MODELLING RENEWABLE ELECTRIC

RESOURCES:

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A CASE STUDY OF WIND ST

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1. SUMMARY

1.1 Introduction

As we enter the twenty-first century, renewable resources can play an expanded role in electric power supply. In the mid-1970s attention was directed toward energy conservation and renewable energy, largely in response to increasing oil prices. The emergence of the concept of "least cost planning" for electric utilities, and the enactment of the PURPA law, provided encouragement for conservation and renewables. Notwithstanding these events, progress since then has been slow for electricity conservation and slower still for renewable electricity supply. Today, these options are receiving increased attention because of escalating fossil fuel prices and deepening environmental problems and concerns, particularly potential climate change from fossil fuel combustion.

While end-use energy efficiency can reduce substantially the total energy requirements for electricity production, we will still need power supply resources. In the absence of alternatives, fossil fuels will continue to contribute significantly to global warming and other environmental problems, even as the more advanced fossil technologies are introduced. Thus, renewable energy resources (solar, wind, geothermal, biomass) will be needed to meet ambitious environmental objectives, most notably the reduction in carbon emissions believed to be necessary for climate stabilization. Actions taken now to better understand the opportunities for, and obstacles to, the use of economically and environmentally attractive renewable electric resources will help realize carbon reduction objectives and avoid the potential costs of later responses to the problem, if not of climate change itself.

The central issue facing renewables in the integrated resource planning process is the appropriate assessment of the *value of renewables* to utility systems. This includes their impact on both energy and capacity costs (avoided costs), and on emissions and environmental impacts, taking account of the reliability, system characteristics, interactions (in dispatch), seasonality, and other characteristics and costs of the technologies. These are system-specific considerations whose relationships may have some generic implications. In this report, we focus on the reliability contribution of *wind electric generating systems*, measured as the amount of fossil capacity they can displace while meeting the system reliability criterion. We examine this issue for a case study system at different wind characteristics and penetration, for different years, with different system characteristics, and with different modelling techniques. In an accompanying analysis we also examine the economics of wind electric generation, as well as its emissions and social costs, for the case study system.

This report was undertaken for the "Innovative IRP" program of the U.S. Department of Energy, and is based on work by both Union of Concerned Scientists (UCS) and Tellus Institute, including *America's Energy Choices* and the UCS Midwest Renewables Project.¹

¹ This work is supported financially, in part by the U.S. Department of Energy through Oak Ridge National Laboratory under contract with Martin Marietta Corporation, and in part by Union of Concerned Scientists (UCS) who also provided in-kind analytical support. We would like to thank the project management at Oak Ridge National

1.2 The Issue

Wind turbine electric power generation is qualitatively different from conventional thermal plant generation, in that it depends upon wind speeds which fluctuate hourly and can have marked seasonal and diurnal patterns. Electric utility system planners and computerized power system planning models, after decades of focus on systems characterized by thermal power plants, must now understand the temporal and "intermittent" nature of wind generation if this resource is to realize its promising role in our generation mix. This is important in assessing the "system reliability" impact, the system economic impact, and the environmental impacts, of wind electric resources. Here we focus on reliability impacts of wind electric generation. The questions that system planners must ask and answer include:

- How much does wind generation contribute to system reliability (relative to conventional thermal units), and how does this depend on system characteristics and the amount of wind generation?
- How is wind generation best simulated in system planning and operating (i.e., dispatch and reliability) models, and what aspects or accuracy are lost?

The *Standard Handbook for Electrical Engineers* (Fink and Beaty 1993) takes a pessimistic view of the contribution of wind to system reliability:

Because of its dilute nature and unpredictable irregularity, wind-energy utilization requires cost-intensive hardware for collection and conversion to useable forms. Until economical energy-storage and reconversion systems are developed, large-scale use of wind energy will be limited to systems employed as supplementary energy sources in conjunction with existing conventional power systems. The cost of energy obtained from such "energy displacers" should then be compared with *only the fuel cost* incurred in conventional power plants. (page 11-18, emphasis added)

Other analysts have taken a more balanced view, pointing out that the contribution of wind to system reliability may be significant, and that wind has capacity value which depends upon system-specific characteristics and the amount of wind (see, for example, Grubb and Myer 1993; and Milligan and Miller 1993).

Laboratory, Eric Hirst, Doug Bauer and Stan Hadley, and our colleagues at UCS, Michael Brower and Michael Tennis for their support and cooperation.

The wind resource is not the only important system characteristic for which electric system operators and planners must contend with uncertainty. Customer loads are "intermittent" in much the same way as is wind generation. Demand-side management measures also have seasonal and daily load shape impacts that must be predicted statistically, as do some hydro-electric generation resources. Even conventional thermal power plants have randomly occurring outages, primarily due to equipment failure.

Thermal power plant forced outages can present similar challenges to system planners since the thermal plant outages are primarily full outages of large magnitude, in which all of the unit's capacity is unexpectedly unavailable. While there are differences between the characteristics of forced outages of thermal plants and fluctuations in wind electric output, they have important common features in terms of their impact on system reliability. For example, large nuclear units (1000 MW and above), have full forced outage rates that have averaged 15 percent over the last 5 years (NERC 1993a). In assessing the reliability value of wind it is, therefore, important to specify the reference -- i.e., system reliability value compared with what type of capacity? In this analysis, we have compared wind with highly reliable, small-sized coal generation.

With regard to the development of models and techniques for electric power system planning, we note the successful efforts that have been made to address the random failures of thermal generating units. Specifically, over the last three decades, probabilistic techniques for representing random generating unit outages have been developed, refined, incorporated into computer models, and widely adopted and applied in electric system planning. We believe that the development, incorporation and application of techniques for addressing the nature of wind and other intermittent renewable resources with marked temporal patterns is already well underway, and presents a significant yet clearly surmountable challenge. Our hope is that this report contributes incrementally to the effort.

1.3 Approach

In this report, we explore the capacity equivalent of wind for a "test (or case study) system", varying key system characteristics, wind characteristics and modelling techniques. The system characteristics of interest are the load pattern (different year's load shapes) and the average unit outage rates. We explore system reliability modelling using both the daily peak method and the hourly load method. Choosing one of these approaches, we analyze wind-turbines at various levels of system penetration, with different tower heights, with different years' wind patterns, with and without site diversity. While the modelling convention adopted by system planners is unrelated to the "true" capacity value of wind, perceptions of the value of wind are crucial to the adoption of cost-effective amounts of wind in electric power systems.

The analysis described in this report was conducted using the ELFIN model (version 1.98) developed by the Environmental Defense Fund (EDF). ELFIN was set up to simulate the dispatch of the test system using weekly load duration curves. Wind turbines were included

in the dispatch simulation by subtracting the hourly wind generation (in MW) from the hourly loads, prior to the creation of load duration curves. In this way, the hourly relationships between wind and load were preserved.

The case study system was created based on the characteristics of a utility in the mid-west U.S., with highly reliable thermal generating units. A set of generic small fossil plant additions was made to the system, representing modifications possible by the middle of the next decade, and the 1985 and 1988 load shapes were used by increasing them to reflect load growth over that period.

The wind electric generation system used in our study is based on data from the Holland monitoring site in Minnesota over the years 1985 and 1988. The raw wind data for that site were converted to generator output over 8760 hour by analysts at Union of Concerned Scientists. To reflect site dependence and the benefits of diversity, wind data from a site in North Dakota was used to generate wind facility output, and data from the Holland site was modified to represent other wind speed and output patterns -- divergent from that based on actual site wind data -- consistent with the overall wind system characteristics. The 8760 hours of wind generation for each site, year and facility was represented as a reduction in load as an input, along with the conventional power supply facilities, to the dispatch/reliability model.

The small fossil capacity equivalent of wind generation was determined by benchmarking the system without wind to a given reliability of about 5 hours in 10 years using the hourly loss of load expectation (LOLE) method which takes account of load loss probability over all 8760 hours of the year.² By adding successive amounts of wind capacity, and subtracting that amount of small fossil capacity which brought the modelled system reliability back to the criterion, the capacity trade-off or equivalence of wind and coal was established.³

After obtaining a set of results using the load reduction method of representing wind electric generation, a comparison was made with representations of wind as a supply resource with temporally varying output.

² We compared this method with the daily peak LOLE method, which measures the expected peak day loss of load *events* by accounting for load loss probability on only weekday peak hours, and using the 1-event-in-10- years LOLE criterion.

³ The benchmark small fossil units were assumed to have 84 percent availability. Thus, to a good approximation, all the results here for the capacity equivalent of wind are relative to such units. To convert these results to the "perfect power equivalent" of wind (i.e. a perfectly reliable unit) they should be multiplied by 0.84.

1.4 Key Conclusions

Modelling

Standard system reliability modelling techniques may be biased against intermittent resources with marked hourly variation such as wind. Specifically, the use of the "daily peak method" for defining and modelling system "loss-of-load-expectation" (LOLE) tends to underestimate the reliability (i.e., capacity) value of wind generation, owing to its sacrifice of detailed information, particularly for systems with wind generation at a high proportion of total system capacity. This approach should be complemented by those which represent all hours and outages over the year.

Care should be taken if "typical weeks" are used in simulations intended to assess the capacity value of intermittent resources. Algorithms used in some dispatch/reliability models for creating typical weeks can produce unstable or spurious results for cases in which the daily peak load method is used to estimate the reliability of systems with wind resources, owing to the loss of information on the wind and load patterns.

Wind generation can be represented in dispatch/reliability models either as a load modification or as a power supply resource. The degree of accuracy in either case will depend on the level of hourly and seasonal detail that is represented. Since power plant *characteristics* (as opposed to their operation) are generally not represented on an hourly basis, modelling wind using the supply approach in conventional models is inherently limited. In contrast, the full 8760 hours of expected wind generation output can be subtracted from loads, before any seasonal (or other temporal) load duration curves are created for the model. Note that both load and wind are thus treated in terms of hourly expected values, without any stochastic variation in each hour. To get a reasonable level of temporal accuracy in representing wind as a power plant, it is necessary to model many sub-periods, in which average (rather than hourly) wind conditions are input.⁴

Modelling wind as a decrement from load and using the hourly method of representing the LOLE criterion has the benefit of preserving as much information as feasible on the details of the wind-load interaction. Both the daily LOLE method and the supply representation of wind, each by sacrificing some information on the wind pattern, led to a reduction in the estimated capacity value of wind for the systems studied here. We expect -- although it is neither confirmed nor contradicted by this research -- that the preferable method of representing intermittent resources in system planning models will depend upon resource-specific and system-specific considerations. For example, where there is significant correlation (positive or negative) between the hourly output of the intermittent resource and the system loads, then a load modification method may be preferable in order to fully preserve this correlation. Where this correlation is significant, if the intermittent resource is to be modelled as a supply

⁴ Here, though, it is possible to represent the stochastic nature of wind by using the forced outage rate capabilities of the reliability model.

resource then the use of a large number of subperiods may be required. Further exploration of these and related issues, including probabilistic load modification and more detail on supply-side representation for additional case study systems, is warranted.

Planning Reserve Margin

The "reserve margin" concept, a widely used "rule-of-thumb" measure of system reliability serves reasonably well as long as the capacity options under consideration have roughly comparable reliability characteristics. Its usefulness is diminished for cases in which large, unreliable nuclear generating units are under consideration for addition to the system mix, and further diminished when considering intermittent resources such as wind.

If the reserve margin concept is to be salvaged for system planning purposes, the traditional use of installed capacity ratings should not be continued. Rather, the capacity ratings for the various types of capacity under consideration must be *normalized* in some acceptable manner. For example, nuclear and intermittent resources can be expressed in terms of "fossil-equivalent" capacity, or "effective load carrying capability"; in the former case the norm could be a standard fossil unit with high reliability, while in the latter it would be a perfectly reliable unit.

Reliability of Wind Electric Generation

The capacity equivalent of wind differs for different wind/load years, owing to the detailed hourly patterns of both wind and load, and the relationship between those patterns. The capacity equivalent of the first increments of wind generation added to an electric power system can be quite significant -- with wind contributing to reliability between about 60 and 100 percent of small fossil for the two wind and load years used in our study -- and should not be ignored in planning studies. At 5 percent wind penetration the cumulative capacity equivalent is 62.5 percent for 1988 and 40 percent for 1985.⁵

As wind capacity penetration increases to about 20 percent of peak load, the fossil capacity equivalent of *incremental* wind additions decreases to the neighborhood of about 15 percent. The *cumulative* fossil equivalent at 20 percent wind penetration was found to be between 23 and 33 percent.⁶ It should be noted that these results reflect exceptional wind years at a very good site and should not be generalized.

⁵ Since these are capacity equivalents in terms of small fossil (at 84 percent availability), in terms of "perfect power equivalence" these results would be about 53 percent and 33 percent, respectively.

⁶ Between 19 and 28 percent in terms of "perfect power equivalence."

A range of studies (Cavallo 1993; Smith 1987) for a variety of systems and conditions give capacity equivalents from about 5 to 60 percent at 5 percent wind penetration, and 2 to 30 percent at 20 percent penetration. Our findings are consistent with these.

While the capacity equivalent of wind declines with increased penetration, the effect of diversity -- combining wind farms at different sites and thus different wind patterns -- is to increase the fossil equivalence for a given amount of wind generation at the higher penetrations. We tested diversity cases in which the wind capacity was installed in equal amounts at two sites. With this diversity the cumulative fossil equivalent at 20 percent penetration increases to about 33 to 43 percent. This additional diversity from three or more sites would likely provide future reliability benefits, although with diminishing incremental returns.

A sensitivity case to modelling wind generation as a supply resource, where some of the detailed information on its pattern is lost, was also performed. The fossil equivalent of wind represented as supply was found to be significantly lower than when represented as a demand reduction. The single outage state (equivalent forced outage rate) method commonly used to represent power plant outages in reliability models can seriously underestimate the reliability contribution of wind. Better results are obtained when the generation pattern of wind is represented with multiple outage states or as a derated plant.

Some caveats are in order in interpreting these results. They are for a utility "test system" with specific characteristics, a particular wind machine, specific sites, and for only two load and wind years. The high capacity equivalent for the 1988 data reflects conditions at a very good site during an exceptional wind year. The capacity equivalent for 1985 -- starting at 40 percent and declining towards 20 percent -- may be more typical. Further exploration of the expected distribution of wind years (or a more typical year) would be desirable to establish a capacity equivalent for planning purposes. Notwithstanding these limitations, the results of this study provide concrete indications of the capacity values of wind under different reliability measurement protocols, reliability modelling techniques, and different wind system characteristics.

Economics of Wind Electric Generation

Our analysis of the case study electric system shows that at current costs, wind power would be competitive with new fossil facilities, and that at costs projected for the year 2000 and beyond they would be more attractive economically than new fossil facilities. Wind generation also reduces system emissions significantly, and with environmental externalities taken into account the comparative economics of wind power becomes even more favorable.

1.5 Further Research

It would be valuable to expand and deepen this research in several ways. First, for the case study system and region additional years of wind data should be modelled to obtain a more complete understanding of likely future conditions. Once such a distribution of wind data is modelled, the results would be better suited (than the preliminary findings here) for taking account of capacity equivalence in system planning. While such results could be obtained from a series of modelling runs for each of a set of wind years, some exploration of directly modelling the wind year distribution for multiple wind years in a single model run would be useful. However, this would require additional modelling techniques to represent multiple wind years as a probability distribution. Further, exploration of diversity benefits, using different or additional sites, would be valuable. Additional modelling of wind as a supply resource (rather than load modifier) would provide better insight into this technique. Analysis of the relationship between wind/load correlation and wind capacity value would provide useful information. This could include statistical analysis of the correlation between hourly wind generation and hourly customer loads and how measures of this correlation relate to the estimate capacity value to the system.

Performing these analyses for additional case study systems in different regions of the country would provide useful information and could form the basis for some more general observations on the conditions affecting wind capacity value. Finally, all of these explorations could be applied to the economic analysis of wind within a least-cost framework.

2. RELIABILITY AND CAPACITY VALUE: GENERAL ISSUES

2.1 Reserves and System Reliability

In planning future capacity requirements, electric utilities commonly use a required "reserve margin" as a measure of the generating capacity needed to meet loads. The reserve margin is usually defined as the percentage by which the system's firm resources exceed peak hour firm customer demand.

$$\text{Reserve Margin} = \frac{(\text{Firm Capacity} - \text{Firm Load}) \times 100}{\text{Firm Peak Load}}$$

Typically, the full seasonal capacity ratings of all generating units and firm purchases are included, even for units with scheduled or unscheduled outages at the time of peak demand. The reason for this is that scheduled outages can generally be planned for off-peak seasons as necessary, while unscheduled outages are the principal events for which reserves are provided in the first place.

However, the reserve margin is not an end in itself, but only a rough indicator of the reliability of an electric utility system. Ideally, it is derived from a reliability criterion and the characteristics of the system. Satisfying a reserve margin requirement is thus a means of ensuring an acceptable level of reliability. Changes in reserve requirements, or in how the requirements are met, could affect the cost of electricity or the risk of shortfalls of electric generation ("loss of load"). Therefore, reserve planning should be approached with appropriate analyses, and an understanding of the relationships between system characteristics, reserves and reliability, and the capabilities and weaknesses of the models and techniques used in these analyses.

Different generating units contribute to system reliability depending on their size and outage characteristics. Thus reserve margin requirements will depend, among other things, upon the generation mix. A single change to the mix, such as the addition of a nuclear generating unit, can change the reserve margin requirement of a utility by several percentage points, owing to its impact on system reliability. Thus, it is important to assess reliability more directly, by calculating "loss of load expectations (LOLE)" (and other measures of the ability to serve load) using computerized models of system reliability. Once a reliability target is established the reserve margin for given mix can be determined for a system. Such means can also be used to compute the relative capacity or reliability value of different generating unit types and sizes for different systems and conditions.

As noted earlier, for intermittent and temporally (diurnally and seasonally) limited generating resources like solar and wind, reliability or capacity value has features both unique and in common with traditional thermal generating units. One way of framing the issue starkly, for example, is to ask whether the presence of wind electric facilities enhance or diminish system

reliability? More precisely and usefully, the question is what is the contribution of wind to system reliability relative to other facility types and how does this contribution differ between systems or at different levels of wind in the mix?

In an attempt to answer these questions, we can apply conventional reliability modelling techniques. Such techniques are embodied in probabilistic "reliability models which require simplifying assumptions. In applying these models to wind electric facilities, we can determine whether these techniques are adequate to the task, given the unconventional character of the wind resource. We can also determine how best to use these standard tools to obtain accurate and useful answers to the wind reliability questions posed here. To pursue this issue, we first discuss the standard reliability modelling approach and the basic relationships between loads, generating facility mix and reliability.⁷ After that, we will turn to our specific analyses of wind electric facilities.

2.2 Measures of Reliability

Generating system reliability is often quantified in terms of the probability that demand is expected to exceed available firm resources. The "loss of load expectation" (LOLE) is the expected *number of occasions* (outage events of any duration) or *cumulative number of hours* over some time period, on an average or probabilistic basis, on which the system will be unable to serve the full load, given its particular load, resource and interconnection characteristics. LOLE is commonly expressed as the number of days (occasions or events) that demand will exceed resources during a 10-year period.

It is important to note that the basic number-of-days-in-10-years definition of loss of load probability does not explicitly address the magnitude or duration of the expected losses. Estimation of the *average duration* of outages can be made if both the number of events and the cumulative hours of loss of load are computed. Another measure of system reliability, the expected *unserved energy*, can be computed and, along with average duration, can be used to compute *average magnitude* of system outages.

Most commonly, reliability criteria are defined in terms of a specified LOLE. Once an LOLE criterion is established, the reserve margin necessary to meet this criterion can be determined by accurately modelling the system. A loss of load probability of 1-day-in-10-years is the criterion most widely used by utilities in the United States. There are, however, significant differences in approaches to modelling, operational definitions of the various factors, and system characterization, that affect both the criterion itself and the reserve margin to meet it. Nonetheless, reserve margins between 15 and 20 percent are typical.

⁷ For a more complete discussion see, e.g., Bernow and Biewald 1988 or Billinton and Allen 1984.

2.3 Factors that Affect Reliability and Reserve Requirements

The major characteristics of a utility system that affect the reliability/reserves relationship are load shape, power plant forced outage rates, plant maintenance outage requirements, the number and size of generating units, transmission interties with and available support from neighboring utilities, availability and effectiveness of emergency intervention procedures.

A lower system load factor will tend to increase reliability and decrease the reserve margin necessary to meet a given reliability criterion. Lower load factors generally permit more opportunities (during seasonal low load periods) for maintenance, without jeopardizing reliability during those periods, thus allowing greater resources to be available during high load periods. It should be noted, however, that load factor itself is just an aggregate measure of load shape, and that the detailed monthly shapes can have an impact upon system reliability as well.

Lower unit forced outage rates will result in greater system reliability and, consequently, a lower reserve margin to meet a given reliability criterion. A similar relationship holds for lower (or more flexible) maintenance outages. Larger units typically have higher than average outage rates and less flexibility in maintenance scheduling, start-up and load following. Peaking and hydro resources generally have low forced outage rates and great flexibility to meet rapidly changing loads. Capacity from a greater number of small units provides greater reliability than the same total capacity from larger units, with the same unit outage rates. Since smaller units also tend to have lower outage rates the reliability advantage is augmented.⁸ Greater interconnection, which permits reliance on neighboring systems for emergency purchases, will result in greater reliability and a lower reserve requirement for a given reliability criterion.

Finally, a number of operating procedures can be used to avoid actual load loss when load exceeds the generating resources that are available under normal conditions. These include shedding interruptible loads, re-scheduling maintenance, use of emergency generator ratings, voltage reductions and, ultimately, appeals to customers to reduce usage. The availability and effectiveness of these measures varies from system to system.

2.4 Impact of Generating Unit Additions

One of the reasons that it is important to conduct reliability analyses, rather than to simply use a single reserve margin for system planning purposes, is that the relationship between reliability and reserve margin can change. In particular, an abrupt change can occur when a new generating unit is brought on-line.

⁸ This advantage of smaller units may in some cases be offset by economies of scale, and augmented by economies deriving from planning flexibility.

Some electric utilities have increased their target reserve margins coinciding with the commercial operation of large new units. For example, Tellus has found that adding large nuclear generating units can increase the reserve margin required to maintain acceptable system reliability. This additional need occurs for two reasons. First, the outage rate of a large nuclear unit is generally higher than the average for the previously existing system plants. Second, the size of a new nuclear unit is generally much greater than the average size of the existing plants.

Thus, prior to the addition of a major resource, an electric system should evaluate the reliability impacts of the addition. This is particularly important if the characteristics of the resource addition are unlike the previously existing capacity mix. For reserve margin requirements to change by several percentage points is not unusual, particularly with the addition of a nuclear generating capacity.

2.5 Reliability Modelling

Computer models are used to calculate the reliability indices of electric utility systems, including LOLE, dependence on supplemental capacity resources (DSCR)⁹, and expected unserved energy. The input data requirements and appropriate methodological approach depend upon the question to be answered.

Sometimes these reliability models are used as a check on the adequacy of reliability over some future planning period. System characteristics are projected and reliability indices are calculated. If the calculated indices compare favorably with pre-determined criteria, then the system plan is judged to be adequate.

Another very common application of reliability modelling is in determining the reserve margin required for a particular system to satisfy a particular reliability criterion. Some of the NERC regions perform such studies in arriving at the system reserve margins which will provide LOLE at a level of 1-day-in-10-years.

The same computerized dispatch models used for production costing calculations are frequently employed for reliability analysis. Probabilistic techniques are used to "simulate" the random nature of forced generating unit outages. Maintenance outage schedules, as will be discussed below, are usually assumed to be fixed. There are many publications that address reliability

⁹ DSCR is a measure of the reliability of a utility system *as if* it were isolated from all others. Thus, as it expresses the expected number of shortage occurrences for that system, it is also a measure of the expected number of occasions when it would need capacity support from neighboring interconnected systems. In effect, DSCR is LOLE without interconnections. For example, a DSCR of 20 days *per year* could be consistent with a LOLE of 1-day-in-10-years if there were sufficient interconnection supports. The ECAR system, and utilities and power pools within it, use DSCR.

modelling generally, for example, books by Billinton and Allen (1984) and Sullivan (1977). Moreover, particular models each have their own documentation.

The essential inputs to computerized reliability models include capacity and outage data for each generating unit, and some representation of customer loads. Intertie support and some of the interconnection procedures are also frequently included in the model.

System load must be represented in a reliability model. The system loads are sometimes input on an hourly basis (all 8760 hours) or on a weekday peak basis (260 hours). The use of hourly loads is generally preferable, in that important measures of reliability such as the expected energy unserved can then be calculated. If only the daily peak loads are input to the model, then the number of events (of loss of load or dependence upon others) can be calculated, but the amount of energy involved cannot. The daily peak method, while still in use, dates back to the early development of analytic techniques for reliability analysis. With computers now widely available, the more detailed approach in which system reliability in all hours is considered must be considered preferable.

By using both the daily peak and the more complete hourly method of load representation, a rich set of reliability measures can be obtained, including the expected number of LOLE or DSCR events, the energy unserved, and, potentially, magnitude and duration information. For example, if analysis using the full hourly load set indicates an expectation of 24 hours of unserved load, and the analysis using daily peak loads indicates that three loss-of-load events are expected, then the average expected duration of each of the three events would be 8 hours (24 divided by 3).

3. THE CASE STUDY ELECTRIC SYSTEM

3.1 Case Study System Characteristics

For our case study system we have chosen a medium sized utility system in the Midwest with a conventional mix of thermal generating plants, including baseload, intermediate and peaking fossil units and baseload nuclear, for a target year in the first decade of the next century. Table 3.1 below provides the capacity and generation mix as well as the peak demand and energy sales for that year.

Table 3.1

Case Study System Generation Mix

	Capacity (MW)	Generation (GWh)	Capacity Factor (%)	Fuel and O&M Cost (\$/MWh)
Coal-Steam	4,300	27,972	74.3	19.9
Nuclear	1,542	12,054	89.2	9.5
Gas Combined Cycle	800	1,936	27.6	51.4
Other Oil/Gas	1,708	518	3.5	103.8
Hydro-electric	131	1,260	94.3	----
Biomass	118	431	41.7	34.1
<u>Purchases</u>	<u>396</u>	<u>597</u>	<u>17.2</u>	<u>13.8</u>
Total System	8,995	44,768	56.8	19.1
Peak Load	8,177 MW			
Sales	39,182 GWh			
Load Factor	54.7%			
Reserve Margin (%)	10%			

The 54.7 percent load factor of the case study system is for 1988. This is quite low compared with most other systems in the U.S., reflecting a small number of high peak days for the system in that year. For example, 1992 data for the nine NERC regional reliability councils, indicates load factors ranging from 57 to 66, averaging 61 percent (NERC 1993b).¹⁰ The

¹⁰ These regional load factors (for groups of utilities) will tend to be somewhat higher than the load factors for individual utilities, as a result of system load diversity. They do, however, give some indication that the test system load factor is lower than typical.

shape of the system loads during peak periods is expected to be particularly important, as this will interact with the hourly pattern of wind generation output during those hours most critical to reliability (LOLE). To explore this issue, and the way in which wind and load patterns interact to affect reliability, we analyzed wind reliability for load shape from another year, 1985, for which the load factor was 63.0 percent.

The average forced and planned outage rates of the generating units in the system are significantly lower than the national average. Table 3.2 shows this comparison.

Table 3.2

Plant Availability: Case Study System and National Average

	Average Forced Outage Rate	Average Maintenance Outage Rate	Equivalent Availability Factor
Case Study	7.4%	6.0%	87.0%
National Average	12.4%	13.6%	75.7%

3.2 Case Study System Reliability

To model reliability for different reserve margins and capacity types, we used the expected system loads for the year 2005 and varied the capacity additions. Both characteristics of the system -- load shape and outage rates -- affect system reliability. One consequence of this system with highly reliable generating units is that it needs lower reserve margin and lower emergency interconnect support to maintain a one-event-in-10-years LOLE. This is evident in Table 3.3, where it can be seen that about 1-day-in-10-years LOLE is achieved at about 10 percent reserve margin and emergency interconnect support at less than 10 percent of system peak.¹¹ The table shows various other measures of reliability at this level of reserves and

¹¹ It is noteworthy that at higher unit average outage rates -- 14.8 percent FOR and 18.0 percent MOR -- reflecting a more nuclear based system, the reserve margin required for 1-day-in-10-years LOLE is at about 17 percent with 15 percent emergency interconnects. This is somewhat low even for a nuclear based system, as the rather low system load factor permits ample potential for scheduling planned outages without compromising reliability; for such a nuclear based system at typical or higher load factors the reserve and interconnect requirements could both be around

emergency interconnect support, including the average outage duration and magnitude, and energy unserved. These values are reasonably representative of other utility systems but, as noted above, at much lower levels of resources. The DSCR of 2.6 days per year, representing the expected number of annual outage events for the system's firm resources alone, without any emergency support, is low compared with other system targets -- typically 15 to 30 -- in the North Central region. This reflects the rather highly reliable system, as does the 2.4 hours (or 1/10th day) in 10 years LOLE measured by the hourly method.

The unserved energy is a typically small fraction of total energy requirements, while the average magnitude of outage events is only 2 percent of system peak (and daily peaks of similar magnitude around which LOLE is concentrated); this is within the range of typical voltage reduction options which, while rarely used, provide additional security against actually shedding (i.e., not serving) loads. As noted earlier, even though conventional utility probabilistic reliability analysis shows loss-of-load *expectation* of 1-day-in-10-years for generating unit insufficiency, such a frequency of outage is not observed in the utility industry.

Finally, the 5.3-hours-in-10-years LOLE using the hourly method of reckoning loss of load, is equivalent to (5.3/24) 0.22 days (not events) in 10 years. Note that for those who use the hourly LOLE method and set the reliability criterion at 1-day-in-10-years, this is extremely reliable even at a less than 10 percent reserve margin, and a 1-day-in-10-years criterion would require even less reserves.¹²

Table 3.3

Measures of System Reliability

Daily Peak LOLE	Average Outage Duration	Average Outage Magnitude	Unserved Energy	DSCR	Hourly LOLE
events/10 yrs	hours/event	MW/event (% peak)	MWh (% energy)	events/yr	hrs/yr
1.0	5.1	175 (2.1)	92.5 (0.2)	2.6	0.53

Figure 3.1, below shows the LOLE - reserve margin relationship for this system, for additions of small fossil units across a wide range of reserve margins. It is based upon system loads for

25 percent.

¹² Those that use the DSCR (rather than LOLE) criterion use the peak day event approach.

the year 2005 and various amounts of capacity added to the current system capacity mix to meet that load. Note that each 800 MW of unit additions on the horizontal axis represents roughly 10 percent of system peak load, and that the point at which 2000 MW of new capacity is added corresponds with a 10 percent system reserve margin. It is at this point (10 percent reserve margin) that a LOLE of 1-day-in-10-years occurs.

Figure 3.1

System Loss of Load Expectation
Versus
Capacity Additions: Small Fossil

4. THE WIND ELECTRIC GENERATING SYSTEM

4.1 Considerations in Wind Electric Potential

Wind energy promises to provide an abundant source of relatively low cost electric generation for the U.S. over the next few decades. Experience has increased and cost estimates have come down in recent years. While the current EPRI estimates for a 1992 order date are about the same as made in 1989 at about \$1200/kW (1993\$), the latest EPRI estimates expect declining installed cost by the turn of the century, at about two-thirds that estimate, and further declines thereafter.

In *America's Energy Choices* (UCS 1991) estimates of wind electric development were made for several scenarios, starting with the Base Case of the U.S. Department of Energy *National Energy Strategy*. The estimates are:

Table 4.1
Wind Electric Development Estimates

	Installed Capacity		Energy Generated (Thousands)	
	2010	2030	2010	2030
National Energy Strategy	8 GW (0.8%)	38 GW (3.4%)	17 GWh (0.4%)	83 GWh (1.5%)
America's Energy Choices -- Climate Stabilization Scenario	67 GW (11%)	216 GW (26.8%)	117 GWh (4.6%)	343 GWh (14.6%)

The amounts targeted were well below the full potential for wind, limited by institutional factors and the reduced need for electricity as a result of energy conservation. Of the 216 GW projected for the U.S in the most ambitious scenario, about 50 GW was projected for the Midwest region.

In its recent report *Powering the Midwest* (UCS 1993), Union of Concerned Scientists estimates a total wind potential of about 4,400 GW in Class 3 and another 2,800 GW in classes 4 through 6 for that region, after exclusions were made for reasons of environmental impact and urban settlement. Thus, the ambitious targets of America's Energy Choices are about 3 percent of the estimated regional potential.

Minnesota and North Dakota, which have areas of good wind regimes most likely to be available to Northern States Power, the case study utility, have about 17 percent of the class 3 potential of the region and 50 percent of the class 4-6 potential. Much of the class 4 potential is in the western part of Minnesota and the mid to eastern part of North Dakota.

Wind power has a number of attributes that contribute to its value, including:

Electricity Cost	--	the cost of generation versus alternatives
Environmental	--	reduced emissions of local and regional air and other pollutants, and of greenhouse gases
Risk Reduction	--	diversity of technology and fuel type in mix; planning from modularity
Resource	--	Reduction of depletable resource use: oil, gas, coal
Reliability	--	contribution to capacity to provide reliability

In this report, our main focus is on the reliability contribution of wind electric generating facilities. The principal motivations for the development and deployment of wind power are the first four attribute on the list above, beginning with its environmental, risk reduction and resource depletion (and energy security) benefits. In order for those benefits of wind power to be realized, it has been important that the costs of wind power become competitive with the costs of conventional resources, as they have. The last attribute, its contribution to reliability is important in both substance and perception, and it also affects costs.

To the degree that wind power is *perceived* as unreliable owing to its intermittence, there could be resistance to its use on more than a token scale. To be sure, even if wind power contributed only energy to displace more expensive or more highly polluting resources, and no contribution to reliability (firm capacity equivalent) it would still be an attractive option. The system planner would have to ensure that other capacity was available to meet the system reliability requirements. With wind power deployment, the principal complementary capacity options are peaking facilities with low installed costs and storage facilities; to the degree that these are needed to complement wind power, they would increase the cost of electricity from wind. Another option is the use of existing storage in hydro-electric facilities. Storage would help ensure that wind contributes more to system reliability and can also be used to improve the economics of wind in a system by displacing otherwise more costly energy.

While electric generation from wind energy has far below perfect reliability, other resources also have random outages, albeit not as frequent. Wind power unavailability at any given hour for good wind regimes can be as high as 70 percent on average, while the forced outage rates of fossil units can range between 5 and 15 percent and those of nuclear facilities even higher. The contribution of wind power to system reliability, relative to conventional resources, is primarily a matter of degree. The capacity equivalent (versus perfect reliability) of fossil units may range from 85 to 95 percent, but for wind power at acceptable sites it could begin as low as 20 to 40 percent. It is this issue, and how the wind capacity equivalent is affected by the

degree of penetration (percent of installed capacity) and diversity through the use of two or more sites, that is explored in the next section of this report.

4.2 Sites for the Study

The wind electric generation facilities modelled here are based on simulations of hourly power output in 1985 and 1988 for an assumed 50-MW wind farm at four sites: Holland, Minnesota (in the southwestern part of the state near the South Dakota border); Comstock, Minnesota (in the western part near the North Dakota border); Beulah, North Dakota (in the central part of the state); and an *ersatz* site modeled using a Rayleigh distribution of hourly wind speeds. The simulated hourly wind farm output for these sites was generated for 8,760 hours each year by Michael Brower and Michael Tennis of UCS, using wind speed data from various sources (described below) and a wind-speed/power-output curve provided by Kenetech Wind Power for its state-of-the-art 33 M-VS machine.¹³ This curve consisted of a rated power output for a 50-MW plant at several discrete wind speeds. Second, between the cut-in and cut-out speeds, the curve was fit to a cubic polynomial so that the wind speed could be converted to power output over a continuum. Third, the recorded wind speeds at the Holland and Beulah sites were adjusted to an assumed 40-meter tower height using a power-law relationship. Fourth, after the 40-meter wind speeds were converted to power output, a 10 percent reduction in power output was applied to account for array losses, parasitic power, and other effects. The choice of the two years provides different wind patterns and wind-load relationships, while the choice of different sites for a year provides different patterns of wind for the same load.

The principal site under study is Holland. The power output for this site was derived from actual hourly wind speed data for 1985 and 1988 provided by NSP. (This site is the location of a new wind power plant built by Kenetech which went into operation in 1994.) The other wind farm sites were developed at UCS to explore the site-diversity, wind-pattern, and height dependence of the reliability contribution of wind facilities. In most cases a 40 meter tower height was assumed, while one case of 30 meters was developed for the Holland site for 1988.

¹³ The power curve was obtained for the Kenetech 33 M-VS machine under a confidentiality agreement between UCS and Kenetech.

Table 4.2

Characteristics of the Wind Generators

Site/Wind Pattern/ Configuration	1985		1988	
	Avg Speed	Cap Factor	Avg Speed	Cap Factor
Holland 40 meters	7.87	31.9	8.22	35.3
Comstock 40 meters	7.91	33.5	8.19	36.4
Beulah 40 meters	7.87	32.7	8.23	34.0
Rayleigh 40 meters	7.94	33.8	8.10	35.2
Holland 30 meters	----	----	7.54	30.1

4.3 Creation of Alternative Wind Farm Sites

In order to explore the impacts on reliability of wind site diversity -- providing electric outputs displaced in time, and thus steadier over time, from two or more wind farm sites -- we developed hourly wind electric generation for three alternative wind farm sites. "Comstock", was generated by shifting the original 1988 Holland data by 3 hours and by introducing a random component to the data (based on observed patterns at Holland and Comstock for 1989); the second, "Beulah", was based on data provided by National Renewables Energy Laboratory (NREL)¹⁴ for Beulah, North Dakota; and the third, "Rayleigh", was a purely random simulation of wind data generated using the Rayleigh distribution.

The mean wind speed for all three data sets is the same as for the Holland site with a 40 meter tower height: 8.2 m/s. However, because each data set has a different wind speed distribution, the average power output and capacity factor varies. Following are descriptions of the methods used to develop each site data set.

Comstock (Holland Shifted)

Comstock is far enough away from Holland (about 150 miles) that one might expect to get some reasonable site-diversity benefit from it, yet not so far that it would entail substantial additional transmission costs. Unfortunately, we have only about 3 months of Comstock wind data for 1989 and none for 1988 for which we have ample data for the Holland site. Our first step was to examine the hourly wind patterns for each month of 1989 Holland and Comstock

¹⁴ We are thankful to Alan Miller and Michael Milligan of NREL for this data, and for valuable discussions of their work.

data to see if any pattern of correlation emerged that could be used to recreate the 1988 data. The aim was to create 1988 wind output data sets that imitate Comstock as closely as possible.

In Figure 4.1 below is a comparison of the wind speeds for one typical month, December, 1989. It is immediately apparent from that graph that there is a fairly close relationship between the *overall* wind patterns at Holland and Comstock, suggesting that both are strongly affected by the same weather patterns passing through the area. At the same time, there appears to be a *phase shift* between them of several hours. By plotting the correlation of the two sets of data as a function of shifts in their relative timing, we found the relationship shown in Figure 4.2

Figure 4.1

Figure 4.2

The correlation peaks at around 60 percent when the Holland data are shifted back by about 3 hours. A similar pattern appears in each month of Comstock and Holland data, which is plausible since Comstock is to the north of Holland and prevailing winds in the area are from the northwest to the southeast. It is significant that the correlation for time shifts greater than 24 hours in either direction is quite weak (around 10 to 20 percent at most), implying that diurnal wind patterns are much less important than large-scale weather events.

Based on these results, in order to create a companion wind data set in 1988 for Comstock site we shifted the 1988 Holland wind data back 3 hours and introduced a random component in an attempt to reproduce as closely as possible the correlation (and its dependence on time shift) observed above. For the random component we added a normal distribution of wind speeds with a mean of zero and a standard deviation chosen to result in approximately the same *peak* correlation observed between Holland and Comstock. The relationship between the standard deviations of the original data set, the random addition, and the combined data set is as follows:

$$\sigma_T^2 = \sigma_H^2 + \sigma_R^2$$

where H refers to the Holland data, R to the random data, and T to the total combined data. The correlation between the Holland data and the combined data is then simply:

$$C^* = \frac{\sigma_H}{(\sigma_R^2 + \sigma_H^2)^{1/2}} C$$

where C is the correlation between the original Holland data and the Holland data shifted 3 hours (but without the random component), which is about 80 percent. It turns out that for all the months for which we have data in 1989, the average correlation between the Comstock and Holland data is about 60 percent. Therefore, to arrive at roughly the same correlation with the shifted data,

$$\sigma_R = f\sigma_H \approx 0.8\sigma_H$$

However, if the original Holland data were simply added to normally distributed random data, then the standard deviation of the combined data will be greater than the standard deviation of the original Holland data, or in other words, extreme wind speeds will occur more frequently. This introduces an unwanted complication that may affect the interpretation of the loss-of-load-probability calculations. To maintain the same standard deviation in the combined data as in the original data, we reduced the deviations in wind speed from the mean by a multiplicative factor r , given by

$$r = \frac{1}{(1 + f^2)^{1/2}} \approx 0.8$$

The equation relating the shifted Holland wind speed in hour i to the original Holland wind speed at hour $i+3$ is therefore:

$$v_s(i) = \langle v_H \rangle + r[v_H(i+3) - \langle v_H \rangle + v_R(i)]$$

Figure 4.3 below gives an idea of what the shifted data look like compared to the original Holland data for the first 200 hours of 1988.

Figure 4.3

Holland Shifted Versus Original Holland Wind Speeds
First 200 Hours of 1988

Note that the wind speed in the shifted data occasionally goes negative, the result of the addition of normally distributed random data, but this has no impact on the power output. The correlation at zero time shift is 58 percent. The relationship between correlation and time shift is shown below in Figure 4.4.

Figure 4.4

Correlation of Shifted
and Original Holland Wind Speeds
1988

Beulah

Very good wind data are available from the Beulah site in North Dakota for 1988. Only about 1 week of data are missing, which we filled in by copying data from other periods in that year. The wind speeds data are somewhat more variable than at Holland and the mean wind speed is about 25 percent lower. We scaled the wind speeds up to a mean of 8.2 m/s. Comparison of Beulah and Holland wind speeds for the first 200 hours of 1988 are shown in Figure 4.5, below.

Figure 4.5

Wind Speeds at Beulah and Holland
First 200 Hours of 1988

The data are clearly correlated, but the level of correlation with Holland is much lower than in the case of Comstock. Figure 4.6 below shows the correlation as a function of time shift. The correlation peaks at 30 percent for a time shift of around 24 hours and is around 20 percent at zero time shift.

Figure 4.6

Correlation of Wind Speeds
at Holland and Beulah
1988

Rayleigh Distribution

The final wind site created is based on a Rayleigh distribution, which is generally found to describe wind speed distributions quite well. Michael Brower and Michael Tennis of UCS used a random number to create a time series of wind speeds following the Rayleigh distribution. While this is not a realistic representation of a temporal wind speed record, as it had no correlation between successive hours, it serves as a representation of an "ideal" diversity case since it was entirely uncorrelated with the site data. The equation for the Rayleigh distribution is:

$$p(v)dv = \frac{\pi v}{2\langle v \rangle^2} e^{-\frac{\pi v^2}{4\langle v \rangle^2}} dv,$$

where v and $\langle v \rangle$ are the wind speed and mean wind speed, respectively. While this has no correlation at all with the Holland site data, its *average* speed was set to match that of Holland and the other sites.

4.4 Uses of the Wind Sites for Diversity Analysis

The four sets of wind data -- Holland, Comstock, Beulah, and Rayleigh -- were used to conduct analyses of wind generation, with various sites and site-combinations, on loss-of-load probability for the case study system. For large deployments of wind power (that is, more than about 5 percent of peak load) it may be especially important to take advantage of site diversity as the capacity value of wind generation, and the economic benefits, will tend to decline with greater penetration. It is useful to think of the various possible combinations of data as being conservative, optimistic, or "realistic." We classify them as follows:

Very conservative: The baseline case using the Holland site alone.¹⁵ Since there is no site diversity at all, this represents the worst case from the point of view of maximizing reliability with large deployments of wind power.

Realistic-conservative: A combination of the Holland and shifted-Holland (Comstock) sites. Since these two data sets are still quite strongly correlated, they do not represent as much diversity as one might expect from more distant sites (such as Beulah). However, it is probably a realistic representation of the diversity effect for sites located in western Minnesota within 100-200 miles of Holland.

Realistic-optimistic: A combination of the Holland and Beulah sites. The correlation is fairly poor, and thus the diversity benefit should be high. But the Beulah site is rather far from Holland and thus perhaps not as likely a candidate as Comstock to be a second site on the NSP system.

Very optimistic: A combination of the Holland and Rayleigh. A pure Rayleigh distribution is the best one can hope for to provide site diversity at high levels of wind penetration.

Note that it may turn out that Holland is better than all of the other sites (or combinations of sites) at relatively low wind deployment levels. This is because Holland's winds in 1988 happen to coincide well with NSP's highest 25 or so peak load hours. At low penetrations, this is where the major loss-of-load effect occurs. As wind deployments increase, however, other peak load hours become more important, and then site diversity becomes essential to ensure that overall wind output is not zero during any substantial number of these hours.

¹⁵ Actually, other of the sites have worse single site characteristics than Holland, but here we focus on the benefits of diversity beginning with Holland.

5. WIND RELIABILITY ANALYSIS

5.1 Modelling Wind Generation Reliability

Wind generation can be represented in dispatch/reliability models either as a load modification (of 8760 hourly loads) or as a power supply resource. The degree of accuracy in either case will depend on the level of hourly and seasonal detail that is represented. Since power plant *characteristics* (as opposed to their operation) are generally not represented on an hourly basis, modelling wind using the supply approach in conventional models is inherently limited. In contrast, the full 8760 hours of expected wind generation output can be subtracted from loads, before any seasonal (or other temporal) load duration curves are created for the model. Note that both load and wind are thus treated in terms of hourly expected values, without any stochastic variation in each hour.

While wind has a stochastic behavior in each hour (while correlated to some degree from hour to hour) so too does load. Utility system reliability analysis rarely represents the annual loads as other than a fixed set of 8760 values, even though it models power supply stochastically through generating unit forced outage rates. Since it is the relationship between wind and load patterns over the hours of the year that affects the reliability impact of wind, it would be best to model both stochastically. However, there is currently no practical technique for fully representing the stochasticity of both wind and load, while maintaining their detailed (e.g., hourly) correlation. For most of this analysis we have chosen to model both load and wind deterministically and have subtracted wind from load over all 8760 hours to get "net load" against which thermal generation availability is measured.

We have also explored modelling wind as a power supply resource for one of the wind cases to compare the results with the load modification method. To get a reasonable level of temporal accuracy in representing wind as a power plant, it is likely to be necessary to model many sub-periods, in which average (rather than hourly) wind conditions are input. In each subperiod the seasonal (or week to week) variation could be captured on an average basis, while the outage rate feature of the reliability model could be used to represent the distribution of wind within that period.

Figure 5.1 shows the reliability/capacity-reserve relationship for wind compared with thermal units for our case study system, for an extreme case in which all new capacity additions are of a single type. The wide range shown, from zero to 4000 MW of capacity additions, corresponds to a range of system reserve margins from about negative 15 percent to positive 35 percent. For three of the capacity types -- coal, natural gas combined cycle, and natural gas combustion turbines -- the LOLE of 1-day-in-10-years is achieved at about 2000 MW of capacity additions, corresponding to a system reserve margin of about 10 percent.

For large coal (800-MW units), the LOLE of 1-day-in-10-years is achieved with 2500 MW of additions, corresponding to a system reserve margin of 16 percent. For nuclear units the LOLE of 1-day-in-10-years is achieved with 3000 MW of additions, corresponding to a system

reserve margin of 23 percent. Thus, for this system we found that each MW of nuclear capacity added had roughly the same system reliability value as two-thirds of a MW of small fossil capacity. The lower reliability value of large coal and nuclear relative to the other types is a result of the larger unit sizes and the higher outage rates. The size and outage rate assumptions for the various capacity types are listed in Table 5.1.

Table 5.1

**Size and Outage Assumptions
for Various Resource Types**

	Unit Capacity (MW)	Equivalent Forced Outage Rates (%)	Maintenance Outage Rate (%)
Combustion Turbine	100	3.5	4.2
Combined Cycle	200	5.5	4.2
Small Coal	200	3.8	12.6
Large Coal	800	7.8	12.6
Nuclear	800	11.9	18.7

Sources: Fossil unit outage rates are based upon EPRI's *Technical Assessment Guide* (1993). Nuclear unit outage rates are based upon NERC/GADS (1993a).

For single-site wind, the system never achieves LOLE of 1-day-in-10-years, regardless of the amount added. In this case, the figure indicates implausibly poor reliability for wind for two reasons: the relatively large amount of wind at a single site and the oversimplification embodied in the daily peak method of modelling reliability. The daily peak method is commonly used, and provides adequate results for analysis of thermal units. For intermittent resources, such as wind, the daily peak method can provide spurious results, because the contribution of the intermittent resource to system reliability during hours other than single daily peak hour can be important. This is discussed further below (in Section 5.4).

Figure 5.1

System Loss of Load Expectation
Versus
Capacity Additions for Various Resource Types

In order to measure the reliability contribution of wind generating systems we represent its "fossil capacity equivalent." This is the amount of thermal capacity (here the benchmark is a new small fossil unit with 84 percent availability) that can be replaced by a given amount wind capacity while maintaining a reliability criterion (e.g., 1-day-in-10-years). We determine this amount of capacity equivalent by iteration, running the reliability/dispatch model with various amounts of small fossil capacity, with a specified amount of wind, until the system reliability criterion is achieved. In the following, then we refer to the "fossil capacity equivalent" or simply the "capacity equivalent" of wind.

5.2 Wind Penetration and LOLE Method

We have compared the amount of small fossil power plant capacity that can be displaced by given amounts of wind generation with the characteristics of the 1988 *Holland site*. The broad characteristics of this system -- peak load, generation mix, load factor and outage rates -- were discussed earlier. Here we explore a range of wind additions up to 30 percent of peak load. The system, in all cases, has overall reliability maintained at a constant level. Our starting point is a system with 10 percent reserve margin, including 1800 MW of new reliable small fossil installed, and 10 percent (800 MW) intertie support, with a 1-day-in-10- years LOLE using the daily peak method. We determine the small fossil capacity equivalent of wind as wind generation is increased from 0 to 30 percent of the system peak, replacing increasing amounts of small fossil capacity while keeping system reliability (LOLE) constant.

We have produced results with two different ways of representing the system reliability criterion -- over all (260) daily peak hours, and over all (8760) hours in the year. With the daily peak method the 1-day-in-10-years criterion was maintained, while with the hourly method a criterion of 5.3 hours-in-10-years was maintained. The second measure was set for the system with its conventional (non-intermittent) generation mix at the point (less than reserve margin) where 1-day-in-10-years LOLE with the daily peak method is achieved. At that point we re-estimated LOLE with the hourly method and found 5.3 hours in 10 years. If we make the reasonable assumption that most of the LOLE is grouped in the hours around the daily peaks as single *events* or occurrences, of some duration, the modelling results indicate that the average duration of a daily peak loss of load event is 5.3 hours as noted in an earlier table.

Table 5.2 provides the results for capacity equivalent of wind using the daily peak (event) and hourly methods of measuring LOLE.

Table 5.2

**Fossil Equivalent of Wind
as a Function of Wind Penetration
1988 Wind and Load Pattern
Holland Site**

Wind Penetration (MW)	<u>Fossil Equivalent</u>	
	Hourly LOLE (MW)	Daily Peak LOLE (MW)
50	40	---
100	70	70
200	140	135
300	200	200
400	250	---
800	400	---
1200	480	
1600	530	400
2400	600	---

These results are shown graphically in Figures 5.2, 5.3 and 5.4 below, where we have fit the model values with smooth curves.

A word on these figures is useful at this point. Throughout this report, "capacity equivalent" results are presented in a three-graph format which deserves a brief explanation. For all of the graphs, the horizontal axis is the same, representing the amount of wind added to the system, in terms of installed MW of wind capacity.

The first graph always has the "cumulative capacity equivalent of wind" as the vertical axis. This is measured in MW of small fossil capacity that is displaced by a particular amount of wind capacity, determined by the iterative system reliability simulations as discussed above.

The second graph depicts the same information as the first, but here the vertical axis is redefined as a percentage. In this second graph, the percentage is "cumulative" meaning that the percentage indicated applies to the full amount of wind added. For example, in graph Figure 5.3 for the hourly load method, the 1600 MW of wind added would, in total displace 530 MW of small fossil capacity, so the cumulative capacity equivalent is 33 percent.

It is also interesting to consider the capacity value on a marginal, or incremental, basis. In the third graph, the capacity value is presented in this way, that is, the percent values plotted indicate the small fossil capacity equivalent of the next small increment of wind capacity

added. For example, from Figure 5.4 we see that at 1600 MW of wind, the incremental capacity equivalent of additional wind capacity is about 15 percent using the hourly LOLE measure; i.e. the next 1 MW of wind added can displace about 0.15 MW of small fossil while maintaining the same system reliability. The lines plotted in the third (incremental) graph are determined by taking the first derivative of the lines fit to the points in the first graph.

Thus, 1-day-in-10-years LOLE is an expectation of one loss of load event of duration 5.3 hours in 10 years. It is important to note, however, that while this relationship may remain fairly stable for conventional thermal systems, it can change over time as system characteristics evolve, and it is clearly system-specific. Typically, we have found systems that we have analyzed to have predicted average outage durations falling between 3 hours and 10 hours.

Figure 5.2
CUMULATIVE Capacity Equivalent of Wind (MW)
Versus
Wind Penetration
(Daily Peak vs. Hourly LOLE Method)

The figures show that as wind penetration grows between 0 and 30 percent (2400 MW for the case study system), its incremental fossil capacity equivalent declines. With the daily peak

LOLE method the value begins at about 100 percent (i.e., 1 MW of wind can displace 1 MW of small fossil), declines to about 33 percent (3 MW of wind displacing 1 MW of small fossil) at 15 percent wind penetration, and to 17 percent at 30 percent wind penetration. With the hourly LOLE method the capacity values of wind does not decline as rapidly with wind penetration, with values of 40 percent and 25 percent at 15 and 30 percent wind penetration, respectively. It is noteworthy that the availability ratio of wind to small fossil -- roughly their relative energy contributions -- is about 0.50. Thus, with the hourly LOLE method this measure is exceeded at penetrations less than 10 percent.

In contemplating these results it is important to bear in mind that the wind generation is all simulated for a single site. With large amounts of wind generation added to the system, site-diversity can be valuable, an issue that we explored and is discussed in a later section.

Figure 5.3
 CUMULATIVE Capacity Equivalent of Wind (%)
 Versus
 Wind Penetration
 (Daily Peak vs. Hourly LOLE Method)

Figure 5.4
 INCREMENTAL Capacity Equivalent of Wind (%)
 Versus
 Wind Penetration
 (Daily Peak vs. Hourly LOLE Method)

5.3 Declining Capacity Value of Wind

The figures discussed above show the capacity value of wind declining with increased penetration of wind on the system. The first increments of wind can displace roughly equivalent amount of small fossil capacity (see, for example, the incremental capacity equivalent roughly at 100 percent in Figure 5.4), while at very high penetrations, the capacity value of wind declines to as low as 10 percent, or even zero if the daily peak method is used.

The rate of decline in capacity value with increased wind penetration is determined by a variety of system-specific characteristics, the most important of which is the relationship between the hourly load shape and the hourly wind generation.

The primary technique used in this study for representing wind generation is to subtract hourly wind generation from hourly customer loads, and then dispatching thermal resources to meet the net load. (Some limited analysis of representing wind generation on the supply side was also done, and is discussed later.) With this load modification approach, at low levels of wind penetration, most of the system peak load hours are reduced, thereby considerably reducing overall system LOLE per unit of wind added. However, because the wind generation is zero in many hours, as large amounts of wind are added we find that the highest hours of the net load become dominated by hours with zero wind. Then, as additional increments of wind are added, the net load in these hours is unaffected. That is, at high levels of wind penetration, the hours in which the net loads are highest (and system reliability worst) tend to be the zero wind hours, so that adding more wind of the same hourly pattern has little or no effect on system reliability.¹⁶

5.4 The Daily Peak and Hourly Methods for LOLE

As noted above, the declining capacity value of wind is particularly pronounced when the daily peak method is used. This raises the natural question: "which method gives the correct assessment of system reliability and therefore the capacity value of wind?" In considering this question, recall that while the two LOLE measures both reflect system reliability, they measure distinctly different things. The daily peak method gives an estimate of the number of loss-of-load events that will occur, while the hourly load method gives an estimate of the amount of time for which some load may be unserved.

In our view, a third, somewhat less common, measure of system reliability -- the amount of energy unserved -- is probably preferable to either of the LOLE measures. The expected amount of unserved energy demand gives a quite direct measure of the effect upon customers. Some studies of the costs and benefits of various levels of system reliability attempt to weigh the costs of additional generating capacity against the benefits of reduced energy unserved,

¹⁶ One approach that is suggested by this declining capacity value is the use of diverse wind sites, particularly at the higher levels of system wind penetration. This is explored below (see, for example, Tables 5.5 and 5.6).

where this energy is priced at the customers' reported "willingness to pay" (in dollars) to avoid the outage. The outage costs are typically "priced" at a single value per Kwh unserved, implying that the total outage cost is directly proportional to the amount of energy unserved.

Assuming that unserved energy is the preferred measure of system reliability, then LOLE by the hourly method would be a better proxy than LOLE by the daily peak method, as the hourly LOLE better reflects unserved energy. For example, with the Holland site 1988 wind data, as wind ranges from 400 MW to 1600 MW of capacity and small fossil is displaced in amounts to maintain the hourly method LOLE constant, the amount of unserved energy increases by only 17 percent. Over the same range, we found that the daily peak method LOLE increased by 74 percent. Thus, for these set of runs, LOLE by the hourly method is an imperfect proxy for unserved energy, but it is far superior to LOLE by the daily peak method.

On the other hand, some of the literature on customer costs of outages is inconclusive on whether the cost of an outage is directly proportional to the amount of energy unserved. For example, Stephenson and Walters (1987) show costs per Kwh that tend to be higher for 1-hour outages than for longer ones, suggesting that some of the perceived costs are related to the number of events rather than the amount of energy unserved. To the extent that this is "true", there may be some validity to the use of the daily peak method as a measure of system reliability.

Also, one might prefer the hourly load method over the daily peak method, simply in that the hourly method contains or preserves more information. It offers a cumulative LOLE measure in which all hours of the year are included, although many will have a small or insignificant contribution to the annual total. The daily peak method, on the other hand, excludes any consideration of 23 hours of each day.

Both methods provide useful information on the character of probabilistically expected outages for a system, from which the lost amenity or economic value from unserved load could be assessed. But for intermittent generating resources, the methods may differ in another respect. When modelling intermittent resources, using the daily peak method, an interesting methodological question arises as to whether the daily peak hour used should be the peak customer load hour, or the highest net load hour (after subtracting the intermittent resource). We believe that the more meaningful approach is to use the highest net load hours, and have adopted this approach for the daily peak method calculations in this study. Most of the analysis presented here, however, is done according to the hourly method, as we believe it to be stronger for system reliability analysis -- particularly where intermittent resources are part of the analysis.

While the daily peak method has been commonly used for system reliability analysis, and it may be fine for conventional thermal-based power systems, we conclude that it is weak for reliability analysis of systems with large amounts of intermittent resources, even when the "net load daily peaks" are used.

5.5 Basic Results for Different Wind/Load Years

We have already examined the fossil capacity equivalent of wind for 1988, and elucidated the difference between use of the daily peak (event) and hourly measure of LOLE. From here on, using the hourly LOLE method, with a criterion of 5.3-hours-in-10-years, we explore further the relationships between wind and reliability. We begin by examining a different wind (and load) year, 1985, with wind and load patterns distinct from those of 1988.

Three effects are intermingled here -- the wind pattern, the load pattern, and the correlation between the two -- that might affect the fossil capacity equivalent of wind. Given the paucity of consistent wind data for different years and sites within the area of the case study utility system, we were limited for this study to the two years -- 1985 and 1988.

As noted above, the 50-MW Holland wind farm only slightly differed in overall energy generation (or capacity factor) between the different wind years. While the capacity factor is relevant to reliability, measuring the average amount of time the facility is generating versus not generating, it is a crude aggregate measure that does not capture the *pattern* of generation (availability) over the hours of the year. Nor does it capture the relationship between that pattern and the pattern of loads.

The 1985 loads have a load factor of 64 percent. This is much higher than the 1988 load factor of 54.7 percent, and high compared with typical load factors in the U.S. which tend to be between these two figures. A high load factor gives less room for maintenance and would result in LOLE coming from more hours in the year; generally, all else equal it is a less reliable system requiring greater capacity reserves, while a low load factor system would have LOLE concentrated in a few hours and would generally require less reserves.

Table 5.3

**Fossil Capacity Equivalent of Wind
for Different Wind/Load Years
1985 and 1988 Wind and Load Patterns
Holland Site**

Fossil Equivalent		
Wind Penetration	1985	1988
50 MW	20 MW	40 MW
100 MW	50 MW	70 MW
200 MW	90 MW	140 MW
300 MW	---MW	200 MW
400 MW	160 MW	250 MW
800 MW	260 MW	400 MW
1200 MW	320 MW	480 MW
1600 MW	370 MW	530 MW
2400 MW	440 MW	600 MW

Figures 5.5, 5.6 and 5.7 display the three curves of fossil capacity equivalence -- cumulative MW fossil per MW wind, cumulative percent of fossil, and incremental percent of fossil -- for 1985 and 1988 conditions for the Holland wind farm. The cumulative fossil capacity equivalent for 1985 wind and loads is systematically lower than for 1988 wind and loads. At 100 MW wind penetration (1.25 percent of peak) the 1985 value is 50 percent compared with 70 percent for 1988. The fossil capacity equivalent values decline to 40 percent and 62.5 percent, respectively at 400 MW penetration (5 percent of peak), and continue to decline to 18.3 percent and 25.0 percent, respectively, at 2400 MW penetration (30 percent of peak).

On an incremental basis, the capacity value of wind additions asymptotically approaches a value of about 10 percent at high levels of wind penetration in both cases.

Figure 5.5
CUMULATIVE Capacity Equivalent of Wind (MW)
Versus
Wind Penetration
(Hourly LOLE Method)
-Holland Site-

Versus
Wind Penetration
(Hourly LOLE Method)
-Holland Site-

Figure 5.7
INCREMENTAL Capacity Equivalent of Wind (%)
Versus
Wind Penetration
(Hourly LOLE Method)
-Holland Site-

5.6 Diversity

Diversity in power plant random outages contributes to system reliability. For thermal power plants, all else equal two (or more) small plants with a given forced outage rate provides more reliable output than a single large plant with the same outage rate and overall installed capacity. This occurs since the larger outage states require that both plants be out simultaneously but, given the random character of their outages, the individual plant outages tend to occur at different times (diversity).

Diversity for wind generating facilities can be effected by siting those facilities at different locations. While the same overall seasonal and even daily patterns might prevail, there can be sufficient differences in the detailed hourly patterns (either from statistical fluctuations in sites completely uncorrelated or from temporal displacements in sites, perhaps nearby, that broadly share the same wind regime). The reason such temporal diversity in wind generation can provide reliability benefits is that a given wind pattern's contribution to reliability is based on, and limited by, its correlation with the load pattern. If there are some load hours that contribute significantly to system LOLE, but have little or no wind from a particular facility in a given year, simply increasing the size of the wind farm will not appreciably increase reliability once the LOLE in the hours where the higher wind output occurs is decreased.¹⁷

To explore the reliability benefits of diversity in wind electric generation, we created three alternative sites with the same **overall** wind generation pattern as the Holland site, and examined pairing each of them with Holland, with Holland at half its capacity and the diversity site providing the other half. The three diversity sites created were:

- Comstock -- The Holland site data, adjusted to reflect a distance of about 150 miles
- Beulah -- Wind pattern from a site in North Dakota normalized to reflect Holland's **overall** generation pattern
- Rayleigh -- A hypothetical site completely uncorrelated with Holland's generation pattern

For more discussion of these data for different wind sites, see Chapter 4.

1988 Load and Wind Pattern

Since there is a correlation between the wind pattern at Holland and the system load pattern, it could be expected that other sites than Holland, especially to the extent that they are uncorrelated, would themselves provide less reliability than Holland but, together with Holland, would improve reliability relative to Holland alone. Table 5.4 below shows the fossil

¹⁷ Indeed, in some hours with sufficiently sized wind facilities, the net load (load minus wind) can become zero, and increases will be irrelevant unless storage is utilized.

equivalent of 1200 MW of wind (15 percent of system peak) at each site. Note that Holland provides the highest fossil equivalent, while Rayleigh provides the lowest, much lower than Holland, Comstock and Beulah, as might be expected for a completely uncorrelated site.

Table 5.4

Comparison of Reliability Contribution of Different Wind Sites
1200 MW of Wind
1988 Wind and Load Pattern

Wind Site	Fossil Equivalent
Holland	480 MW (40%)
Comstock	420 MW (35%)
Beulah	395 MW (33%)
Rayleigh	240 MW (20%)

Despite their lower *individual* reliability contribution, each site combined with Holland contribute greater reliability than Holland alone, with the same overall installed capacity. This is evident in Table 5.5, below.

Table 5.5

Diversity Benefits to Reliability of Different Wind Sites
1200 MW of Wind
1988 Wind and Load Pattern

Wind Site Composition	Fossil Equivalent
Holland	480 MW (40%)
Holland and Comstock	500 MW (42%)
Holland and Beulah	570 MW (48%)
Holland and Rayleigh	550 MW (46%)

There is clear improvement from diversity at 1200 MW wind penetration (15 percent of system peak). Note that, while the combination with Beulah provides the best diversity at this penetration (about 19 percent increase in fossil equivalent), the combination with Rayleigh is almost as good (about 14 percent increase) notwithstanding its very low individual contribution.

But does the diversity benefit depend on the wind penetration? If as noted earlier, higher penetrations of a given wind pattern exhausts the reliability contribution from that wind facility, owing to the specific correlation of wind to load, one could expect that adding diversity (i.e.,

contributions at other load hours where LOLE is significant) would improve the reliability contribution of wind at the higher penetrations. This is shown in Table 5.6. below.

Table 5.6

**Diversity Benefits of Different Wind Sites
as a Function of Wind Penetration
1988 Wind and Load Pattern**

Wind Site Composition	Fossil Equivalent at Wind Penetration of			
	400 MW	800 MW	1200 MW	1600 MW
Holland	250 MW	400 MW	480 MW	530 MW
Holland and Comstock	235 MW	400 MW	500 MW	580 MW
Holland and Beulah	235 MW	420 MW	570 MW	690 MW
Holland and Rayleigh	210 MW	400 MW	550 MW	675 MW

Table 5.6, and Figures 5.8, 5.9, and 5.10 compare the Holland alone and the three diversity cases, showing cumulative fossil equivalent in MW, cumulative fossil equivalent in percent, and incremental fossil equivalent in percent, as a function of wind capacity penetration. Note that at 1600 MW (20 percent of system peak) the cumulative fossil equivalent is roughly 40 percent, and the incremental is in the 20 to 30 percent range. Moreover, the figures indicate that the relative contributions of the diversity combinations continue to diverge from the single site at penetrations above 1600 MW.

Figure 5.8
Diversity Value of Wind in 1988
CUMULATIVE Capacity Equivalent (MW)
Versus
Wind Penetration

Diversity Value of Wind in 1988
 CUMULATIVE Capacity Equivalent (%)
 Versus
 Wind Penetration

Figure 5.10
 Diversity Value of Wind in 1988
 INCREMENTAL Capacity Equivalent (%)
 Versus
 Wind Penetration

1985 Load and Wind Pattern

The diversity analysis described above was done using the 1988 wind/load year. We also annualized diversity for the 1985 wind/load year. The results for 1985 are presented in Table 5.7, Table 5.8, Figure 5.11, Figure 5.12, and Figure 5.13.

Table 5.7

Reliability Contribution of Different Wind Sites
1200 MW of Wind
1985 Wind and Load Pattern

Wind Site	Fossil Equivalent
Holland	320 MW (27%)
Comstock	315 MW (26%)
Beulah	250 MW (21%)
Rayleigh	305 MW (25%)

Comparing the results for 1985 in Table 5.7 with the results for 1988 in Table 5.4, we see that for three of the four sites, the fossil equivalent dropped significantly, which for the Rayleigh wind data, the fossil equivalent increased. For all the combined wind sites, however, the capacity value was lower for the 1985 data, even for the Holland/Rayleigh combination.

Table 5.8

Diversity Benefits of Different Wind Sites
for Different Load/Wind Years
1985 Wind and Load Pattern

Fossil Equivalent of Wind Penetration of Wind Site Composition				
	400 MW	800 MW	1200 MW	1600 MW
1985				
Holland	160 MW	260 MW	320 MW	370 MW
Holland and Comstock	160 MW	280 MW	355 MW	420 MW
Holland and Beulah	180 MW	320 MW	430 MW	525 MW
Holland and Rayleigh	180 MW	305 MW	400 MW	480 MW

Figure 5.11
 Diversity Value of Wind in 1985
 CUMULATIVE Capacity Equivalent (MW)
 Versus
 Wind Penetration

Figure 5.12
Diversity Value of Wind in 1985
CUMULATIVE Capacity Equivalent (%)
Versus
Wind Penetration

Figure 5.13
Diversity Value of Wind in 1985
INCREMENTAL Capacity Equivalent (%)
Versus
Wind Penetration

5.7 Effect of Tower Height

The results given heretofore for the fossil capacity equivalent of wind electric generation are for a wind machine of 40 meter height. In order to examine the effect of tower height a second machine, with height at 30 meters, was simulated (by UCS) at the Holland site for the year 1988. The basic overall characteristics of the 50-MW 1988 wind farm at Holland for 40 and 30 meters were given in Table 4.2 on p. 20, along with those of other sites/years.

For 1988 wind at Holland the 40 meter height has average wind speed of 8.22 meters/sec and annual capacity factor of 35.3 percent, while the 30 meter height has average wind speed of 7.54 meters/sec and annual capacity factor of 30.1 percent.

The results are given in Table 5.9, below and Figures 5.14, 5.15 and 5.16.

Table 5.9

**Fossil Equivalent of Wind at Different Tower Height
as a Function of Wind Penetration
1988 Wind and Load Pattern**

Fossil Equivalent at Wind Penetration of				
Wind Site Composition	400 MW	800 MW	1200 MW	1600 MW
Holland -- 40 meters	250 MW	400 MW	480 MW	530 MW
<u>Holland -- 30 meters</u>	<u>200 MW</u>	<u>335 MW</u>	<u>420 MW</u>	<u>490 MW</u>
Ratio	80%	84%	88%	92%

It is noteworthy that the cumulative fossil equivalent of the two alternative wind farms each follow the same overall pattern that we have seen before, with the 30 meter system consistently below that of the 40 meter as expected. Note that the ratio of the equivalent at 30 meters to 40 meters rises from 80 percent at 400-MW wind penetration (5 percent of peak load) to 92 percent at 1600 MW (20 percent of peak load). This can be compared with the ratios of average wind speed and capacity factor, 91.7 percent and 85.3 percent, respectively, with some broad similarity but no obvious pattern.¹⁸

¹⁸ More such analysis would be required to determine the relationships between these aggregate parameters and the results.

The convergence between the 30 and 40 meter fossil capacity equivalents of wind at higher penetrations may relate to the phenomenon seen earlier, of a saturation at higher levels beyond which extra capacity of the same pattern provides diminishing returns.

Figure 5.14
Effect of Wind Tower Height
CUMULATIVE Capacity Equivalent of Wind (MW)
Versus
Wind Penetration

Figure 5.15
Effect of Wind Tower Height
CUMULATIVE Capacity Equivalent of Wind (%)
Versus
Wind Penetration

Figure 5.16
Effect of Wind Tower Height
INCREMENTAL Capacity Equivalent of Wind (%)
Versus
Wind Penetration

5.8 Effect of System Outage Rates

The system that we have been analyzing thus far has relatively low plant outage rates (and correspondingly high reliability). To explore the effect of high outage rates we examined the national mix of thermal power plants to obtain the national average outage rates, shown in Table 5.10, below.

We know without any analysis that system reliability depends strongly upon the power plant outage rates, but not whether the reliability contribution of wind to a system (its fossil capacity equivalent) depends on the underlying outage rates of the system. To explore this issue we constructed a high outage case, with the forced outage rates and maintenance outage rates of the case study system doubled and tripled respectively, except for those incremental fossil units which we displace with wind.

Table 5.10

System Average Outage Rate Assumption

	Average Forced Outage Rate	Average Maintenance Outage Rate	Equivalent Availability Factor
Low Outage Rate Case Study	7.4	6.0	87.0%
High Outage Rate Case Study	14.8	18.0	69.9%
National Average Outage Rate	12.4	13.6	75.7%

With the 1988 load data, we found that for the high outage rate case, with no wind, the system achieved 1-day-in-10-years LOLE at a 17 percent reserve margin. Analysis of the value of wind for the high outage rate case found that for the 40-meter Holland wind site at 1200-MW penetration, the fossil capacity equivalent of the wind for the test system is somewhat higher at much higher system outage rates. Specifically, 1200 MW of wind was found to be

equivalent to 530 MW of fossil for the high outage rate case, and 480 MW of fossil with base case outage rates. We are not certain whether and to what extent this result might be significant and generalizable.

5.9 Modelling Wind As Supply

For most of the analysis presented here, wind generation was modelled as a modification to load. That is, the ELFIN model subtracts hourly wind generation (in MW) from hourly customer load data (also in MW) yielding a net load, which the system's non-wind generators are dispatched. This approach is attractive, in that it preserves a fairly detailed representation of the wind resource (hourly average values) in combination with a simplified load duration curve approach to dispatch simulation. Correlations in the timing of wind and load are reflected in the analysis.

We did, however, explore some options for representing wind as a supply resource in the ELFIN model. This could be useful, because in many cases hourly wind data may not be available. Also, supply-side representation may be more convenient with some computerized reliability models. Representing wind as a supply resource may also offer opportunities for incorporating the stochastic nature of the resource in an interesting way.

For system reliability, the key inputs for a generating resource in a production costing model include the capacity rating (in MW) and the forced outage rate (percentage of the time that the unit is unavailable on a random basis). With most models (including ELFIN) capacities and forced outage rates can also be specified for intermediate states in order to represent partial outages. For this analysis, we represented wind as a supply resource by three different methods: 1) capacity derating, 2) equivalent full forced outage rate, and 3) a 3-state model. Each of these was done on a weekly basis, so that the weekly amount of wind generation was held constant, in all cases matching the amount of weekly wind generation used in the load modification method.

The capacity derating approach is a "one-state" representation, in which the wind generator is assumed to operate in every hour of the subperiod (in this case a week) at a capacity rating lower than its installed capacity, such that it generates the correct amount of energy. Effectively, this method represents partial wind turbine output by putting the wind generator at its average generating level in all hours.

The equivalent full forced outage (EFOR) method is, in a sense the opposite approach. Here, partial wind turbine output is folded into the forced outage rate assumption, so that when the simulated wind generator is operating it generates at its full installed capacity, but it does so for fewer hours. This is a "two-state" model, in which the wind generator is at either zero or its full installed capacity.

Finally, we tested a three-state model, in which the wind turbine was simulated with three operating states: zero (i.e., not generating, full installed capacity, and a partial capacity state. The inputs were constructed such that the percentages of time at zero and at full installed capacity correspond with the hourly wind data. The partial outage state was then constructed such that operation at that state for the remaining time produces the correct amount of energy.

The three methods are depicted in Figure 5.17.

For the Holland 1988 wind data, the inputs for modelling wind on the supply side are listed in Table 5.11. This assumes 1200 MW of installed capacity at the Holland site, and includes generation and average capacity on a weekly basis. For the capacity derating method, the capacity figures in Table 5.9 were used. For the EFOR method, the outage rates in the right most column were used.

Figure 5.17

Wind Supply Modelling Options

Data are for the Holland wind site for 1988

Table 5.11

Data for Modelling Holland-Site Wind as a Supply Resource

Week	Weekly Generation (MWH)	Capacity at 100% Availability (MW)	Forced Outage Rate at 100% of Capacity (%)
0*	31,223	650	46%
1	91,336	544	55%
2	109,278	650	46%
3	72,956	434	64%
4	48,929	291	76%
5	100,659	599	50%
6	60,729	361	70%
7	86,706	516	57%
8	104,709	623	48%
9	68,663	409	66%
10	133,175	793	34%
11	59,645	355	70%
12	129,257	769	36%
13	68,379	407	66%
14	105,829	630	48%
15	82,782	493	59%
16	47,867	285	76%
17	87,740	522	56%
18	93,752	558	53%
19	100,778	600	50%
20	87,857	523	56%
21	103,657	617	49%
22	67,416	401	67%
23	87,161	519	57%
24	60,884	362	70%
25	81,223	483	60%
26	64,528	384	68%
27	94,391	562	53%
28	52,535	313	74%
29	25,585	152	87%
30	79,083	471	61%
31	78,411	467	61%
32	68,263	406	66%
33	60,528	360	70%
34	54,978	327	73%
35	81,086	483	60%
36	84,938	506	58%
37	58,879	350	71%
38	83,666	498	58%
39	65,243	388	68%
40	43,577	259	78%
41	71,333	425	65%
42	88,271	525	56%
43	88,582	527	56%
44	87,558	521	57%
45	67,283	400	67%
46	55,756	332	72%
47	101,604	605	50%
48	55,864	333	72%
49	58,749	350	71%
50	127,236	757	37%
51	97,396	580	52%
52*	54,800	381	68%
Total or average	4,122,713	471	61%

*Week zero represents the first two days of the year.
Week 52 represents the last 6 days of the year.

Table 5.12

**Comparison of Reliability Value
of Wind Using Different Modelling Techniques**
1988 Wind and Load Pattern
1200 MW at Holland Site

Method for Wind Representation	MW of Small Fossil Displaced
Load Modification	480
<u>Supply Resource</u>	
Capacity Derating	400
Equivalent Forced Outage Rate	100
3-State Method	330

The results for our supply side cases are listed in Table 5.12. The figure of 480 MW of small fossil capacity displaced by 1200 MW of wind capacity was produced by the load modification method and has been discussed earlier. With the amount fossil displaced at only 100 MW, the EFOR method gives the most pessimistic assessment of the value of wind. We believe this to be inaccurate, in that the assumed probability distribution for the wind generation is greatly understates the amount of time that some amount of wind generation will be available. For the Holland data analyzed here, the number of hours with zero wind generation is 916 for 1988, but the simulation by the EFOR method has approximately 5300 hours at zero generation. We conclude that the EFOR method is not an acceptable approach for simulating wind generation.

The three-state method, as expected, gives results between the two prior methods tested. We believe that for many applications, a three-state method will provide an acceptably accurate representation of wind generation.

If higher order methods were tried (e.g., a five-state method) results would be more precise than those for the three-state method. They would, however, remain below those for the capacity derating method, which is a theoretical upper limit on the reliability value of wind as determined for supply side modelling approaches of this type.

This raises the obvious question as to why the load modification approach gave a higher value to wind than the "theoretical upper limit" for supply side representations offered by the capacity derating method. This must be because the hourly pattern of the wind correlates reasonably well (or at least better than randomly) with the hourly load pattern, allowing wind

modelled on an hourly basis -- on the load side -- to contribute more to system reliability than smoothed out wind on the supply side. In the extreme, if the annual reliability simulations were done with 8760 subperiods (rather than the 53 used here), the difference between representing wind on the load side and on the supply side (using a "subperiod" average amount of wind generation) would disappear.

For this case study system, the derating approach to modelling wind appears to produce reasonable results. We cannot, however, generalize from this result at this time. Further exploration should be undertaken of the conditions under which a capacity derating approach gives a similar result to the load modification approach.

Finally, we note our belief that improved modelling of intermittent resources for electric power system planning is possible. The current limitations include a lack of hourly resource data for specific interesting sites and the absence of commercially available planning software which can simulate hourly, seasonal and annual variation jointly in resources and customer loads. Site monitoring efforts will address the former. Model development efforts will address the latter. The accurate representation of intermittent resources in system reliability analyses is also held back by current common practice for utility planning which lags behind the state of the art.¹⁹ As new modelling approaches are developed and applied, it will be necessary to (re)examine the ubiquitous system reliability criterion of 1-day-in-10- years LOLE.

¹⁹ For example, the use of the daily peak method is, and we believe should be, out of date. Also, reliance upon "reserve margin targets" as anything more than a rule of thumb valid only under certain specific conditions is unjustified and problematic. The fairly common practice of representing conventional generating unit outages by the "EFOR" method is another example.

6. ECONOMICS OF WIND ELECTRIC GENERATION

6.1 Costs of Wind and Other Generating Options

Many observers have noted that wind power systems can provide electric generation at costs that are now competitive with conventional and advanced fossil facilities, as well as nuclear and hydro-electric power. This is particularly important, not only as regards the cost of electricity and the preservation of depletable energy resources -- the traditional attraction of renewable energy resources -- but also because of the environmental benefits of wind relative to conventional generation options. Most importantly, the near term goal of carbon stabilization and the longer term goal of climate stabilization make the wind option even more attractive as its costs have declined.

We have shown that the *reliability impacts* of wind power depend on generic characteristics as well as site and system-specific interactions. The same is the case for the *economic and environmental impacts* of wind power. We begin, then, with a generic comparison of the economic and environmental impacts of wind and alternative electric generating resources, and will then proceed to examine these impacts by modelling wind power for our case study system.

Since wind is an intermittent energy resource, with capacity factors ranging from 10 to 50 percent, we compare it to resources with baseload, intermediate and peaking characteristics. Included are pulverized coal with flue gas desulphurization (FGD), integrated coal gasification combined cycle (IGCC), natural gas combined cycle (NGCC), combustion turbine using natural gas with (CTSI) and without (CT) steam injection, wood-fired steam turbine, and bio-gasification steam injection turbine. We have selected the coal options for the East/West Central regions using Illinois bituminous coal. The IGCC is a single 500-MW unit, the pulverized coal is a single 300-MW unit, the NGCC is a 200-MW unit, the CT is an 80-MW unit, and the wood facility is a 50-MW unit. In addition to these new facilities we also include life-extension with scrubber retrofit for existing coal steam-electric systems.

Table 6.1 below, shows the technology costs (in 1993 dollars) and characteristics of different electric generation options using estimates primarily from the latest EPRI *Technical Assessment Guide* (EPRI 1993), supplemented by others sources including the U.S. DOE (DOE 1991) for life extension/scrubber retrofit, and *America's Energy Choices* (UCS 1991) for advanced biomass facilities.

Based on the EPRI document, we compare the thermal generating options with wind power for 50-MW wind farms (143 machines of 0.35 Kw) ordered in 1992 and 2000, respectively, the lower costs for 2000 reflecting the downward evolution of costs with experience and production increases. The capital costs of the wind facilities include an additional 2 percent to account for substation and grid interconnection equipment.

Table 6.1

Costs and Characteristics of Power Supply Options

	Capital Cost (\$/kW)	Fixed O&M \$/kW-y)	Variable O&M (\$/MWh)	Heat Rate (MMBtu/ MWh)	Equivalent Availability (%)
Coal Life Ext	646	11.2	12.5	10.00	75.0
Pulverized Coal	1607	47.2	2.0	10.16	84.0
IGCC Coal	1695	51.2	0.4	8.99	85.7
NGCC	595	26.5	0.4	7.52	88.9
Comb Turb	484	11.6	0.1	13.09	83.5
Comb Turb Steam Inj	822	32.5	0.6	9.90	87.5
Wood Steam	1883	87.7	10.2	14.31	85.0
BIG/STIG	1325	----	1.1	10.50	85.0
Wind (1992)	1194	25.2	0.0	-----	10-50
Wind (2000)	815	16.5	0.0	-----	10-50

Table 6.2 below shows the busbar costs of electric generation from each of these facility types, at their typical capacity factors. We have assumed wind capacity factors of 25 percent and 35 percent, which are typical of the range encountered in class 3 through class 5 wind sites at 30 meters tower height. Higher tower height and/or wind regimes would provide energy at higher capacity factors. We show capacity factors of 80 percent for coal and biomass units, 80 percent, 50 percent, and 25 percent for NGCC units, and 25 percent and 10 percent for combustion turbines.

Table 6.2
Costs of Power Supply Options
In Service 2005
Levelized 1993 c/kWh

<u>Plant Type</u> <u>(Cap Factor)</u>	<u>Capital</u> <u>Cost²¹</u>	<u>Fixed</u> <u>O&M</u>	<u>Variable</u> <u>O&M</u>	<u>Fuel²⁰</u>	<u>Total</u>
Coal Life Ext (80%)	1.09	0.16	1.25	1.98	4.48
Pulverized Coal (80%)	2.68	0.67	0.20	2.01	5.56
IGCC Coal (80%)	2.83	0.73	0.04	1.78	5.38
Wood Steam (80%)	2.71	1.25	1.02	4.85	9.83
BIG/STIG (80%)	1.91	----	1.10	3.56	6.57
NGCC (80%)	0.94	0.38	0.04	3.99	5.35
NGCC (50%)	1.51	0.61	0.04	3.99	6.15
NGCC (25%)	3.02	1.21	0.04	3.99	8.26
Gas Comb. Turbine (25%)	2.32	0.52	0.01	6.94	9.79
Gas Comb. Turbine, Steam Injection (25%)	3.94	1.48	0.06	5.25	10.73
Gas Comb. Turbine (10%)	5.80	1.30	0.01	6.94	14.05
Wind 1992 (35%)	3.93	0.82	----	----	4.75
Wind 1992 (25%)	5.51	1.15	----	----	6.66
Wind 2000 (35%)	2.68	0.56	----	----	3.24
Wind 2000 (25%)	3.76	0.76	----	----	4.52

²⁰ Fossil fuel prices are based on *Annual Energy Outlook 1994* (DOE/EIA 1994) for 2005 -- \$1.75/MMBtu for coal and \$3.60/MMBtu for natural gas (in 1993 \$) -- with escalation thereafter assumed to be 1.0 percent/year for coal and 3 percent/year for natural gas. The wood fuel price was assumed to be \$3.00/MMBtu (1993 \$) in 2005, escalating at 1.0 percent/year thereafter. Thirty-year levelization factors are: 1.131 for coal and wood; 1.472 for natural gas.

²¹ The levelized real fixed charge factors used to annualize these capital costs -- 0.101 for renewables, 0.105 for combustion turbines, 0.111 for combined cycle, and 0.117 for fossil steam -- were taken from EPRI TAG (1993).

In the table we see that life-extension of existing coal, with scrubber retrofit to meet clean air act requirements²², is the lowest cost near term baseload option (although life extension with a shift to low sulphur coal may be even lower cost), followed by new coal-fired power supply and natural gas combined cycle facilities. For peaking at low capacity factors the lowest cost option is conventional natural gas combustion turbine, while for intermediate operation natural gas combined cycle is lowest cost.

The busbar costs of wind will differ significantly for different wind regimes which can provide electric output ranging from 10 to 50 percent capacity factor. At capacity factors above 30 percent wind facilities ordered in 1992 have *prima facie* comparable costs to the fossil baseload options, and lower than the intermediate and peaking options. The EPRI projections of costs for wind facilities ordered by 2000 show clear advantages for wind at capacity factors above 25 percent. However, as the wind facilities do not provide the same reliable capacity per installed MW these comparisons are a rough first approximation. With storage or combustion turbine back-up for comparable reliability the costs of wind generation could be 20 to 30 percent higher than shown above; still wind will remain competitive.

The foregoing comparisons do not take account of emissions and their costs (either as externalities or as actual costs in a tax or tradable permit system). With emissions taken into account, e.g., by monetizing their externalities, the non- or low polluting options, including wind, would have relatively better economics, and the more efficient, lower polluting fossil options (e.g., natural gas combined cycle) would improve relative to their more polluting alternatives. Below is a table that shows the busbar costs, emissions of SO₂, NO_x and CO₂, and total social costs using illustrative sets of externalities values for these pollutants.

Two sets of externalities values were chosen for the illustration of their impact -- a set based on the values adopted by Commissions in Massachusetts and Nevada (\$1500/ton for SO₂, \$6500/ton for NO_x, and \$25/ton for CO₂) and a set with lower values (\$500/ton for SO₂, \$2000/ton for NO_x, and 15/ton for CO₂)²³. These results are shown in Table 6.3, where it is apparent that, with externalities and particularly CO₂, wind becomes preferable to the best fossil options -- natural gas combined cycle -- even with additional peaking capacity costs for equivalent reliability.²⁴ Note also, that advanced biomass becomes competitive with NGCC as well.

²² The scrubber cost for reduction of 2.5 lb/MMBtu SO₂ from existing coal boilers is about \$464/ton, which is in the neighborhood of projected trade prices for SO₂ allowances.

²³ The California Energy Commission has promulgated significantly higher values for SO₂ and NO_x: in 1995 \$, about \$10,000/ton and \$15,000/ton, respectively, for the South Coast Air Quality Management District, and about \$4,000/ton and \$7,000 ton, respectively, for district maxima in other parts of the state.

²⁴ Note that these comparisons are for the 30-year period beginning 2005, for later year in-service dates fuel price escalation will make natural gas less attractive versus all other options; the reverse is the case for earlier year in-service dates.

Table 6.3

**Costs, Emissions and Social Costs
of Power Supply Options
In Service 2005**

Plant Type (Cap Factor)	Market Costs Lev 1993 c/kWh	Emissions (lb/MWh)			Social Costs Lev 1993 c/kWh With Externalities	
		SO ₂	NO _x	CO ₂	Low	High
Coal Life Ext (80%)	4.48	9.5	5.4	2,130	6.86	9.61
Pulverized Coal (80%)	5.56	4.0	3.0	2,164	7.58	9.54
IGCC Coal (80%)	5.38	0.8	0.5	1,780	6.79	7.83
Wood Steam (80%)	9.83	0.1	1.4	-----	9.97	10.29
BIG/STIG (80%)	6.57	0.1	0.6	-----	6.63	6.77
NGCC (80%)	5.35	---	0.6	895	6.08	6.66
NGCC (50%)	6.15	---	0.6	895	6.88	7.46
NGCC (25%)	8.26	---	0.6	895	8.99	9.57
Gas Combustion Turbine (25%)	9.79	---	1.5	1,558	11.11	12.23
Gas Combustion Turbine, Steam Injection (25%)	10.73	---	0.8	1,178	11.69	12.46
Gas Combustion Turbine (10%)	14.05	---	1.5	1,558	15.37	16.49
Wind 1992 (35%)	4.75	---	---	-----	4.75	4.75
Wind 1992 (25%)	6.66	---	---	-----	6.66	6.66
Wind 2000 (35%)	3.24	---	---	-----	3.24	3.24
Wind 2000 (25%)	4.52	---	---	-----	4.52	4.52

6.2 Economic Comparisons for the Case Study System

The economics of wind for particular wind sites within a particular utility system will not necessarily conform to the simple busbar analysis provided above. As we have found that wind reliability, and thus fossil capacity equivalent, depends on the site and system (involving wind and load correlations and power plant mix), the economics will also be so dependent. Similarly, the power plant mix will affect the energy and emissions impacts of wind power. These two factors are related to the avoided capacity and energy (and emissions) costs of the system, which are system-specific and affected by the power supply (or load modification) pattern of the resource whose avoided costs are being determined.

To explore these interactive effects we have modelled the economics of our case study system - using the ELFIN production costing model -- with two different levels of wind power penetration -- 400 MW and 1200 MW (5 percent and 15 percent of peak load, respectively) for a given wind/load pattern year (1985) both with and without two-site diversity. (Note that the fossil capacity equivalent for 1985 was the lower of the two wind/load pattern years studied in our reliability analyses.)

We began by selecting a set of additions of baseload (coal) and peaking (combustion turbine) facilities to add to the existing system resources to meet the requirements of the year 2005 (1985 load shape escalated to year 2005 demands), and escalated the fuel and O&M costs of the generation mix to that year's dollars. The additions -- 1140-MW coal and 600-MW combustion turbines -- were chosen to approximately optimize the sum of new capital costs and generation costs, on a 30-year real levelized basis. Then, model runs were made with the wind capacity substituting for coal capacity based on the fossil capacity equivalents for the 1985 wind/load pattern.²⁵

For 400 MW of wind at the Holland site, 160 MW of coal capacity was removed, while for 1200 MW of wind at Holland, 320 MW of coal capacity was removed. With diversity from the Holland and Beulah sites, the amount of coal capacity removed was 180 MW and 430 MW, respectively, for 400 MW and 1200 MW of wind.

Table 6.4 summarizes the mix of system resources that the wind energy displaces in each case.

²⁵ These results are approximate. If the mix were re-optimized for each wind capacity scenario, rather than displacing coal strictly according to the wind capacity equivalent, the overall costs of the wind capacity scenarios would tend to be lower than those found here.

Table 6.4

**Case Study System Resource Mix
Displaced by Wind Energy**

	<u>No Wind</u>	<u>Single Wind Site</u>		<u>Two-Site Diversity</u>	
		400 MW	1200 MW	400 MW	1200 MW
Wind Energy (CF)	-----	1243 GWh (35.4%)	3730 GWh (35.5%)	1257 GWh (35.9%)	3773 GWh (35.9%)
New Coal	-----	1147 Gwh	2408 GWh	1220 GWh	2979 GWh
New CT	-----	33	286	8	491
Existing Coal	-----	50	895	22	217
Existing Oil/Gas	-----	10	78	10	58
Purchased Power	-----	2	25	(2)	5
Hydro	-----	0	0	0	0
Nuclear	-----	0	0	0	0
Wood/RDF	-----	1	38	0	24

The displaced energy mix is dominated by new and existing coal generation, the new coal generation reduced as these units are removed from the system. For the single wind site at Holland, the fraction of coal in the displaced energy decreases as the wind penetration increases from 400 MW to 1200 MW (with new coal decreasing and existing coal increasing); the same occurs, but less pronounced, with two-site diversity at Holland and Beulah. In moving from single site to two-site diversity the overall fraction of coal increases at 400 MW at penetration and decreases at 1200 MW penetration, while the fraction of new coal increases.

Table 6.5 below summarizes the system economic results assuming wind at 1992 costs and the 1985 wind pattern. The impact of wind power on system costs is comparable to that of coal power for the case study system, for wind at its 1992 cost of \$1194/kW and coal at a cost of \$1607/kW. There are very small differences -- less than about 2 percent -- between the total costs for all of the above scenarios. The addition of 400-MW wind power (5 percent of peak) at Holland slightly increases the overall costs, while the addition of 1200 MW (15 percent of peak) at Holland increases costs about 2 percent; for two-site diversity at the combined Holland/Beulah sites, the overall costs decrease slightly at 400 MW and increase slightly at 1200 MW.

Table 6.5
Economics of Wind Integration
Into Case Study System

1985 Wind/Load Patterns
1992 WIND FACILITY COSTS

Resource Mix	MegaWatts				
	<u>No Wind</u>	<u>Single Wind Site</u>		<u>Two-Site Diversity</u>	
Wind	----	400	1200	400	1200
Coal	1140	980	820	960	710
CT	600	600	600	600	600

Costs

Million \$ 1993 Levelized Costs: 2005-2035

Capital Costs

Wind	-----	\$ 58.3	\$174.9	\$ 58.3	\$174.9
Coal	\$268.1	\$230.5	\$192.8	\$225.8	\$167.0
CT	\$ 37.5	\$ 37.5	\$ 37.5	\$ 37.5	\$ 37.5

Production

<u>Costs</u>	<u>\$653.0</u>	<u>\$633.3</u>	<u>\$574.8</u>	<u>\$634.1</u>	<u>\$583.4</u>
Total Costs	\$958.6	\$959.6	\$980.0	\$955.7	\$962.8

The breakeven capital cost of wind power is found here to be between about \$1050 and \$1250/kW for penetrations between 5 and 15 percent of peak, respectively, for the cases considered. This is comparable to EPRI's current cost estimate of \$1194/kW. Additional diversity -- wind farms at multiple sites -- would tend to improve the economic competitiveness of wind.

While it takes more wind capacity to back out a unit of fossil capacity (lower fossil capacity equivalent), and thus the capacity cost savings of wind is poorer, at the higher wind penetrations, this is offset by the greater energy cost savings achieved from that greater amount of wind capacity (when the ratio of the wind to coal capacity factor -- about 40 to 50 percent - - is higher than the percent capacity equivalent. The capacity equivalents of each wind case are shown in Table 6.6.

Table 6.6
Summary of Capacity Tradeoffs
Case Study Analysis of Wind Economics

Wind Penetration	Coal Displaced	Percent Capacity Equivalent
<u>Single Site</u>		
400 MW (5%)	160 MW	40%
1200 MW (15%)	320 MW	27%
<u>Two-Site Diversity</u>		
400 MW (5%)	180 MW	45%
1200 MW (15%)	430 MW	36%

Finally, according to EPRI's projections, wind power capital cost will be far lower than these breakeven costs by the mid 1990s, and at about \$815/kW it will be far lower by the year 2000. Results for the year 2000 wind facility costs are given in Table 6.7 below, where it is apparent that for the cases of the system with 5 to 15 percent wind, total costs will be between 2 and 5 percent below the no wind case.

Table 6.7
Economics of Wind Integration
Into Case Study System

1985 Wind/Load Patterns
2000 WIND FACILITY COSTS

Resource Mix		MegaWatts			
		<u>Single Wind Site</u>		<u>Two-Site Diversity</u>	
Wind	----	400	1200	400	1200
Coal	1140	980	820	960	710
CT	600	600	600	600	600

Costs

Million \$ 1993 Levelized Costs: 2005-2035

Capital Costs

Wind	-----	\$ 39.6	\$118.9	\$ 39.6	\$118.9
Coal	\$268.1	\$230.5	\$192.8	\$225.8	\$167.0
CT	\$ 37.5	\$ 37.5	\$ 37.5	\$ 37.5	\$ 37.5

Production

<u>Costs</u>	<u>\$653.0</u>	<u>\$633.3</u>	<u>\$574.8</u>	<u>\$634.1</u>	<u>\$583.4</u>
Total Costs	\$958.6	\$940.9	\$924.0	\$937.0	\$906.8

6.3 Case Study System: Social Costs of Wind

The foregoing results do not take account of the environmental benefits of wind (relative to coal). This would render wind electric energy an even more economical option than coal for our case study system and conditions. In this section we take account of the emissions and externalities costs associated with our case study scenarios. In Table 6.8 we show the total system costs for the 1992 wind facility cost and the low externalities values (\$500/ton for SO₂, \$2000/Ton for NO_x, and \$15/Ton for CO₂).

Table 6.8

Market Costs, Emissions and Social Cost
of Alternative Wind Penetration
into Case Study System

1985 Wind/Load Patterns
1992 WIND FACILITY COST

Million \$ 1993 Levelized: 2005-2035

<u>Scenario</u>	Market Cost (Million \$)	Annual Emissions			Emissions Cost (Million \$)	Social Cost (Million \$)
		SO ₂ (10 ³ Tons)	NO _x (10 ³ Tons)	CO ₂ (10 ⁶ Tons)		
Base Case	958.6	74.5	82.5	34.3	716.7	1675.4
<u>Single Site</u>						
400-MW Holland Site	959.6	72.0	80.0	32.9	689.5	1649.1
1200-MW Holland Site	980.0	67.0	73.0	30.4	635.5	1615.5
<u>2-Site Diversity</u>						
400-MW Holland/Beulah	955.7	72.0	79.5	33.0	690.0	1645.7
1200-MW Holland/Beulah	962.8	67.0	73.5	30.4	636.5	1599.3

In Table 6.9 we make the same comparisons with the year 2000 wind facility costs.

Table 6.9

Market Costs, Emissions and Social Cost
of Alternative Wind Penetration
into Case Study System

1985 Wind/Load Patterns
2000 WIND FACILITY COST

Million \$ 1993 Levelized: 2005-2035

<u>Scenario</u>	Market Cost	Annual Emissions			Emissions Cost	Social Cost
		SO ₂	NO _x	CO ₂		
	(Million \$)	(10 ³ Tons)	(10 ³ Tons)	(10 ⁶ Tons)	(Million \$)	(Million \$)
Base Case	958.6	74.5	82.5	34.3	716.7	1675.4
<u>Single Site</u>						
400-MW						
Holland Site	940.9	72.0	80.0	32.9	689.5	1630.4
1200-MW						
Holland Site	924.0	67.0	73.0	30.4	635.5	1559.5
<u>2-Site Diversity</u>						
400-MW						
Holland/Beulah	937.0	72.0	79.5	33.0	690.0	1627.0
1200-MW						
Holland/Beulah	906.8	67.0	73.5	30.4	636.5	1543.3

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