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POTENTIAL EFFECTS OF WIND ELECTRIC GENERATORS ON CONVENTIONAL ELECTRIC GENERATORS IN KANSAS

by

CHRISTOPHER KEAR DUFFEY

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Approved by:

Gary Johnson
Major Professor

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CHAPTER I

INTRODUCTION

Since the Jnly, 1980 conception of the Kansas Wind Resonrce Assessment Project at Kansas State University, wind data at eight Kansas locations has been collected nsing stand-alone wind data acqnisition systems. After data was collected and stored on tape in the field, it was transferred to KSU by mail, processed, and stored on the Wind Project Data General Nova compnter. Now that a snbstantial data base has been established, stndies of wind energy prodnction can now be made. This thesis incorporates three years of wind and ntility data from 1980 to 1982, and analyzes the effects that wind power generated dnring this time conld have had on conventional ntility operation.

To analyze the effects of injected wind power, five major calcnlations are nsed. In each calcnlation, ramping is a term applied to the rate of change of power ontpnt, and is the principal fignre of merit nsed thronghont this thesis. The major calcnlations consist of a 24 honr average and worst case ramping day, a 12 month average and worst case ramping year, an average and worst case ramping weekend and weekday, a distribntion of ramping rates, and a percent energy loss cnrve dne to upwards ramping control. Each of these calcnlations is discnssed in detail below within Chapter III, and aid in detecting the effects that injected wind power has on the ntility.

In addition to the indnced ramping effects on ntility operation, a correlation stndy is also given. This brief stndy ntilizes antocorrelation and crosscorrelation functions, and allows detection of wind power and Kansas load demand patterning.

Next, to establish a base from which to work, definitions for analysis are given to acqnaint the reader with three terms nsed thronghont this thesis.

Percent Penetration - the fraction of rated wind power ontpnt to rated ntility power ontpnt (assnmed to be 3000 MW).

Farm - a single wind site, possibly consisting of nnmerons wind tnrbines, all nnder identical wind conditions. Since all turbines at a site are assumed under identical wind conditions, the terms wind farm and wind turbine will be interchangeable.

Wind Array - two or more farms covering a state wide area.

As noted above, a 3000 MW penetration base is nsed. This is done since the plot of ntility power prodnction appears to peak aronnd 3000 MW (a good ronnd fignre) for Kansas Power and Light and Kansas Gas and Eleotric combined power prodnction. Also, these ntilities were nsed since they represent approximately 75% of Kansas power prodnotion, and had demand data that was conveniently available.

Next, to establish a basic knowledge of the four sites nsed in this stndy, a brief description for each site is given, while approximate geographical locations of each site are shown in Fignre 1.1.

Tnttle Creek, the first site established nnder the Wind Resonrce Assessment Project at KSU, is located on the Corps of

Engineers tower at Tuttle Creek reservoir near Manhattan, Kansas. It was established July 3, 1980 and has a base elevation of 1250 feet above sea level. The tower lies to the west end of Tuttle Creek dam on a well exposed hill, while normal water level of the reservoir is 1075 feet above sea level.

Wright, which only has a maximum 30 m tower height, is located on the KTVC-TV microwave relay tower at Wright, Kansas. The site was installed August 15, 1980, and has a base elevation of 2530 feet above sea level. This tower is located at the south-east corner of Wright near a school, is open to the south and east, and has a grain elevator 1/3 mile to the northwest.

Plainville, located on the Dale Roll farm 2 miles west of Plainville, Kansas, is positioned on an Oil Field Communication tower, and was installed October 11, 1980. It has a base elevation of 2160 feet above sea level, and is well exposed from all directions except for a house and trees 100 yards east of the tower.

Finally, Atlanta, established September 25, 1981, is located 1 and 3/4 miles north of Atlanta. The tower has a base elevation of 1430 feet above sea level and lies on a hill which is well exposed from all directions.

To conclude the introduction, special note is made regarding the plots used in subsequent analyses. Since over 120 plots were generated for this study, only samples from the original number are used as examples within this thesis. If additional plots are needed to verify any results below, refer to the Kansas Wind Resource Assessment Project at Kansas State University.

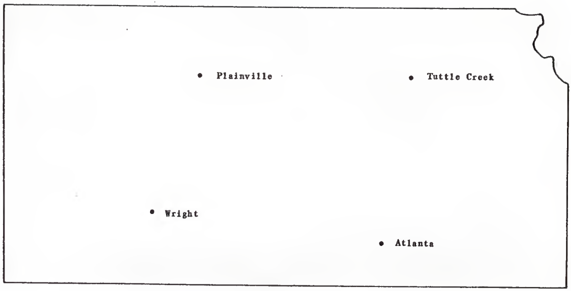


Figure 1.1. Geographical layout of analyzed Kansas wind sites.

CHAPTER II

LITERATURE REVIEW

Much research has already been done in the area of wind generation effects on utility systems. In fact, most studies to this date analyze the effects that thunderstorm induced wind generation have on utility operation. The major analyzing method used in these studies involves modeling wind behavior and utility operation, with some reports using actual measured wind speeds to simulate wind turbine power output. Finally, the reports then study the effect that injected wind generation has on area control error or ACE.

In one study by Schlueter, Park, Modir, Dorsey, and Lotfalian [8], worst case effects of wind farm power production due to thunderstorm fronts were analyzed. The paper utilized a modeled wind speed profile, the Mitchell model [10], to analyze how this dramatic change in power affected the overall area control error. One of the major points of the paper stated that given a high enough wind power penetration, the rapid increase and decrease in wind power production due to thunderstorms could cause a violation of utility performance requirements, an example being ACE equaling zero at least one time in all ten minute periods. However, the paper states that this problem can be controlled by limiting the total wind generation capacity to less than the automatic load following capability of automatic generation control, limiting echelon [8] penetration between 2 and 3%, and by shutting down portions of a farm before a thunderstorm pass.

In a second paper [9], Schlueter, Park, Lotfalian, Shayanfar, and Dorsey expanded on the paper given above. Since a definite problem in load following capability could exist under adverse conditions, the authors investigated modifications to power systems operation to compensate for significant wind power penetration. These modifications consisted of setting higher requirements for spinning reserve, load following capability, and unloadable generation. Thus, the problem of increased ACE could be reduced by modifying parameters on existing generation methods, and would be desirable since implementation of a complex control system for the utility control of dispersed wind generation would be costly. However, when such standards are set higher, production, operation, and maintenance costs would likewise increase since units not otherwise required would be running.

In their most recent paper [10], Schlueter, Park, Lotfalian, Shayanfar, and Dorsey introduce three more methods for reducing thunderstorm induced power changes from large wind turbine arrays. These methods include selection of a wind turbine model for particular sites, selection of an appropriate siting configuration, and wind array controls. If these methods are used, then previous wind farm requirements set in [8] would not depend on the capacity of the farm, but on the wind turbine selection and siting configuration, while coordinated blade pitch controls would be used to reduce the effective farm penetration level.

Also of interest is the effect that small wind turbines have on utility generation performance. In a paper by Curtice and Reddoch [11], a simulation model of a utility's automatic generation control was modified by including synthesized data representing an aggregate output of small turbines. Since small wind turbines have less inertia than large turbines, their output power variations would tend to be more frequent. In essence, for turbines with variations greater than 0.01 cycles per second, an added noise component of relatively higher frequency would be injected into the power system. This component is likely to be uncontrollable, and if large enough, could cause the quality of the utility's system performance to decrease. That is, higher ACE values, longer times between zero crossings, etc. would result.

In summary, the papers discussed above show how, given significant penetration, wind generation can produce undesirable effects on a utility's load following capability. Also, several methods are mentioned by which rapid changes in power output from large wind turbine arrays could be reduced, and how modification of power system operation could be used when there is significant wind power penetration. In this thesis, the two methods used to aid in controlling negative effects due to injected wind generation will be upwards ramping and wind array controls.

CHAPTER III

METHODS, PROCEDURES, AND DATA

Within this chapter, defining relations and data validity are discussed to give insight into the analysis of wind power effects on conventional generation for this thesis. The main areas of discussion involve calculations for wind power, ramping rates, ramping distributions, ramping control, and correlation, with an additional section on the validity of the wind and utility sample data sets.

Wind Power Production

In calculating wind power from mean hourly speeds, the model used will be that in Figure 3.1. This model incorporates a linear relation between wind speed and power output from the cut-in wind speed (u_c) to the rated wind speed (u_r). The relation between power and wind speed is actually a cubic relationship, but as stated in [5], low efficiencies at low wind speeds help to linearize the power output curve. This is also verified by the actual power output operation of a MOD-2 wind turbine shown in Figure 3.2. This thesis will base power production calculations to simulate turbines similar to the MOD-2.

Also, considering the furling wind speed (u_f), no action is taken to shut down power production during calculations for two reasons. First, the turbine model used in this thesis incorporates u_o values of 5, 6, and 7 mps and u_r values of 10, 12, and 14 mps respectively. Since these values closely follow those of

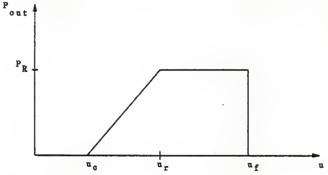


Figure 3.1. Wind turbine power output vs. windspeed.

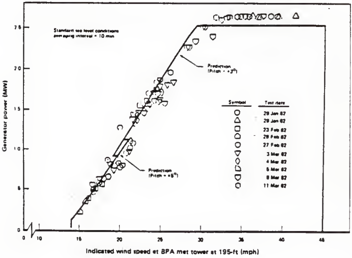


Figure 3.2. Performance curve for MOD-2 wind turbine (unit 3)[4].

the MOD-2, which can have a 60 mph furling wind speed [4], and no wind data used in this report exceeds 50 mph, no furling condition is ever reached. Second, the wind speeds used in calculating modeled wind power production are mean hourly speeds. The collection time period for this data is not short enough to detect gusting wind speeds in excess of 60 mph, and thus need for such detection in power calculations would be unnecessary. The above two arguments do not neglect the fact that a wind speed above 60 mph could have occurred during valid data collection, but suggest that detection of such conditions could only occur if such wind speeds persisted over an hourly period of data collection.

For the model shown in Figure 3.1, a more precise expression for the average power output of the turbine is

$$\begin{aligned} P_e &= 0 && u < u_c \\ P_e &= \frac{P_R}{(u_r - u_c)}(u - u_c) && u_c \le u \le u_r \qquad (3.1) \\ P_e &= P_R && u > u_r \end{aligned}$$

where P_e is the electrical power out, P_R is the rated power, and u is the mean hourly wind speed. A sample plot of power output using this equation can be seen in Figure 3.3. This output power landscape is calculated from wind speeds measured at the Tuttle Creek 50 m tower. Two successive blow-ups of this landscape show the hourly power output over a 120 hour period which corresponds to April 6, 1982 at 8 am to April 11, 1982 at 12 pm. Note that

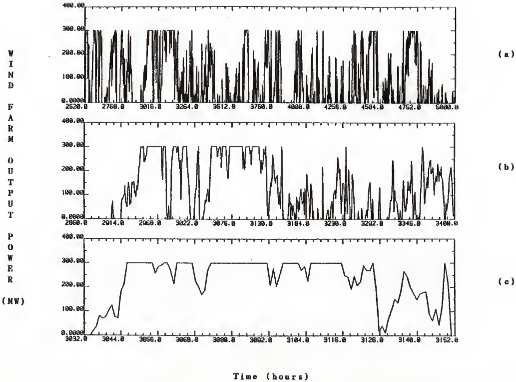


Figure 3.3. Successive blowups (a,b,c) of wind power profile for Tuttle Creek 50m.

the scale on the horizontal axis of Figure 3.3 is in hours, and corresponds to the hour in year 1982.

Another important note to make concerns the injection of wind power into the utility grid. This will be done by first assuming that the utility power data matches Kansas load demand. In using this assumption, since coincident wind and utility power production will be adding together to meet Kansas load demand, to find the resultant utility power output, wind power will be subtracted from the Kansas load demand. An example plot of this operation can be seen in Figure 3.4. Note that this figure has the coincident wind power production in the lower plot.

Ramping Rates

Calculating the ramping rates from the wind and utility demand data will be done by utilizing their power output as the average power over an entire hour. Thus, if KPL and KGE satisfied a Kansas load demand of 1000 MWhrs for a particular hour of the day, the average power output would be 1000 MW over the entire hour. So, on an hour by hour basis using average hourly power output, ramping rates are calculated using

$$\text{Ramping Rate} = \frac{\text{Pave}_2 - \text{Pave}_1}{60} \quad \text{MW/min} \qquad (3.2)$$

where Pave_1 and Pave_2 are consecutive average hourly powers, and 60 has the dimension of minutes. For increasingly smaller time intervals, this expression would approach the derivative or instantaneous rate of change of the electrical power output. In a

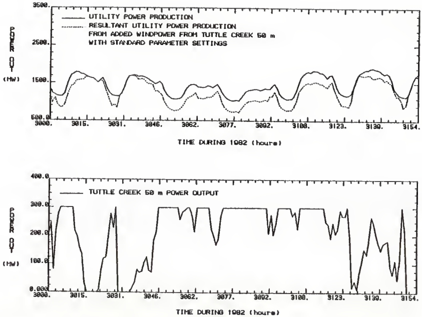


Figure 3.4. Plot showing subtraction of wind power.

more general form,

$$R_j = \frac{P_{j+1} - P_j}{60} \quad \text{MW/min} \qquad (3.3)$$

where R is the average hourly ramping rate, and P is the hourly average power production.

<u>24 Hour Ramping Calculations</u>

24 hour ramping rates are best described as 24 hours in which three years of data have been condensed. That is, each hour for the entire period is summed or compared with its fellow hour of another day. The final results from the 24 hour calculations give mean ramping rates for a 24 hour day, standard deviations of the periods ramps with their corresponding mean ramp, and maximum and minimum ramps for a worst case 24 hour day. Given the following variable definitions,

$M(m,n)$ – the number of days in the nth month of the mth year

m – 1 = 1980, 2 = 1981, 3 = 1982, 4 = 1983

Y – the number of years in the total period

R – the mean ramping rate for a particular hour

D_{24} – summations of the squared 24 hour ramping rates

$\tilde{m}_{24}$ – 24 hour mean ramping rates (mean 24 hour day)

$\tilde{\sigma}_{24}$ – 24 hour standard deviations of ramping rates

S_{24} – summations of 24 hour ramping rates

N_{24} – total number of days in period

$i = 1,2,3,\ldots,24$

the means and standard deviations for the 24 hour rates are calcnlated as follows:

$$\tilde{m}_{24}(i) = \frac{\sum_{L=1}^{Y} \sum_{k=1}^{12} \sum_{j=1}^{M(L,k)} R_{ijkL}}{\sum_{m=1}^{Y} \sum_{n=1}^{12} M(m,n)} = \frac{S_{24}(i)}{N_{24}} \quad \text{MW/min} \qquad (3.4)$$

$$D_{24}(i) = \sum_{L=1}^{Y} \sum_{k=1}^{12} \sum_{j=1}^{M(L,k)} R^2_{ijkL} \quad (\text{MW/min})^2 \qquad (3.5)$$

$$\tilde{\sigma}_{24}(i) = \sqrt{\frac{D_{24}(i) - \dfrac{(S_{24}(i))^2}{N_{24}}}{N_{24} - 1}} \quad \text{MW/min} \qquad (3.6)$$

In addition, the two worst case days for minimum and maximum ramping rates are found by comparing the present calculated rate with the smallest and largest rates obseved np to that point. If the present rate is smaller or larger than the existing min or max, it replaces that qnantity and becomes the new min or max. These results show at what hours of the day worst case ramping occnrred. From all of the 24 hour resnlts, average and worst case daily ramping trends can be seen and compared between various power production schemes.

<u>12 Month Ramping Compntations</u>

As with the 24 hour ramping compntations, the 12 month compntations create a year in which each month is represented by typical and worst case ramping for the month. Along with these qnantities, the standard deviation of all ramping for a particular month-set about the mean monthly ramp is also calcnlated. The term month-set emphasizes the fact that even though the resnlts are labeled for a single month, np to three months of data (three months with the same name for three years) are nsed in calcnlations. Also, special note should be taken to the mean 12 month results which incorporate absolute valued ramping rates. Since the average ramping rate over a month is approximately zero (as many positive ramps as negative), the magnitude of ramping is nsed, thns giving information on absolnte average monthly trends. Given the following variable definitions,

$M(m,n)$ - the number of days in the nth month of the mth year

$m - 1 = 1980,\ 2 = 1981,\ 3 = 1982,\ 4 = 1983$

Y - the number of years in the total period

R - the mean ramping rate for a particnlar hour

D_{12} - summations of the squared 12 month ramping rates

$\tilde{m}_{12}$ - 12 month mean ramping rates (absolute)

$\tilde{\sigma}_{12}$ - 12 month standard deviations of ramping rates

S_{12} - summations of 12 month ramping rates

N_{12} - total number of hours in month period (3 months)

$k = 1,2,3,\ldots,12$

the means and standard deviations for the 12 month rates are calculated as follows:

$$\tilde{m}_{12}(k) = \frac{\displaystyle\sum_{L=1}^{Y} \sum_{j=1}^{M(L,k)} \sum_{i=1}^{24} |R_{ijkL}|}{\displaystyle 24 \cdot \sum_{m=1}^{Y} M(m,k)} = \frac{S_{12}(k)}{N_{12}(k)} \quad \text{MW/min} \qquad (3.7)$$

$$D_{12}(k) = \sum_{L=1}^{Y} \sum_{j=1}^{M(L,k)} \sum_{i=1}^{24} R^2_{ijkL} \quad (\text{MW/min})^2 \qquad (3.8)$$

$$\tilde{\sigma}_{12}(k) = \sqrt{\frac{D_{12}(k) - \dfrac{(S_{12}(k))^2}{N_{12}(k)}}{N_{12}(k) - 1}} \quad \text{MW/min} \qquad (3.9)$$

In addition, for the worst case minimum and maximum 12 month year, a similar procedure to that for 24 hour calculations is used. These results yield the worst ramping which occurred during the three-month sets. All of the 12 month results allow for comparison between calculations for different power production schemes, and show average and worst case monthly trends.

Weekend-Weekday Ramping Calculations

To conclude the ramping computations, weekend and weekday ramping rates are calculated to give results that compress three years of ramping rates into typical and worst case ramping for a weekend and a weekday. Also, the standard deviations for the weekend-weekday ramping rates are calculated with their respective mean value. Again, as in 12 month computations, note that the mean weekend-weekday rates are formulated using absolute ramping. Given the following variable definitions,

R - the mean ramping rate for a particnlar honr

D_2 - summations of the aquared weekend-weekday ramping rates

$\tilde{m}_2$ - weekend-weekday mean ramping rates (absolnte)

$\tilde{\sigma}_2$ - weekend-weekday standard deviations of ramping rates

S_2 - summationa of weekend-weekday ramping ratea

N_2 - total number of rampa for weekends and weekdays

W - number of weeka in total period

$s(k) = 1$ for $k=1$; 3 for $k=2$ $e(k) = 2$ for $k=1$; 7 for $k=2$

$k = 1,2$ (weekend, weekday)

the means and atandard deviationa for the weekend-weekday ramping rates are calcnlated as followa:

$$\tilde{m}_2(k) = \frac{\sum_{L=1}^{W} \sum_{j=s(k)}^{e(k)} \sum_{i=1}^{24} |R_{ijkL}|}{24We(k)} = \frac{S_2(k)}{N_2(k)} \quad \text{MW/min} \qquad (3.10)$$

$$D_2(k) = \sum_{L=1}^{W} \sum_{j=s(k)}^{e(k)} \sum_{i=1}^{24} R^2_{ijkL} \quad (\text{MW/min})^2 \qquad (3.11)$$

$$\tilde{\sigma}_2(k) = \sqrt{\frac{D_2(k) - \dfrac{(S_2(k))^2}{N_2(k)}}{N_2(k) - 1}} \quad \text{MW/min} \qquad (3.12)$$

In addition, for the worst case weekend-weekday ramping compntations, the same procednre to determine theae valnes as used above is implemented. All weekend-weekday results allow for comparison between calculations for different power production schemes, and show average and worst case weekend-weekday differences.

Ramping Distribution

In recaping the average and worst case ramping calculations described above, it was noted that the results given by those calculations allowed perception of the effect that added wind generation would have on utility operation. However, to gain an overall picture of how all ramping rates within a given range are affected, another method must be used. This method, a calculated ramping distribution, allows insight into the distributed nature of ramping rates, and allows closer inspection of effects due to injected wind power generation.

Within the routines for this thesis, the procedure for finding the desired distribution involves finding the probabilty density function (pdf) of the ramping rates, and then calculating the distribution from the defining equation which links the pdf and the probability distribution. As seen in Figure 3.5, an approximate pdf can be made up of distinct bins, each bin being $2a$ wide and centered about α. To find this approximate pdf, a relation must be found between the probability of a range of ramps occurring, and the pdf itself. In looking at Figure 3.5 again, note that for proper definition of probability over an interval of a continuous pdf, that

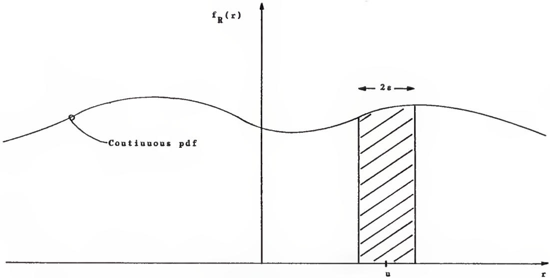


Figure 3.5. General curve for pdf of ramping rates.

$$P[\alpha-\varepsilon < R \leq \alpha+\varepsilon] = \int_{\alpha-\varepsilon}^{\alpha+\varepsilon} f_R(r)dr \qquad (3.13)$$

where R ia the random variable for ramping rates. However, if the bin width ahown in Fignre 3.5 ia amall enough, then the probability, which is the area under the pdf cnrve, ia approximately

$$P[\alpha-\varepsilon < R \leq \alpha+\varepsilon] \cong 2\varepsilon f_R(\alpha) \qquad (3.14)$$

Also, for large N, it is known that

$$P[\alpha-\varepsilon < R \leq \alpha+\varepsilon] \cong \frac{\text{No. of } r_i \text{ between } \alpha-\varepsilon \text{ and } \alpha+\varepsilon}{N} \qquad (3.15)$$

where r_i is the ith discrete ramp. If the approximationa given by equationa 3.14 and 3.15 are now combined, then the formula for the approximate pdf becomea

$$\tilde{f}_R(\alpha) \cong \frac{\text{No. of } r_i \text{ between } \alpha-\varepsilon \text{ and } \alpha+\varepsilon}{2N\varepsilon} \qquad (3.16)$$

where $\tilde{f}_R(\alpha)$ is the approximate pdf of the ramping rates [6].

Now that the pdf has been defined by an approximate numerical method, the distribntion can be found nsing the relation between the pdf and the diatribution function. From statistics, the relation between continuoua-probability density and distribntion functions is

$$F_R(r) = \int_{-\infty}^{r} f_R(\alpha)d\alpha \qquad (3.17)$$

where $f_R(\alpha)$ is the value of the pdf at α. However, this distribution function gives the probability that a ramp of R or less has been observed (integrating from 0 to r), and is the converse of what is desired (the probability of observing a particular ramp R or greater). To obtain the desired result, if the pdf were integrated from r to ∞, the new distribution ($F_{new}(r)$) would be

$$F_{new}(r) = 1 - F_R(r) = 1 - \int_{-\infty}^{r} f_R(\alpha)d\alpha = \int_{r}^{\infty} f_R(\alpha)d\alpha \qquad (3.18)$$

To write this in a more reasonable form, the continuous components must be replaced with their respective discrete parts. In substituting 2s for $d\alpha$, $\tilde{f}_R(\alpha)$ (from equation 3.16) for $f_R(\alpha)$, summation signs for integrals, and noting that the 2s's cancell, equation 3.18 becomes

$$\tilde{F}_{new}(r) = \sum_{\alpha=r}^{\infty} \frac{\text{No. of } r_i \text{ between } \alpha-s \text{ and } \alpha+s}{N} \qquad (3.19)$$

Now, for actual calculations, ∞ is replaced by the maximum and minimum values of $\pm$10.0 MW/min, s is set to 0.1 MW/min for a 0.2 MW/min bin width, r is restricted to the range $-10.0 \leq r \leq 10.0$, and α is incremented by $\pm$ 0.2 MW/min. Finally, positive and negative ramping distributions, $\tilde{F}_P(r)$ and $\tilde{F}_N(r)$, are calculated separately, and are represented by

$$\tilde{F}_P(r) = \sum_{\substack{\alpha=r \\ (\text{by } 0.2)}}^{10.0} \frac{\text{No. of } r_i \text{ between } \alpha-s \text{ and } \alpha+s}{N} ; 0.0 \leq r \leq 10.0 \quad (3.20)$$

and

$$\tilde{F}_N(r) = \sum_{\substack{\alpha=r \\ (\text{by } -0.2)}}^{-10.0} \frac{\text{No. of } r_i \text{ between } \alpha-a \text{ and } \alpha+a}{N}; -10.0 \le r \le 0.0 \quad (3.21)$$

Earlier, it was stated that within routine calculations, that in calculating the distribution, the pdf would be calculated first. This is true up to a constant value divisor. Instead of calculating equation 3.16 as it is written, the equation times 2a is calculated (the interior of equations 3.20 and 3.21) and thus allows direct summation without having to multiply the pdf by 2a to obtain results.

Upwards Ramping Control

In the analysis of wind power affected ramping rates, all analysis so far has assumed that turbine operation has had no outside control. In actual operation though this will most likely not be the case. Within this section, a simple control algorithm that limits wind turbine upwards ramping by spilling generated power is discussed.

As shown in the previous section, a wind turbine produces power with respect to wind speed according to a curve like that of Figure 3.1, with a resultant wind power profile as seen in Figure 3.3. For a general profile of mean hourly powers (Figure 3.6), if some power P_2 is greater than P_1 such as to give a ramping rate greater than some desired limit R_L, then the control algorithm spills power to keep that ramping rate at R_L. Spilling

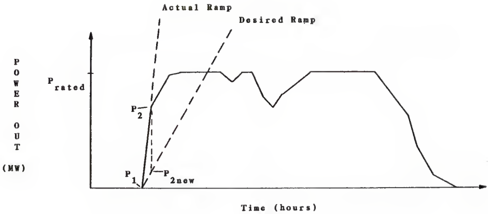


Figure 3.6. General wind power profile showing actual . desired ramp.

of wind power is accomplished mainly throngh blade pitch control. Thia new power P_{2new} replacea P_2 and ia calcnlated by

$$P_{2new} = P_1 + 60R_L \qquad \text{MW} \tag{3.22}$$

where R_L is in MW/min, P_1 and P_2 are in MW, and 60 carries the dimenaion minntes. Also, to measure the amount of lost power dne to thia ramping control, the power loss is summed for all cases of excess ramping, and is then divided by the total amonnt of power prodnction for the period. This resnlt gives the percent power loss dne to ramping control, and allows for comparison between different power prodnction schemes and different amounts of control.

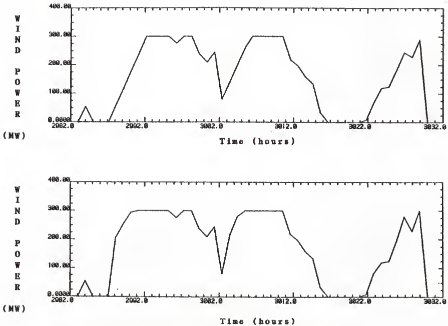
Aa far as control of actnal wind farms is concerned, the technology of power prodnction control to help economic dispatch, for example, haa been in nse for at least 20 yeara. Thns, the implementation of a control scheme on wind power prodnction wonld be of major importance. The control algorithm nsed in this thesia looks only at ramping rate magnitndes, and does not take into conaideration the entire power system as a whole. Also, for wind arrays consiating of two or more farms, the control algorithm nsed in this thesis monitors the aggregate ramping of the wind array and not each site individnally. If this were in actnal operation, a control center wonld then have to monitor each individnal site, add their individnal contribntions together, and spill power at the most convenient site(s) to maintain economic dispatch and keep ramping at a deaired level.

An example of ramping control as seen on a wind power profile is shown in Fignre 3.7. The control, seen as positive parallel slopes, is qnite evident in the npper plot.

Correlation

Besides ramping observations, another area of intereat is the way in whioh ntility load demand and wind power prodnction correlate. That is, the way that Kansas load demand patterns after Kanaas wind. This analysis involves antooorrelation and crosscorrelation fnnctions, and treats wind and ntility data as discrete signals to be analyzed in a signal proceasing method [6]. Theae resnlts show how a aignal correlates with itself, and how two signals correlate together.

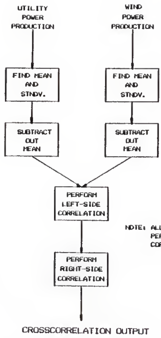
For the analysis performed in this thesis, the prooednre nsed to find antocorrelations is shown in Fignre 3.8, while the procednre to find crosacorrelations ia shown in Fignre 3.9. For both procedures, the aignals are preprocessed by snbtracting the mean from every element (aee Fignre 3.10, example of zero mean ntility data), or taking ont the DC component. Next, the correlation is performed while each resnlt for a shift k is divided by the prodnct of the standard deviations of both aignala (the prodnct for the antocorrelation ia thns the sqnare of the single signal standard deviation). This has the effect of normalizing the correlation reanlts within a range of [+1.0, -1.0]. Finally, note that the correlation fnnctions naed are fnnctions of time difference only, and thns show how correlation varies with time shifting of data sets.



(a)

(b)

Figure 3.7. Wind power with (a) and without (b) 1.0 MW/min ramping control.



NOTE: ALL NORMALIZING IS
PERFORMED WITHIN
CORRELATION CALCULATIONS.

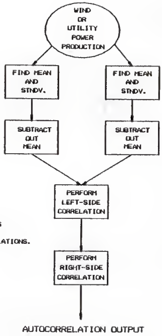


Figure 3.8. Crosscorrelation flowchart.

Figura 3.9. Autocorralation flowchart.

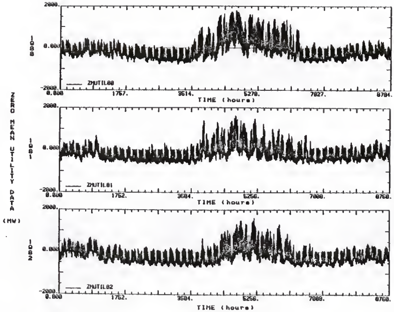


Figure 3.10. Zero mean utility data.

In equation form, the left ($\tilde{R}_{w,u}(k)$) and right ($\tilde{R}_{u,w}(k)$) side crosscorrelations are written as

$$\text{Left Side} \qquad \tilde{R}_{w,u}(k) = \frac{1}{\sigma_U \sigma_W N} \sum_{i=1}^{N} w(i)u(i+k) \qquad (3.23)$$

$$\text{Right Side} \qquad \tilde{R}_{u,w}(k) = \frac{1}{\sigma_U \sigma_W N} \sum_{i=1}^{N} u(i)w(i+k) \qquad (3.24)$$

where u is the utility data set, w is the wind data set, N is the total number of overlapping valid data points, σ_U is the standard deviation of the utility data, and σ_W is the standard deviation of the wind data. At this point, the most confusing argument is that of the difference between the left-side correlation (denoted w,u) and the right-side correlation (denoted u,w). If the utility is considered the base by which the equations are defined for the cross correlation, then the left side correlates earlier occurring winds with utility data of a later time, while the right side correlates later occurring winds with utility data that occurred earlier. For example, for the right side of the crosscorrelation plot shown in Figure 3.11, if the winds for Tuttle Creek occurring 3 hours later blew 3 hours earlier, then the utility demand and wind power generation would correlate on a 24 hour cycle (the peak close to the center of the plot would indeed be on zero instead of being shifted by three hours).

Finally, to calculate the autocorrelation of both wind and utility data, the equation

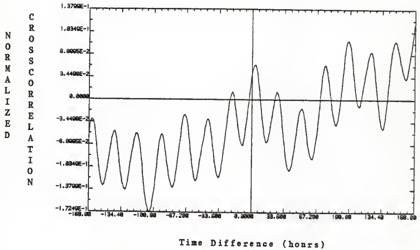


Figure 3.11. Utility and Tuttle Creek 50m crosscorrelation.

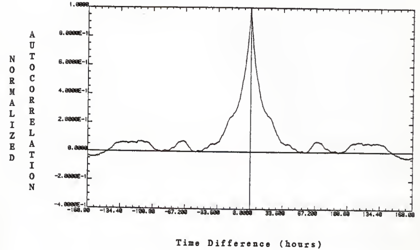


Figure 3.12. Plainville 50m Autocorrelation.

$$\tilde{R}_{X,X}(k) = \frac{1}{N\sigma_X^{\,2}} \sum_{i=1}^{N} x(i)x(i+k) \qquad (3.25)$$

is used, where x is the data being analyzed, σ_X is the standard deviation of the data, and $\tilde{R}_{X,X}$ is the autocorrelation of the data. In showing how a signal correlates with itself, important information on data validity can be extracted. This subject will be addressed fully in the next section.

An example plot of the autocorrelation for Plainville 50 m is shown in Figure 3.12. As can be seen in the figure, symmetry is a major feature of the autocorrlation function. Also, in noting that the horizontal scale is in hours, this plot shows high correlation up to plus or minus five hours time shift.

Data Set Validation

Because the results of this analysis rely heavily on the accuracy of the wind and utility data used, this section is included to verify correctness of the data sets. Both the utility and the wind data suffer from problems in hourly synchronization, and thus both data sets could be offset up to two hours.

Since the start of wind data collection at Kansas State University, problems with data transfer, operator error, and transducer failure have caused an incomplete data set to be collected. Also, when data was available, problems in synchronization could have possibly lead to offsets of up to two hours between consecutive tapes of data. Two hours is chosen as the maximum since one hour definitely arose from change in time, central standard to central daylight, and another hour is added to include any other possible problems that might have occurred.

Utility data on the other hand is completely synchronized with its respective time and time change. However, when the utilities make the time change from standard to daylight, move ahead one hour, they record zero energy production for the lost hour. So, instead of shifting the entire data set back to cover this hole, an interpolation is made between adjacent hours of energy production, and the situation is treated as though there was never a time change. At first this would not seem valid, but since the utility never records the extra energy that it produces when changing from daylight to standard time, the hour offset due to this problem only occurs for at most six months, and averages out for the year. Finally, for the routines used in this analysis, it is important to note that the utility data has one projected hour of data added to the end of the data set. This is done so that the calculations of ramping rates can extend to the last available hour of data.

To show that these effects will not alter the outcome of results significantly, a closer look at the autocorrelation of wind power output must be made. In looking back at Figure 3.16 it is found that wind data correlates highly (50 % correlation) with itself even when shifted in time by up to 5 hours, and for a time shift of 2 hours, is even better, showing 80 % correlation. Thus, even if the wind data were offset by two hours, the outcome would not be significantly different since the major variations of wind occur beyond a time shift of two hours. In fact, from

Figure 3.16, major variations (periodic trends) appear to be occurring on 24 hour and 4 day cycles. So, since the utility offset averages out over a yearly period and wind correlates well with itself up to a 2 hour time shift, results obtained from these two data sets will express true occurrences.

CHAPTER IV

RESULTS AND DISCUSSION

After making numerous runs of each of the main routines, results for ramping, and correlation were compiled and analyzed. These results constitute the heart of this thesis, and show the effects that added wind generation could have on utility operation.

For all of the results discussed below, standard input parameters for the wind power calculations will be used unless otherwise noted. These parameters consist of a 300 MW rated wind array power output, a cut-in turbine wind speed of 6.0 mps, a rated turbine wind speed of 12.0 mps, no upwards ramping control, and a wind array of one farm.

Utility Ramping

Utility ramping by itself is needed as a base by which comparisons can be made. In following analyses, this base result is often termed the utility norm or unaffected utility, and represents the normal case of utility operation without any type of added wind generation.

24 Hour Results

With the utility 24 hour ramping rates, the first phenomena seen should be that of the ever present morning pickup of Kansas load demand. In looking at Figure 4.1 and noting that the horizontal axis increments are 1.15 hours, it is found that the morning pickup, with its highly visible first positive hump,

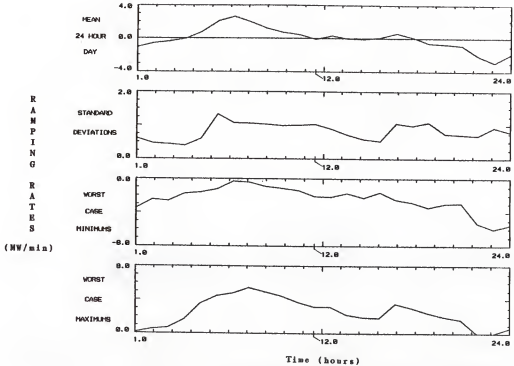


Figure 4.1. 24 hour results for utility power production.

appears to have an average peak of 2.63 MW/min. Also seen in this plot are the noon and evening picknps (aecond and third positive hnmps), while the evening fall off obtains an average negative peak of -2.88 MW/min. Another interesting resnlt can be observed in the plot of the standard deviation. As can be seen in Fignre 4.1, the greatest variation in ramping occnrs dnring the morning picknp between 6 and 7 am (some are contemplating getting ont of bed for work), while the least amount of variation occnrs dnring the tail end of the work day (everyone takes a break or goes home from work) and dnring the early morning honrs (everyone is asleep). These reanlts are not in the least snr-priaing, bnt are none the less humorons. For maximum ramping, it is also seen that worst case aitnations occnr dnring the morning picknp with a peak of 5.43 MW/min. Since this peak occnrs around 8 am, a snspective canse wonld be that of the atart to the eight honr work day. Finally, the minimum ramping calcnlations show worst case fall off to occnr at 10 pm and have a minimnm valne of -5.95 MW/min. A anspective canse again is that of indnatrial natnre.

12 Month Ramping Resnlts

In looking at ramping ratea on a monthly time axis, intni-tion snggests that the number of variations will decrease. This wonld be dne mainly to the averaging ont of the dinrnal and weekly cycles, thns showing only seasonal variations. The 12 month resnlts in Fignre 4.2 have this characteristic, and show one major trend, that being all aronnd increaaes dnring anmmer

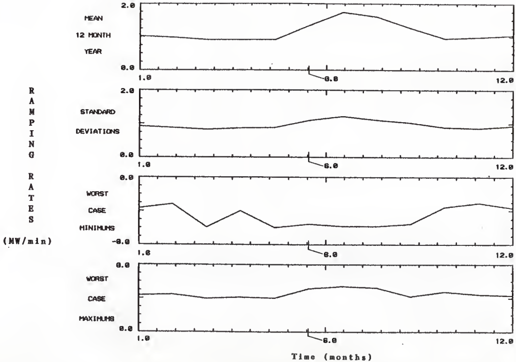


Figure 4.2. 12 month resnlts for utility power production.

months. Thus, during this time there is increased ramping and increased deviation, while there are lower minimums and higher maximums. The worst case values for the minimums and maximums match those of the worst case 24 hour results, and occur during the evening fall off and morning pickup respectively.

Weekend-Weekday Results

Concerning these results, there appears to be hardly any noticeable differences between the weekdays and the weekends. However, as seen in Figure 4.3, the weekends do show a slight increase in both the mean value and the deviation from that mean value, while the weekdays show slightly higher worst case ramping conditions. This matches what would be expected, since during the weekend the 8 hour work day pattern is not as prevalent causing more random and spontaneous power demand. Also, the greater minimum and maximum ramping occurrence during the week would seem to stem from industrial operations which occur during this time.

Ramping Distribution Results

As in the 12 month results just mentioned above, the distribution (Figure 4.4) has only one major trend, that being exponential in nature, and decreasing towards higher ramping rates. This trend shows that higher ramping rates have a decreasing exponential probability of occurrence and indicates utility ramping rarely to exceed 5.0 MW/min.

Wind Power Ramping

Wind power ramping results are used primarily to show the

KPL AND KGE RAMPING COMPUTATIONS

WEEKEND-WEEKDAY MEANS (ABSOLUTE)

WEEKEND --> 1.22 WEEKDAY --> 1.11

WEEKEND-WEEKDAY STANDARD DEVIATIONS (ABSOLUTE)

WEEKEND --> 1.09 WEEKDAY --> .98

WEEKEND-WEEKDAY MINIMUMS

WEEKEND --> -5.93 WEEKDAY --> -5.95

WEEKEND-WEEKDAY MAXIMUMS

WEEKEND --> 5.17 WEEKDAY --> 5.43

Figure 4.3. Weekend-weekday results for utility power production.

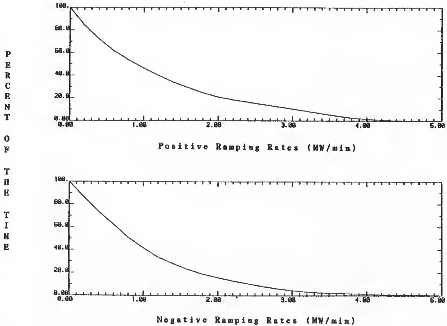


Figure 4.4. Ramping distributions for utility power production.

ramping effects of wind power production alone. Since wind is fairly random, one would tend to think the ramping results from such power production to be random also. However, to take a complete look at the wind and verify such ideas, the following analysis of wind power ramping is made.

<u>24 Hour Results</u>

By inspecting the 24 hour results for all the sites, it was found that wind ramping rates, as wind itself, are very random. As seen in Figure 4.5 for Atlanta 50 m, the mean ramping rates have no apparent pattern, while the standard deviations, minimums, and maximums do the same. From the minimums and maximums however, the worst case ramping can be averaged, and is observed to be around -3.0 MW/min and 3.0 MW/min respectively. Even though only one site is shown in the figure for 24 hour ramping computations, all other sites have approximately the same results.

<u>12 Month Ramping Results</u>

For the 12 month ramping rates, the diurnal cycle is averaged out again, thus allowing seasonal variations to show. As seen in Figure 4.6 for Tuttle Creek 50 m however, the mean 12 month rates show no seasonal variation whatsoever, and appear to be rather uniform in nature over the entire yearly period. The standard deviation also has this character, but shows a slight increase in deviation towards the center of the year. Finally in the minimums and maximums, some trends begin to show. As seen in the minumum ramping plot, the early summer months show the worst

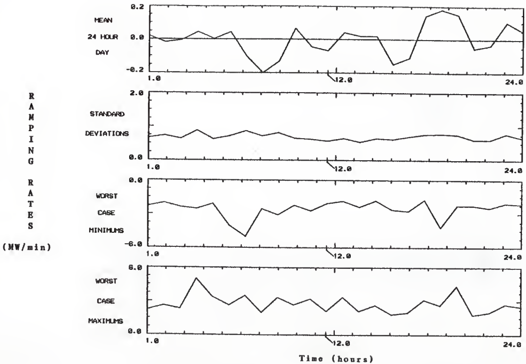


Figure 4.5. 24 hour results for wind power produced at Atlanta 50m.

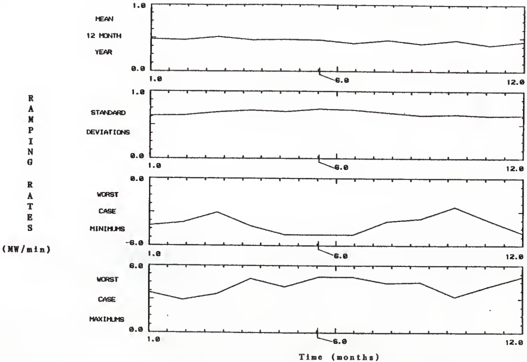


Figure 4.6. 12 month results for wiud power produced at Tuttle Creek 50m.

sustained negative ramping conditions for the entire year, reaching -5.0 MW/min (due to drop from rated power of 300 MW to zero power in one hour). Also, the postitive rates show this effect for the early summer months, and reach the opposite extreme of 5.0 MW/min (due to increase from zero power to rated power of 300 MW in one hour). So, even though wind power is a randomly occurring variable, there is some seasonal variation in its production.

Utility Ramping After Wind Power Injection

To analyze resultant utility ramping effects, three of the major calculations used above and control of wind power production parameters will be used. The calculations consist of 24 hour ramping rates, ramping distributions, and percent energy loss, while control of the wind power production will be accomplished through siting of a wind farm, choosing cut-in and rated wind speeds for a turbine, allowing specific amounts of wind array penetration, and increasing the number of farms in a wind array. Note for the discussion below, that 12 month and weekend-weekday results will not be used. This is done since 12 month results are not complete for all of the sites, due to incoomplete data sets, and weekend-weekday results for added wind power show random effects.

<u>Siting Control</u>

Siting control involves taking a look at the results from different sites and determining the optimum site for location of a farm, within the site limitations of this study. At first, one wonld think of this as applying no control to the injected wind power, bnt when looked at on a broader basis of site to site, is actually control of a specification for implemented wind generation.

Referring to Fignre 4.7, the ramping distribntion for the 50 m resnlts tend to be exponentially decreasing towards higher ramping conditions. Tnttle Creek and Plainville create increased utility ramping over the entire range of rates, and for 2.0 MW/min or greater, both show approximately a 10% increase in the probability of ocenrrence for negative rates. Atlanta affects the ntility only lightly in the positive rates, and for 2.0 MW/min or greater, begins to help the ntility with negative ramping. This feature of added wind generation aiding ntility operation is either a statistical mishap, in that all of the data for this particular time period gave snch a resnlt, or Atlanta is trnly a beneficial site for the production of wind energy.

For the 30 m distribution resnlts, all sites raise the ntility's distributed ramping rates for both positive and negative ramping. Althongh the cnrves are jumbled together, Tuttle Creek shows an increased negative effect on the ntility beyond that of the other three sites for negative ramping. However, since this difference is very small, the fonr sites at 30 m show signs of having coincident effects on utility ramping.

In continuing observance of site effects, if the 24 hour mean ramping rates are inspected (Figure 4.8), of the three sites at 50 m, Atlanta again shows to be the most varied from the

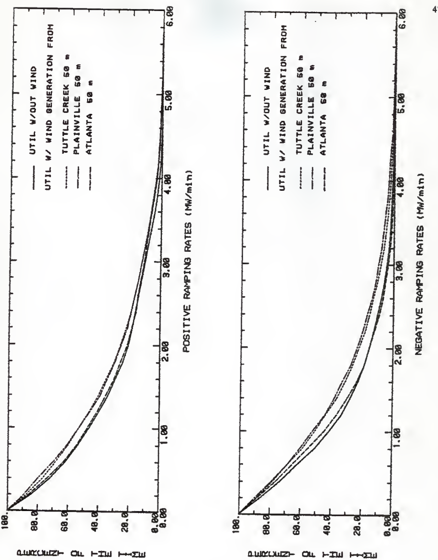


Figure 4.7. Utility ramping distribution after wind power injection.

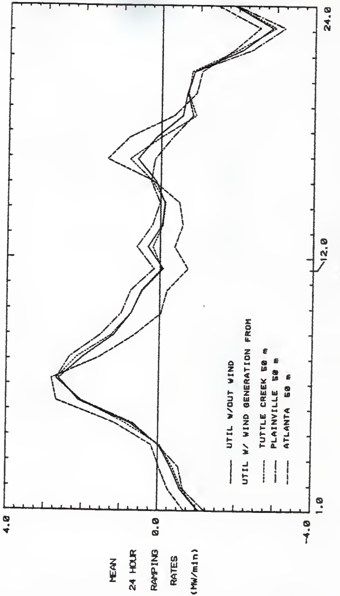


Figure 4.8. Utility 24 hour means after wind power injection.

ntility norm. Atlanta tends to make positive ramping increasingly positive, and varies on its effects to negative ramping. Plainville and Tnttle Creek also cansa the ntility to stray away from average operation, bnt have decreaaad effects as compared to those of Atlanta. In fact, Tnttle Creek at 50 m has very little impact on the average operation of tha ntility as seen in the plot of 24 hour mean rasnlts.

The 30 m 24 honr mean rasnlts compare directly to the distribntions for 30 m towers in that they all appear to act the same. This time, Wright pnlls away from the gronp by having a slightly higher peak ramp during the evening dinner honr, and by altering the shape of the morning pickup. Still thongh, the 30 m effects show to be most conaistent between sites.

Moving to tha standard deviations of the 24 honr resnlts (Fignre 4.9), in the 50 m oase, Atlanta again separates from Tnttle Creek and Plainvilla. Instead of having a complete increase in standard deviation, Atlanta's effect on the ntility canaes tha standard deviation to fall below that of the ntility norm dnring the honrs of 7 am to 1 pm. Tnttle Creek and Plainville however, canse ramping rates to deviata greater dnring this tima by 0.2 MW/min, and canse the ntility to maintain higher deviations for the entira 24 hour period. This is also tha case for all 30 m standard deviations, with the exception of Plainville which dips balow the unaffactad ntility for one hour.

For tha worst caaa minimums and maximums, all sites, both 30 and 50 m (Fignres 4.10 and 4.11), cansa greater extreme ramping caaas for most of their 24 honr periods. Also, an interesting

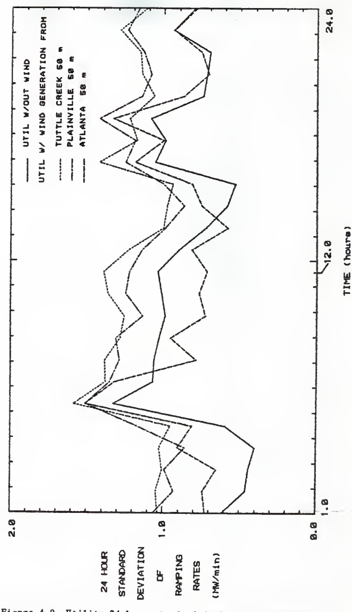


Figure 4.9. Utility 24 hour standard deviations after wind power injection.

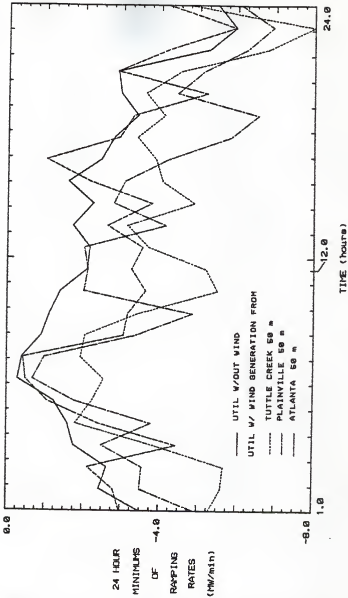


Figure 4.10. Utility 24 hour minimums after wind power injection.

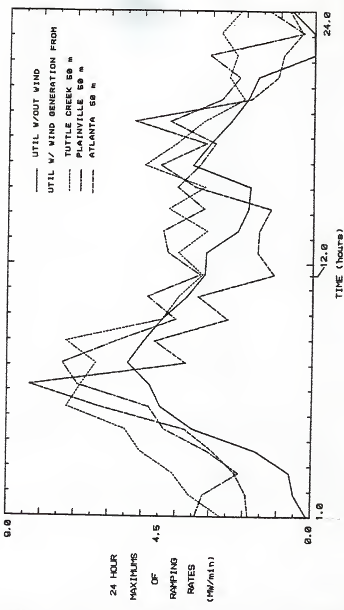


Figure 4.11. Utility 24 hour maximums after wind power injection.

outcome is seen in Atlanta's effect on the utility for the 24 hour maximums. Atlanta causes utility maximums to decrease again from 7 am to 1 pm, but during the morning and evening pickups, causes a higher extreme ramping case to occur, above even those of Plainville and Tuttle Creek. So, as seen earlier, Atlanta was an excellent site when the distributions were studied, but shows to have the greatest extreme ramping. This result is very possible since the distribution would most likely not register the few worst case conditions occurring at higher ramping rates.

Cut-In and Rated Wind Speed Control

For the cut-in and rated wind speed control results and all results to follow, a base core of sites and tower heights will be used. This is done to limit the number of test cases that must be run to analyze the results of wind power injection control. The sites to be used will be Tuttle Creek 50 m, Plainville 50 m, Atlanta 50 m, and Wright 30 m. It is important to note that only one 30 m tower will be used, since all 30 m towers for the various locations have relatively the same ramping characteristics as discused in the previous section.

Starting with the ramping distributions, it is seen that increasing u_c and u_r causes a proportional decrease in the ramping distributions for all sites (Figure 4.12). It would seem from this that higher u_c and u_r perform a filtering action for low wind speed cut-ins (which create a higher noise component). Atlanta (Figure 4.13) shows the same trend of a lower distribution for higher u_c and u_r, but as seen earlier, drops the utility

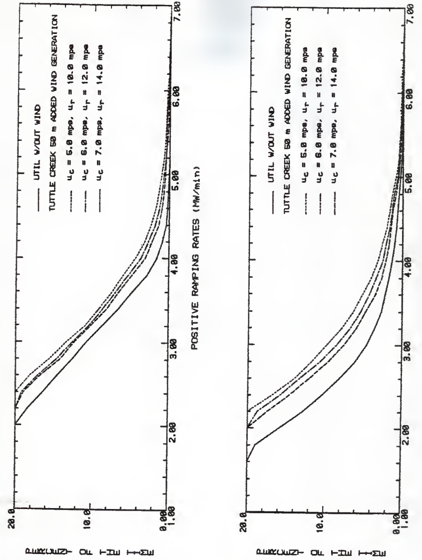


Figure 4.12. Utility ramping distributions after Tuttle Creek injection for three values of u_c and u_r.

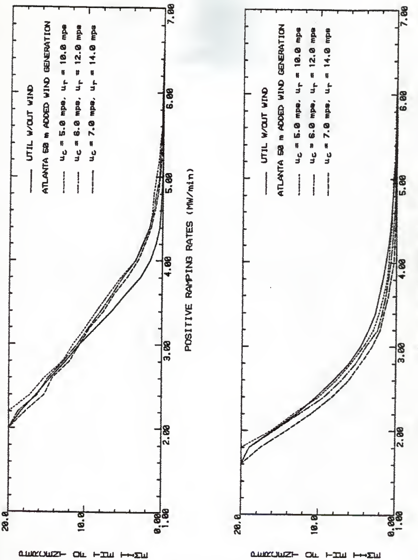


Figure 4.13. Utility ramping distribution after Atlanta injection for three values of u_c and u_r.

distribution below that of the unaffected ramping case.

For the average 24 hour day, changes in n_c and n_r do not create any visible trend. Injected wind power does alter the shape of the mean 24 hour curve, but as n_c and n_r are varied, the curves show no deviation from the standard parameter curve discussed under site control. However, the standard deviation to this mean curve (Figures 4.14 and 4.15) shows a definite trend of increased ramping deviation due to decreases in n_c and n_r. This trend is seen for all sites, and in the worst case for Tuttle Creek, increases the standard deviation by 0.5 MW/min during the morning pickup.

For the 24 hour minimums and maximums, all sites show the majority of ramping to be more severe. No real trend can be spotted for variations in n_c and n_r, while the injected wind power again shows its negative affect upon the utility worst case ramping conditions. An interesting effect is also noted at Atlanta, where the greatest worst case ramp of 8.5 MW/min occured. All other sites stayed well below the 8.0 MW/min level.

<u>Penetration Control</u>

As with the variation of n_c and n_r, the variation of penetration causes a dramatic trend to occur on the distribution of ramping rates. For all sites, as wind power penetration is increased, both negative and positive ramping distributions rise as a result. In fact, for the Tuttle Creek (Figures 4.16 and 4.17), Plainville, and Wright positive distributions, the change from zero to 15% wind penetration causes a 10% increase in observation of ramping rates greater than or equal to 2.0 MW/min, and

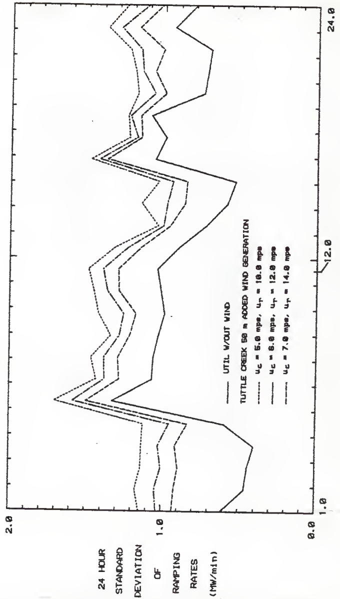


Figure 4.14. Utility 24 hour standard deviations after Tuttle Creek injection for three values of u_c and u_r.

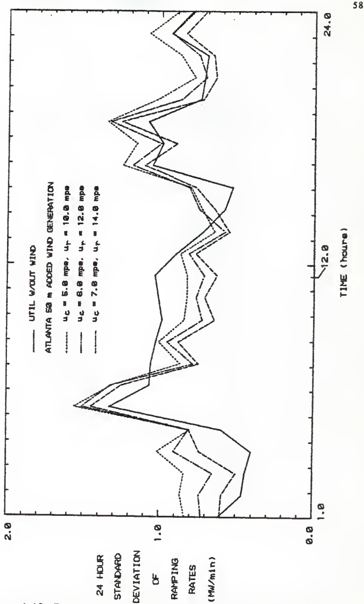


Figure 4.15. Utility 24 hour standard deviations after Atlanta injection for three values of u_c and u_r.

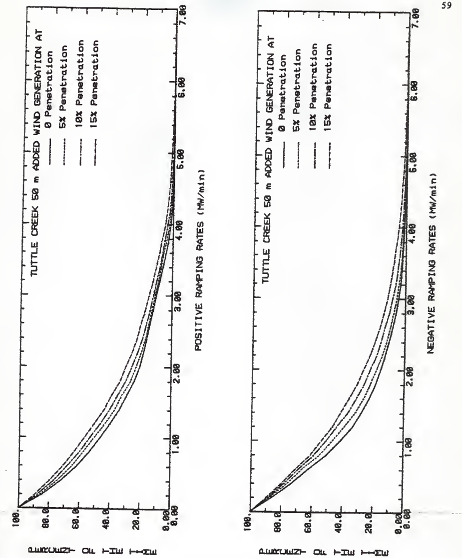
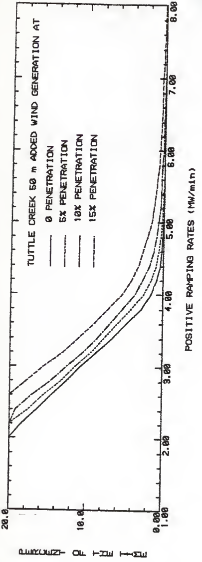


Figure 4.16. Utility ramping distributions after Tuttle Creek injection at three penetration levels.



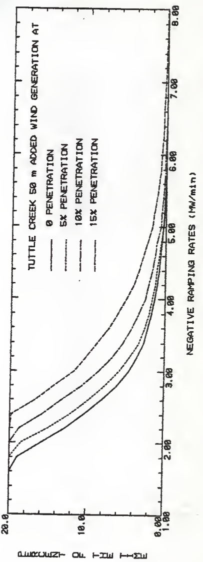


Figure 4.17. Blow up of Figure 4.16.

likewise for the negative distribution. Atlanta again has the feature of falling below the unaffected utility distribution, but for the positive distribution, moves entirely above for 3.0 MW/min or greater.

For the mean 24 hour day, all sites show no trend for increasing penetration. This would tend to show that the average value of wind power as calculated by 24 hour periodic sampling, is a constant, and is not dependent on the amplitude of the power production. From the 24 hour plots, note that even though there are no noticeable variations with respect to penetration, the injected wind power still causes the utility to deviate from its standard 24 hour mean profile.

As expected, increasing penetration, like the distributions, causes all around increases in the 24 hour standard deviation, with Atlanta and a few other rare cases showing values below the utility norm. As seen at Tuttle Creek, an increase from zero to 15% penetration causes the standard deviation to increase by 0.5 MW/min. Also, the minimums and maximums (Figure 4.19) had the same increasing trend, but showed most notice at the higher penetration levels of 10 and 15%. As an example, during the morning pickup for Atlanta, worst case ramping increased from the utility norm of 5.5 MW/min to 6.0 MW/min at 5% penetration, 8.25 MW/min at 10% penetration, and finally to just under 11.0 MW/min at 15% penetration. For minimum ramping, Tuttle Creek (Figure 4.18) had the worst impact causing a −10.5 MW/min ramp during the late evening fall off.

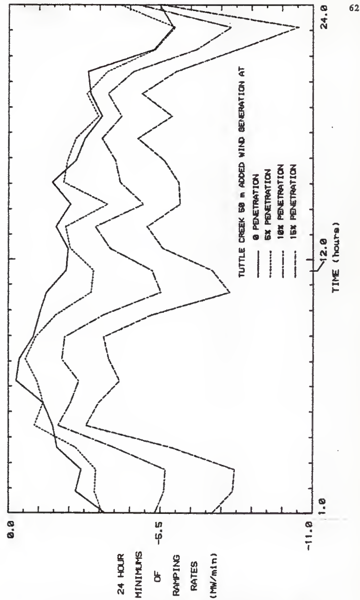


Figure 4.18. Utility 24 hour minimums after Tuttle Creek injection at three penetration levels.

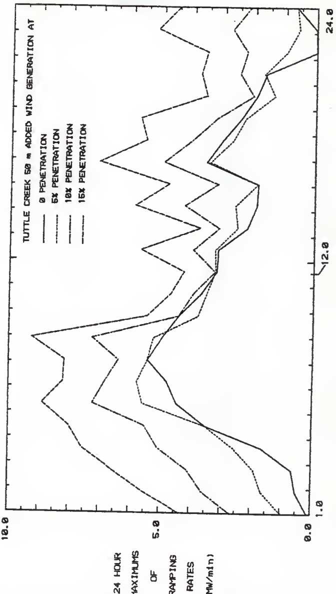


Figure 4.19. Utility 24 hour maximums after Tuttle Creek injection at three penetration levels.

<u>Upwards Ramping Control</u>

As noted in the procedures section, resultant utility power production is calculated by subtracting wind power from the Kansas load demand. Thus, when upwards wind power ramping is controlled, the main effect appears on cases of negative utility ramping. That is, the utility will decrease power output to allow wind power to assume more of the load. So, in looking at the distributions of the modified utility, inspection shows that indeed the postive ramping distribution remains unchanged, while the negative distribution shows a decreased trend with increasing amounts of control. The numerical value of control in MW/min will actually get less, but represents increased control. This trend (Figure 4.20) is observed for all sites, while Atlanta again begins to dip below the negative distribution for the utility norm at 2.0 MW/min.

As with the penetration variations, changes in control do not create trends in the average 24 hour day. These successive results would tend to show that the mean 24 hour day is a characteristic mainly of the site and not of wind power production methods. However, as seen in the standard deviation for the 24 hour results, increased control helps bring widely deviating wind induced ramps closer to those of the utility norm. This trend is seen for all sites, while Atlanta still shows signs of aiding utility ramping deviations from morning till noon.

For the minimum 24 hour ramps, a very beneficial trend develops. As control is increased, the worst case minimums of the utility affected by wind power begin to approach those of the

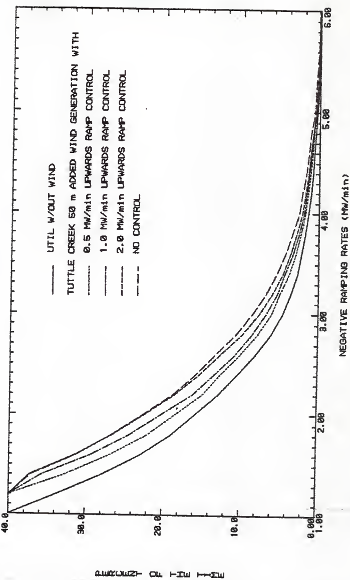


Figure 4.20. Negative utility ramping distribution after Tuttle Creek injection at three penetration levels.

ntility norm (Fignre 4.21). In fact, for the 0.5 MW/min control, all sites aid the ntility in worst case ramps for particnlar honrs. This wonld tend to be so sinoe wind power that picks np and adds to meet Kansas load demand, shonld canse the ntility to ramp with less intensity as long as the wind power is added at a steady rate. Another important effect that control has on the minimums is that of decreasing the spiked behavior of the worst casa ramps of the affected ntility. In easance, the control acts as a low ramping rate pass filter for negative ramping. The 24 honr maximnms however, show no avidant trends for change in control, and only in a few instanoas do the sites create slight deoreases in worst case ramping.

Now that the ramping characteristics for ramping oontrol have been addressed, a look at the percent energy loss dne to npwards ramping control can be made. For each site at 50 m (Fignre 4.22), it can be saen that this percent loss decreases from Tnttle Creek, to Plainville, to Atlanta, while at 30 m decreases from Tnttle Creek, to Plainville, to Wright, to Atlanta. For 0.5 MW/min control, Tnttle Creek shows the greatest percent energy loss of 18.0% at 50 m, while Wright 30 m gives the least amount of losa at 11.4%.

Wind Array Control (mnltiple farm)

As seen with npwards ramping control, the effect of added wind generation can be smoothed by limiting wind turbine ramping. Another method nsed to solve this problem, is that of mnltipla farm wind arrays, and for this discnssion, will be accomplished

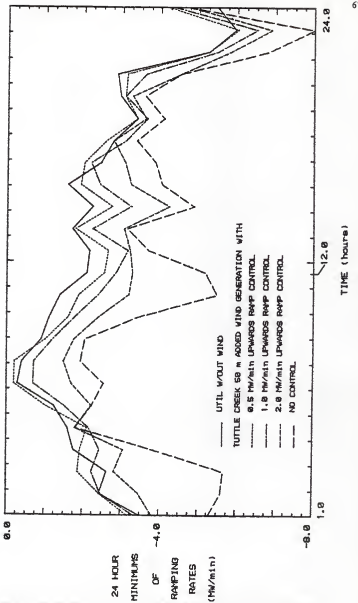
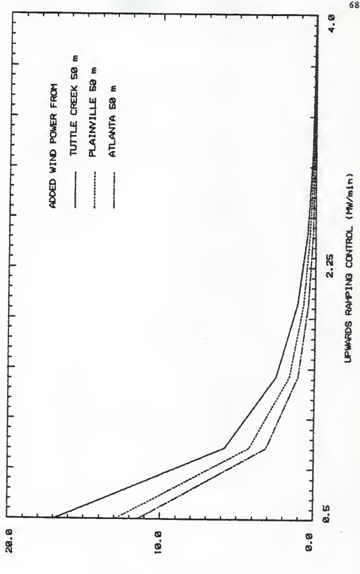


Figure 4.21. Utility 24 hour minimums after Tuttle Creek injection with three levels of control.



Fignre 4.22. Percent energy loss dne to control for 50m sites.

by using up to three sites for wind power production. The resultant effects caused by this injected wind power will be calculated and analyzed for a single site wind array at Tuttle Creek 30 m, a two site wind array consisting of Tuttle Creek and Wright 30 m, and a three site wind array consisting of Tuttle Creek, Wright, and Plainville 30 m. Note that 30 m sites are used in this analysis since no three site overlap is available for valid 50 m data.

Proceeding to the distribution results (Figures 4.23 and 4.24), the two site negative distribution begins to align with the utility norm around 3.75 MW/min, while the three site wind array actually falls below at this point, producing a much desired result. For the positive rates, at first the two and three site wind array effects follow the distribution of the single site effect, but fall off rapidly around 4.5 MW/min, and finally approach the unaffected utility distribution. Also, the three site wind array appears to fall to the utility norm much quicker than the two site array, thus showing that increasing the number of sites decreases the likelihood of experiencing higher ramps.

For the 24 hour means, as more sites are combined, aggregate Kansas wind regime characteristics become visible. These variations consist of minor modifications to the morning pickup, with a major increase in utility ramping needed during the evening pickup, when overall winds tend to decrease.

As seen earlier for ramping control, standard deviations of the 24 hour rates show significant decreases for two and three site wind arrays. For about five hours out of the day, the

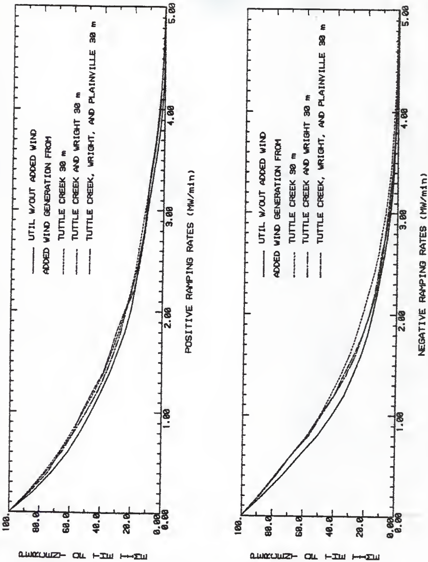


Figure 4.23. Utility ramping distributions after injected wind power from 1, 2, and 3 site wind arrays.

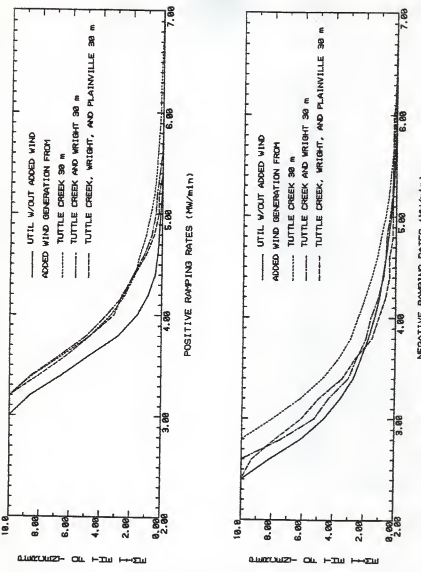


Figure 4.24. Blow up of Figure 4.23.

deviation is shown to fall jnst below that of the nnaffected ntility, and in only one case, the evening picknp, increases the standard deviation. This increase in deviation wonld tend to snpport the idea that in terma of the aggregate Kansas wind regime, winds fall off fairly rapidly dnring the early evening hours.

Proceeding to the 24 hour minimnma (Fignre 4.25), almost all honrs show aid to the ntility for three site injection, while increasing the nnmber of sites greatly decreases worst case effects dne to a single site injection. This also happens with the maximnma (Fignre 4.26), bnt aid to the ntility only occnrs abont half the time for the three site array, and one third of the time for the two site array. The two and three site wind arrays also smooth the spiked behavior of worst case ramping conditions as seen for a single site injection.

In terms of percent energy loss, as the nnmber of sites in an array increaaes, the energy loss dne to npwards ramping control decreases. As seen on the plot of percent energy lost versns control (Fignre 4.27) for a three site array, percent loss drops below 5.0% for 0.5 MW/min control, and below 1.0% for 1 MW/min control. So, as wind power ramping becomes smoothed by mnltiple farms, leaa power is lost to control.

Aggregate Control Example

This example shows that if beneficial parameters for sites (wind array aize, n_c and n_r, ramping control) are chosen, that higher penetration effects can be made to match those of a lower

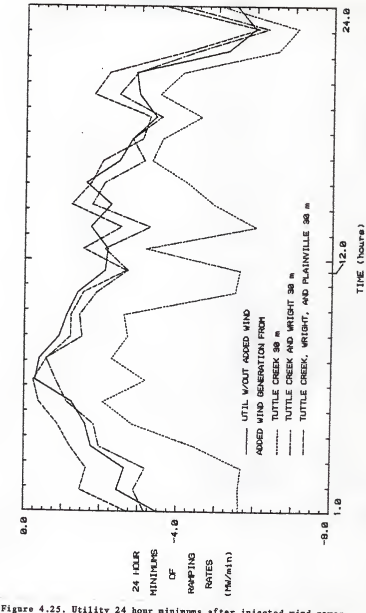


Figure 4.25. Utility 24 hour minimums after injected wind power from 1, 2, and 3 site wind arrays.

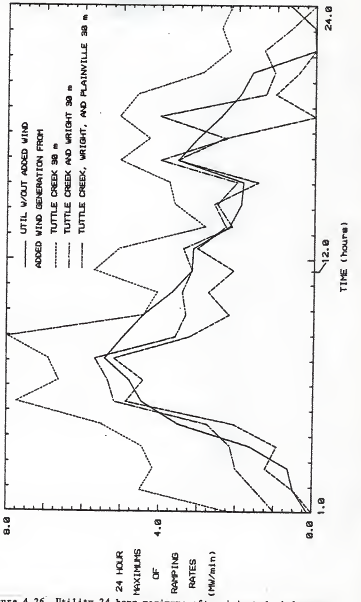


Figure 4.26. Utility 24 hour maximums after injected wind power from 1, 2, and 3 site wind arrays.

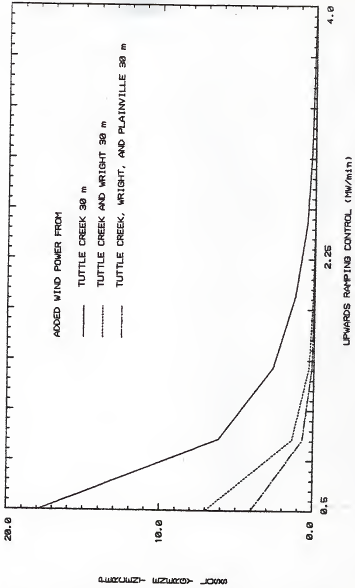


Figure 4.27. Percent energy loss due to control on 1, 2, and 3 site wind arrays.

penetration level. To show this effect, the control model will consist of a three site wind array containing Tuttle Creek, Wright, and Plainville 30 m, all with u_c = 7 mps and u_r = 14 mps, at 15% wind array penetration, and finally having 1.0 MW/min ramping control. The results from this case will be compared against three other test cases:

1. Tuttle Creek 30 m, u_c = 5 mps, u_r = 10 mps, no control, and 5% penetration.
2. Utility without any added wind generation.
3. Tuttle Creek 30 m, u_c = 7 mps, u_r = 14 mps, no control, and 15% penetration.

Beginning with the positive ramping distribution, it is seen that the three site smoothing effect starts to occur around 4.0 to 5.0 MW/min, and causes the affected distribution to approach the utility norm and the 5% penetration case before reaching 5.2 MW/min. Earlier in the distribution, the control model was well above all other cases, but proves to be satisfactory as long as it decreases before reaching higher ramping conditions.

For the negative distribution, the control example homes in much quicker to the utility norm around 4.0 MW/min, and shows to be a beneficial power source after this point. This trend was also seen under the ramping control, and so must be a combined smoothing effect from the three site array and upwards ramping control.

As seen earlier, the 24 hour means show the difference between a single site characteristic and that of the aggregate Kansas wind regime. Also, aggregate injection again causes the utility to deviate further from the utility norm during evening pickup. Likewise, the standard deviation for the control model shows the aggregate effect by going above all cases dnring the evening pickup. However, for most hours the control model shows aid to the utility, and results in following the 5% penetration case closely.

Continuing with 24 hour minimums and maximums, it is found that both are bronght under control. In fact, the control model shows aid to the utility minimums for over half of the worst oase 24 hour day. Thus, the minimums have now been brought down to a reasonable level which can be dealt with by the ntility. The maximums (Figure 4.28) are affected in the same way as the minimums, showing only two cases of going slightly above the 5% penetration maximums.

Finally, an important note shond be made regarding upwards ramping control. Since this type of control was incorporated, there will be a detremental effect to the efficiency of produced wind generation. However, when all power loss dne to npwards ramping control is summed and divided by the total power production, it is found that for this example with 1.0 MW/min ramping control, only 2.01% of the total energy production was lost.

Correlation

To conclude the Results and Discussion, a study of wind and utility power correlation will be addressed. First, ntility and wind power autocorrelations will be discussed to observe the components of correlation that each has individually. Then, the

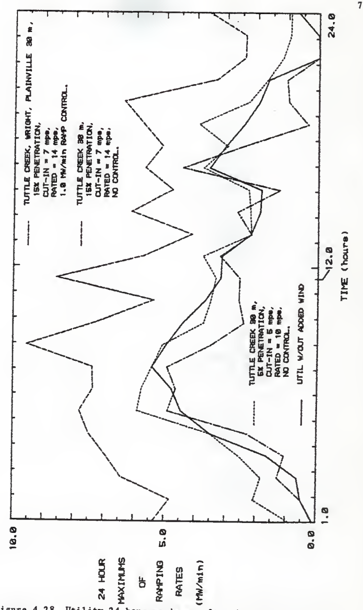


Figure 4.28. Utility 24 hour maximums after injection of wind power from aggregate control example.

crosscorrelation of the utility power with various sites of standard power production parameters will be analyzed for trends and patterns. All of the correlation plots generated for this analysis have a maximum time shift of one week (168 hours) in both the positive and the negative direction. This will not allow detection of any trends that might occur beyond a one week time shift.

<u>Autocorrelation</u>

Beginning with the utility autocorrelation, it is seen that all correlation values for increasing time shift are positive. This is an interesting phenomena, but turns out to be a trivial subsequence of the zero mean data set. Since the time shift for the autocorrelation has a maximum shift of one week, the values will stay positive due to a lower frequency component (that of seasonal variation, see Figure 3.10). Thus, a time shift of 3 months or greater would be needed to show the seasonal variation within the autocorrelation. However, disregarding the positive nature of these values, it is seen that the main component appearing is that of the 24 hour diurnal nature of Kansas load demand. In addition, the weekly demand cycle can also be seen as the curve maximums dip during midweek time shift, and rise for zero and one week time shifts.

Next, the wind power autocorrelation for both Tuttle Creek and Plainville shows more of the random result that would be expected of power produced from wind. As seen in the plots for these two sites, both have the dramatic peak which occurs at zero time shift for autocorrelations of a random nature. However, it is also seen that wind is not completely random (gradual drop from 100% correlation), and has 80% correlation at time shifts of ± 2 hours. Thus, the autocorrelation shows that variation in winds must occur over higher time periods since correlation is still around 20% for even a daily shift. This is valuable information, and is discussed in Data Validation. Finally, the four to five day frontal cycle is evident in the lower frequency component that begins to show two days from zero time shift. Notice that between Tuttle Creek and Plainville, the frequency of this component is relatively the same, but shows to have very dissimilar waveforms.

Crosscorrelation

Crosscorrelations are computed for all sites, and help to show how a particular site correlates with the Kansas load demand. Note that all of the results from this calculation have waveforms which consist of very small correlation values. This should be the case since wind as noted before is a relatively random signal and will have low correlation with the demand of Kansas people and industry. However, of more importance is the shape that the correlation waveform takes as time shift is increased.

Beginning with Tuttle Creek, the crosscorrelation shows that both Tuttle Creek and the utility have a good 24 hour correlation component. Also, if the wind profile were shifted back in time by three hours (later wind speeds occurring three hours earlier), then the 24 hour componenet would overlap exactly, and cause the peak close to the center of the plot to indeed occur at the center.

Plainville on the other hand, has a greater time shift till overlap of the diurnal cycles. The plot for this crosscorrelation shows Plainville needing a six hour time shift to align the 24 hour cycle of the wind with that of the utility. Note that in this plot, the 24 hour cycle is not as smooth as that for Tuttle Creek, and would thus indicate that Plainville does not follow the diurnal cycle as readily as Tuttle Creek.

Moving to Atlanta, its crosscorrelation with the utility appears to be similar to that of Plainville (not as smooth a diurnal correlation as Tuttle Creek), but shows a much greater time shift of 12 hours until the 24 hour cycle has a peak in correlation. This tends to indicate that Atlanta wind speeds vary 180 degrees out of phase with the utility, and have some form of a nocturnal jet.

Completing the single site crosscorrelations, Wright like Tuttle Creek shows close correlation with the utility 24 hour cycle. However, it is seen that at the peak of this correlation, Wright takes a slight dip in the correlation waveform for all 24 multiples of time shift. This could be a characteristic of Wright itself, or as with Atlanta, could be a circumstance of the incomplete data set used in this analysis. Whatever the case, Wright's crosscorrelation plot shows decreasing wind power when the utility is at its peak power production for the day.

Finally, to complete the crosscorrelation analysis, multiple site wind arrays are used to correlate with the utility. As seen for a two site wind array (Tuttle Creek and Plainville 50 m), the 24 hour correlation cycles start to fade, but show a four hour time shift from zero to peak the crosscorrelation. For the three site wind array (Tuttle Creek, Wright, and Plainville 30 m), the 24 hour cycle fades even more and now is hardly recognizable. From this, it is noted that increasing the number of sites decreases the diurnal correlation between utility and wind array, thus causing the data sets to tend toward independence in this area.

CHAPTER V

CONCLUSIONS AND RECOMMENDATIONS

From the results and discussion of ramping effects and correlation analysis given in the previous chapter, the following conclusions and recommendations are made.

1. All sites used in this study show detrimental effects to the utility in some way, shape, or form. However, at the 50 m level, Tuttle Creek and Plainville prove to be better sites since Atlanta showed to have the most severe worst case ramping conditions of the three sites. At 30 m, all sites behave relatively the same, thus giving no best case condition.

2. Since results for all sites showed lowering of the ramping distributions for increases in u_c and u_r, for the options used, u_c = 7.0 mps and u_r = 14.0 mps would be recommended. Even though this selection decreases total wind energy production, its main advantage is in decreasing excessive ramping due to low wind speed cut in.

3. In recaping previous results, it was noted that as different sites were added to the utility, that each site created a modified version of the utility's average 24 hour day. However, as seen in later results, as u_c and u_r, penetration, and ramping control were varied, no noticeable trends varied from these modified versions. This would support the conclusion that the mean 24 hour averages are functions of site and not of parameters

used to vary the means of wind power production.

4. As expected, increasing penetration causes a proportional increase in ramping deviations and worst case minimums and maximums. However, as seen in the aggregate control example, a wind array of three sites with 15% penetration can have relatively the same impact as that of a 5% single site case, if control parameters are chosen correctly.

5. Since increasing ramping control causes the affected negative utility distribution to come closer to the utility norm, ramping control is recommended. Even though this might consist of a complex network, such control would benefit utility operation. A typical value for this thesis which gives good control and minimal power loss is 1.0 MW/min.

6. In terms of the number of sites in a wind array, two or more sites per array is suggested to smooth the effects of injected wind power. Even though the aggregate wind array showed results of producing an increase in the evening pickup for 24 hour means, this is of little importance as compared to the resultant decrease in worst case minimums and maximums to the level of the utility norm. Thus, multiple site farms do change the average operation of the utility, but offer large benefits in terms of worst case ramping.

7. For the correlation, it is noted that wind power and Kansas load demand do show a correlative component on the diurnal cycle. Even though the correlation values are small this correlation

pattern is still very evident. Tuttle Creek and Plainville have the closest correlation with Kansas load demand, while Atlanta tends to be 12 honrs ont of correlation.

8. Finally, as more sites are added into a wind array, the 24 honr correlation cycle decreases, and as seen in a three site correlation with the ntility, is hardly recognizable. This re- snlt shows that wind power snd Kansas load demand become increas- ingly independent in terms of diurnal correlation as the number of sites increases.

From these conclnsions and recommendations, it can be seen that the negative effect of added wind generation can be redneced to controllable levels. To completely see the benefit of wind power however, these effects wonld have to be incorporated into a stndy on the benefits and cost of snch wind power production, which lies beyond the scope of this thesis. Finally, to verify the results for Atlanta 50 m, a follow up stndy is recommended for the years 1981 to 1983, when adequate utility data has become svailable.

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12. Dr. Gary L. Johnson, Kansas Wind Resource Assessment, July 1980 - June 1982, August 1982, Department of Electrical Engineering, Kansas State University.

APPENDIX A

RAMP3 PROGRAM LISTING

```
C*******************************************************************************
C
C       COMBINED RAMPING RATE CALCULATION ROUTINE
C
C       DG FORTRAN 5 SOURCE FILENAME:           RAMP3.FR
C
C       DEPARTMENT OF ELECTRICAL ENGINEERING    KANSAS STATE UNIVERSITY
C
C       REVISION        DATE                    PROGRAMMER
C       --------        ----                    ----------
C       00.0            JULY 10, 1984           CHRISTOPHER DUFFEY
C
C*******************************************************************************
C
C       PURPOSE
C
C               THIS ROUTINE CALCULATES RAMPING RATES FOR UTILITY DATA
C               THAT HAS BEEN INJECTED WITH WIND POWER,
C               CALCULATED THROUGH A WIND POWER PRODUCTION MODEL.
C
C       ROUTINE(S) CALLED BY THIS ROUTINE
C
C               VMEM - DG SYSTEM CALL
C               MAPDF - DG SYSTEM CALL
C               CHECK - DG SYSTEM CALL
C               VDUMP - DG SYSTEM CALL
C               VLOAD - DG SYSTEM CALL
C               ISTASH - STORE EXTENDED INTEGER VALUE ROUTINE
C               IEXTD - RECALL EXTENDED INTEGER VALUE ROUTINE
C               RINPUT - REAL VARIABLE PROMPT ROUTINE
C               IINPUT - INTEGER VARIABLE PROMPT ROUTINE
C               HNAME - HFILE FILENAME GENERATION ROUTINE
C               STAT - DG SYSTEM CALL
C               OPEN - DG SYSTEM CALL
C               READRW - DG SYSTEM CALL
C               CLOSE - DG SYSTEM CALL
C               REPLY - UTILITY LIBRARY CALL
C               OPENW - UTILITY LIBRARY CALL
C               OPENR - UTILITY LIBRARY CALL
C               RESET - DG SYSTEM CALL
C
C*******************************************************************************
C
C       NOTE 1: This routine uses extended memory to perform calculations.
C               For more information, refer to the subroutines ISTASH and
C               IEXTD.  Also, refer to the DATA GENERAL FORTRAN 5 PROGRAMMER'S
C               GUIDE, RDOS, starting on page II-21-1.
C
C       NOTE 2: To run this routine properly, the NOVA computer must be
C               partitioned in the following manner.
C
C                       Execute these commands from the background,
C                       while in the RDOS directory DPOF.
C
C                               CNTRL-F
C                               SMEM 7 (CR)
C                               EXFG/E CLI (CR)
```

```
C
C      NOTE 3: To patch this routine for operation on different consecutive
C              years of demand data, use the patch variables IYBEG and IYEND.
C              These variables represent the years of data to be analyzed,
C              and are represented as follows.
C
C                              1 = 1980
C                              2 = 1981
C                              3 = 1982
C                              4 = 1983
C
C      NOTE 4: Noting that for days of the week Sat=1, Sun=2, ..., Fri=7,
C              the start days of the years 1980, 81, 82, 83 are
C              respectively 4, 6, 7, 1.
C
C*****************************************************************************

C*** COMMON DECLARATION USED IN EXTENDED MEMORY ALLOCATION

      COMMON  WINDOW(1024)

C*** VARIABLE DECLARATIONS

      LOGICAL   ANS                         ;USER REPLY
      LOGICAL   DEBUG                       ;ROUTINE DEBUGGER FLAG
      LOGICAL   ANSWER                      ;USER REPLY
      LOGICAL   NODAT                       ;DATA EXISTANCE FLAG
      LOGICAL   WSKIP                       ;SKIP WIND DATA FLAG
      LOGICAL   RCNTRL                      ;RAMP CONTROL FLAG
      REAL   SUMR(24)/24*0.0/               ;SUM OF RAMPING RATES
      REAL   SUMRSQ(24)/24*0.0/             ;SUM OF SQUARED RAMPING RATES
      REAL   RMAX(24)/24*-999.0/            ;MAX RAMPING RATES
      REAL   RMIN(24)/24*999.0/             ;MIN RAMPING RATES
      REAL   STNDV(24)/24*0.0/              ;STND DEV OF RAMPING RATES
      REAL   MEAN(24)/24*0.0/               ;MEAN OF RAMPING RATES
      REAL   DATA(744)/744*0.0/             ;DATA FOR 1 MONTH, LOC, TOWER
      REAL   INFO(744)/744*0.0/             ;INFORMATION HEADER
      REAL   RCNT(24)/24*0.0/               ;REAL COUNTER FOR CALCULATIONS
      REAL   RLOOP                          ;REAL LOOP PARAMETER
      REAL   RLOC                           ;REAL MEM LOCATION FOR TEST
      REAL   RAMP                           ;RAMP RATE FOR 1 HR (MW/MIN)
      REAL   RDAY                           ;NUMBER OF CALCULATED DAYS
      REAL   WEND , WDAY                    ;WEEKEND, WEEKDAY HOUR TOTALS
      REAL   RWEEK                          ;NUMBER OF WEEKS IN PERIOD
      REAL   RHOUR                          ;NUMBER OF CALCULATED HOURS
      REAL   SQSUMR                         ;SQUARE OF RAMPING SUMMATION
      REAL   SIZE                           ;RETURNED SIZE IN BYTES
      REAL   PWR                            ;CALCULATED WINDPOWER
      REAL   UC                             ;CUT-IN WINDSPEED
      REAL   UR                             ;RATED WIND SPEED
      REAL   RTOWER                         ;50 OR 30 METER DATA
      REAL   RLOCAT                         ;SITE LOCATION NUMBER
      REAL   FRAC                           ;FRACTION OF WIND POWER
      REAL   RLOOP1                         ;REAL LOOP PARAMETER
      REAL   CPWR                           ;COMBINED POWER EFFECTS
      REAL   RATED                          ;RATED WINDFARM OUTPUT (MW)
      REAL   WPLOSS                         ;SUM OF LOST WIND POWER
```

```
      REAL   CNT                                    ;COUNTER FOR GOOD DATA
      REAL   WPSUM                                  ;TOTAL WIND POWER PROD
      REAL   MAXRAMP                                ;MAXIMUM CONTROL RAMPING
      REAL   CUTINWS(8)/8*0.0/                      ;CUT-IN WINDSPEEDS
      REAL   RATEDWS(8)/8*0.0/                      ;RATED WINDSPEEDS
      REAL   NSUM(51)/51*0.0/                       ;NEG RAMPING HIST SUMS
      REAL   PSUM(51)/51*0.0/                       ;POS RAMPING HIST SUMS
      REAL   NRES(51)/51*0.0/                       ;NEG DISTRIBUTION % RESULTS
      REAL   PRES(51)/51*0.0/                       ;POS DISTRIBUTION % RESULTS
      REAL   LLIMIT                                 ;LOWER BIN LIMIT (HIST)
      REAL   ULIMIT                                 ;UPPER BIN LIMIT (HIST)
      REAL   PCNT                                   ;# OF POS RAMP RATES
      REAL   NCNT                                   ;# OF NEG RAMP RATES
      REAL   TRAMP                                  ;TEMP -RAMP
      REAL   RATE1 , RATE2                          ;PRINT OUT RAMP RATES
      REAL   FRACTION(8)/8*0.0/                     ;FRACTION OF FARM POWER
      INTEGER   MNUM(4,12)/48*0/                    ;DAYS IN EACH MONTH
      INTEGER   IYBEG , IYEND                       ;YEAR LOOP PARAMETERS
      INTEGER   NUMDAY                              ;NUMBER OF TOTAL CRUNCH DAYS
      INTEGER   IDAY , IMONTH                       ;LOOP PARAMETERS
      INTEGER   IHOUR , IYEAR                       ;LOOP PARAMETERS
      INTEGER   PWR1 , PWR2                         ;TWO CONSEC HOUR POWERS X100
      INTEGER   PDIFF                               ;ENERGY DIFFERENCE (MW X100)
      INTEGER   N(12)/12*0/                         ;TOTAL HOURS/MONTH FOR 3 YEARS
      INTEGER   SDOY(4)/4,6,7,1/                    ;START DAY OF YEAR 80,81,82,83
      INTEGER   WEEK                                ;NUMBER OF WEEKS IN PERIOD
      INTEGER   IWK                                 ;LOOP VARIABLE FOR WEEK
      INTEGER   BCNT                                ;RETURNED BLOCK COUNT
      INTEGER   IREC                                ;RECORD NUMBER FOR DATA
      INTEGER   IPWR                                ;INTEG VAL OF WIND POWER X100
      INTEGER   ICHK(18)                            ;STATUS VARIABLE
      INTEGER   IPARM                               ;LOOP PARAMETER
      INTEGER   NPWR2                               ;NEW PWR2 FROM RAMP CONTROL
      INTEGER   NUMSITE                             ;NUMBER OF SITES
      INTEGER   SITE(8)/8*0/                        ;SITE NUMBERS
      INTEGER   TOWER(8)/8*0/                       ;TOWER HEIGHTS
      INTEGER   I , J                               ;LOOP PARAMETERS
      INTEGER   LOAD1 , LOAD2                       ;TWO CONSECUTIVE LOADS
      DOUBLE PRECISION COMPLEX   FILNAM             ;H-FILE DATA FILENAME

C*** VARIABLE INITIALIZATIONS

      IYBEG  = 1
      IYEND  = 3
      DEBUG  = .FALSE.
      ANSWER = .FALSE.

C*** INITIALIZE EXTENDED MEMORY FOR REAL (4-BYTE) VARIABLE SIZE

      CALL VMEM  (ICNT , IERR)
      CALL MAPDF (ICNT+2 , WINDOW , 2 , IERR)
      CALL CHECK (IERR)
      CALL MAPDF (2 , IERR)
      CALL CHECK (IERR)

C*** INITIALIZE DAYS IN MONTH ARRAY (FOR I, 1=80,2=81,3=82,4=83)
```

```
      DO 10 I = 1 , 4
          MNUM(I,1) = 31
          MNUM(I,2) = 28
          MNUM(I,3) = 31
          MNUM(I,4) = 30
          MNUM(I,5) = 31
          MNUM(I,6) = 30
          MNUM(I,7) = 31
          MNUM(I,8) = 31
          MNUM(I,9) = 30
          MNUM(I,10) = 31
          MNUM(I,11) = 30
          MNUM(I,12) = 31
10    CONTINUE

C*** ACCOUNT FOR LEAP YEAR (1980)

          MNUM(1,2) = 29

C*** ASK USER FOR DEBUGGING OPTION AND EXT MEM LOAD

      CALL REPLY ("DEBUG ? (YES/NO) " , DEBUG)
      CALL REPLY ("SKIP AVE CALCULATIONS ? (YES/NO) " , WSKIP)
      CALL REPLY ("LOAD EXT MEM FROM DISK ? (YES/NO) " , ANSWER)
      IF (.NOT. ANSWER) GO TO 14

C*** LOAD IN AN EXTENDED MEMORY FILE

      CALL OPENR (3 , "INPUT FILE ? " , 0 , SIZE)
      CALL VLOAD (3 , BCNT , IERR)
      CALL CLOSE (3 , IERR)
14    CONTINUE

C*** INITIALIZE THE NUMBER OF DAYS TO BE USED IN CALCULATIONS

      NUMDAY = 0
      DO 17 I = IYBEG , IYEND
         DO 15 J = 1 , 12
             NUMDAY = NUMDAY + MNUM(I,J)
15       CONTINUE
17    CONTINUE

C*** INITIALIZE THE 2ND HALF OF EXTENDED MEMORY WITH 0'S

      TYPE " "
      TYPE "INITIALIZING 2ND HALF OF EXTENDED MEMORY"
      RLOOP = 26500.0
      DO 13 I = 1 , NUMDAY * 24 + 1
         RLOOP = RLOOP + 1.0
         CALL ISTASH (0 , RLOOP)
13    CONTINUE

C*** READ IN THE WIND DATA FOR THE GIVEN SITE, AND
C*** STORE THE CALCULATED POWER IN EXTENDED MEMORY
C
C*** PROMPT THE USER FOR INFORMATION
```

```
      NUMSITE = 0
      TYPE " "
      CALL RINPUT (RATED , 15 , "RATED WINDFARM POWER OUTPUT ? ")
      TYPE " "
      CALL REPLY ("PERFORM RAMPING CONTROL ? (YES/NO) " , RCNTRL)
      IF (.NOT.RCNTRL) GO TO 7
      CALL RINPUT (MAXRAMP , 14 , "MAX RAMPING RATE ? (MW/MIN) ")
7     TYPE " "
16    CALL RINPUT (RLOCAT , 6 , "LOCATION ?  ")
      CALL RINPUT (RTOWER , 9 , "30 OR 50 METER ?  ")
21    CALL RINPUT (UC , 10 , "CUT-IN WIND SPEED ? ")
      CALL RINPUT (UR , 10 , "RATED WIND SPEED ?  ")
      CALL RINPUT (FRAC , 19 , "FRACTION OF TOTAL POWER PRODUCTION ?  ")
      TYPE " "
      NUMSITE = NUMSITE + 1
      SITE(NUMSITE) = IFIX(RLOCAT)
      TOWER(NUMSITE) = IFIX(RTOWER)
      CUTINWS(NUMSITE) = UC
      RATEDWS(NUMSITE) = UR
      FRACTION(NUMSITE) = FRAC

      RLOOP = 26500.0
      NODAT = .TRUE.

      DO 50 IYEAR = IYBEG , IYEND
         DO 40 IMONTH = 1 , 12
            CALL HNAME (IMONTH , IYEAR , FILNAM)

C*** CHECK FOR DEBUG - FILENAME CHECK

            IF(.NOT. DEBUG) GO TO 19
            WRITE(10,18) FILNAM
18          FORMAT(A16)
19          CONTINUE

C*** CHECK FOR FILE EXISTANCE

            CALL STAT (FILNAM , ICHK , IERR)
            IF (IERR .EQ. 13) GO TO 30

C*** THIS FILE EXISTS, READ IN THE INFORMATION HEADER FOR THE FILE

            CALL OPEN (3 , FILNAM , 2 , 2976 , IERR)
            CALL READRW (3 , 1 , INFO , 1 , IERR)

C*** SEARCH FOR DATA

            I = 1
            IREC = 2

20          CONTINUE
            IF(INFO(I) .GT. 90.0) GO TO 28
            IF((INFO(I).NE.RLOCAT) .OR. (INFO(I+1).NE.RTOWER)) GO TO 25

C*** DATA HAS BEEN FOUND FOR THIS MONTH, YEAR, LOCATION, AND TOWER

            TYPE "DATA FOUND FOR" , IMONTH , IYEAR+79
```

```
              IF (DEBUG) TYPE "START LOCATION = " , RLOOP+1.0
              NODAT = .FALSE.
              CALL READRW (3 , IREC , DATA , 1 , IERR)
              GO TO 35
25            CONTINUE
              IREC = IREC + 1
              I = I + 2
              GO TO 20

C*** NO DATA FOUND

28            CONTINUE
              TYPE "NO DATA FOR " , IMONTH , IYEAR+79
              NODAT = .TRUE.
              GO TO 35

C*** NO FILE FOUND

30            CONTINUE
              TYPE "NO FILE FOR " , IMONTH , IYEAR+79
              NODAT = .TRUE.

C*** CALCULATE THE ELECTRIC WIND POWER AND STORE IN EXTENDED MEMORY

35            CONTINUE
              DO 38 IHOUR = 1 , MNUM(IYEAR,IMONTH)*24
                 IF(DATA(IHOUR) .LT. UC) PWR = 0.0
                 IF(DATA(IHOUR) .GT. UR) PWR = RATED * FRAC
                 IF((DATA(IHOUR).GT.UR) .OR. (DATA(IHOUR).LT.UC)) GO TO 37
                 PWR = RATED / (UR - UC) * (DATA(IHOUR) - UC) * FRAC
37               CONTINUE
                 IF(DATA(IHOUR) .GT. 90.0) PWR = 3200.0
                 IF(NODAT) PWR = 3200.0
                 RLOOP = RLOOP + 1.0

C*** THE POWER TIMES 10 IS STORED TO MAINTAIN ACCURACY

                 IPWR = IFIX(PWR*10.0)
                 IF (IPWR .GT. 30000) GO TO 39
                 IPWR = IPWR + IEXTD(RLOOP)
39               CALL ISTASH (IPWR , RLOOP)
38            CONTINUE
              CALL CLOSE (3 , IERR)
40         CONTINUE
50      CONTINUE

        CALL REPLY ("ADD ANOTHER LOCATION ? (YES/NO) " , ANS)
        IF (ANS) GO TO 16

C*** CHECK FOR DEBUG - MEMORY TEST

55      IF (.NOT.DEBUG) GO TO 78
        CALL REPLY ("MEM TEST ? (YES/NO) " , ANSWER)
        IF(.NOT.ANSWER) GO TO 78
60      CALL RINPUT (RLOC , 12 , "REAL LOC FOR MEM TEST ? ")
        IGET = IEXTD (RLOC)
        WRITE (10,70) RLOC , IGET
```

```
70      FORMAT ("MEM LOC (",F7.0,") HAS THE VALUE ---> ",I7)
C*** PROMPT USER FOR CHANGE OF VALUE

        CALL REPLY ("CHANGE THIS MEM LOC ? (YES/NO) " , ANSWER)
        IF (.NOT. ANSWER) GO TO 75
        CALL IINPUT (IGET , 10 , "THE NEW VALUE IS ?  ")
        CALL ISTASH (IGET , RLOC)
75      CONTINUE

        CALL REPLY ("RUN AGAIN ? (YES/NO) " , ANSWER)
        IF (ANSWER) GO TO 60

C*** PROMPT USER TO DUMP EXTENDED MEMORY TO DISK

78      CALL REPLY ("DUMP EXT MEM TO DISK ? (YES/NO) " , ANSWER)
        IF (.NOT. ANSWER) GO TO 80
        CALL OPENW (3 , "OUTPUT FILENAME FOR MEM DUMP ? " , 0 , SIZE)
        CALL VDUMP (3 , BCNT , IERR)
        CALL CLOSE (3 , IERR)
80      CONTINUE

C*** UPWARDS RAMPING CONTROL ALGORITHM

        IF (.NOT. RCNTRL) GO TO 53

        TYPE " "
        TYPE "PERFORMING RAMP CONTROL"
        WPLOSS = 0.0
        CNT = 0.0
        RLOOP = 26500.0
        WPSUM = 0.0
        IF (IEXTD(26501.0).LT.30000) WPSUM = FLOAT(IEXTD (26501.0))/10.0

        DO 52 IPARM = 1 , NUMDAY*24
            RLOOP = RLOOP + 1.0
            PWR1 = IEXTD (RLOOP)
            PWR2 = IEXTD (RLOOP + 1.0)
            IF (PWR2.LT.30000) WPSUM = WPSUM + FLOAT(PWR2)/10.0
            IF (PWR2.LT.30000) CNT = CNT + 1.0
            IF ((PWR1.GT.30000).OR.(PWR2.GT.30000)) GO TO 52
            PDIFF = PWR2 - PWR1
            RAMP = FLOAT(PDIFF)/600.0
            IF (RAMP.LE.MAXRAMP) GO TO 52
            NEWR2 = PWR1 + IFIX(MAXRAMP*600.0)
            CALL ISTASH (NEWR2 , RLOOP+1.0)
            WPLOSS = WPLOSS + FLOAT(PWR2-NEWR2)/10.0
            IF ((PWR2-NEWR2).LT.0) TYPE "RAMP CONTROL LOGIC ERROR"
52      CONTINUE
53      CONTINUE

C*** CALCULATE COMBINED POWER PRODUCTION

        TYPE " "
        TYPE "COMBINING WITH UTILITY POWER DATA"
        RLOOP1 = 0.0
        RLOOP  = 26500.0
```

```
      DO 84 IYEAR = IYBEG , IYEND
         DO 83 IMONTH = 1 , 12
            DO 82 IDAY = 1 , MNUM(IYEAR , IMONTH)
               DO 81 IHOUR = 1 , 24
                  RLOOP1 = RLOOP1 + 1.0
                  RLOOP  = RLOOP  + 1.0
                  CPWR = FLOAT(IEXTD(RLOOP1))-FLOAT(IEXTD(RLOOP))/10.0
                  IF (IEXTD(RLOOP) .GT. 30000) CPWR = 32000.0
                  CALL ISTASH (IFIX(CPWR) , RLOOP1)
81             CONTINUE
82          CONTINUE
83       CONTINUE
84    CONTINUE

C*** SET LAST ELEMENT+1 TO 32000

      CALL ISTASH (32000 , RLOOP1 + 1.0)

C*** PROMPT USER TO DUMP EXTENDED MEMORY TO DISK

      CALL REPLY ("DUMP EXT MEM TO DISK (YES/NO) ? " , ANSWER)
      IF (.NOT. ANSWER) GO TO 86
      CALL OPENW (3 , "OUTPUT FILENAME FOR MEM DUMP ---> " , 0 , SIZE)
      CALL VDUMP (3 , BCNT , IERR)
      CALL CLOSE (3 , IERR)
86    CONTINUE

C*** FIND THE DISTRIBUTION OF THE RAMPING RATES

      TYPE " "
      TYPE "PERFORMING DISTRIBUTION CALCULATIONS"
      RLOOP1 = 26500.0
      RLOOP = 0.0
      PCNT = NCNT = 0.0
      DO 92 I = 1 , 50
         NSUM(I) = 0.0
         PSUM(I) = 0.0
         NRES(I) = 0.0
         PRES(I) = 0.0
92    CONTINUE

      DO 95 IPARM = 1 , NUMDAY*24
         RLOOP = RLOOP + 1.0
         LOAD1 = IEXTD (RLOOP)
         LOAD2 = IEXTD (RLOOP + 1.0)
         IF ((LOAD1.GT.30000).OR.(LOAD2.GT.30000)) GO TO 95
         PDIFF = LOAD2 - LOAD1
         RAMP = FLOAT(PDIFF)/60.0

C*** GENERATE THE HISTOGRAM OF THE DATA SET

         DO 94 I = 1 , 51
            IF (RAMP .LE. -0.10) GO TO 93
            LLIMIT = FLOAT(I-1)/5.0 - 0.10
            ULIMIT = FLOAT(I-1)/5.0 + 0.10
            IF((RAMP.LE.LLIMIT).OR.(RAMP.GT.ULIMIT)) GO TO 94
```

```
              PCNT = PCNT + 1.0
              PSUM(I) = PSUM(I) + 1.0
              IF (RAMP .LE. 0.10) GO TO 93
              GO TO 95

93            CONTINUE
              TRAMP = -RAMP
              LLIMIT = FLOAT(I-1)/5.0 - 0.10
              ULIMIT = FLOAT(I-1)/5.0 + 0.10
              IF((TRAMP.LT.LLIMIT).OR.(TRAMP.GE.ULIMIT)) GO TO 94
              NCNT = NCNT + 1.0
              NSUM(I) = NSUM(I) + 1.0
              GO TO 95
94          CONTINUE
95      CONTINUE

C*** CHECK FOR DEBUG - NSUM AND PSUM

        IF (DEBUG) TYPE "NSUM AND PSUM"
        IF (DEBUG) TYPE NSUM
        IF (DEBUG) TYPE PSUM

C*** SUM THE HISTOGRAM INTO A DISTRIBUTION

        DO 97 I = 1 , 51
            DO 96 J = 52-I , 51
                NRES(52-I) = NRES(52-I) + NSUM(J)
                PRES(52-I) = PRES(52-I) + PSUM(J)
96          CONTINUE
97      CONTINUE

C*** TURN THE SUMS INTO PERCENT OF THE TIME THAT THIS
C*** RAMPING RATE OR GREATER HAS BEEN OBSERVED

        DO 98 I = 1 , 51
            NRES(I) = (NRES(I)/NCNT)*100.0
            PRES(I) = (PRES(I)/PCNT)*100.0
98      CONTINUE

C*** PERFORM CALCULATIONS FOR 24 HOUR AVERAGES OVER DESIRED PERIOD,
C*** CALCULATE MEANS, STANDARD DEVIATIONS, MINS, MAXS

        IF (WSKIP) GO TO 450
        RLOOP = 0.0
        DO 85 I = 1 , 24
            RCNT(I) = 0.0
85      CONTINUE

        TYPE " "
        TYPE "PERFORMING 24 HOUR COMPUTATIONS"
        DO 100 IDAY = 1 , NUMDAY
            DO 90 IHOUR = 1 , 24
                RLOOP = RLOOP + 1.0
                PWR1 = IEXTD (RLOOP)
                PWR2 = IEXTD (RLOOP + 1.0)
                IF((PWR1.GT.30000) .OR. (PWR2.GT.30000)) GO TO 90
                PDIFF = PWR2 - PWR1
```

```
              RAMP = FLOAT(PDIFF) / 60.0
              RMAX(IHOUR) = AMAX1 (RMAX(IHOUR) , RAMP)
              RMIN(IHOUR) = AMIN1 (RMIN(IHOUR) , RAMP)
              SUMR(IHOUR) = SUMR(IHOUR) + RAMP
              SUMRSQ(IHOUR) = SUMRSQ(IHOUR) + RAMP*RAMP
              RCNT(IHOUR) = RCNT(IHOUR) + 1.0
90        CONTINUE
100     CONTINUE

C*** FINISH 24 HOUR CALCULATIONS

        DO 110 IHOUR = 1 , 24
           RDAY = RCNT(IHOUR)
           MEAN(IHOUR) = SUMR(IHOUR)/RDAY
           SQSUMR = SUMR(IHOUR) * SUMR(IHOUR)
           STNDV(IHOUR) = (SUMRSQ(IHOUR)-SQSUMR/RDAY)/(RDAY-1.0)
           STNDV(IHOUR) = SQRT (STNDV(IHOUR))
110     CONTINUE

C*** CHECK FOR DEBUG - 24 HOUR TEST

        IF(.NOT. DEBUG) GO TO 112
              TYPE "MEANS FOR 24 HOUR"
              TYPE MEAN
              TYPE "STNDVS FOR 24 HOUR"
              TYPE STNDV
              TYPE "MINS FOR 24 HOUR"
              TYPE RMIN
              TYPE "MAXS FOR 24 HOUR"
              TYPE RMAX
              PAUSE "PRESS ANY KEY TO CONTINUE"
112     CONTINUE

C*** WRITE 24 HOUR DATA TO THE LINE PRINTER

        WRITE (12,299)
        DO 113 I = 1 , NUMSITE
           WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                    FRACTION(I)*100.0
113     CONTINUE
        WRITE (12,590) RATED
        IF (RCNTRL) WRITE(12,595) MAXRAMP
        WRITE (12,301)
        DO 114 I = 1 , 12
           WRITE (12,302) I , MEAN(I) , I+12 , MEAN(I+12)
114     CONTINUE

        WRITE (12,303)
        DO 116 I = 1 , 12
           WRITE (12,302) I , STNDV(I) , I+12 , STNDV(I+12)
116     CONTINUE

        WRITE (12,299)
        DO 119 I = 1 , NUMSITE
           WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                    FRACTION(I)*100.0
119     CONTINUE
```

```
      WRITE (12,590) RATED
      IF (RCNTRL) WRITE(12,595) MAXRAMP
      WRITE (12,304)
      DO 117 I = 1 , 12
         WRITE (12,302)  I , RMIN(I) , I+12 , RMIN(I+12)
117   CONTINUE

      WRITE (12,305)
      DO 118 I = 1 , 12
         WRITE (12,302) I , RMAX(I) , I+12 , RMAX(I+12)
118   CONTINUE

299   FORMAT("1",////////," ",23X,"COMBINED RAMPING COMPUTATIONS",//)
300   FORMAT(" ",9X,"LOCATION ",I2," ",I2," M, UC=",F4.1,
     *        " MPS, UR=",F4.1," MPS, % FARM = ",F5.1)
301   FORMAT(////," ",32X,"24 HOUR MEANS",/)
302   FORMAT(" ",18X,I3," --> ",F6.3,10X,I3," --> ",F6.3)
303   FORMAT(////," ",24X,"24 HOUR STANDARD DEVIATIONS",/)
304   FORMAT(////," ",30X,"24 HOUR MINIMUMS",/)
305   FORMAT(////," ",30X,"24 HOUR MAXIMUMS",/)

C*** WRITE 24 HOUR DATA TO DISK

      TYPE " "
      TYPE "WRITING 24 HOUR DATA TO DISK"
      CALL OPENW (1 , "FILENAME FOR MEAN 24 HOURS ? " , 96 , SIZE)
      CALL OPENW (2 , "FILENAME FOR STDV 24 HOURS ? " , 96 , SIZE)
      CALL OPENW (3 , "FILENAME FOR RMIN 24 HOURS ? " , 96 , SIZE)
      CALL OPENW (4 , "FILENAME FOR RMAX 24 HOURS ? " , 96 , SIZE)

      CALL WRITRW (1 , 1 , MEAN , 1 , IERR)
      CALL WRITRW (2 , 1 , STNDV , 1 , IERR)
      CALL WRITRW (3 , 1 , RMIN , 1 , IERR)
      CALL WRITRW (4 , 1 , RMAX , 1 , IERR)

      CALL CLOSE (1 , IERR)
      CALL CLOSE (2 , IERR)
      CALL CLOSE (3 , IERR)
      CALL CLOSE (4 , IERR)

C*** INITIALIZE ARRAYS

      DO 115 I = 1 , 24
         SUMR(I) = SUMRSQ(I) = STNDV(I) = MEAN(I) = RCNT(I) =0.0
         RMAX(I) = -999.0
         RMIN(I) = 999.0
115   CONTINUE

C*** PERFORM CALCULATIONS FOR 12 MONTHS, AVERAGE, MEAN, STANDARD
C*** DEVIATION, MIN AND MAX FOR EACH MONTH.

      RLOOP = 0.0

      TYPE " "
      TYPE "PERFORMING 12 MONTH CALCULATIONS"
      DO 150 IYEAR = IYBEG , IYEND
         DO 140 IMONTH = 1 , 12
```

```
              DO 130 IDAY = 1 , MNUM(IYEAR,IMONTH)
                 DO 120 IHOUR = 1 , 24
                    RLOOP = RLOOP + 1.0
                    PWR1 = IEXTD (RLOOP)
                    PWR2 = IEXTD (RLOOP + 1.0)
                    IF((PWR1.GT.30000) .OR. (PWR2.GT.30000)) GO TO 120
                    PDIFF = PWR2 - PWR1
                    RAMP = FLOAT(PDIFF) / 60.0
                    RMAX(IMONTH) = AMAX1 (RMAX(IMONTH) , RAMP)
                    RMIN(IMONTH) = AMIN1 (RMIN(IMONTH) , RAMP)
                    SUMR(IMONTH) = SUMR(IMONTH) + ABS(RAMP)
                    SUMRSQ(IMONTH) = SUMRSQ(IMONTH) + RAMP*RAMP
                    RCNT(IMONTH) = RCNT(IMONTH) + 1.0
120              CONTINUE
130           CONTINUE
140        CONTINUE
150     CONTINUE

C*** FINISH 12 MONTH CALCULATIONS

        DO 190 IMONTH = 1 , 12
           RHOUR = RCNT(IMONTH)
           MEAN(IMONTH) = SUMR(IMONTH) / RHOUR
           SQSUMR = SUMR(IMONTH) * SUMR(IMONTH)
           STNDV(IMONTH) = (SUMRSQ(IMONTH)-SQSUMR/RHOUR)/(RHOUR-1.0)
           STNDV(IMONTH) = SQRT(STNDV(IMONTH))
190     CONTINUE

C*** CHECK FOR DEBUG - 12 MONTH TEST

        IF(.NOT. DEBUG) GO TO 195
              TYPE "MEANS FOR 12 MONTH"
              TYPE MEAN
              TYPE "STNDVS FOR 12 MONTH"
              TYPE STNDV
              TYPE "MINS FOR 12 MONTH"
              TYPE RMIN
              TYPE "MAXS FOR 12 MONTH"
              TYPE RMAX
              PAUSE "PRESS ANY KEY TO CONTINUE"
195     CONTINUE

C*** WRITE 12 MONTH DATA TO THE LINE PRINTER

        WRITE(12,299)
        DO 180 I = 1 , NUMSITE
           WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                    FRACTION(I)*100.0
180     CONTINUE
        WRITE (12,590) RATED
        IF (RCNTRL) WRITE(12,595) MAXRAMP
        WRITE (12,309)
        DO 196 I = 1 , 6
           WRITE (12,302) I , MEAN(I) , I+6 ,  MEAN(I+6)
196     CONTINUE

        WRITE (12,306)
```

```
      DO 197 I = 1 , 6
         WRITE (12,302) I , STNDV(I) , I+6 , STNDV(I+6)
197   CONTINUE

      WRITE (12,307)
      DO 198 I = 1 , 6
         WRITE (12,302) I , RMIN(I) , I+6 ,  RMIN(I+6)
198   CONTINUE

      WRITE (12,308)
      DO 199 I = 1 , 6
         WRITE (12,302) I , RMAX(I) , I+6 , RMAX(I+6)
199   CONTINUE

309   FORMAT(" ",///," ",25X,"12 MONTH MEANS (ABSOLUTE)",/)
306   FORMAT(/," ",18X,"12 MONTH STANDARD DEVIATIONS (ABSOLUTE)",/)
307   FORMAT(/," ",29X,"12 MONTH MINIMUMS",/)
308   FORMAT(/," ",29X,"12 MONTH MAXIMUMS",/)

C*** WRITE 12 MONTH DATA TO DISK

      TYPE " "
      TYPE "WRITING 12 MONTH DATA TO DISK"
      CALL OPENW (1 , "FILENAME FOR MEAN 12 MONTH ? " , 48 , SIZE)
      CALL OPENW (2 , "FILENAME FOR STDV 12 MONTH ? " , 48 , SIZE)
      CALL OPENW (3 , "FILENAME FOR RMIN 12 MONTH ? " , 48 , SIZE)
      CALL OPENW (4 , "FILENAME FOR RMAX 12 MONTH ? " , 48 , SIZE)

      CALL WRITRW (1 , 1 , MEAN , 1 , IERR)
      CALL WRITRW (2 , 1 , STNDV , 1 , IERR)
      CALL WRITRW (3 , 1 , RMIN , 1 , IERR)
      CALL WRITRW (4 , 1 , RMAX , 1 , IERR)

      CALL CLOSE (1 , IERR)
      CALL CLOSE (2 , IERR)
      CALL CLOSE (3 , IERR)
      CALL CLOSE (4 , IERR)

C*** INITIALIZE ARRAYS

      DO 200 I = 1 , 2
         SUMR(I) = SUMRSQ(I) = STNDV(I) = MEAN(I) = 0.0
         RMAX(I) = -999.0
         RMIN(I) = 999.0
200   CONTINUE

C*** PERFORM CALCULATIONS FOR WEEKDAY-WEEKEND.
C
C*** DISCARD THE FIRST FEW DAYS UP TO THE START OF A NEW
C*** WEEK AND, THE LAST FEW DAYS AT THE END OF THE DATA
C*** THAT FORM AN INCOMPLETE WEEK.

      RLOOP = 0.0
      RDAY = FLOAT(NUMDAY - 1)
      WEND = 0.0
      WDAY = 0.0
```

```
      IF(SDOY(IYBEG) .EQ. 1) GO TO 210
      RLOOP = 8.0 - FLOAT(SDOY(IYBEG))

210   CONTINUE

      RWEEK = (RDAY - RLOOP) / 7.0
      WEEK = IFIX(RWEEK)

      TYPE " "
      TYPE "PERFORMING WEEKEND-WEEKDAY CALCULATIONS"
      DO 260 IWK = 1 , WEEK

C*** PERFORM WEEKEND TOTALS

         DO 230 IDAY = 1 , 2
            DO 220 IHOUR = 1 , 24
               RLOOP = RLOOP + 1.0
               PWR1 = IEXTD (RLOOP)
               PWR2 = IEXTD (RLOOP + 1.0)
               IF((PWR1.GT.30000) .OR. (PWR2.GT.30000)) GO TO 220
               PDIFF = PWR2 - PWR1
               RAMP = FLOAT(PDIFF) / 60.0
               RMAX(1) = AMAX1 (RMAX(1) , RAMP)
               RMIN(1) = AMIN1 (RMIN(1) , RAMP)
               SUMR(1) = SUMR(1) + ABS(RAMP)
               SUMRSQ(1) = SUMRSQ(1) + RAMP*RAMP
               WEND = WEND + 1.0
220         CONTINUE
230      CONTINUE

C*** PERFORM WEEKDAY TOTALS

         DO 250 IDAY = 3 , 7
            DO 240 IHOUR = 1 , 24
               RLOOP = RLOOP + 1.0
               PWR1 = IEXTD (RLOOP)
               PWR2 = IEXTD (RLOOP + 1.0)
               IF((PWR1.GT.30000) .OR. (PWR2.GT.30000)) GO TO 240
               PDIFF = PWR2 - PWR1
               RAMP = FLOAT(PDIFF) / 60.0
               RMAX(2) = AMAX1 (RMAX(2) , RAMP)
               RMIN(2) = AMIN1 (RMIN(2) , RAMP)
               SUMR(2) = SUMR(2) + ABS(RAMP)
               SUMRSQ(2) = SUMRSQ(2) + RAMP*RAMP
               WDAY = WDAY + 1.0
240         CONTINUE
250      CONTINUE
260   CONTINUE

C*** FINISH WEEKEND-WEEKDAY CALCULATIONS

      MEAN(1) = SUMR(1) / WEND
      MEAN(2) = SUMR(2) / WDAY
      SQSUMR = SUMR(1) * SUMR(1)
      STNDV(1) = (SUMRSQ(1)-SQSUMR/WEND)/(WEND-1.0)
      STNDV(1) = SQRT(STNDV(1))
      SQSUMR = SUMR(2) * SUMR(2)
```

```
      STNDV(2) = (SUMRSQ(2)-SQSUMR/WDAY)/(WDAY-1.0)
      STNDV(2) = SQRT(STNDV(2))

C*** CHECK FOR DEBUG - WEEKEND-WEEKDAY TEST

      IF(.NOT. DEBUG) GO TO 265
            TYPE "WEEKDAY-WEEKEND MEANS"
            TYPE MEAN(2) , MEAN(1)
            TYPE "WEEKDAY-WEEKEND STNDVS"
            TYPE STNDV(2) , STNDV(1)
            TYPE "WEEKDAY-WEEKEND MINS"
            TYPE RMIN(2) , RMIN(1)
            TYPE "WEEKDAY-WEEKEND MAXS"
            TYPE RMAX(2) , RMAX(1)
            PAUSE "PRESS ANY KEY TO CONTINUE"
265   CONTINUE

C*** WRITE WEEKEND-WEEKDAY COMPUTATIONS TO LINE PRINTER

      WRITE(12,299)
      DO 270 I = 1 , NUMSITE
         WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                  FRACTION(I)*100.0
270   CONTINUE
      WRITE (12,590) RATED
      IF (RCNTRL) WRITE(12,595) MAXRAMP
      WRITE (12,311)
      WRITE (12,313) MEAN(1) , MEAN(2)
      WRITE (12,314)
      WRITE (12,313) STNDV(1) , STNDV(2)
      WRITE (12,315)
      WRITE (12,313) RMIN(1) , RMIN(2)
      WRITE (12,316)
      WRITE (12,313) RMAX(1) , RMAX(2)

311   FORMAT(" ",///,21X,"WEEKEND-WEEKDAY MEANS (ABSOLUTE)",/)
313   FORMAT(" ",14X," WEEKEND --> ",F6.2,10X," WEEKDAY --> ",F6.2)
314   FORMAT(///," ",15X,"WEEKEND-WEEKDAY STANDARD DEVIATIONS (ABSOLUTE)",/)
315   FORMAT(///," ",25X,"WEEKEND-WEEKDAY MINIMUMS",/)
316   FORMAT(///," ",25X,"WEEKEND-WEEKDAY MAXIMUMS",/)

C*** WRITE WEEKEND-WEEKDAY DATA TO DISK

      TYPE " "
      TYPE "WRITING WEEKEND-WEEKDAY DATA TO DISK"
      CALL OPENW (1 , "FILENAME FOR MEAN WEEK ? " , 8 , SIZE)
      CALL OPENW (2 , "FILENAME FOR STDV WEEK ? " , 8 , SIZE)
      CALL OPENW (3 , "FILENAME FOR RMIN WEEK ? " , 8 , SIZE)
      CALL OPENW (4 , "FILENAME FOR RMAX WEEK ? " , 8 , SIZE)

      CALL WRITRW (1 , 1 , MEAN , 1 , IERR)
      CALL WRITRW (2 , 1 , STNDV , 1 , IERR)
      CALL WRITRW (3 , 1 , RMIN , 1 , IERR)
      CALL WRITRW (4 , 1 , RMAX , 1 , IERR)

      CALL CLOSE (1 , IERR)
      CALL CLOSE (2 , IERR)
```

```
      CALL CLOSE (3 , IERR)
      CALL CLOSE (4 , IERR)

450   CONTINUE

C*** OUTPUT PERCENT ENERGY LOST IN CONTROL ALGORITHM

      IF (.NOT.RCNTRL) GO TO 510
      WRITE (12,299)
      DO 480 I = 1 , NUMSITE
         WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                  FRACTION(I)*100.0
480   CONTINUE
      WRITE (12,590) RATED
      WRITE(12,595) MAXRAMP
      WRITE(12,500) (WPLOSS/WPSUM)*100.0
500   FORMAT(//," ",17X,"PERCENT ENERGY LOSS FOR CONTROL = " , F5.2," %")
510   CONTINUE

C*** OUTPUT RAMPING DISTRIBUTION TO LINE PRINTER

      WRITE (12,299)
      DO 470 I = 1 , NUMSITE
         WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                  FRACTION(I)*100.0
470   CONTINUE
      WRITE (12,590) RATED
      IF (RCNTRL) WRITE(12,595) MAXRAMP
      WRITE (12,351)
      DO 390 I = 1 , 25
         RATE1 = FLOAT(I-1)/5.0
         RATE2 = (FLOAT(I-1)+25.0)/5.0
         WRITE (12,350) RATE1 , PRES(I) , RATE2 , PRES(I+25)
390   CONTINUE
      WRITE (12,353) 10.00 , PRES(51)

      WRITE (12,299)
      DO 490 I = 1 , NUMSITE
         WRITE (12,300) SITE(I),TOWER(I),CUTINWS(I),RATEDWS(I),
     *                  FRACTION(I)*100.0
490   CONTINUE
      WRITE (12,590) RATED
      IF (RCNTRL) WRITE(12,595) MAXRAMP
      WRITE (12,352)
      DO 395 I = 1 , 25
         RATE1 = FLOAT(I-1)/5.0
         RATE2 = (FLOAT(I-1)+25.0)/5.0
         WRITE (12,360) -RATE1 , NRES(I) , -RATE2 , NRES(I+25)
395   CONTINUE
      WRITE (12,363) -10.0 , NRES(51)

351   FORMAT(//," ",20X,"POSITIVE RAMPING PERCENTAGE OF TIME",//)
360   FORMAT(" ",4X,2(5X,"RAMP < ",F6.2," —> ",F6.2," %"))
350   FORMAT(" ",4X,2(5X,"RAMP > ",F6.2," —> ",F6.2," %"))
352   FORMAT(//," ",20X,"NEGATIVE RAMPING PERCENTAGE OF TIME",//)
363   FORMAT(" ",40X,"RAMP < ",F6.2," —> ",F6.2," %")
353   FORMAT(" ",40X,"RAMP > ",F6.2," —> ",F6.2," %")
```

```
590     FORMAT(//," ",23X,"RATED FARM POWER = ",F7.1," MW")
595     FORMAT(//," ",15X,"MAXIMUM ALLOWED POSITIVE RAMP = ",F7.2," MW/MIN")

C*** OUTPUT PERCENT RESULTS TO DISK

        CALL OPENW (3 , "+RAMP % OUTPUT FILENAME ---> " , 204 , SIZE)
        CALL WRITRW (3 , 1 , PRES , 1 , IERR)
        CALL CLOSE (3 , IERR)

        CALL OPENW (3 , "-RAMP % OUTPUT FILENAME ---> " , 204 , SIZE)
        CALL WRITRW (3 , 1 , NRES , 1 , IERR)
        CALL CLOSE (3 , IERR)

        END
```

POTENTIAL EFFECTS OF WIND ELECTRIC GENERATORS ON CONVENTIONAL ELECTRIC GENERATORS IN KANSAS

by

CHRISTOPHER KEAR DUFFEY

B. S., Kansas State University, 1983

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ABSTRACT

The thesis shows the effects that wind generated electric power has on conventional electric generation in Kansas for the years 1980 to 1982. To perform this analysis, ramping rates in MW/min of the utility, wind, and utility with added wind generation were inspected and showed detrimental effects to utility operation. However, variations in cut-in and rated turbine wind speeds, penetration, wind array size, and amounts of upwards ramping control were incorporated and showed trends of decreasing negative ramping effects due to injected wind generation. From this, it was found that a three site farm at 15% penetration with appropriate control parameters behaved with the same impact as a single site farm at 5% penetration. Also discussed, was the correlative relationship between Kansas load demand and Kansas wind power production. For single site farms, a direct diurnal correlation was seen, while multiple site wind arrays showed decreasing diurnal correlation for an increasing number of combined wind farms.