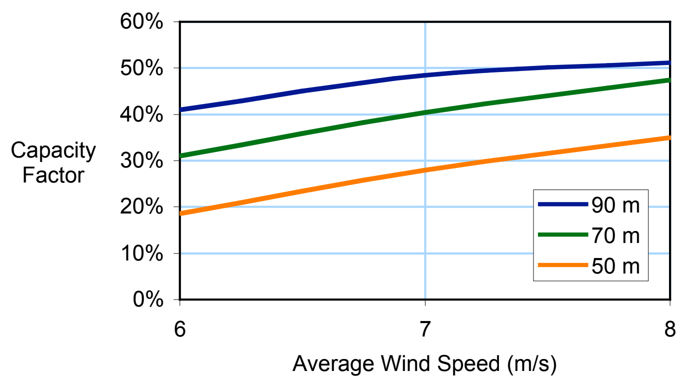

Figure 3.5 Turbine Average Annual Capacity Factor as a Function of Wind Speed and Rotor Diameter

3.2 Diurnal Generation Patterns

Wind turbine power generation varies considerably over time, but significant diurnal and seasonal patterns are evident in the data. To depict these patterns, the ten-minute power output/capacity factor data were averaged over the entire month and plotted as a function of the time of day for a given month. The diurnal power generation pattern for the months of March, April, November, and December is provided in Figure 3.6 for the 70 m rotor operating at the 7 m/s reference site. There is a consistent diurnal pattern in the capacity factor during these months, with a relatively strong average capacity factor of 50.1%. This pattern is notably different than the diurnal patterns shown in the months of January, February, September, and October (Figure 3.7), which is characterized by low average capacity factor (18.9%). The months of May, June, July, and August exhibit a strong diurnal pattern and a high average capacity factor of 52.1% as shown in Figure 3.8. May is a transition period and has a diurnal pattern which differs from the others in this group. July and August show the strongest diurnal fluctuations in generating capacity.

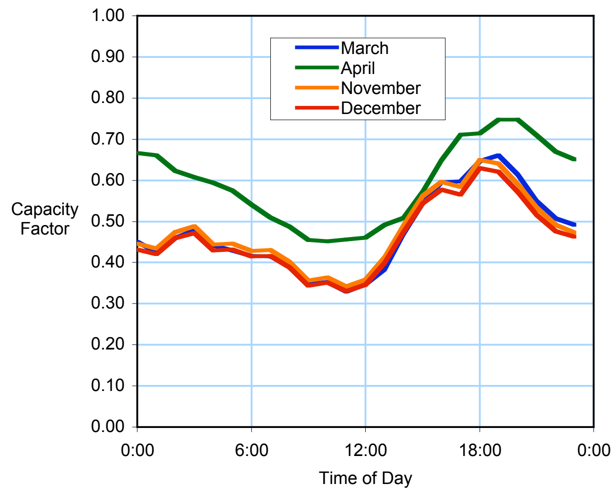

Figure 3.6 March, April, November, and December Daily Capacity Factor for the 70 m Turbine and 7 m/s Wind Speed

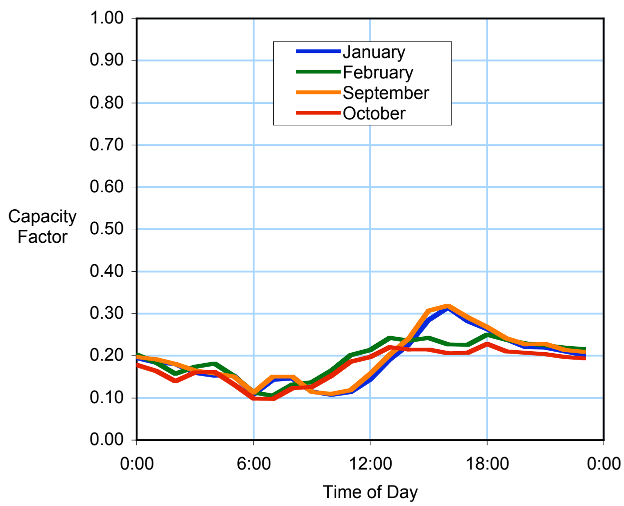

Figure 3.7 January, February, September, and October Daily Capacity Factor for the 70 m Turbine and 7 m/s Wind Speed

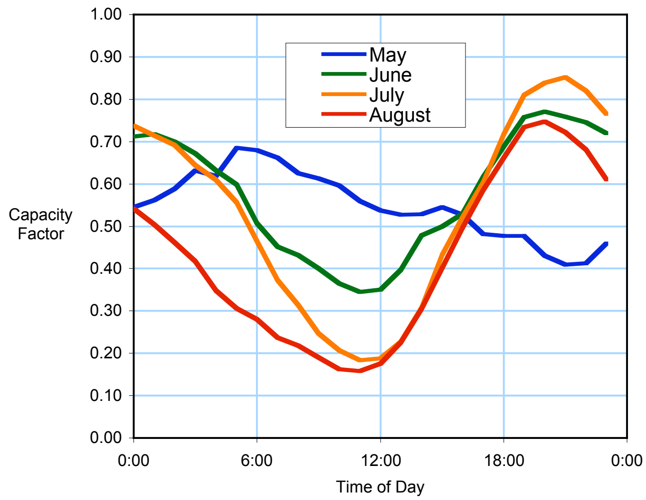

Figure 3.8 May, June, July, and August Daily Capacity Factor for the 70 m Turbine and 7 m/s Wind Speed

It is interesting to note that the observed diurnal patterns are not exactly symmetrical according to the season. The winter/fall diurnal patterns alternate with each other and may be related to the passage of large-scale weather systems. This observation will require further investigation to identify the underlying causes.

It is important to remember that observed patterns are the result of local and regional meteorological conditions; they should not be viewed as representative of the state as a whole. Rather, these data show that wind generation is not random and can be characterized by the time of year and the time of day.

3.3 Statewide Power Demand

Electric power demand also exhibits time dependent patterns that have strong seasonal and diurnal variation. The statewide electrical power demand was obtained from the California Independent System Operator (CAISO) as hourly averages for 2001. These data are plotted graphically by quarter in Figures 3.9 through 3.12. The maximum statewide power demand was 41.2 GW and the minimum demand was 17.7 GW.

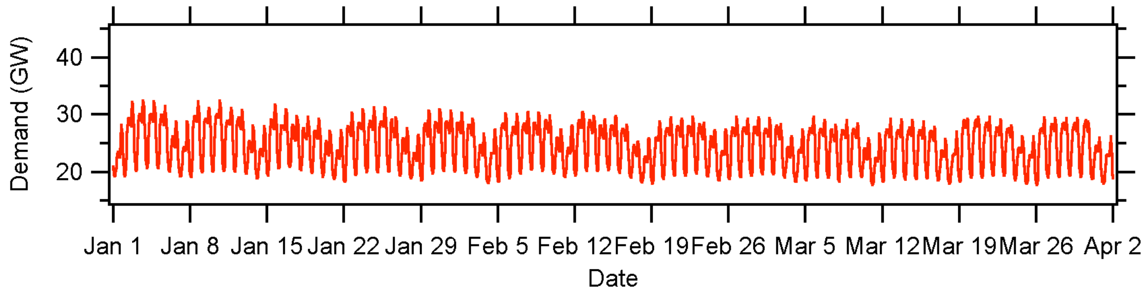

Figure 3.9 First Quarter 2001 Power Demand

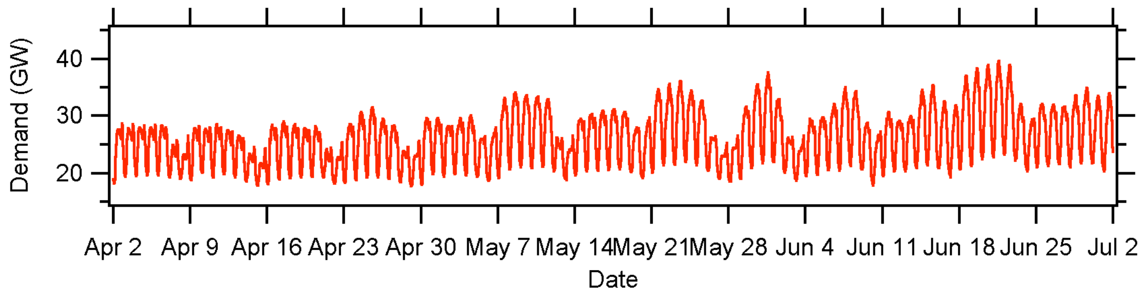

Figure 3.10 Second Quarter 2001 Power Demand

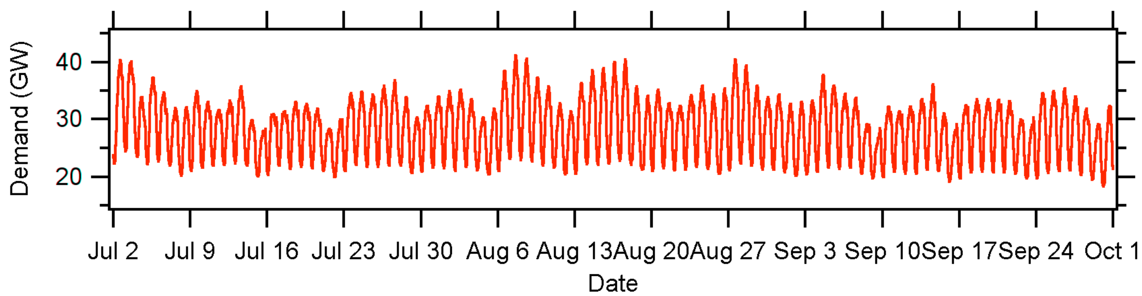

Figure 3.11 Third Quarter 2001 Power Demand

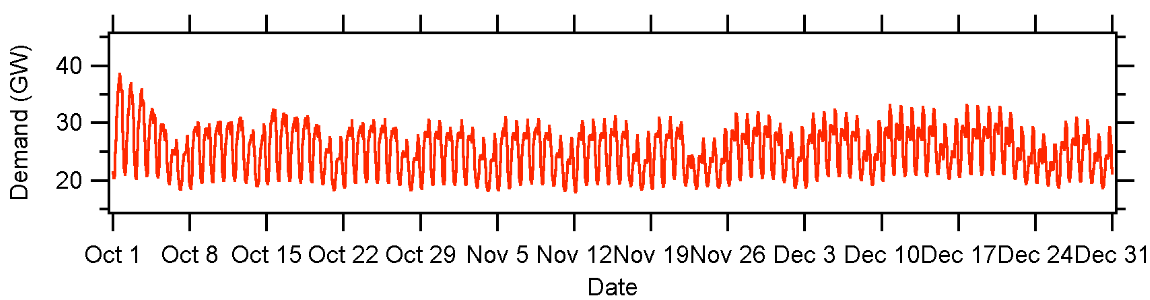

Figure 3.12 Fourth Quarter 2001 Power Demand

Power demand shows a strong diurnal variation of approximately 8 to 18 GW. The diurnal variation becomes more pronounced in the summer months due to air conditioning demands. Average daily power demand was calculated on a monthly basis and is shown graphically in Figures 3.13 through 3.16. The data were converted to a non-dimensional form called a demand factor. The demand factor was calculated for each hour by dividing the value by the peak power for the year 2001. Thus, the graphs show power demand as a average hourly fraction of the maximum system demand.

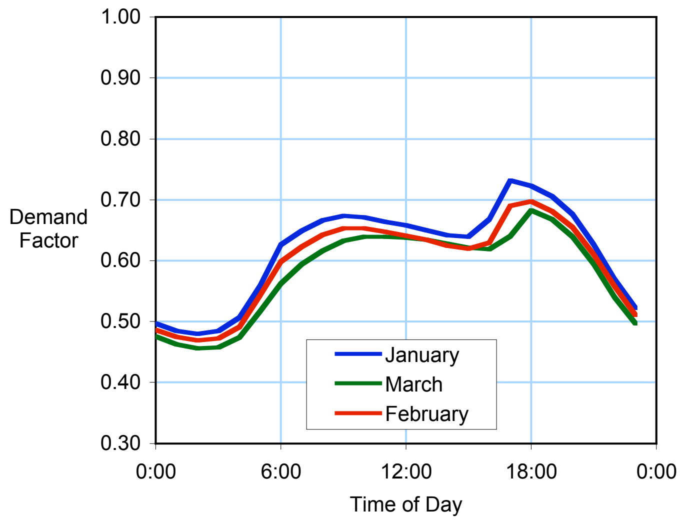

Figure 3.13 First Quarter 2001 Average Daily Demand Factor

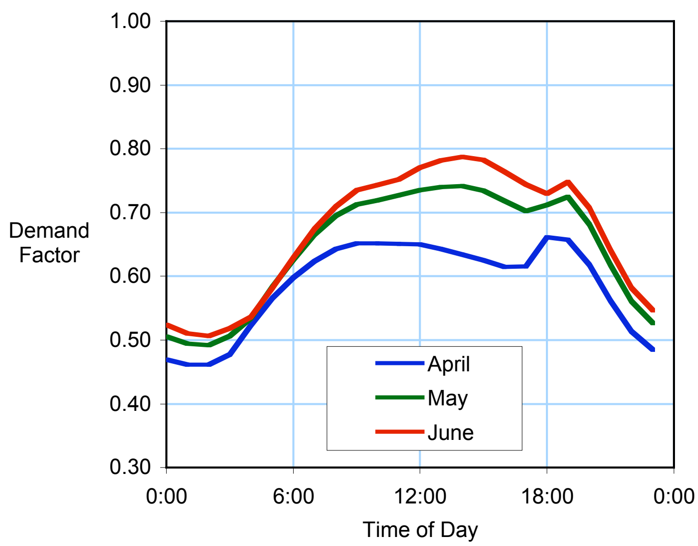

Figure 3.14 Second Quarter 2001 Average Daily Demand

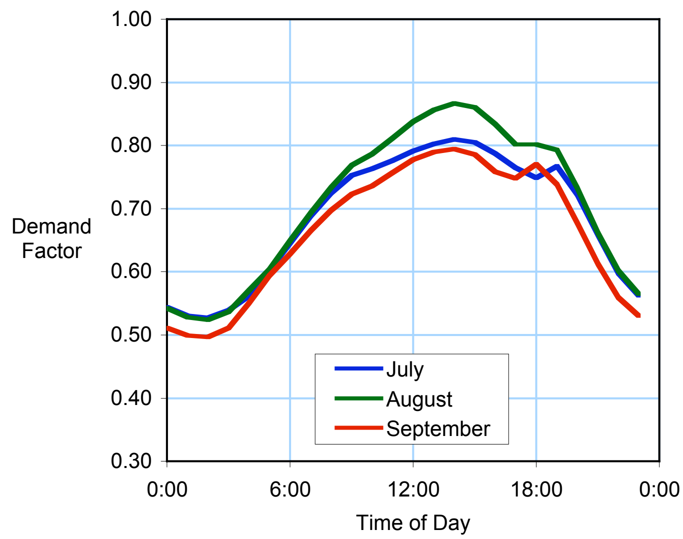

Figure 3.15 Third Quarter 2001 Average Daily Demand

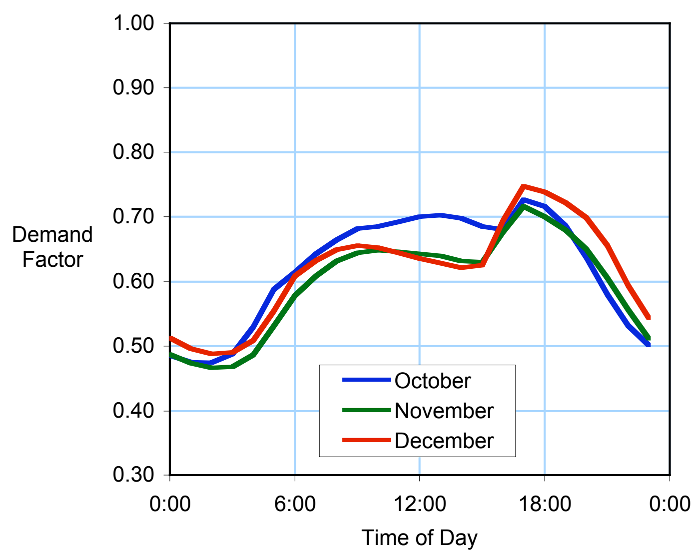

Figure 3.16 Fourth Quarter 2001 Average Daily Demand

3.4 Peak Demand Periods

The top ten peak demand periods all occurred during the summer months and are summarized in Table 3.1. The month of August had the most peak demand days and the time of peak demand was generally in the mid-afternoon around 3:00 p.m.

Table 3.1 Top Ten Peak Demand Days of 2001

Date	Time	Demand (GW)	Demand Factor
June 21	3:00 PM	39.6	96.1%
June 22	1:00 PM	38.1	92.5%
July 2	3:00 PM	40.2	97.6%
July 3	3:00 PM	40.1	97.3%
August 7	3:00 PM	41.2	100.0%
August 8	3:00 PM	40.5	98.3%
August 16	3:00 PM	39.9	96.8%
August 17	2:00 PM	40.0	97.1%
August 27	3:00 PM	40.4	98.1%
August 28	3:00 PM	39.4	95.6%

Time series plots of wind turbine capacity factor and statewide demand factor are shown in Figures 3.17 to 3.19 for a summer peak period and in Figures 3.20 to 3.22 for a summer non-peak period. These graphs illustrate the effects of site average wind speed and rotor size on generator capacity over time. The graphs show clearly how larger rotors reach rated power earlier, and maintain it over a longer period, thereby improving average capacity factor and load matching.

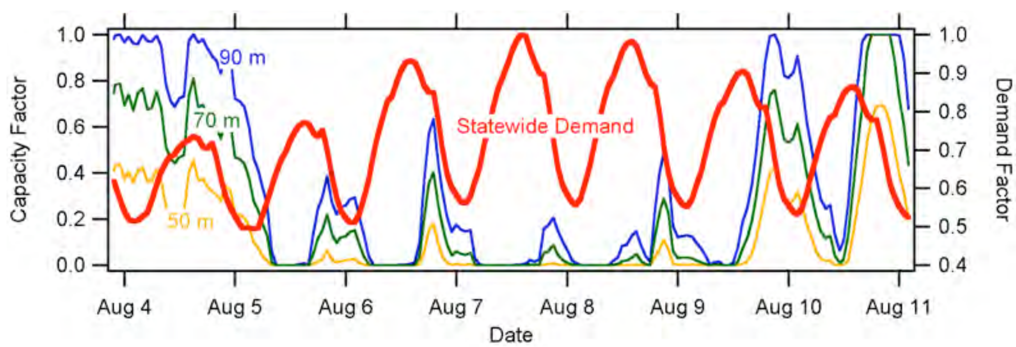

Figure 3.17 Turbine Capacity and Statewide Demand During a Summer Peak Period at the 6 m/s Reference Site

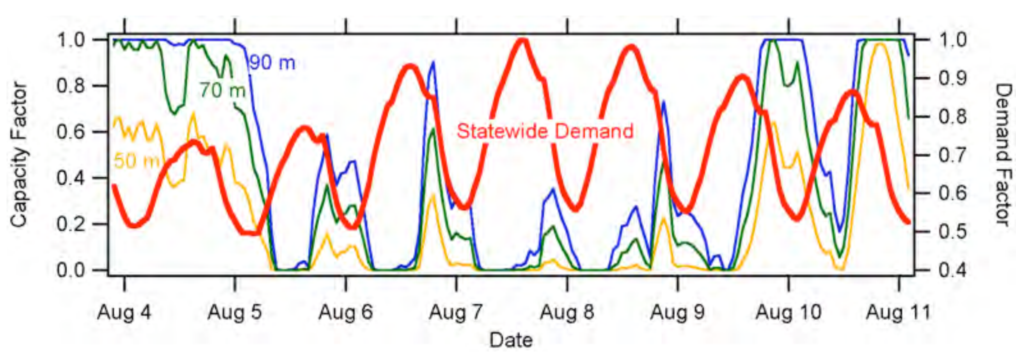

Figure 3.18 Turbine Capacity and Statewide Demand During a Summer Peak Period at the 7 m/s Reference Site

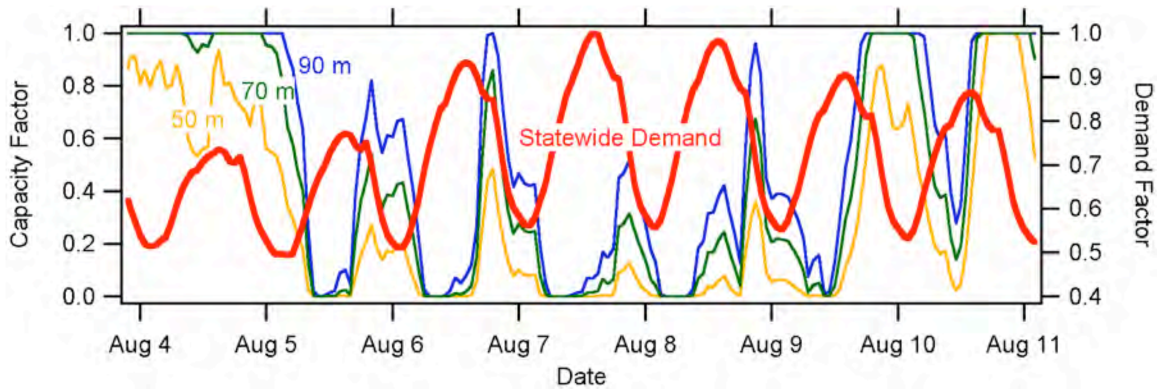

Figure 3.19 Turbine Capacity and Statewide Demand During a Summer Peak Period at the 8 m/s Reference Site

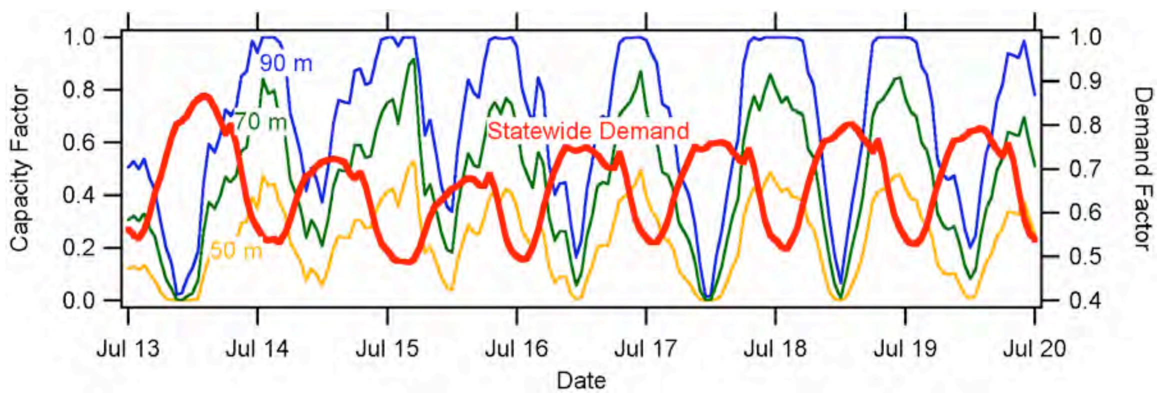

Figure 3.20 Turbine Capacity and Statewide Demand During a Summer Non-Peak Period at the 6 m/s Reference Site

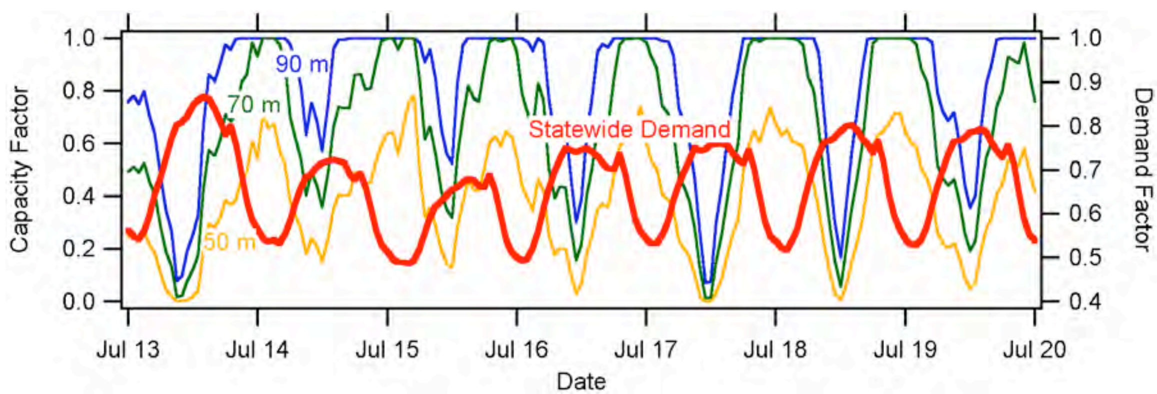

Figure 3.21 Turbine Capacity and Statewide Demand During a Summer Non-Peak Period at the 7 m/s Reference Site

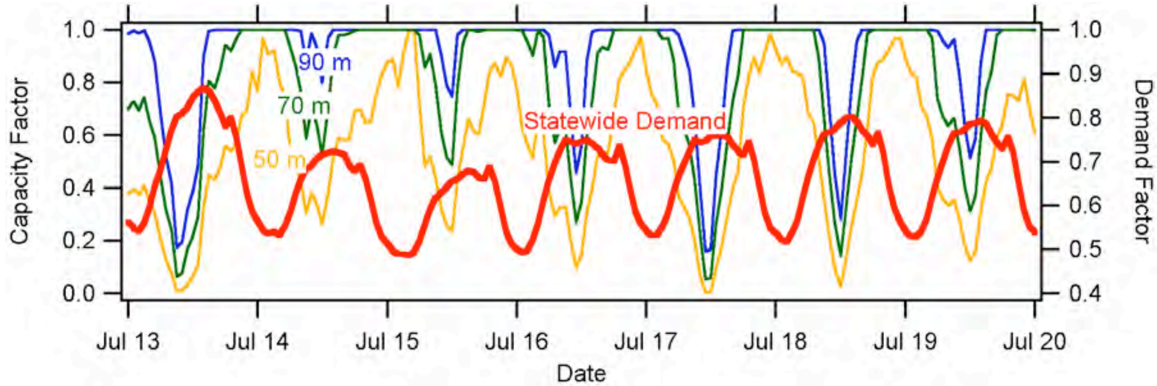

Figure 3.22 Turbine Capacity and Statewide Demand During a Summer Non-Peak Period at the 8 m/s Reference Site

A graph of average wind turbine capacity factor as a function of statewide demand factor is provided in Figures 3.23 to Figure 3.25.

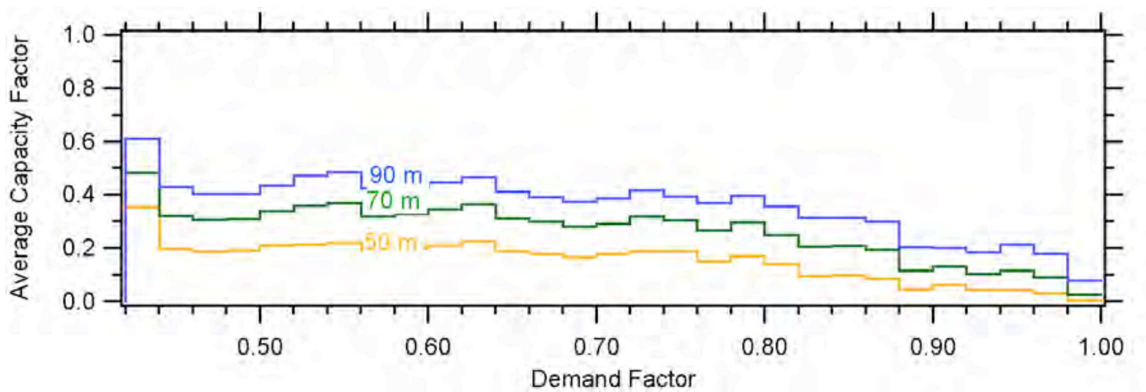

Figure 3.23 Average Capacity Factor as a Function of Demand Factor at the 6 m/s Reference Site

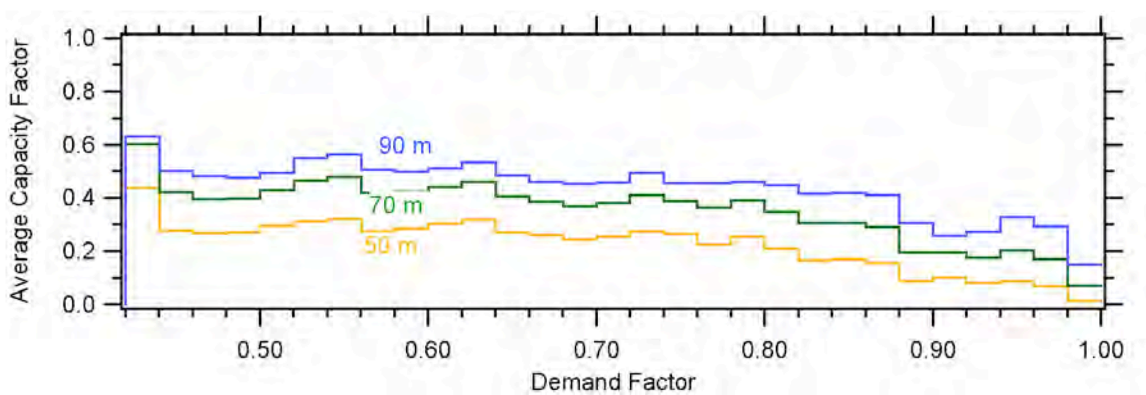

Figure 3.24 Average Capacity Factor as a Function of Demand Factor at the 7 m/s Reference Site

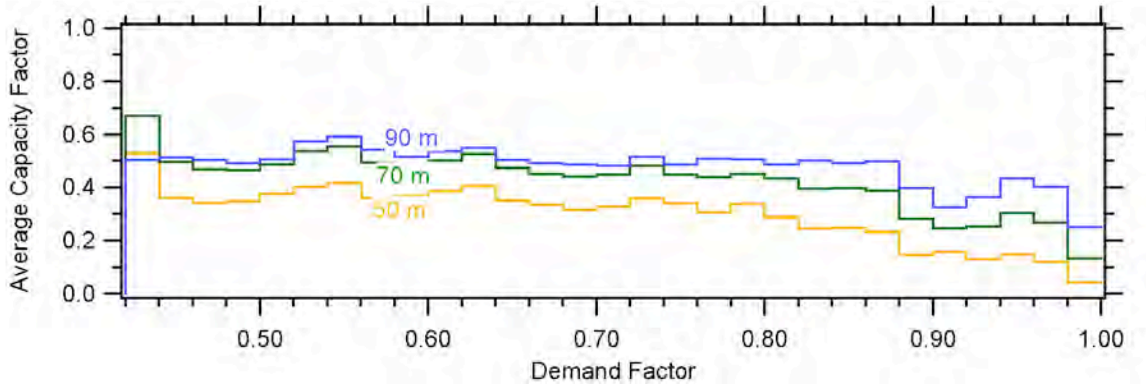

Figure 3.25 Average Capacity Factor as a Function of Demand Factor at the 8 m/s Reference Site

Power generation at the Tehachapi reference sites shows wind capacity gradually decreasing with increasing system demand. The capacity data at the 7 m/s reference site is presented in Figure 3.26, along with trend lines calculated using a polynomial curve fit. This graph also shows that the correlation between wind capacity and demand can be improved by reducing the specific power of the turbines (increasing rotor size for a given rating) at low wind sites.

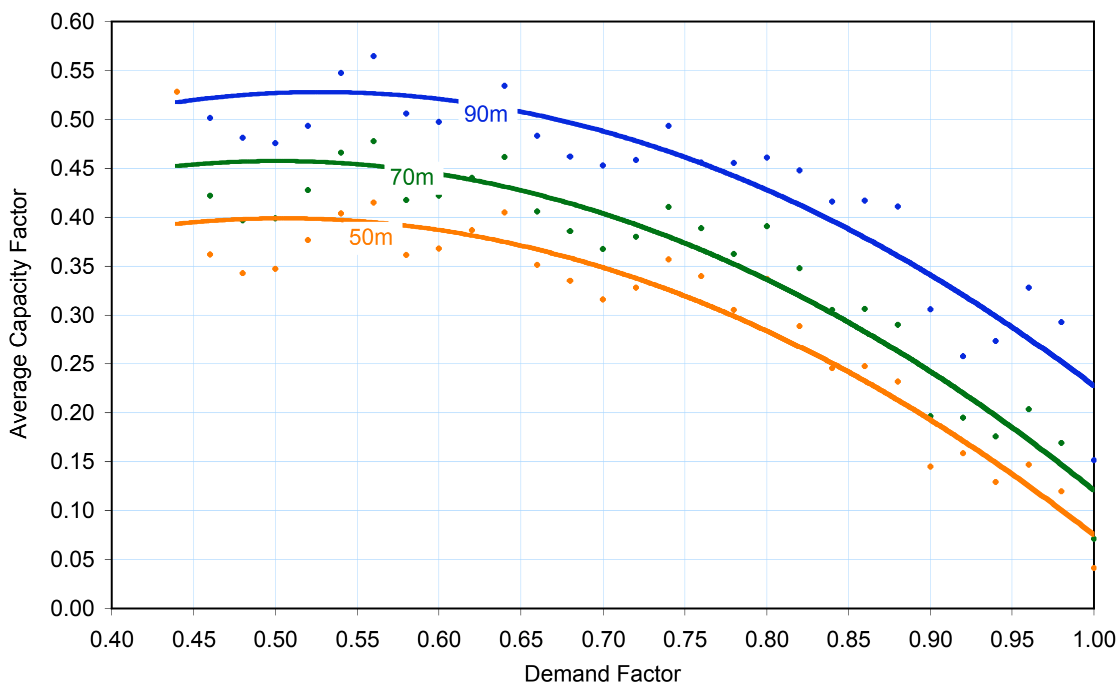

Figure 3.26 Average Capacity Factor as a Function of Demand Factor for the 7 m/s Reference Site

3.5 Diurnal Marginal Capacity

Comparisons of wind generation and system demand were developed based on the time of day. The marginal capacity was defined as the difference between the demand factor and the capacity factor . This number was calculated by subtracting the average monthly demand factor for a given hour of the day from the average monthly wind turbine capacity factor for the same time period. The monthly average marginal capacity is plotted in Figures 3.26 through 3.29 for the 70 m turbine operating at the 7 m/s site.

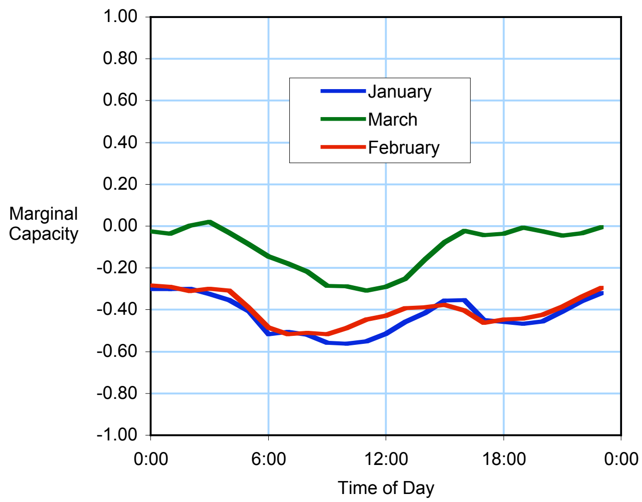

Figure 3.26 First Quarter 2001 Marginal Capacity of the 70 m Turbine at the 7 m/s Reference Site

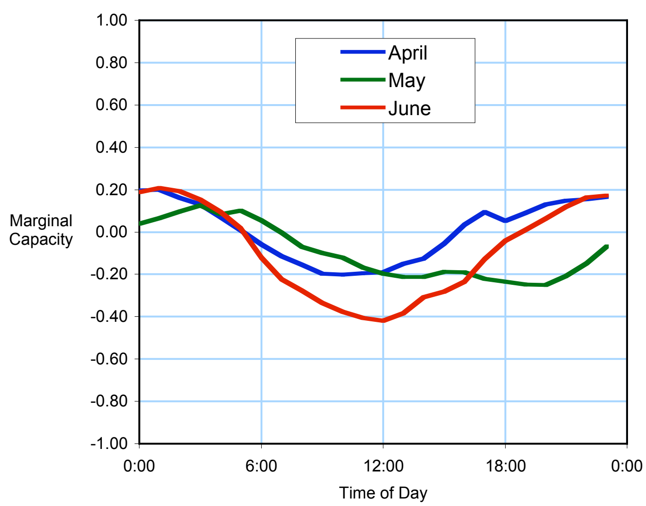

Figure 3.27 Second Quarter 2001 Marginal Capacity of the 70 m Turbine at the 7 m/s Reference Site

Marginal capacity tends to reach a minimum about noon and peaks in the late evening hours. The marginal capacity can be improved by increasing the rotor size and reducing the turbine specific power as shown in Figure 3.30, which depicts the average values of the three model turbines for the month of August. However, rotor size alone cannot overcome the mid-day capacity deficit. Wind generation marginal capacity could also benefit from short term energy storage systems, which would store excess power at night for delivery the following day.

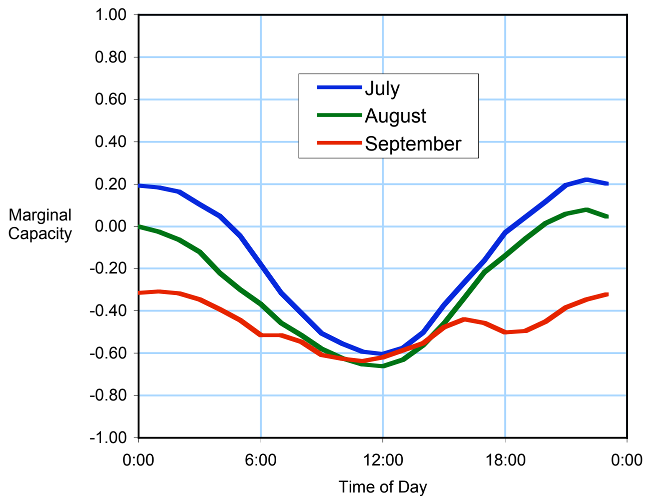

Figure 3.28 Third Quarter 2001 Marginal Capacity of the 70 m Turbine at the 7 m/s Reference Site

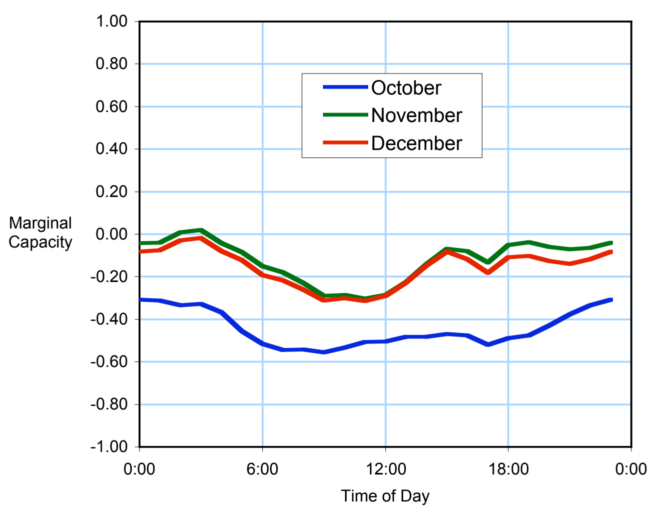

Figure 3.29 Fourth Quarter 2001 Marginal Capacity of the 70 m Turbine at the 7 m/s Reference Site

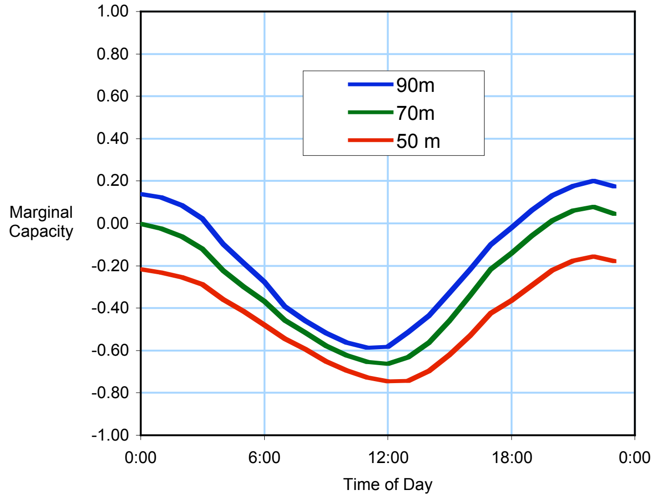

Figure 3.30 Comparison of August 2001 Marginal Capacity at the 7 m/s Reference Site

4.0 POWER VALUE AND REVENUES

4.1 Time Dependent Valuation of Electricity

The value of electric power generation is highly dependent upon the season and time of day. Properly allocating the value of wind generation to the electric power system is difficult and subject to a wide range of assumptions. A methodology for standardized valuation of energy was prepared in support of California's 2005 Title 24 Building Efficiency Standards Update [4]. The Time Dependent Valuation (TDV) methodology accounts for the economic reality that the cost of generating and delivering electricity depends upon when and where it is needed. The TDV economic model derives hourly valuations for electricity based upon one of sixteen California climate zones, which were available as electronic data files. Commercial electric TDV data for climate zone 14 was selected as the valuation basis for this study, because it is representative of the reference site location near Mojave, California.

The hourly electric TDV data were normalized by the annual average value to form a non-dimensional value factor. This factor represents the value of electricity at a specific time as a fraction of the average value of that energy and is presented graphically in Figure 4.1. For much of the year there is minimal variation in electricity value; however, strong diurnal variations occur on summer weekdays. During peak summer hours, the value of electricity is approximately three to four times the average value.

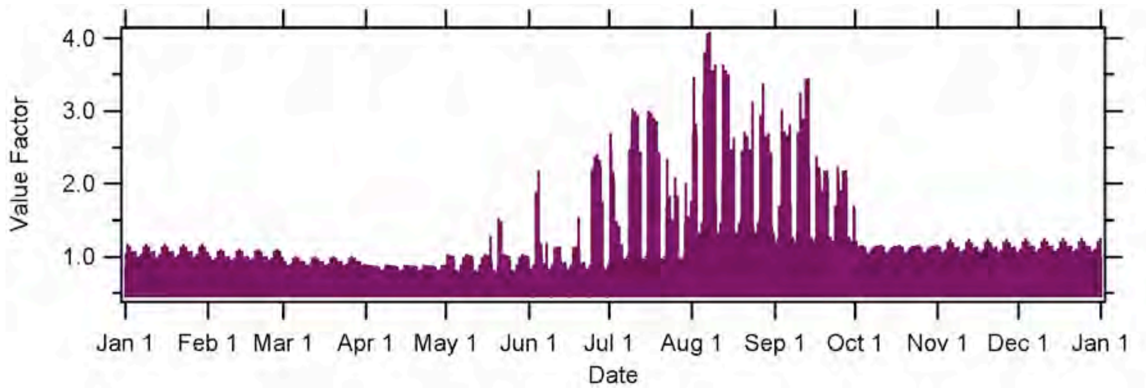

Figure 4.1 Mojave Commercial Electricity Value Factor

A graph of the commercial value of electricity and the corresponding wind generation capacity factor at the 7 m/s reference site is presented in Figure 4.2 for a summer peak period. This graph shows data for a full week and has five value peaks corresponding to each of the weekdays. The data show that electricity value on the weekends is only slightly elevated above the annual average.

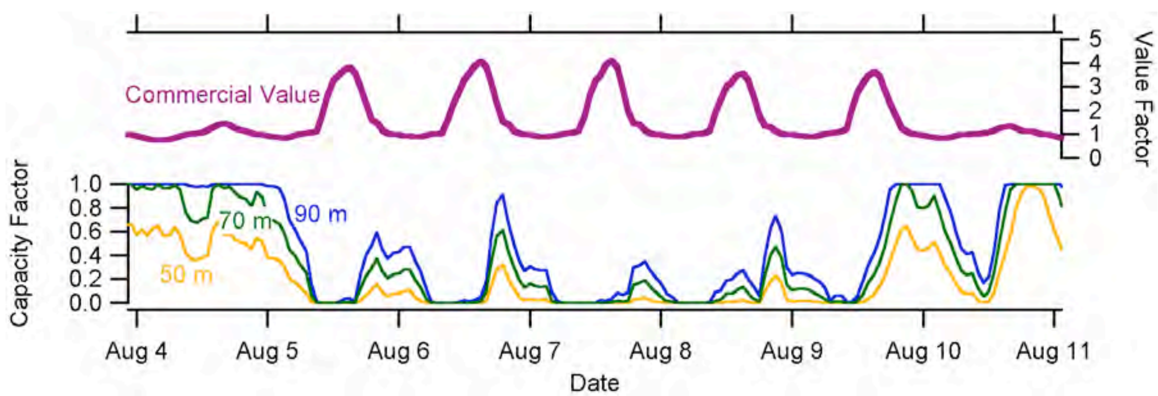

Figure 4.2 Capacity Factor and Electricity Value Factor During a Summer Peak Period at the 7 m/s Reference Site

4.2 Wind Generation Revenue

The revenue produced by the wind turbine is proportional to the energy generated and its value at a given time. A revenue factor can be calculated and is equal to the product of the capacity factor and the value factor. The revenue factor is similar to the capacity factor, except that it is adjusted to account for the time dependent value of power generation. A comparison of capacity factor and revenue factor is shown in Figures 4.3 and 4.4 for two representative summer periods. These graphs show that periods of high capacity are not necessarily the periods of best revenue and that including time dependent valuation can have a major impact on how wind generation is economically valued.

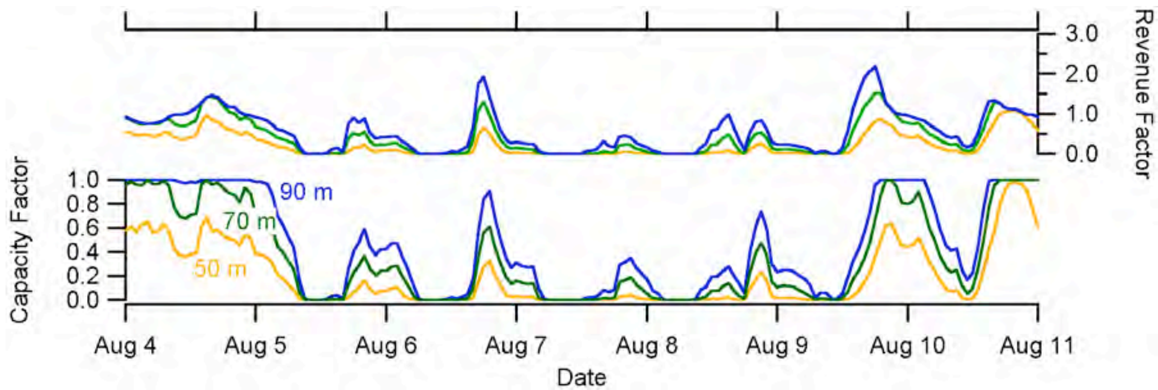

Figure 4.3 Revenue Factor and Capacity Factor During a Summer Peak Period at the 7 m/s Reference Site

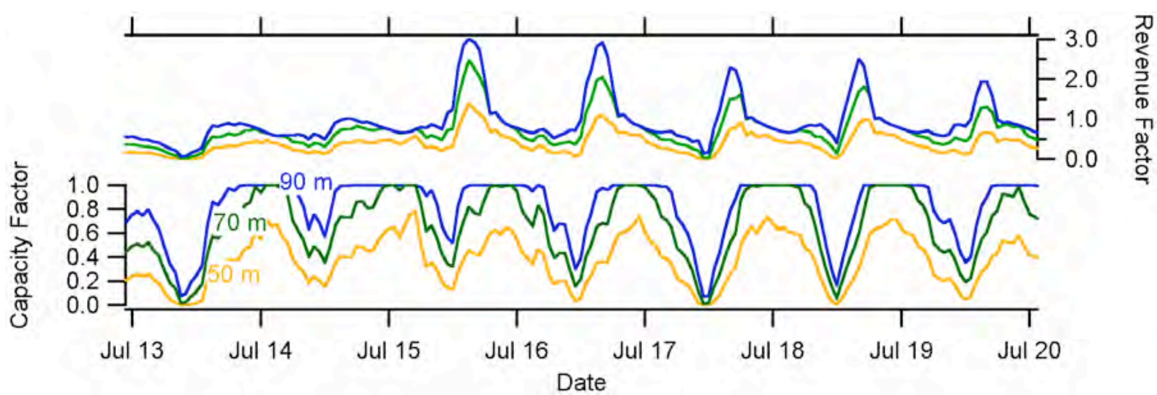

Figure 4.4 Revenue Factor and Capacity Factor During a Summer Non-Peak Period at the 7 m/s Reference Site

The average annual revenue factor provides a better indicator of the overall value of the wind turbine generator than does the average annual capacity factor. A summary of average annual revenue factors is provided in Table 4.1.

Table 4.1 Summary of Average Annual TDV Revenue Factors

Wind Speed (m/s)	Annual TDV Revenue Factor		
	Rotor Diameter (m)		
	50 m	70 m	90 m
6	17.3%	29.3%	39.2%
7	25.3%	38.6%	46.8%
8	33.2%	45.6%	50.1%

In the case of constant electricity valuation the revenue factor is equal to the capacity factor. A comparison of the TDV revenue factor to the values assuming constant electricity valuation is presented in Table 4.2.

Table 4.2 Comparison of Constant Value and TDV Revenue Factors

Wind Speed (m/s)	TDV vs Constant Revenue		
	Rotor Diameter (m)		
	50 m	70 m	90 m
6	-7.0%	-5.5%	-4.4%
7	-6.3%	-4.5%	-3.5%
8	-5.1%	-3.8%	-2.1%

These data show that wind generation at the reference sites is somewhat less valuable on a time dependent basis. The data also show that revenue factors are improved with the larger rotors, although it is not clear if the additional revenue is sufficient to offset the higher cost of the turbine.

5.0 SUMMARY

5.1 Conclusions

This goal of this study was to establish a sense for the variations in wind power generation at several key sites in California and assess the change in these levels according to the time of day and the season of the year. Representative wind data was obtained, adjusted to standard air density, and scaled to three annual reference wind speeds: 6 m/s, 7 m/s, and 8 m/s. These data were then used to determine the power output of three representative 1 MW wind turbines with different rotor sizes: 50 meter diameter, 70 m diameter, and 90 meter diameter. The output from these turbines was compared against the statewide system electrical demand and trends were observed. Revenue calculations were performed using a time dependent valuation methodology.

The study documents the relative changes in turbine performance that can be obtained by decreasing the specific power of the turbine, which is accomplished by increasing the rotor diameter for a given rated power. Because of the larger rotor, turbines with reduced specific power can be expected to have higher initial capital cost and increase the cost of energy. However, reducing the specific power provides a number of potentially valuable benefits by increasing the wind plant capacity factor, providing greater production during peak demand periods, reducing blade tip noise, and providing for geographical expansion of viable wind resources.

Key conclusions of the study are:

- Turbine rotor optimization for specific power will depend upon the wind conditions of a given site and the time valuation of the energy generated.
- Restricting the upper operating range of the wind turbines did not have a major impact on turbine performance at low wind sites and may be an effective means for improving economics of low wind turbine designs.

5.2 Recommendations

More information is needed to assist in developing wind generation assets that are well optimized to California's electricity needs. Additional work is needed to evaluate the representative performance trends of wind generators at a range of locations within the state using time dependent valuation methodologies. The goal of that work would be to evaluate locations within California which have potential for wind energy development and assess their value to the electric system.

The TDV methodology developed for the Title 24 Building Efficiency Standards provides a rational and consistent framework for valuing electricity as a function of time. However, the TDV data were developed for the purposes of valuing energy savings by the end-user and may not be representative of the valuation from the generation perspective. It would be useful to develop and document generation TDV data for specific regions and climate zones within California. These data would provide the basis for performing detailed economic evaluation of specific site and equipment combinations.

It would also be beneficial to study potential methods for firming wind generation capacity. Firming could be accomplished using energy storage or combining wind with other generation resources (such as photovoltaic) to obtain improved characteristics.

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2. Wind Performance Report Summary 1996-1999, California Energy Commission Staff Report, P500-01-018, October 2001.

3. Wind Turbine Power Performance Testing, International Standard, International Electrotechnical Commission, IEC 61400-12, 1998.

4. Time Dependent Valuation of Energy for Developing Building Efficiency Standards, Time Dependent Valuation (TDV) Formulation 'Cookbook', prepared for PG&E by Heschong Mahone Group and Energy and Environmental Economic, 15 March 2001