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Matching Utility Loads with Solar and Wind Power in North Carolina

Dealing with Intermittent Electricity Sources

by

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March 2010

Matching Utility Loads with Solar and Wind Power in North Carolina: Dealing with Intermittent Electricity Sources, by John Blackburn (March 2010), is on the Web at www.ieer.org/reports/NC-Wind-Solar.pdf.

Minor corrections were made on September 27, 2010.

Foreword

By Arjun Makhijani

I met John Blackburn in mid-2008 at a lunch organized by Jim Warren, Executive Director of the North Carolina Waste Awareness & Reduction Network (NC WARN) in Raleigh, North Carolina. He had read my book *Carbon-Free and Nuclear-Free: A Roadmap for U.S. Energy Policy* and found in it a resonance for his own views regarding the desirability of a renewable energy system in the United States. Dr. Blackburn had already written *The Renewable Energy Alternative* in 1986 and *Solar Florida* in 1993. He taught economics and finance at Duke in the Department of Economics (1959-1980, except one year at the American University of Beirut, 1961-1962). He began researching energy issues a few years before his retirement from Duke, including energy economics, renewable energy, energy efficiency, and energy and development.

I was thrilled when he said that the idea of optimizing solar and wind discussed in C*arbon-Free and Nuclear-Free* was a good one and he wanted to try put together a first, approximate model for North Carolina. After all, he noted, North Carolina had good wind in the winter and at night (in the West) and, of course, better sunshine in the day in the summer. In particular, he had already been wrestling with the hourly solar-wind complementarity as he wrote up the draft North Carolina renewable energy study (for all energy uses, not just electricity) in 2006-2008. I told him that if he did the study IEER would publish it.

Matching Utility Loads with Solar and Wind Power in North Carolina: Dealing with Intermittent Electricity Sources is the result. This report is an initial study for how solar and wind loads can be matched up and supplemented by other sources of energy to match the electricity load profiles (adjusted somewhat for efficiency) in a state. This study is not designed as an investment plan or a roadmap. Rather it provides a technical **template** and a case study of how solar and wind can be combined to reduce intermittency on a daily basis and on a seasonal basis. Dr. Blackburn has done this wonderfully, using daily and seasonal load data, adjusted for improvements in efficiency, and joining it to measured and estimated wind and solar data for North Carolina. As he notes, the partition of wind and solar, which together make up 76 percent of the annual generation in his model is not optimized; rather an initial assumption was made that wind and solar would contribute equal amounts. This facilitated the development of the template; however, any other fractions can also be used. The economics of renewable electricity systems are not covered in this report. They were addressed in my book *Carbon-Free and Nuclear-Free: A Roadmap to U.S. Energy Policy*. In practice, the relative capital cost of solar and wind and the requirements for storage and reserve capacity corresponding to different combinations of technologies will play a role in optimizing the mix that would be selected.

This report shows that with modest amounts of resources such as hydropower (both normal and pumped storage), some natural gas generation, and some purchased power, loads can be met even at times of low renewable supply. The hydropower resources used in this study already exist in North Carolina and no new capacity is assumed. The heart of the study is in Dr. Blackburn's tables and the graphs based on them, that were so ably prepared by Hugh Haskell, who is an IEER Senior Science Fellow. It should also be noted that there was no attempt to make this into a 100 percent renewable electricity scenario. However, using this as a template, and adding some optimization and additional storage aspects, IEER will do this for both Minnesota and Utah in the coming year.

The approach developed here in how hydropower and pumped storage will be very useful for adding other forms of storage in these studies.

I am very grateful that Dr. Blackburn has developed this terrific template for putting together solar and wind with real-world load data. And he did it all as a volunteer. He had some help and would like to acknowledge the invaluable assistance of Daina Lind, summer intern at NC WARN and a graduate student in Economics at Duke. Ms. Lind patiently and cheerfully took on the tedious task of assembling thousands of hourly figures for solar and wind generation and helping to organize them into the format used in the paper. He also thanks Jim Warren of NC WARN for devoting a summer internship to this project and Fred and Alice Stanback, whose generosity makes the summer internship program at NC WARN possible. A draft of this report was reviewed by Dr. M.V. Ramana, an energy expert at Princeton University. I also reviewed it. As is usual when IEER publishes a report by a non-staff member, we stress that the views expressed here are Dr. Blackburn's own. But I want to note here that I generally concur with them, given that I advocate the development of a 100 percent renewable energy sector in the United States.

I am confident that this report will provide inspiration and a template for how to proceed with the development of a fully renewable electricity sector that will meet the goals of reliability (in the sense of keeping loss-of-load probability down to the levels that are normal for today's grid) and also allow exploration of economic optimization of renewable energy sources, storage, and smart grid technologies. I truly appreciate the brilliant work that Dr. Blackburn has done in developing this approach.

Arjun Makhijani
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Takoma Park, Maryland
March 2010

Executive Summary

Matching Utility Loads with Solar and Wind Power in North Carolina Dealing with Intermittent Electricity Sources

by John Blackburn, Ph.D.
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Those reluctant to endorse a widespread conversion to renewable energy sources in the U.S. frequently argue that the undeniably intermittent nature of solar and wind power make it difficult, if not impossible, to provide reliable power to meet variations in demand without substantial backup generation. Several studies, concentrating on areas with ample sources of both wind and solar power have suggested that a combination of the two, when spread over a sufficiently wide geographic area, could be used to overcome the inherent intermittency of each separately, reducing the need for backup generation. Moreover, since the backup power is required at more or less randomly distributed times, the availability of baseload power, so strongly entrenched in utility circles, becomes more or less irrelevant.

This study examines these ideas with data gathered in the state of North Carolina. Contrary to the idea that such an arrangement will be subject to heavy backup requirements from conventional sources, the clear conclusion of the study is that backup generation requirements are modest and not even necessarily in the form of baseload generation.

In North Carolina the two largest potential renewable electricity sources are solar and wind generation. The former is the case almost everywhere in the U. S., the latter is also the case in North Carolina, given wind resources in the mountains, along the coast, and offshore, both in the Sounds and in the ocean. Hydroelectricity (now 2,000 megawatts (MW) and potentially 2,500 MW) and biomass combustion represent the other renewable sources available in the State.

Solar and wind generation have some obvious complementarities. Wind speeds are usually higher at night than in the daytime, and are higher in winter than in summer. Solar generation, on the other hand, takes place only in the daytime and is only half as strong in winter as in summertime.

The study described here used hourly North Carolina wind and solar data for the 123 days of the sample seasonal months of January, July, October, and April. This entailed making 2,952 observations at each of three wind sites and three solar sites or 17,712 entries in all. In the absence of actual kilowatt-hour output data for long periods from functioning installations in widely separated locations, wind speed and solar irradiation were taken at the three sites each and converted to presumed wind and solar power outputs. Wind data was converted using the specifications of the wind turbines chosen for the study, shown below. Actual power readings for shorter periods from solar installations at two sites (from readings made in different years), were used to calibrate the presumed solar output at the chosen sites.

The generation patterns given by these sites were, for this initial exploration, taken to be representative of all of the sites in North Carolina. Solar and wind power generation constructed as outlined above were then scaled up to represent 80% (40% each) of average utility loads for the four sample months, with the remainder coming from the hydroelectric system (8%) and assumed biomass cogeneration (12%). The annual utility load was taken to be 90 billion kWh, a somewhat more energy-efficient version of the present 125 billion kWh load. Average hourly loads in each of the four seasons were taken from Duke Energy’s 2006 load profile. These were modified to show some reduction in summer and winter peaks as structures become more energy-efficient and enjoy disproportionate reductions in heating and especially cooling energy demands. The reductions were based on the author’s data set of measured energy use in more than one hundred North Carolina homes.

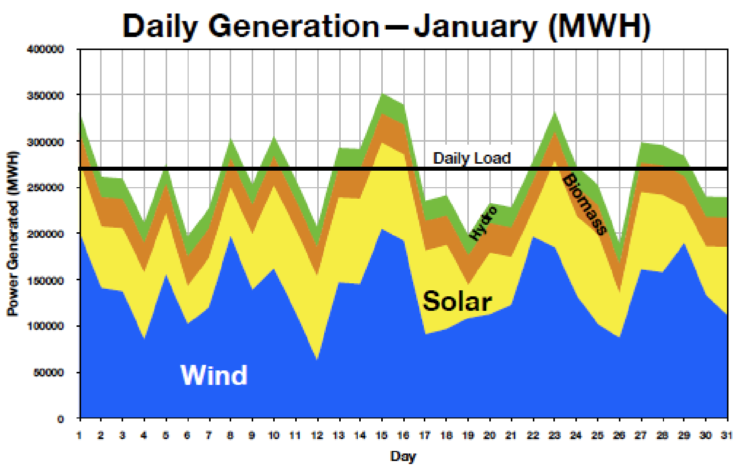
Wind generation was calculated from wind speeds using the cut-in, cut-out speeds and power curve for the General Electric 1.5 MW turbine (model 1.5xle). Solar generation was taken to be proportional to solar radiation at a ground level flat surface. Not surprisingly, wind generation from the three wind sites combined showed less variability than at each site separately. Solar generation did likewise, but with less variation to begin with. The literature suggests that day-by-day and hour-by hour wind variation would be further reduced by adding many more sites far enough apart to have somewhat different hourly wind regimes.

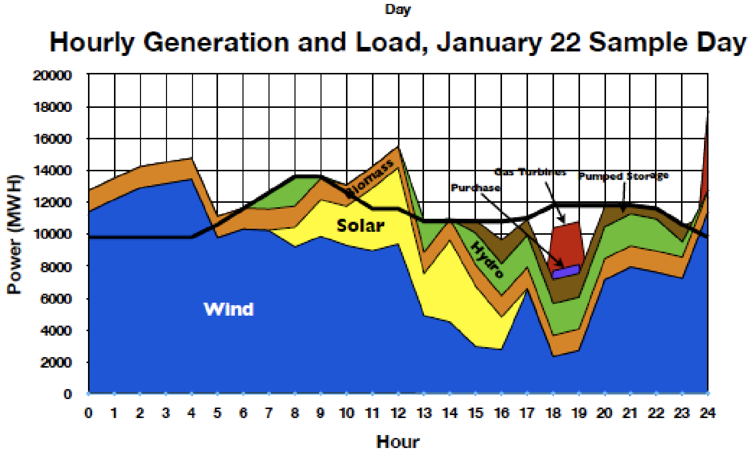
North Carolina has several means of evening out differences between variable generation and load from hour to hour within days, but very limited ability to carry stored energy forward from day to day. The hydroelectric system is already used as a means to meet peak demands with a generation system heavily oriented toward baseload generation. In addition, there is pumped storage capacity in the Duke Energy system amounting to 2,100 MW, of which 1,360 MW has up to 24 hours of storage. In the summer, hourly storage is supplemented by the capacity of some large commercial customers to make ice in off-peak times and then run air conditioning systems without running the chillers at peak times in the afternoon and evening. In addition, the two largest utilities now have some 2,000 MW of load control arrangements.

As smart grids are developed, some customers will be able to respond to real-time pricing, offering still more opportunities to shift loads during the day. Still other storage opportunities may arise when plug-in hybrid vehicles are in use and have two-way communications with grid operators.

With these possibilities in view, days and hours were examined in the data set in order to determine how many days and hours would need auxiliary generation, either by purchase from other systems or by (probably gas turbine) back-up generation within the system.

As the day totals in each of the four sample months were examined, it was apparent that the sum of solar and wind generation, day by day in each month were approximately normally distributed, with standard deviations running about one-fourth of the mean. In January, for example, mean daily generation for the month was about equal to the 80% specified above. Daily total power generation for the sample month of January as well as the hourly power generation for a sample day in January are shown here. Larger versions of these charts as well as charts for other sample months and another sample day are shown in the main text. Day totals varied, with about half the days showing above average generation and half below average. Within the below-average days, two-thirds were below average by a quarter or less of the mean. Only very rarely was the shortfall more than half the mean. Some days with above-average wind and solar generation still had hours when supplemental generation would be needed, but not often. When all the days and all of the hours were considered, it appeared that auxiliary generation amounting to 6% of the annual total generation would be sufficient to fill in nearly all of the gaps between hourly





renewable generation and hourly utility loads. The backup generation amounted to purchases from other systems up to 5% of hourly loads, and 2,700 MW of gas-fired capacity. There were 17 hours in the four months considered when still more backup power would be needed, or a loss-of-load probability of .0058

The out-of-system purchases or back-up generation in the system dropped the wind-solar contribution to 78% of the load. These results are shown in Table 1 of the main text (online at www.ieer.org/reports/NC-Wind-Solar.pdf.)

The important conclusion is that intermittent solar and wind energy, especially when generated at dispersed sites and coupled with storage and demand-shifting capacities of a system like North Carolina's, can generate very large portions of total electricity output with rather minimal auxiliary backup.

Matching Utility Loads with Solar and Wind Power in North Carolina
Dealing with Intermittent Electricity Sources

A. Introduction

North Carolina has abundant solar and wind resources as well as significant other renewable electricity sources. In 2007 the State adopted a renewable portfolio standard of 12½ percent of utility kilowatt hour sales, thereby joining the (now) more than thirty states with such requirements. Renewable energy targets in the 20-25% range are now spreading with the most aggressive standards now at 33% and 40% in California and Hawaii respectively.

Studies which consider much higher penetrations of solar and wind energy are beginning to appear.[1] This investigation continues that line of research and explores a high-penetration scenario (in the 70%-80% range) for wind and solar electricity generation in North Carolina. The levels of output for the two sources, especially wind, may not be attained in the State, but the general idea is to explore the intermittency problem with North Carolina patterns of wind and solar output. Wind and solar electricity are the largest potential renewable electricity sources in most parts of the world. Both of these are intermittent by nature and therefore are thought to be difficult to integrate into electricity grids at penetrations beyond, say 10%-20%. These intermittent sources of renewable electricity are still thought, in some utility circles, to require substantial, if not total, backup supplies.**[2]**

This investigation explores a scenario which, at the outset, involves solar and wind

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[1] Interest in high-penetration solar-wind scenarios is mounting rapidly. An early study which received much less attention than it deserved was published in 1992. See Henry Kelly and Carl J. Weinberg, "Utility Strategies for Using Renewables" in Thomas P. Johansson, et. al., *Renewable Energy*, Island Press, Washington, D. C., 1992. p. 1011. They examined cases with intermittent renewables up to 50%.

A recent addition to this growing literature was reported in *Wired Science,* December 18, 2008. Elaine Hart, a graduate student at Stanford, reported on simulations of the California grid in which showed that 70% of demand on a summer day could be met from solar and wind sources. The paper was presented at a meeting of the American Geophysical Union. Since the hydroelectric system was not used to help balance hourly changes in the load, natural gas provided the balancing energy.

A large-scale and very significant study is now underway– The Western Wind and Solar Integration Study. Nine investor-owned utilities and the Western Area Power Administration are involved.

[2] Utility attitudes are changing as more and more of them accept wind generation and participate in the Utility Wind Integration Group. Duke Energy now allows a 17% capacity credit for wind generation. Progress Energy still regards it as "not dispatchable" with "little or no capacity value" (2009 Integrated Resource Plan, p. 9).

generation at 80% of utility loads, along with the only other renewable electricity sources now available in North Carolina -- hydroelectric power (8%) and biomass generation or cogeneration (12%).

The study takes advantage of the practice, in North Carolina, of running the hydroelectric facilities in part in response to peak demand rather than running them steadily all day. It also envisages the use of pumped storage capacity, existing load control programs, and ice storage in commercial air conditioning systems. Next the study considers the advantages of another large prospective storage technology – batteries in plug-in electric and hybrid vehicles. Compressed air energy storage might also be considered in North Carolina: geological studies show that rock storage is possible in the western half of the State.[3] However, it is not explicitly integrated into the calculations shown in the tables and graphs in this report.

All of these strategies for matching loads to generation may not be sufficient; some further backup in the form of power purchased from other systems or from in-system power sources (probably gas turbines) may be required. The object of this analysis is to examine the hourly matching of available power to hourly loads and to estimate how much backup power, if any, might be needed. This is not intended as a scenario for 100 percent renewable electricity, though it approaches that target in large measure.

As it turns out in this simulation, these additional backup measures add only about 6% to the power supply required to balance hourly availability with hourly loads and some of this power, purchased from other systems, might also be renewable. The in-state solar-wind fraction recedes to about 76% of system generation. This is still a much larger fraction of electricity supply than those usually considered. The development of a 100 percent renewable scenario is left to efforts now underway at Institute for Energy and Environmental Research.

B. Rationale for the high wind-solar generation scenarios

Solar radiation falling on North Carolina **each day** is more than 400 times larger

[3] A small area of aquifer storage is also available in the southeastern part of the State. CAES sites in the United States are shown in a map included in Craig Severance, "Enabling Wind, Sun To Be Our Main Power Supplies:Quest for Storage," *Energy Bulletin*, August 29, 2009. CAES was examined in the hourly and daily analyses described later in this paper, but only led to a small reduction in the number of hours in which demand could not be met (4 of 17 hours). It might well be essential in states not as well endowed as North Carolina with hydroelectric and pumped storage generation.

than **annual** energy use in the State. It has not been put to use on a large scale until now because of the cost of the conversion equipment. These costs are now declining rapidly. With existing subsidies, solar photovoltaic electricity can be generated profitably and sold to utilities at 18 cents per kWh or less. This electricity price is comparable to or even lower than some estimates of unsubsidized electricity prices from new nuclear plants, whose upper limits have extended well over 20 cents per kWh, or possibly from new coal plants with carbon capture and storage capability. Both of these technologies have costs which are subject to large uncertainties. As the manufacture and installation of photovoltaic equipment increases in scale further cost reductions may be expected, so that unsubsidized “grid parity” is not an unreasonable expectation within a decade or so. As the cost of solar installations falls, capacity can increase rapidly. Worldwide, new solar photovoltaic installations reached nearly 6,000 MW in 2008, bringing the cumulative total installed to 15,000 MW. This represents a five-fold expansion in just five years.[4]

The very high wind output considered here is in a range just now being examined for North Carolina. Studies of the wind-generation capacities of the 50 states were made in the 1980's and 1990's with a potential generating figure of 8 billion kWh per year shown for North Carolina. The consultants who studied North Carolina's renewable energy and energy efficiency potentials in 2006 suggested 1,500 MW and about 4 billion kWh as a possible wind generation figure, including the use of some mountain ridges. The early wind power measurements were based mostly on wind speeds not far off the ground, with a formula to extrapolate these measurements to probable speeds as high as turbines usually are placed. Later research has determined that wind speeds generally rise more rapidly with increased distance off the ground than was indicated by the earlier formula. Accordingly the wind potential for the 50 states could be increased dramatically.

Soon after these disclosures, the Department of Energy released its very large estimates of U. S. offshore wind energy potential. Still more recent studies have raised even higher the estimated wind-generating potential of the U. S. New estimates for some of the states have been published by the Department of Energy. Ohio, which showed a

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[4] Progress Energy is now offering 18 cents per kWh for solar PV electricity. With existing tax credits and with the recent decline in PV prices, sales at this price can be quite profitable for developers. Expected further declines in module and installation costs could make this an unsubsidized but profitable kWh cost. If new coal or nuclear plants are built, their outputs may well have costs in this range. PV installed worldwide capacity has risen from 3,000 MW in 2003 to 15,000 MW in 2008.

1991 estimate of 5 billion kWh, turned out to have a potential more than twenty times higher. Virginia, which had a 1991 estimate of 17 billion kWh, turned out, in a later study to have an onshore potential of 50 billion kWh, with another 50 billion available offshore. The North Carolina State Energy Office in 2009 released a 30 billion kWh wind scenario (12,325 MW capacity) with the larger part coming from offshore sources. This was related to the national investigation of a 20% wind contribution to U. S. electricity supplies.[5]

The figures used in this North Carolina scenario for solar and wind generation are quite high -- some 41 billion kWh each. The choice of equal solar and wind contributions is an initial assumption and is not optimized in any way. This scenario would include a high-percentage development of all onshore potential, some considerable offshore development, and possibly some contribution from Virginia as well. The main point here is to do an initial exploration of the intermittency issue, and to do so with parameters for wind and solar variability based on North Carolina data.

C. Data Sources

A study of this nature requires hourly output data at wind and solar installations for a least one month in each of the four seasons. It also requires hourly data on utility loads for the same months. The ideal source for wind and solar generation data would be actual, measured, and simultaneous kWh output of fully-functioning wind turbines and photovoltaic installations at each of three or more sites – and these for a period of, say, three years.

As is almost always the case, the ideal data do not exist or are not available to

[5] Estimated wind power potential in the U. S. and in the fifty states were made in the 1980's and early 90's. For many years the standard reference for U. S. onshore wind power potential was *An Assessment of the Available Windy Land Area and Wind Energy of the Contiguous U. S*., Pacific Northwest Laboratory, 1991. These estimates were based on thousands of wind speed records taken mostly near ground level. New and much higher estimates for U.S. and world potential generation were published in 2003. Archer, C. L. and Jacobson, Mark Z. “Spatial and Temporal Distributions of U.S. Winds and Windpower, at 80 m Derived from Measurements,” *Journal of Geophysical Research,* 2003. When the Department of Energy published its findings on U.S. offshore wind potentials, North Carolina was one of the states with enough offshore resources in adjacent and shallow waters to meet its entire electricity demand from that source. U. S. Department of Energy, *A Framework for Offshore Wind Energy*, October, 2005.

The highest (and most recent) estimate of wind energy potential is found in Xi Lu, Michael B. McElroy, and Juha Kiviluoma, “Global Potential for Wind-Generated Electricity,” *Proceedings of the National Academy of Sciences,* July 7, 2009. The much higher estimates for Ohio are given in U. S Department of Energy, National Renewable Energy Laboratory, “Ohio-Average Wind Speed Estimates to 100-m Height” (Map). For Virginia, see *A Portfolio-Risk Analysis of Electricity Supply Potions in the Commonwealth of Virginia*, prepared for the Chesapeake Climate Action Network October, 2005. The 2009 figure from the State Energy Office is found in *Offshore Wind in North Carolina*, prepared by Bob Leker for presentation for the Advisory Subcommittee-Offshore Energy Exploration, dated April 27, 2009.

researchers. PV hourly output from two installations in Piedmont North Carolina was available for a few months in 2009. No hourly wind data from existing wind generation was available. The proxies developed were, in the case of solar PV output, radiation data at ground level for three North Carolina sites (Wilmington, Raleigh, and Asheville) in 2005. This series correlated well with the data from measured output that was available in the short period of overlap.[6]

For wind energy output, wind speed data at ten minute intervals for at least a year was available for two mountain sites and several coastal sites. Data for the same period at three sites was not available; rather, the three separate (and uncorrelated) data sets for different periods were taken as proxies for data from two widely-separated mountain sites and the (even more distant) coastal site. Wind speed data was then used to estimate the hourly kWh that would be generated at each site. Wind speeds as measured at each site were first extrapolated to the hub height characteristic of turbines now being installed around the world – 90 meters. Then, cut-in and cut-out speeds and other power generation parameters for the General Electric 1.5 MW turbine (model 1.5xle) were applied to the wind speed data in order to provide hourly estimates of electricity generation.[7]

These procedures resulted in hourly estimates of wind and solar electricity output for each day in January, April, July, and October at each of the three wind sites and each of the three solar sites (2,952 hourly values for each of six sites or 17,712 hourly values in all). KWh output figures for the sites were then combined and scaled up to the 41 billion kWh range used in the investigation.

The annual utility load considered in this investigation is in the 90-95 billion kWh range. This may be thought of as an energy-efficient version of the present annual electricity use in North Carolina (125-130 billion kWh) with another five billion kWh for electric and plug-in hybrid vehicles. Hourly loads for each of the four seasons were taken

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[6] The solar radiation data source is given in Appendix 1. The data for several 2009 months was taken from installations at the N.C. Zoo in Asheboro and the large installation in Raleigh monitored by the N.C. Solar Center.

[7] GE turbine characteristics taken from GE's specification sheet for the model. An excellent study of North Carolina wind energy and the associated capacity credit was carried out by Lena M. Hansen as her master's thesis in the Nicholas School. Ms. Hansen found good proxies for wind-electricity production at two mountain sites and one coastal site. Her data showed some positive correlation between the two mountain sites and negative correlations between the coastal and mountain sites. Lena M. Hansen, “Can Wind Be a 'Firm' Resource? A North Carolina Case Study,” *Duke Environmental Law and Policy Forum,* Spring, 2005. Ms Hansen is part of a team at the Rocky Mountain Institute which published a solar-wind integration study, “S*patial and Temporal Interactions of Solar and Wind Resources in the Next-Generation Utility.”*

from Duke Energy data for the year 2006 and then scaled up to represent the statewide hourly demand figures The summer and winter peaks were modified to reflect energy efficiency measures already assumed in the total load for the year. Specifically, summer peaks, almost entirely due to air conditioning loads, were reduced somewhat to conform to data from energy- efficient North Carolina homes showing that as efficiency levels increase, there is a greater-than-proportionate reduction in air conditioning electricity demands. A similar but smaller effect for space heating was also applied to the winter hourly demand data.[8]

The Duke Energy data show hourly loads averaged over each month. The 3 pm figure for energy demand in the month of July, for example, is the average of all of the 3 pm figures for the 31 days in July. This study makes no attempt to introduce hourly variations around these averages – that is a task for a follow-up study. It should be noted that these (now quite wide) fluctuations around utility load hourly averages are due almost entirely to weather. As buildings reach higher and higher standards of thermal efficiency these fluctuations will be smaller. Moreover, in the summer months (where annual peak demands are found) air conditioning loads are partly correlated with ground-level solar radiation, hence with solar electricity output.

D. Organizing and Analyzing the Data

For each of the six sites and each of the four seasons, it was necessary to compute mean daily outputs of wind and solar electricity and the standard deviations around those means. Within the days, hourly wind and solar outputs are also calculated. As one might expect, there is considerable variation from day to day in both wind and solar daily output. There is further a considerable variation from hour to hour inside days. These are the basic problems of matching intermittent outputs to given loads. Daily loads in a month and hourly loads within each day are considered separately since there are existing storage

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[8] Duke Energy Carolinas' average hourly demand by month is found in Forefront Economics Inc. et al., *Duke Energy Carolinas DSM Action Plan: North Carolina Report,* August 2007, p.7. Adjustments for the greater-than-proportional reductions in electrical heating and cooling energy in energy-efficient homes are based on the author's collection of detailed home energy use data from more than 100 homes in the Triangle area. In the average electrically-heated home in the Duke service area, 30% of electricity use is for heat; 19% in all homes is used for air conditioning. (Forefront Economics, p.13). The figure given there for heating is 15%, but only half the homes in the sample use electricity for heat, hence the 30% figure for electrically-heated homes). By way of contrast, in the most energy-efficient homes in the author's sample, the respective figures are 24% of home electricity use for heating and 6% for air conditioning – much smaller fractions of much lower energy use overall.

facilities for within-day storage, but very little capacity for storing electricity over longer periods.   In this analysis, electricity generation and loads are balanced within each 24-hour period. This is a case in which means and standard deviations here are treated in a different fashion than is the case in most wind intermittency studies. Investigators typically compute means and standard deviations over long periods – a month or a year at hourly or even ten-minute intervals. The focus here is on day-to-day intermittency and storage issues, and the separate issue of supplementary power for days in which wind and solar generation fall short. The means and deviations here, therefore, should not be directly compared to those of other studies.

In dealing with these issues, one first notes that combining outputs from the three wind sources greatly reduces the variability both by the hour and by the day. In looking at October daily outputs from each wind site, for example, standard deviations run around 0.68-0.9 times mean output. When the three sites are considered together, the standard deviation declines to 52% of the mean.[9]

There is a smaller gain in combining solar outputs from the three sources, since the outputs are already highly correlated. The interested reader may examine the results in Appendix 2, where daily solar-wind outputs for representative months in each of the four seasons are tabulated. Hourly outputs for some sample days are shown in Appendix 3. (See Figures 1 through 5 on the following pages for the graphs based on those tables.)

[9] The reduction in the variability of wind power when more and more sites distant from each other are connected to the grid is very well documented. See Cristina L. Archer and Mark Z. Jacobson, "Supplying Baseload Power and Reducing Transmission Requirements by Interconnecting Wind Farms," *Journal of Applied Meteorology and Climatology,* November 2007. The authors studied hourly wind generation data from 19 separated wind farm sites in the Midwest. Among their significant findings they noted that wind energy had a base-load equivalent of 33% to 47% as compared to coal plants. That is, in 87% of the year's hours (the operating hours of baseload coal plants) wind plants together were generating 33% to 47% of their average output. Another study is Troy Simonson and Bradley Stevens, *Regional Wind Energy Analysis for the Central United States*, Energy and Environmental Research Center, Grand Forks, North Dakota. Ms. Hansen, cited in note 7, found the same effect in her study of three sites for North Carolina.

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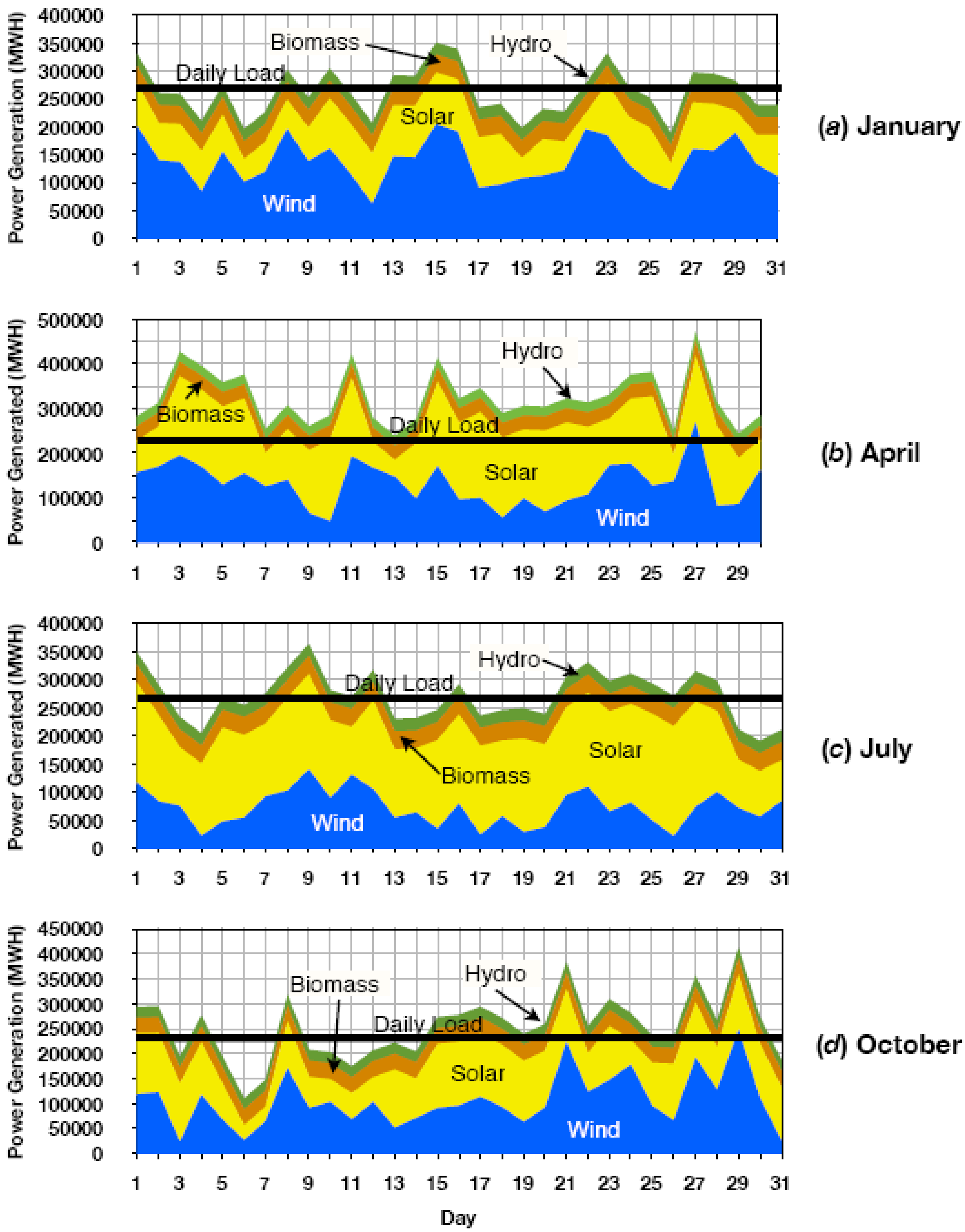

Figure 1
Daily average renewable power generation for four sample months

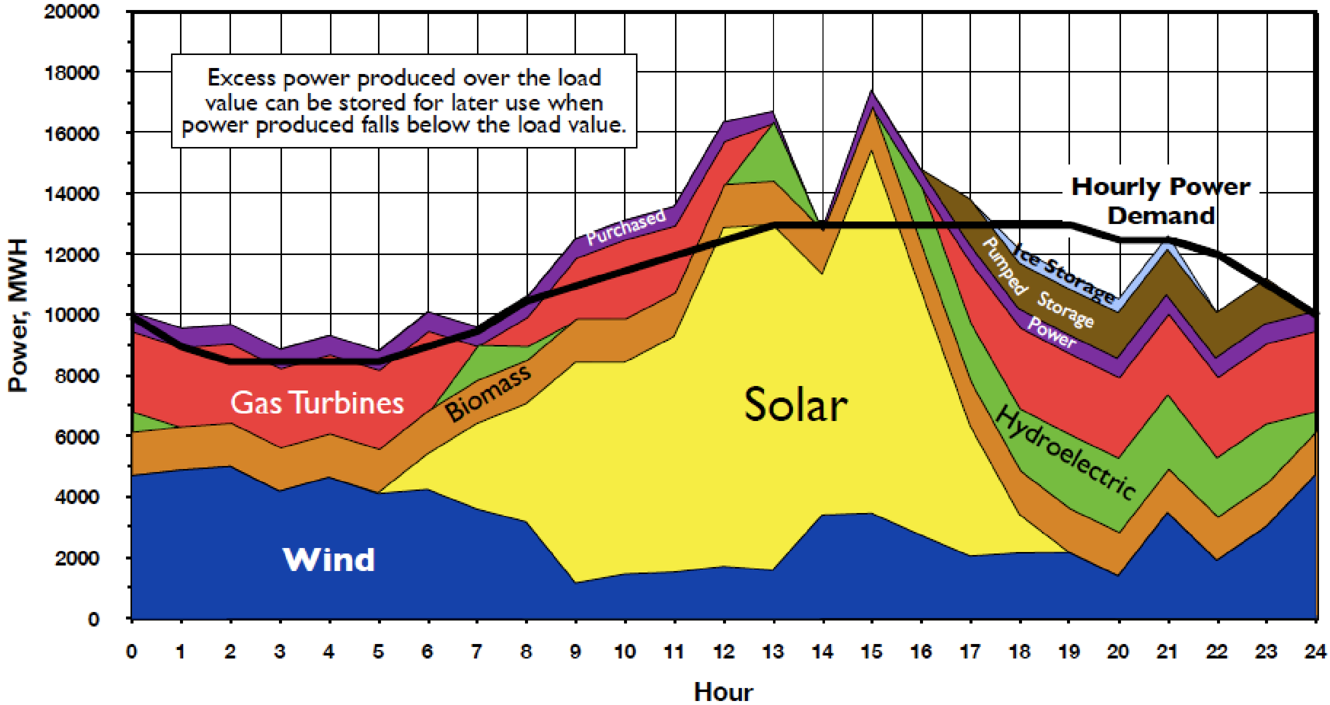

Figure 2
Hourly Power Generation and Load for a sample day in July

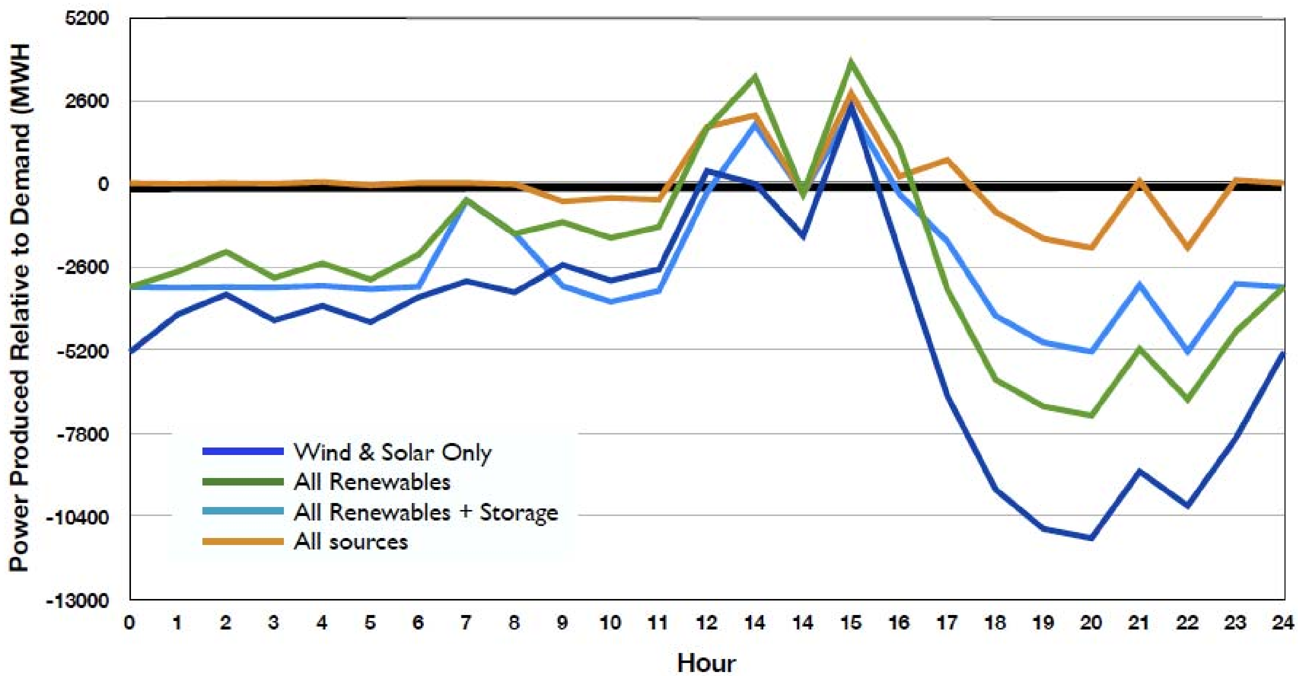

Figure 3
Power Produced Relative to Demand for a Sample Day in July

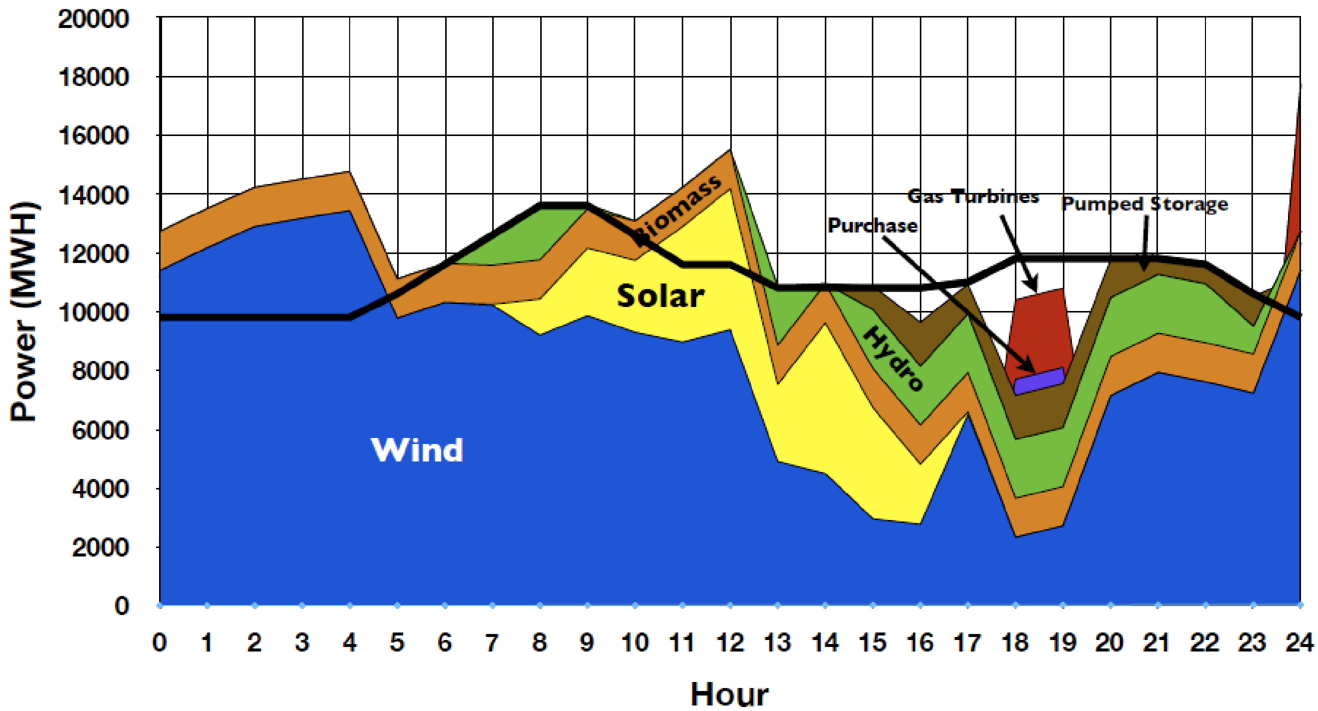

Figure 4
Hourly Power Generation and Load for a Sample Day in January

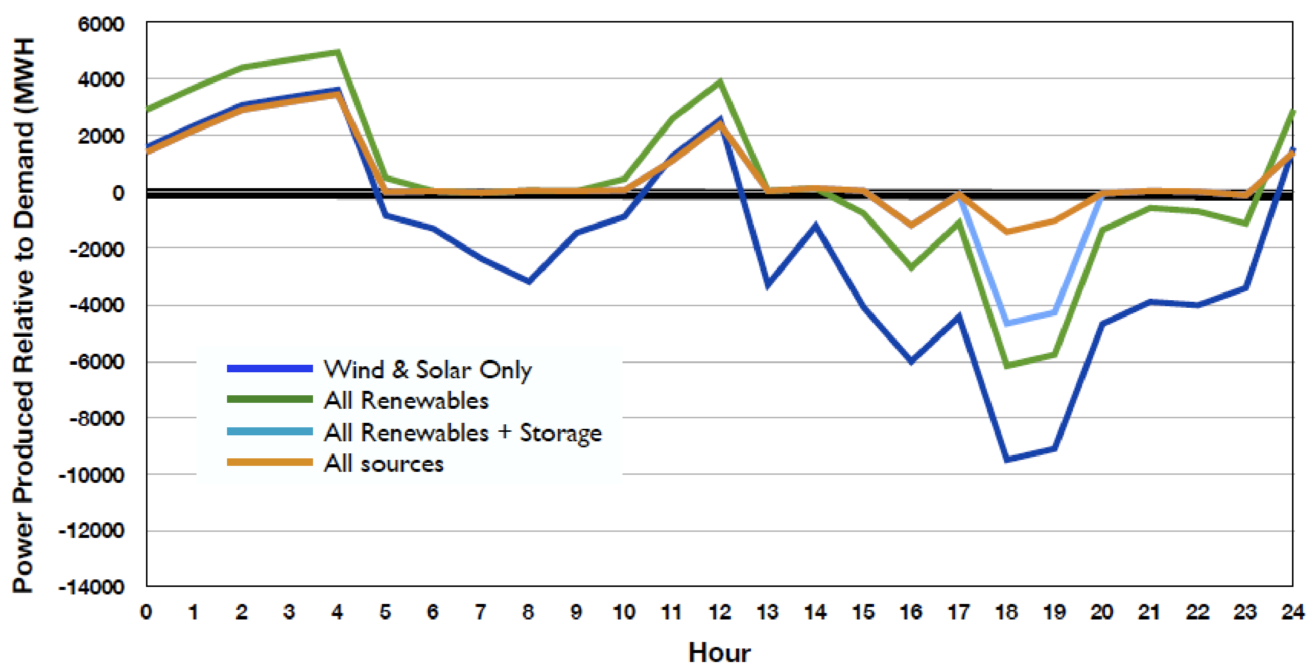

Figure 5
Power Produced Relative to Demand for a Sample Day in January

Another drop in the standard deviations around daily mean output takes place when wind and solar outputs are combined, since wind outputs and solar outputs are not correlated. Indeed, that is the whole point of considering systems with both sources. When wind and solar output are combined, it turns out that the daily outputs as they vary around the monthly mean are normally distributed. Moreover, the day-to-day variation as measured by the standard deviation around the mean declines from the 0.6-0.9 range (in the individual wind sites) to the 0.25 range. That is, about two-thirds of the daily kWh outputs in a given month will fall within the range of 0.75 – 1.25 times the mean for the 30-31 days in the month. Or, put a little differently, there will be daily shortfalls in half of the days of the month but in two- thirds of these shortfall days the shortfall will range from 0-25 percent of average output. We therefore must deal with larger shortfalls in one sixth of the days and most of these larger shortfalls will be between 0.25 and 0.5 times the mean.

Hourly outputs within each day continue to vary, but much less so with combined solar and wind outputs than would be the case with wind sources only. These calculations also confirm a degree of complementarity in the two sources. Wind generation is stronger at night than in the daytime, and strongest in winter when solar output may be half that of the summer. The key finding with respect to daily energy supply in systems which rely heavily on wind and solar generation for a large share of total electricity use may be restated as follows: ***The wind and solar components will oversupply their share of system requirements for half the days of the year, and undersupply their share for the other half. This shortfall will amount to about 25% or less of their daily average output in 2/3 or more of the days of short supply. Shortfalls will exceed 50% of daily average only rarely (one day in this particular simulation). Oversizing the wind and solar components by 10%, as is done here, will greatly reduce these shortfalls. As Table 1 indicates, supplementary power supplies amount to 6% of total system supplies. Wind and solar generation, supplemented by hydroelectric and biomass generation, do all of the other 94%.***

Table 1 shows power generation in each of the four sample months with heavy reliance of wind and solar sources. Biomass generation or cogeneration and hydroelectric generation are also shown at the levels discussed earlier in the text. Auxiliary support consists of purchases from other systems or backup generation from gas turbines. These auxiliary sources do more than just cover daily shortages; they must also deal with shortfalls which occur in some of the hours in a day when in-system storage is insufficient.

Table 1

Power Generation By Season and By Source (000) MWh

Month	Wind	Solar	Biomass	Hydro-electric	Auxiliary	Total Available	Load	Sell/ Excess (1)
January	4290	2222	992	682	1071	9257	8382	875
% of load	46%	24%	11%	7%	12%	100%	91%	9%
April	3977	4175	960	660	191	9963	6690	3273
% of load	40%	42%	10%	7%	2%	100%	67%	33%
July	2262	4523	992	682	950	9409	8308	1101
% of load	24%	48%	11%	7%	10%	100%	88%	12%
								0
October	3287	2902	992	682	63	7926	7099	827
% of load	39%	34%	12%	8%	1%	94%	84%	10%
Four Sample Months' Total	13816	13822	3936	2706	2275	36555	30479	6076
% of Total	38%	38%	11%	7%	6%	100%	83%	17%
Result Scaled Up to a Year	41448	41466	11808	8118	6825	109665	91437	18228
% of Total	38%	38%	11%	7%	6%	100%	83%	17%

Notes

(1) Sizing the systems to the best year-round match results in large excess solar and wind energy in April. The remaining excess generation results from using gas-fired and purchased power to meet hourly shortages resulting from wind variability. The excess arises from upswings in solar and wind energy beyond hourly demand and storage capabilities.

Simplifying Assumptions

There are many features of utility analysis which are not incorporated into the present study. It is already complicated enough. One can then, in a later version, introduce the remaining features, though doing so would probably require a much more elaborate model with its own computer programs. Seasonal variations in hydroelectricity generation are not considered. As noted earlier (p. 9) utility hourly loads are averages in each of the four months. Transmission and distribution losses as well as losses in storing and then retrieving energy are not treated. The former usually run around 6% or so, and the latter, in pumped storage or storage strategies considered, at 20% or so. Also not considered are lags or ramp-up times in responding to changes in the intermittent sources. There are highly sophisticated issues for electrical engineers having to do with power quality issues such as voltage and cycle stability which are well beyond the reach of this effort.

E. Seasonal Mismatch

When a system with solar and wind electricity in roughly equal parts is examined, there will be some seasonal mismatch as to available solar and wind electricity and the seasonal load.

This occurs because one must specify a given capacity for each source matched to the ***year's*** load, which does not necessarily give an ideal match between the seasonal availability of the two sources and the ***seasonal*** load. Having specified a capacity for the year, one is not free to use different solar and wind capacities in the fall, say, as compared with the summer.

Wind capacity is strongest in winter and weakest in summer, while spring winds are stronger than those of the fall. Solar capacity is strongest in summer, as one might expect, but is less productive in the fall than in the spring and weakest of all in winter. When the systems are sized to the year's demand, there will be an abundance of electricity in the spring while the other seasons are more or less well-matched to the load, at least given the characteristics of the North Carolina wind and solar outputs. Output will be close to the load in the summer and winter, these being the seasons of weather-related peak demand. These seasonal characteristics are shown in Table 1. This means that, especially in the spring, that some power can be sold outside the system or even be wasted altogether, as some power is now.[10]

F. Utility Rates, Time of Use Pricing

The success of systems with high amounts of intermittent sources will depend in large part on the use of smart grids, electricity rates which vary with the quantities available, and customer capabilities to respond to ongoing rate changes. These features

[10] Some wind energy is now wasted when transmission lines or utility systems cannot handle all that is produced. Also, utilities keep “spinning reserves” in order quickly to match changes in demand. These may soon be replaced (and the waste avoided) by such quick-response storage methods as flywheels.

will be especially important for utility customers with vehicle-charging arrangements.

We are accustomed to systems for which time-of use pricing is available mostly to large commercial and industrial customers and to only a few residential consumers. Given the present patterns of generation, rates are lowest at night, when baseload capacity is running and demands are relatively low. This rate pattern is likely to be revised drastically in systems with large amounts of solar and wind capacity. Rates are likely to be lowest in the daytime, since the solar power component more than offsets the typically rising energy use as the day unfolds or at other times when renewable energy supply is greatest relative to demand.

G. Coping with Intermittent Sources: Hydroelectricity, Pumped Storage, and Ice Storage

The first steps in matching hourly outputs to hourly loads may be taken with existing utility system capabilities. They are now used by the utilities, which have large baseload generating capacity. This capacity must be matched with hourly loads which rise and fall daily. This matching is accomplished in part by running the hydroelectric facilities at times of peak demand rather than steadily all the time.

The hydroelectric capacity used in this investigation also assumes that the remaining undeveloped hydroelectric resources will be brought online, and that some of them, like most of the existing capacity, may be run at the hours when electricity is most needed. This capability is constrained by stream flow considerations, but one may assume that there will be as much flexibility in deploying these enhanced resources as there is now with the existing facilities. Accordingly, in the tables in which hourly use is examined within the days, hydroelectric facilities are deployed in hours of insufficient wind and solar output, up to the maximum rate of 2,500 MWh and up to a total of 22,000 MWh per day. This is the daily usage figure which is consistent with a yearly output of 8 billion kWh. This treatment is shown in the sample daily tables in Appendix 3 (Table 3).

Pumped storage is considered next. Duke Energy, North Carolina's largest utility, has 2,090 MW of pumped storage capacity located in South Carolina. These facilities serve Duke's electricity system in both states. The utility plans to add 50 MW in the next few years, bringing the total to 2,140 MW. Since North Carolina now accounts for about 2/3 of Duke's sales, the pumped storage is allocated for the purposes of this study as follows: One facility has 1,360 MW and 24 hours of capacity. This is allocated to North Carolina in the amount of 1,000 MW, just to keep round, easy-to-use numbers. The other has 730 MW, soon to be raised to 780 MW. Of this, 500 MW is allocated to North Carolina. The figure for the hours of storage in this second facility is not available, but is assumed to be 9 hours for this analysis. This is reflected in the daily tables which have been prepared so that in each day 1,500 MW may be stored for nine hours (using both units), with 1,000 MW for another 15 hours in the larger unit. (24 hours in total for that facility) Maximum daily storage, therefore, is 9 hours x 1,500MW + 15hours x 1,000MW or 28,500 MWh. This maximum daily storage is frequently not used, since there may not be enough surplus wind or solar generation available to completely fill the reservoirs. In this simulation, pumped storage is assumed to be filled daily and discharged as needed. No carryover capability from day to day is assumed, or relied upon, even though there may be some in days of good wind and solar generation. The North Carolina portion of the storage reservoirs are filled at a rate no greater than 1,500 MW per hour as surplus generation may be available. The stored energy may be released as needed to fill in when there are hourly shortages. The storing and discharging activity is also shown in two sample days, Appendix 3, Table 3.

In the summer season, when air conditioning is a major element of electricity demand, there may be some excess electricity in the first half of the day. This could be used to make ice, from which cooling may be drawn in the afternoon and early evening hours without then running the chilling equipment. This addition to standard air conditioning equipment is particularly useful in bridging the gap between the peak of solar electricity production (usually 11 am to 4 pm) and the peak air conditioning demand (2 pm to 8 pm). This technology is assumed here to be available only to large commercial customers. 500 MW may be stored per hour up to four hours, and then released at a similar rate.[11] The signal to users is, of course, the varying hourly rate for time-of-use customers. Rates, as noted above, are likely to be lowest during times when the combined availability of solar and wind electricity is greatest, which, in most cases, will be in the daylight hours. They may rise abruptly when wind, solar, or combined generation

[11] Commercial air conditioning demand in North Carolina is about 6 billion kWh per year, which is at least 20 million kWh daily in the warm months. The 2 million kWh of daily storage used in the tables is probably an underestimate. Duke Energy, which provides about half of the State's electric power, estimates commercial air conditioning annual use to be 3 billion kWh. See Forefront Economics, op. cit. Note 8.

decrease.

The three storage strategies just discussed are illustrated in the hourly schedules of two sample days shown in Appendix 3. The sample daily tables shown there examine hourly generation, storage, and load for each of two days and indicate how these strategies compensate, in part, for hourly mismatches between generation and load.

Another storage possibility which might be considered is that of compressing air in sealed underground caverns and then using the air pressure, along with gas combustion turbines to add power as needed (CAES). This would further reduce the few hours in the sample days when there might otherwise be a loss-of-load For simplicity, it was not included in this analysis.

H. Purchased Power and Auxiliary Generation

Some of the hourly swings in generation are too great to be offset altogether by the various storage means examined so far, possibly even with CAES. Some days are short of electricity, so that supplemental power will be needed. No amount of within-day storage capacity can create more electricity; it will have to be secured from some source, if longer term storage (more than one day) or some means of load control are not available. Moreover, when the day begins, the utility operators will not know whether it will be a short- or an over-day. They probably have better forecasts of cloud cover and solar generation than they have of wind-electricity availability. This uncertainty may be lessened as forecasting tools for wind availability are developed, but it can hardly be eliminated altogether. In some seasons it will be necessary to secure purchased power and even run auxiliary units (probably gas turbines) early in the day just to ensure that the pumped storage facilities are full, if enough wind energy does not appear early in the day to begin filling them. This is necessary because there may be some hourly shortages larger than the combined capacities of supplementary generation, out-of system purchases and in-system storage. Utilities will need to develop a new set of operating rules. In these simulations, purchased power is limited to 5% of system demand and auxiliary power is minimized, based on a probability of need given the other parameters of the system. 2,700 MW, used at a 22% capacity factor, appears to be sufficient. This is, incidentally, much less than the existing gas-fired capacity in North Carolina (over 6900 MW). Instead of purchased power, the use of existing gas-fired capacity could also be increased.

If there are other systems which also rely on solar and wind generation, and if they are sufficiently far away as to have different wind-solar patterns, all of the systems can benefit from inter-system exchanges and each system can reduce its reliance on auxiliary generation.

I. Load Control, Price-induced Demand Shifts and Vehicle Batteries

Utilities still have some maneuvering room in addition to the features just outlined. North Carolina's two major utilities have load control arrangements with some of their customers which total more than 2,000 megawatts. As time-of-use pricing is introduced, and smart grids, which keep customers informed of the kWh price of the moment are introduced, still more flexibility comes into the system. The final innovation considered here is the widespread use of electric, and especially, plug-in hybrid vehicles. Utilities must be ready to provide daily charging for these vehicles. They will have some discretion as to when this charging is done. With the appropriate smart grid features, utilities may also withdraw and then replace power from all vehicles that are connected to the grid and have been designated by owners as participants in the program. This investigation assumes the presence of two million plug-in hybrid vehicles each with an expected daily use of 7-8 kWh and with 16 kilowatt hour storage batteries. These are the expected parameters for the Chevrolet Volt which is scheduled to be on sale in 2010. With the possibility of two-way flows of information and electricity, the electricity grid will have, in effect, 14,000-16,000 megawatt-hours of daily sales, the timing of which is subject to a significant amount of control via utility software and time-of-use pricing. (This is 5-6 billion kWh per year, which, as already noted, is included in the energy-efficient version of North Carolina's existing electricity annual use). The vehicles may also, with predetermined parameters of response to changing grid prices, supply power to the grid and have it replaced later as, for example, when the wind picks up and time-of-use prices drop.

These last three arrangements bring enormous new demand-shaping and storage possibilities to the electric grid. They complete the task of accommodating grids to intermittent power sources. ***They permit the utility systems to operate with a complement of backup generation capacity which is smaller than the backup facilities commonly used in the present systems and their huge centralized coal or nuclear baseload plants.***

Incidentally, with these characteristics of flexible grids, the absence of huge quantities of baseload power (none of which is included in this scenario) is of little consequence. As any of the tables in this study clearly indicate, it is the presence of storage capacity and the use of quick-turn on supplementary facilities that are of decisive importance. One uses solar- and wind-generated electricity whenever they are available and then “plugs” the holes in electricity supply with load-shaping, storage, purchases, and auxiliary generation. Electricity demand is met hour by hour, with no necessity of storing any energy from day to day, though that capability would be helpful. Surplus electricity, which will necessarily appear at some times of strong winds, may be sold to other systems with somewhat different generation profiles, or may have to be wasted. In an optimized system, with smart grid elements, wasted energy could be considerably reduced.

J. A Closer Look at Daily Patterns

In half of the 123 days examined (31 each in January, July and October, with 30 in April), the daily generation from renewable sources more than covers the utility load. Even on these days, however, there may be overages in some hours and shortages in others. That is the case in the one of the two sample days examined in Appendix 3. Hydroelectric generation is used in the “short” hours and pumped storage, to the extent that the reservoirs have been filled, is also deployed. In July, some ice storage capability is also available. As long as the remaining hourly shortages are in a range which can be covered by load control, time of use pricing, or the use of electricity stored in vehicle batteries, no auxiliary sources need be used. Since the system operators do not know beforehand which hours may have diminished wind or solar generation, they must sometimes run auxiliary equipment or purchase power from outside the system just to make sure that the pumped storage reservoirs have some available power and that all capacity is not overwhelmed by a sudden drop-off in, say, wind generation.

There are some days in all seasons when renewable generation falls far short of the day's demand. This occurs with a shortfall greater than one standard deviation of the daily mean in less than one-sixth of the days examined. Purchased power (as indicated above, up to 5 percent of the average daily load), is added in, and auxiliary, gas-fired equipment is turned on. In these examples 2,700 MW of gas-fired capacity is sufficient to cover hourly shortages, and that is used in relatively few hours of the year. If, early in the day, power is short, gas turbines may be used to do more than cover the moment's shortage – they may be run to accumulate water in the pumped-storage reservoirs so that, in the case of later shortfalls, both auxiliary turbines and pumped storage facilities may be run simultaneously.

In the course of this analysis, daily generation and loads were computed for each of the 123 days examined. The next step was to establish tentative backup kWh quantities for the 61 days showing insufficient supplies of electricity – i.e., those for which the totals of the renewable sources did not meet the daily load. These daily quantities for the four sample months are tabulated in Appendix 2. That table shows, for each day in January, April, July, and October, wind and solar energy supplied, along with other system renewable generation (biomass generation, cogeneration and hydroelectricity). It was not necessary to examine overages and shortages for each of the 2,952 hours. Instead, 26 days (624 hours) were selected for more detailed examination, giving particular attention to the days with short supplies; one of these days is shown in Appendix 3. This sample was examined in each hour for any additional backup power for every day beyond that which would simply balance the daily figures of output and load. This process of sampling 26 days provided the basis for estimating the backup requirements for all 123 days. The backup requirements, if any, for each of the 26 sample days is shown on the tables for the four months in Appendix 2. When these backup kWh requirements are regressed on the daily over/short total, an equation is derived which is then used to calculate the backup requirements for all 123 days. The electricity generation and disposition for the entire year can then be calculated from the sample months in each season. There will be surplus electricity to be offered for sale to other systems. In the 123 days examined, there was only one day when demand could not have been fully met with purchases of 5% and backup gas turbines at 2,700 MW capacity – there was a shortfall in twelve of the hours of that day. There were two other days in which for two hours and three hours, respectively demand was not fully met. This indicates a loss-of-load probability of six tenths of one percent. U.S. utilities now use a planning process which aims at a much lower loss-of-load probability – about .0003. This work is offered with the expectation that further analysis with storage and smart grid developments can bring the system to a planned loss-of-load probability similar to those used today. Incidentally, the author has lived in four locations for periods of 3-25 years, and has yet to experience an outage-free period as long as those planned for.

K. Conclusion

The important conclusion from all of the calculations is that a system with annual sales of 91 billion kWh can be run with 76% of total generation coming from intermittent solar and wind sources. The intermittent sources would be assisted by 2,000 megawatts of biomass generation or cogeneration, 2,500 megawatts of hydroelectric capacity, and 1,500 megawatts of pumped storage. If such a system also has ice storage (in the summer), load control, and access to vehicle batteries, it can be run with some modest outside-of-system purchases and 2,700 megawatts of auxiliary gas-fired capacity. Purchases and auxiliary generation are needed for 6% of electricity loads. There were, in this simulation, 17 hours out of the 2,952 examined in which generation would fall short. These results were obtained with only three onshore windpower sites. The periods of shortfall would be reduced in a system with multiple wind sites distributed over a wide area (North Carolina has 200 mile long area in which mountain winds are strong, 320 miles of coastline and vast areas offshore). Also, the auxiliary power needs shown here would be somewhat smaller if carry-over power in pumped storage facilities were applied to needs in succeeding days.

The conclusions of this study, of course, are subject to the simplifying assumptions enunciated early in this report that one must make in order to begin to analyze such complexity. Of the many further refinements that would be appropriate, only one is likely to modify the conclusions by more than a few percentage points. As the variation in hourly utility loads is introduced, there would be some additional hours in which purchased power or auxiliary would be needed. This would take place primarily in the winter and to a lesser extent in the summer. It is the weather-related loads that introduce most of the variation around monthly means for each hour. In the summer, cooling loads, as indicated already, are partially correlated with solar electricity production. Another study may take up this task – time did not permit its inclusion here.

The conclusion, to summarize, is that a high-penetration solar and wind utility system is possible, that it requires supplementation of about 6% of electricity demand, from sources now used for peaking purposes. A corollary observation is that the concept of baseload generation is more or less irrelevant to its successful operation of such a system.

Appendix 1: Data Sources

N.C. solar radiation data taken from *National Solar Radiation Data Base,* http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/hourly/list_by_state.html.

Wind data for anemometer at Beech Mountain, http://averyweather.com/Current+Conditions/Beech+Wind.

Another mountain site, location unidentified, has wind speed data at www.wind.appstate.edu/wdata/site_DP.htm.

The coastal site data was one of ten for which the N.C. Solar Center has wind speed data – Stacey Tall Towers. Brian Miles at the Center kindly provided this file in Excel format.

Utility load data is taken from Duke Energy 2006 information as noted in note 8.

Appendix 2: Daily Tables for a Sample Month in Each of the 4 seasons

The following four tables (2A through 2D) show generation from each source for each day of the month in January, April, July, and October. The totals from each month have already been shown in Table 1 in the text. At the bottom of the columns for wind generation, solar generation and wind/solar combined (the first three columns) the daily means and standard deviations are shown. In January, for example, average daily wind generation is 138,382 MWh and average daily solar generation is 71,692 MWh. January is a good month for wind power, and a poor one for solar generation. (By contrast, note the reversal of roles in July, Table 2C.) Wind is the more variable of the two (see the standard deviations for each) and combining the sources tempers the variability. The next two columns show daily generation from biomass and hydroelectric sources, then a total daily generation column. Next comes a column showing the daily load and daily shortages or overages in meeting the load from the renewable sources only. Auxiliary power from purchases or gas turbine generation is shown in the next column, only for the days singled out for hourly analysis (six in January). As already indicated, these sample days are used to calculate total system backup needs for the four months, and then entered in Table 1.

In general, many of the days will need somewhat more auxiliary power than the day over-short totals indicate because there are hourly imbalances which are obscured in looking at totals for the day only. Estimates of the auxiliary requirements for the full 123 days are made as follows:

Auxiliary requirements are calculated directly using hour-by-hour analysis for the 26 sample days. For these 26 observations, auxiliary power needs are regressed on daily over-short figures which yields a linear equation (r2=0.85) showing the dependence of auxiliary requirements on daily over-short kWh. This equation is then applied to all of the 123 days, thus yielding an estimate of auxiliary power needs for all four months. When the calculated figures are compared with the days in the 26 day sample the estimates based on the regression equation are on the high side. Thus the findings with respect to auxiliary power needs in the text and in Table 1 are probably somewhat overstated. This seems to be appropriate, since when one is considering possible power shortages one may as well be conservative.

Table 2A: Daily Generation, January Wind, Solar, Biomass-Fired and Hydroelectric Generation

Day	Wind (MWH)	Solar (MWH)	Wind, Solar Combined	Biomass Cogeneration (MWH)	Hydroelectric Generation (MWH)	Total Generation (MWH)	Daily Load (MWH)	Daily Over (Short)	In Sample Days Analyzed Auxiliary Purchases (MWH)	Auxiliary gas turbine (MWH)
1	200928	76339	277268	32000	22000	331268	270400	60868	0	0
2	140832	66605	207437	32000	22000	261437	270400	-8963		
3	137145	68308	205453	32000	22000	259453	270400	-10947		
4	84887	72521	157408	32000	22000	211408	270400	-58992		
5	155143	66315	221458	32000	22000	275458	270400	5058		
6	101581	40728	142309	32000	22000	196309	270400	-74091	13200	64800
7	119812	53500	173312	32000	22000	227312	270400	-43088		
8	196737	52534	249272	32000	22000	303272	270400	32872		
9	138510	60364	198874	32000	22000	252874	270400	-17526		
10	161876	89822	251698	32000	22000	305698	270400	35298		
11	114486	90515	205001	32000	22000	259001	270400	-11399		
12	62060	90963	153023	32000	22000	207023	270400	-63377		
13	147191	91753	238944	32000	22000	292944	270400	22544		
14	145366	92350	237716	32000	22000	291716	270400	21316		
15	204860	93175	298035	32000	22000	352035	270400	81635		
16	192162	93763	285925	32000	22000	339925	270400	69525		
17	90895	90445	181340	32000	22000	235340	270400	-35060		
18	96535	90945	187480	32000	22000	241480	270400	-28920		
19	108270	35778	144047	32000	22000	198047	270400	-72353	13200	64800
20	112487	66552	179039	32000	22000	233039	270400	-37361		
21	122492	51709	174201	32000	22000	228201	270400	-42199		
22	196260	28387	224647	32000	22000	278647	270400	8247	1100	5400
23	185056	93315	278372	32000	22000	332372	270400	61972		
24	133219	85828	219047	32000	22000	273047	270400	2647		
25	101664	96976	198640	32000	22000	252640	270400	-17760		
26	86794	47873	134668	32000	22000	188668	270400	-81732	13200	64800
27	161005	83607	244612	32000	22000	298612	270400	28212		
28	157818	83853	241671	32000	22000	295671	270400	25271		
29	189515	40351	229866	32000	22000	283866	270400	13466	0	0
30	133208	52877	186084	32000	22000	240084	270400	-30316		
31	111038	74400	185438	32000	22000	239438	270400	-30962		
Sum	4289831	2222453	6512284	992000	682000	8186284	8382400	-196116	40700	199800
Average	138382	71692	210074							
Std Dev	33860	11731	45592							
% of Mean	24%	16%	22%							

Table 2B: Daily Generation, April, Wind, Solar, Biomass and Hydroelectric Generation

Day	Wind (MWH)	Solar (MWH)	Wind, Solar Combined	Biomass Cogeneration (MWH)	Hydroelectric Generation (MWH)	Total Generation (MWH)	Daily Load (MWH)	Daily Over (Short)	In Sample Days Analyzed Auxiliary Purchases (MWH)	Auxiliary gas turbine (MWH)
1	157156	71968	229124	32000	22000	283124	223000	60124	0	0
2	170470	89506	259976	32000	22000	313976	223000	90976	0	0
3	195786	177660	373446	32000	22000	427446	223000	204446	0	0
4	170548	172271	342819	32000	22000	396819	223000	173819	0	0
5	129515	175913	305428	32000	22000	359428	223000	136428	0	0
6	155794	167478	323272	32000	22000	377272	223000	154272	0	0
7	125967	74206	200173	32000	22000	254173	223000	31173	0	0
8	140190	114180	254369	32000	22000	308369	223000	85369	0	0
9	66457	140767	207224	32000	22000	261224	223000	38224	2750	10800
10	47194	185411	232605	32000	22000	286605	223000	63605	0	0
11	193302	175738	369040	32000	22000	423040	223000	200040	0	0
12	167533	57573	225106	32000	22000	279106	223000	56106	0	0
13	147894	37647	185541	32000	22000	239541	223000	16541	0	0
14	98871	124125	222996	32000	22000	276996	223000	53996	0	0
15	171764	189361	361125	32000	22000	415125	223000	192125	0	0
16	96306	173008	269314	32000	22000	323314	223000	100314	0	0
17	99756	192802	292557	32000	22000	346557	223000	123557	0	0
18	55435	180469	235903	32000	22000	289903	223000	66903	0	0
19	98616	154873	253489	32000	22000	307489	223000	84489	0	0
20	68797	182716	251513	32000	22000	305513	223000	82513	0	0
21	93808	175439	269247	32000	22000	323247	223000	100247	2750	0
22	108362	151617	259979	32000	22000	313979	223000	90979	0	0
23	174220	104156	278376	32000	22000	332376	223000	109376	0	0
24	177284	146096	323379	32000	22000	377379	223000	154379	0	0
25	128194	200324	328518	32000	22000	382518	223000	159518	0	0
26	137203	60373	197576	32000	22000	251576	223000	28576	0	0
27	268957	150326	419283	32000	22000	473283	223000	250283	0	0
28	82531	177994	260524	32000	22000	314524	223000	91524	0	0
29	86572	103770	190342	32000	22000	244342	223000	21342	1650	2500
30	162421	67746	230167	32000	22000	284167	223000	61167	0	0
Total	3976902	4175511	8152413	960000	660000	9772413	6690000	3082413	7150	13300
Daily Mean	132563	139184	271747							
Std. Dev.	48698	47712	59439							
% of Mean	37%	34%	22%							

Table 2C: Daily Generation, July, Wind, Solar, Biomass and Hydroelectric Generation

Day	Wind (MWH)	Solar (MWH)	Wind, Solar Combined	Biomass Cogeneration (MWH)	Hydroelectric Generation (MWH)	Generation Sum (MWH)	Daily Load (MWH)	Daily Over (Short)	In Sample Days Analyzed Auxiliary Purchases (MWH)	Auxiliary gas turbine (MWH)
1	117291	178011	295302	32000	22000	349302	268000	81302	2200	4000
2	84216	153600	237816	32000	22000	291816	268000	23816		
3	75745	104481	180226	32000	22000	234226	268000	-33774		
4	22744	128742	151486	32000	22000	205486	268000	-62514	11550	50900
5	48249	166749	214999	32000	22000	268999	268000	999	5350	24100
6	54941	147140	202081	32000	22000	256081	268000	-11919		
7	92749	129664	222412	32000	22000	276412	268000	8412		
8	103267	164871	268138	32000	22000	322138	268000	54138		
9	140912	169725	310637	32000	22000	364637	268000	96637	0	0
10	89531	139021	228552	32000	22000	282552	268000	14552		
11	131057	85187	216244	32000	22000	270244	268000	2244	1100	2000
12	105707	158060	263766	32000	22000	317766	268000	49766		
13	54735	122273	177008	32000	22000	231008	268000	-36992		
14	64323	113952	178274	32000	22000	232274	268000	-35726		
15	34806	158446	193252	32000	22000	247252	268000	-20748		
16	80027	158419	238447	32000	22000	292447	268000	24447		
17	24239	158472	182711	32000	22000	236711	268000	-31289		
18	57578	135202	192781	32000	22000	246781	268000	-21219		
19	29469	166398	195867	32000	22000	249867	268000	-18133		
20	38035	147544	185579	32000	22000	239579	268000	-28421		
21	95420	156480	251899	32000	22000	305899	268000	37899		
22	109878	167627	277505	32000	22000	331505	268000	63505	3300	13800
23	65803	178248	244051	32000	22000	298051	268000	30051		
24	81979	175571	257550	32000	22000	311550	268000	43550		
25	49733	190177	239910	32000	22000	293910	268000	25910		
26	21918	195874	217791	32000	22000	271791	268000	3791		
27	74224	187965	262189	32000	22000	316189	268000	48189		
28	100542	144428	244970	32000	22000	298970	268000	30970		
29	72478	86039	158517	32000	22000	212517	268000	-55483	12400	46000
30	56190	81597	137787	32000	22000	191787	268000	-76213	13200	63500
31	84423	72863	157286	32000	22000	211286	268000	-56714		
	2262206	4522826	6785032	992000	682000	8459032	8308000	151032	49100	204300
Daily Mean	72974	145898	218872							
St Dev	31707	33161	43683							
% of mean	43%	23%	20%							

Table 2D: Daily Generation, October   Wind, Solar, Biomass-Fired and Hydroelectric Generation

Day	Wind (MWH)	Solar (MWH)	Wind, Solar Combined	Biomass Cogeneration (MWH)	Hydroelectric Generation (MWH)	Total Generation (MWH)	Daily Load (MWH)	Daily Over (Short)	In Sample Days Analyzed Auxiliary Purchases (MWH)	Auxiliary gas turbine (MWH)
1	118851	121808	240659	32000	22000	294659	229000	65659		
2	122697	118744	241441	32000	22000	295441	229000	66441		
3	23154	117331	140485	32000	22000	194485	229000	-34515	7700	35100
4	117186	105113	222299	32000	22000	276299	229000	47299		
5	67459	71836	139296	32000	22000	193296	229000	-35704		
6	26664	29739	56403	32000	22000	110403	229000	-118597	13200	64800
7	65090	29080	94170	32000	22000	148170	229000	-80830		
8	170454	93535	263989	32000	22000	317989	229000	88989		
9	91010	63076	154087	32000	22000	208087	229000	-20913		
10	103484	45442	148926	32000	22000	202926	229000	-26074		
11	68471	52464	120935	32000	22000	174935	229000	-54065		
12	103223	49910	153132	32000	22000	207132	229000	-21868		
13	51818	116120	167937	32000	22000	221937	229000	-7063		
14	71082	79578	150660	32000	22000	204660	229000	-24340		
15	91207	128382	219589	32000	22000	273589	229000	44589	6600	8100
16	96054	127864	223919	32000	22000	277919	229000	48919		
17	113633	126565	240199	32000	22000	294199	229000	65199		
18	92762	124722	217484	32000	22000	271484	229000	42484		
19	63250	122624	185874	32000	22000	239874	229000	10874		
20	92115	113548	205663	32000	22000	259663	229000	30663		
21	222590	106175	328764	32000	22000	382764	229000	153764	0	0
22	123328	77331	200660	32000	22000	254660	229000	25660		
23	147499	108088	255587	32000	22000	309587	229000	80587		
24	178544	48918	227462	32000	22000	281462	229000	52462		
25	95379	86600	181979	32000	22000	235979	229000	6979		
26	66497	113302	179799	32000	22000	233799	229000	4799		
27	192407	110449	302856	32000	22000	356856	229000	127856		
28	127541	85345	212887	32000	22000	266887	229000	37887		
29	247213	110607	357821	32000	22000	411821	229000	182821		
30	110823	109229	220052	32000	22000	274052	229000	45052		
31	25915	108027	133942	32000	22000	187942	229000	-41058	9350	42800
Sum	3287399	2901555	6188954	992000	682000	7862954	7099000	763954		
Avg/day	106045	93599	199644							
St Dev	52754	30179	64337							
% of mean	50%	32%	32%							

Appendix 3: Sample Days

The first sample day examined here is **July 29**. Hourly generation and load figures, which are shown as day totals only in the July Table 2C in Appendix 2, are shown in hourly detail in Table 3A. The reader is reminded that daily operating power for electric and plug-in hybrid vehicles is already included in the hourly load figures. Electricity added to or withdrawn from vehicle battery storage is balanced during the 24-hour period and is over and above the daily electricity use for operating the vehicles.

The day begins with lower-than average wind output, so the load of 10,000 MWh is met in part with 550 MWh of purchased electricity, and the gas turbine is run so that only a portion of the available hydroelectric capacity need be run. The system operators know only that some cloud cover is forecast for the day. The course of wind output for the day is not known. As a rule, the system operators try to fill the pumped storage units during the first half of the day. If the winds are not strong enough to start pumping in the early morning hours, then the gas turbines are run and purchased power, up to 5% of average loads, is activated. Production continues to be short of hourly loads through the morning hours, so the purchases and gas turbine generation continue. Ice storage begins at commercial air conditioning customers to give additional storage for the evening hours. As solar production mounts, gas turbine generation slows, while hydroelectric generation continues to be held back for later use. Remaining excess power is added to any vehicle batteries which are connected and willing to receive it.

By 5 pm electricity production has declined, so hydroelectric and pumped storage both provide additional power at their maximum hourly levels of 2,000 MW and 1,500 MW respectively. Wind generation continues to fall below average. Remaining shortfalls are covered with load control and electricity drawn from vehicle batteries at premium prices. The cumulative draw on these sources is about 6,500 MWh through the last six hours of the day, with 2,000 MWh as the maximum hourly draw. This will be replaced during the early morning hours of the following day.

As the day ends, it becomes apparent that generation from the renewable sources has fallen short of demand by 55,491 MWh. This shortfall was met by a similar-sized draw on purchased power and generation from gas turbines. The hourly imbalances were covered by running the hydroelectric resources at strategic times, by the pumped storage facilities, the ice storage facilities, utility load control measures and the use of vehicle batteries.

The second sample day examined is **January 22**. The hourly figures are shown in Table 3B.

There is, by a small margin, enough power generated for the day, but this does not necessarily mean that each hour's load is covered. The day is one of strong winds, but relative weak solar generation. In the early morning hours, strong winds cover the hourly loads easily, permitting the pumped storage units to begin filling immediately. No hydroelectric power is needed at first, making it available for later hours as well. By 5 am wind generation has fallen a bit and the day's load is increasing. Only 500 MWh is added to the pumped storage facilities in that hour. From 7 am until 10 am some hydroelectricity is used to cover the increasing load. By then solar output is meeting part of the load and the pumped storage units resume filling. Weaker winds in the afternoon require some assistance from the hydroelectric system and some power from the pumped storage units. At 6 pm the wind generation falls to such a low point that purchased power and gas turbine generation are needed along with the hydroelectric units and pumped storage to meet the load. Winds again pick up, so that no auxiliary power is needed again. The remaining hours in which electricity supply falls short are easily covered from the hours with excess supply with load management and vehicle battery storage arrangements. About 10,000 MWh are available to be sold to neighboring utilities if they have need of any.

Table 3A: Hourly Generation and Load, July 29 Sample Day

Hour	Wind Generation (MWH)	Solar Generation (MWH)	Combined (MWH)	Biomass Generation (MWH)	Hydroelectric Generation (MWH)	Sum (MWH)	Hourly Load (MW)	Over (Short) (MWH)	Pumped Storage (MWH)	Purchase (MWH)	Gas Turbines (MWH)	Ice Storage (MWH)	New Over Short (MWH)
0	4740	0	4740	1333	700	6773	10000	-3227	0	550	2700		23
1	4921	0	4921	1333	0	6254	9000	-2746	-500	550	2700		4
2	5039	0	5039	1333	0	6372	8500	-2128	-1100	550	2700		22
3	4227	0	4227	1333	0	5560	8500	-2940	-300	550	2700		10
4	4681	0	4681	1333	0	6014	8500	-2487	-700	550	2700		64
5	4147	26	4173	1333	0	5506	8500	-2994	-300	550	2700		-44
6	4283	1167	5451	1333	0	6784	9000	-2216	-1000	550	2700		34
7	3634	2818	6452	1333	1200	8985	9500	-515	0	550	0		35
8	3209	3897	7106	1333	500	8939	10500	-1561	0	550	1000		-11
9	1198	7268	8466	1333	0	9799	11000	-1201	-1500	550	2100	-500	-551
10	1487	6987	8474	1333	0	9807	11500	-1693	-1500	550	2700	-500	-443
11	1552	7768	9320	1333	0	10653	12000	-1347	-1500	550	2300	-500	-497
12	1737	11165	12902	1333	0	14235	12500	1735	-1500	550	1500	-500	1785
1	1613	11393	13006	1333	2000	16339	13000	3339	-1500	300	0		2139
2	3433	7935	11368	1333	0	12701	13000	-299	0	0	0		-299
3	3488	11964	15452	1333	0	16785	13000	3785	-1500	550	0		2835
4	2765	8084	10850	1333	2000	14183	13000	1183	-1500	550	0		233
5	2072	4292	6365	1333	2000	9698	13000	-3302	1500	550	2000		748
6	2178	1264	3442	1333	2100	6875	13000	-6125	1500	550	2700	500	-875
7	2192	9	2201	1333	2500	6034	13000	-6966	1500	550	2700	500	-1716
8	1417	0	1417	1333	2500	5250	12500	-7250	1500	550	2700	500	-2000
9	3500	0	3500	1333	2500	7333	12500	-5167	1500	550	2700	500	83
10	1924	0	1924	1333	2000	5257	12000	-6743	1500	550	2700		-1993
11	3039	0	3039	1333	2000	6372	11000	-4628	1500	550	2700		122
SUM	72478	86039	158517	31992	22000	212509	268000	-55491	-3900	12400	46700	0	-291

Table 3B: Hourly Generation and Load, January 22 Sample Day

Hour	Wind Generation (MWH)	Solar Generation (MWH)	Combined (MWH)	Biomass Generation (MWH)	Hydroelectric Generation (MWH)	Sum (MWH)	Hourly Load (MW)	Over (Short) (MWH)	Pumped Storage (MWH)	Purchase (MWH)	Gas Turbines (MWH)	Ice Storage (MWH)	New Over Short (MWH)
0	11383	0	11383	1333	0	12716	9800	2916	-1500			0	1416
1	12162	0	12162	1333	0	13495	9800	3695	-1500				2195
2	12884	0	12884	1333	0	14217	9800	4417	-1500				2917
3	13162	0	13162	1333	0	14495	9800	4695	-1500				3195
4	13426	0	13426	1333	0	14759	9800	4959	-1500				3459
5	9768	0	9768	1333	0	11101	10600	501	-500				1
6	10300	0	10300	1333	0	11633	11600	33	0				33
7	10213	26	10239	1333	1000	12572	12600	-28	0				-28
8	9188	1229	10417	1333	1900	13650	13600	50	0				50
9	9850	2300	12150	1333	150	13633	13600	33	0				33
10	9282	2449	11731	1333	0	13064	12600	464	-400				64
11	8951	3924	12874	1333	0	14207	11600	2607	-1500				1107
12	9367	4801	14169	1333	0	15502	11600	3902	-1500				2402
1	4882	2625	7506	1333	2000	10839	10800	39	0				39
2	4475	5126	9602	1333	0	10935	10800	135	0				135
3	2932	3783	6715	1333	2000	10048	10800	-752	800				48
4	2751	2036	4787	1333	2000	8120	10800	-2680	1500	0			-1180
5	6490	88	6578	1333	2000	9911	11000	-1089	1000				-89
6	2298	0	2298	1333	2000	5631	11800	-6169	1500	550	2700		-1419
7	2694	0	2694	1333	2000	6027	11800	-5773	1500	550	2700		-1023
8	7117	0	7117	1333	2000	10450	11800	-1350	1300				-50
9	7905	0	7905	1333	2000	11238	11800	-562	600				38
10	7582	0	7582	1333	2000	10915	11600	-685	700				15
11	7198	0	7198	1333	950	9481	10600	-1119	1000				-119
SUM	196260	28387	224647	31992	22000	278639	270400	8239	-1500	1100	5400	0	13239