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OPERATIONAL, COST, AND TECHNICAL STUDY OF LARGE
WINDPOWER SYSTEMS INTEGRATED WITH AN EXISTING
ELECTRIC UTILITY

Final Report, SwRI Project 15-4242

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April 1976

Work Performed Under Contract No. EY-76-C-02-2621

Southwest Research Institute
San Antonio, Texas

MASTER

U.S. Department of Energy

Solar Energy

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FINAL REPORT SwRI Project 15-4242

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April 1976

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REA

ABSTRACT

Detailed wind energy assessment from the available wind records, and evaluation of the application of wind energy systems to an existing electric utility were performed in an area known as the Texas Panhandle, on the Great Plains. The study area includes parts of Texas, eastern New Mexico, the Oklahoma Panhandle and southern Kansas. In large part, the area is served by the network of the Southwestern Public Service Company with headquarters in Amarillo, Texas. That company has been a major study participant in this program, and much of the work reported has been performed by its engineering personnel.

The region is shown to have uniformly distributed winds of relatively high velocity, with average wind power density of 0.53 kW/m^2 at 30m height at Amarillo, Texas, a representative location. The annual period of calm is extremely low. The terrain is largely flat and featureless, consequently the values of available windpower can be interpolated between existing weather stations with considerable accuracy. The most favorable winds within this region extend in a belt roughly 100 miles wide, from south of Amarillo, increasing in average velocity in a north-northeastward direction into southern Kansas.

Three separate compressed air storage systems with good potential were analyzed in detail, and two potential pumped-hydro facilities were identified and given preliminary consideration. Aquifer storage of compressed air is a promising possibility in the region.

However, in no case was a unique combination of wind machines and storage components found that presented a cost effective overall system. Rather, the favored approach from all aspects is the separate consideration of WTG, implemented throughout the system at locations determined by the wind and factors other than storage; and storage facilities, considered as separate entities. The acceptance of power from the WTG on a free run-of-the-wind basis is shown to be the most cost-effective mode of operation.

A serious limitation in the compressed air storage scheme, is the requirement for natural gas for the turbines.

Southwestern Public Service Co. computer programs were used to calculate the worth of wind turbine generators in various configurations with and without storage on the SwPS system. These results show that a baseline 1000 kW WTG rated at 10 meters/sec. at 60 meters can support investment costs without storage ranging from about \$300/kW at 1975 fuel rates to \$600/kW with continuous fuel escalation of 6%/year over the

life of the machine. With storage, the same machine and its proportionate share of total storage system cost can support investment costs of \$530/kW at 1975 fuel prices. The added value of firmed WTG, however, is not commensurate with the cost of energy storage subsystems required.

Technical requirements for WTG for utilization on the SwPS network were analyzed. No unusual requirements were found to exist and safe, satisfactory installations of these machines on rural distribution and sub-distribution lines were found to be within normal power engineering practice. Operation of WTG must be unattended and automatic. Maintenance problems associated with long-term operation of a large number of these machines is of concern, particularly for dismantling and replacement of rotor blades and other major components by utility maintenance crews.

A study of the institutional and legal problem posed by use of wind energy systems in Texas, disclosed no impediments to the orderly development of the wind resource. At the present time, there are no power plant siting requirements in Texas other than for those including nuclear fuel or discharging effluent.

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I. INTRODUCTION

This study of potential wind-energy utilization by an electric utility applies to an area lying principally in Texas, on the Great High Plains. The latter lie to the east of the base of the Rocky Mountains, and extend south-eastward into northwest Texas. The study area is known locally by the Spanish "Llano Estacado", ("staked plains"), and includes most of the Texas and Oklahoma panhandles, eastern New Mexico and the edge of southern Kansas. The area is shown on the map in Figure 1, in conjunction with the system map of the Southwestern Public Service Company, which serves most of the area with electric power.

The region stretches over a large part of the most extensive level plain of its kind in the United States. It is bounded to the southeast by the Cap Rock escarpment, the dividing line between the High Plains and the lower Rolling Plains of west Texas. The Cap Rock is an outstanding natural boundary line which was found to generally define the eastern limit of the best winds as determined in this study.

The region may be further divided geographically into the North and the South Plains. Land in the former is largely devoted to wheat and grain-sorghum farming, and cattle ranching. Petroleum development is extensive. Amarillo is the largest city in the North Plains with a population of approximately 130,000.

The South Plains is also a prominent grain-sorghum producer, and leads Texas in cotton production. Lubbock is the principle city with a population of approximately 150,000. The South Plains, from Lubbock to Amarillo, is flat and relatively featureless, with little topographic relief. The single exception is the Palo Duro Canyon of the Prairie Dog Town fork of the Red River from near Canyon, 30 miles south of Amarillo, to the edge of the escarpment, some 50 miles to the southeast, one of the most extensive canyon systems in the United States.

North of Amarillo, the land gradually slopes to the Canadian River with a loss of approximately 1500 ft. of elevation. North of the river the plain again slowly rises to the Oklahoma Panhandle. This area, roughly 30 miles wide along the Canadian River, is known as the "Canadian River Brakes". Here the river has eroded the prairie over recent geologic time, leaving a series of flat, table-like projections and gently rising slopes.

The Oklahoma panhandle and southwestern Kansas are devoted principally to cattle ranching and wheat farming. Irrigation is practiced throughout the region from an underground water source known as the "Ogollala" formation.

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Figure 1
SYSTEM MAP OF SOUTHWESTERN PUBLIC SERVICE COMPANY

The region is generally arid with an average annual rainfall of approximately 20 inches. The climate ranges from high, almost desert heat in the summertime to moderate cold in the wintertime, with some snowfall. Temperatures below 0°F are infrequent, and the area exhibits only moderate icing conditions. Adding a considerable measure of severity to the climate generally, is the wind. Visitors to the panhandle are convinced that the wind blows continually.

Severe thunderstorms occur with some frequency in the spring and fall, and the region lies within the Great Plains tornado belt; even so, the historic occurrence of severe tornado damage is not extensive. The record high temperature in Amarillo is 108°F, the record low - 16°F, with an average of 71 days above 90° and 107 days below 32° annually.

II. WIND ASSESSMENT ANALYSIS

The Southwestern Public Service Company provides electric power for a large area in the Texas and Oklahoma Panhandles as well as parts of southeastern New Mexico and a small area of southern Kansas. The SwPS electric power service area lies within a belt of consistent high winds, and provides a model for assessment of the feasibility of practical generation and utilization of electric power from the natural winds. The characteristics of the wind in the region play a prominent role in this utilization. Section II, "Wind Assessment Analysis", describes a study of the potential of the winds of the model region to produce electric power using realistic wind turbine generators deployed in practical arrays.

The sequential objectives of this part of the study, reported in the following paragraphs, were as follows:

- A. Wind Energy Distribution. Estimate the distribution of flow of kinetic energy of the wind per unit vertical area, at various heights above ground level, throughout the model region.
- B. Potential Electrical Energy Generation. Estimate the distribution of potential aeromotive electrical energy production rates, based on selected wind turbine generator performance characteristics, throughout the model region.
- C. Potential Windpower Utilization. Estimate an upper limit on windpower utilization based on various specifications of unit spacings and groupings within the model region.
- D. Practical Windpower Utilization. Based on the wind potential and practical utility considerations, estimate the maximum realistic role of windpower on the SwPS system during the period of the next twenty years.
- E. Limited Wind Measurement. Instrument an isolated site in the Guadalupe Mountain foothills near Carlsbad, New Mexico and a site in the Lake Meredith Valley in Texas for short-term continuous wind speed recordings. Analyze these data with concurrent data from the nearest weather stations, and estimate site-specific wind potential.

A. Assessment of Wind Energy Distribution

1. Methodology

The electrical distribution system of the Southwestern Public Service Company (SwPS) of Amarillo, Texas schematically described in Figure 1, extends from near Carlsbad, New Mexico through the Texas and Oklahoma panhandles to the southern part of Kansas.

Southwestern Public Service Company is a privately owned electric utility with a total generating capacity in excess of 2,000 MW serving a total service area of more than 45,000 sq. miles. The system is thus characterized by a high ratio of transmission and distribution line length to generating capacity. A list of individual generating plants on the system is given in the inset in Figure 1.

At the present time (1975) the fuel consumption of the SwPS generating system consists almost totally of natural gas. The region contains the largest gas field in the world (Panhandle-Hugoton) which has traditionally provided a source of low-cost energy. Much of the field is now approaching depletion, however, and except for current supply contracts, fuel prices to the utility are increasing drastically for the first time in nearly 40 years.

There are 17 locations near or within the SwPS service area for which detailed wind records are available⁽³¹⁾ on magnetic tape from the National Climatic Center⁽¹⁾ (NCC). All of these stations are used in this assessment and are displayed in Figure 2 with a schematic of the SwPS service area.

The objective of this assessment of wind energy distribution is to evaluate the kinetic energy flux of wind as a continuous function at various heights above ground level throughout the SwPS service region. This is accomplished by using the wind records at each of the 17 data stations to compute 17 local long-term average wind regimes at the height above ground of the local anemometer. The wind regimes are represented by wind speed-duration curves or tables, a relationship between wind speed and percent of time for which the wind matches or exceeds a given speed. These wind regimes are extrapolated to heights of 30, 45, 60 and 75 meters using empirical height-speed relationships with due consideration of stability conditions of the region. The height adjusted wind regime tabulations are converted to windpower and wind speed. This procedure yields 17 assessments of the wind power regime at scattered locations throughout the SwPS service area. These points are extended to a continuous distribution function by the simple expedient of linear interpolation. This implies the tacit use of two assumptions or approximations. First, the windpower regime of the local data station is assumed

FIGURE 2
LOCATION OF DATA STATIONS AND SERVICE AREA OF SWPSC

to be representative of the windpower distribution of the region and second, the region is assumed to exert no topographic influence on the windpower regime.

The influence of topography on wind speed has been the subject of extensive investigation by many⁽²⁻¹⁴⁾. It has been found that hills and ridges may speed up the wind, relative to free stream wind at the same height in the boundary layer, by a factor of up to 1.5 or reduce it by factors as low as 0.71, depending on topographical conformation, wind speed and direction, degree of atmospheric stability, and other obscure factors.

The type of ground cover is another important factor of the surface influence on the wind boundary layer. Tall forests and urban structures create local turbulence and energy dissipation^(10,11). These effects are decreasing functions of height within the boundary layer.

Therefore the degree of topographic relief and height and type of ground cover are the major factors influencing the validity of interpolation of wind data between data stations. Interpolation is expected to be quite good for flat smooth terrain and totally inadequate for mountainous terrain. The topography of the region has been characterized by Hammond⁽¹⁵⁾ in terms of classes of land surface form. The SwPS service region is characterized, in the majority, as Hammond class A2c, meaning terrain with relief features of 30-90 meters, with more than 80 percent of the area gently sloping and 50-75 percent of that gentle slope on the upland. The region is further characterized as smooth plains. Only two major topographic features are within or near the region. Open high hills, the Guadalupe foothills, with relief of 150-300 meters, are proximal to the southwestern extent of the system and may offer sites with outstanding potential for windpower generation, but being outside the SwPS region, do not influence intraregional interpolation. To the north of Amarillo lie tablelands with relief of 90-150 meters, appearing as a broad valley running southwest to northeast. A fairly large lake, Lake Meredith, is located in the valley and in the path of the prevailing southwesterly winds and may topographically influence the winds by a funnel effect of the valley walls. The greatest portion of the region is extraordinarily flat and smooth.

The potential natural vegetation is also nearly uniform over the SwPS region of service. Kuchler⁽¹⁶⁾ has produced a national map of potential natural vegetation and classifies the region for Grana-Buffalo grass. The only portion of the region covered naturally by other than grass, is the southwestern extreme, which is characterized as shrubland. That part of the region under cultivation is primarily put to short staple cotton.

Thus the majority of the land of the region analyzed is uniformly smooth of terrain and uniformly similar in potential natural ground cover. Therefore, data obtained from weather stations located in the region are taken as representative of the surrounding area and linear interpolation among stations is considered a credible representation of the wind regime distribution.

2. Data Base

The data stations used in this assessment are displayed in Figure 2 and listed in Table 1. The data are recorded on magnetic tape and were transcribed from written records by the National Climatic Center.

The data were collected by either the National Weather Service (formerly the U. S. Weather Bureau) or the weather service of the U. S. Air Force in the case of the stations at Clovis, New Mexico (Cannon Air Force Base) and Big Spring, Texas (Webb Air Force Base). Prior to and through December 31, 1964, wind speed data were collected every hour on the hour as a "spot" observation, defined as a one minute average of the anemometer display or trace as estimated by the observer at the time of record. After that date, data were recorded every three hours, beginning at 0000 hours central standard time. The period of record at each location selected for use in this analysis is the most recent period available of at least five years continuous record in the case of hourly data, or of at least 10 years continuous record in the case of three hourly data.

The basic unit of wind speed used by the weather services is the knot. The recorded data are in whole number values as determined by observer estimation. Of the range of wind speeds recorded, the low end of the scale is the most suspect of inaccuracy. The anemometers used by the weather stations during the periods of record utilized in this study are of the rotating cup type and are of various makes and designs. This type of instrument has a threshold starting wind speed below which it will not operate and at which it will operate sporadically and inaccurately. Because of lack of uniformity of manufacture of the instruments used, no rigorous error specifications may be assigned. The data record for wind speeds less than 3 knots is generally considered unreliable for this general class of instrument. For this study, however, only the flux of kinetic energy is of concern, a factor of the wind speed cubed, so that only a small fraction of the available energy in the wind is contained in the very low end of the wind speed range. Therefore, little error is introduced in the assessment of wind energy or energy extraction rates by this instrument's inaccuracy.

6

	NCC Station No.	Station Name	Period of Record Used	Ground Elevation above sea level, meters	Anemometer Height above Ground, meters / feet		Mean Annual Pressure, mbar	Mean * Annual Temperature °K
		<u>TEXAS</u>						
1.	23047	Amarillo	01/62-12/72	1098	7.0	23	887	291.7
2.	23005	Fig Spring	01/66-12/70	782	9.1	30	921	291.2
3.	23007	Childress	01/50-12/54	595	11.0	36	941	290.2
4.	93042	Dalhart	01/50-12/54	1216	15.2	50	875	286.4
5.	23042	Lubbock	01/49-12/64	988	20.7	68	899	288.6
		"	01/66-12/72	988	7.6	25	899	288.6
6.	23023	Midland	01/60-12/72	869	6.7	22	912	290.9
7.	23040	Wink	01/50-12/54	856	9.1	30	913	301.6
		<u>NEW MEXICO</u>						
8.	93033	Carlsbad	01/50-12/54	986	15.2	50	900	290.3
9.	23051	Clayton	01/64-12/73	1515	9.1	30	844	284.7
10.	23008	Clavis/Cannon	01/61-12/70	1305	6.7	22	866	287.4
11.	93034	Hobbs	01/50-12/54	1113	11.0	36	886	290.0
12.	23043	Roswell	01/61-12/69	1102	5.5	18	886	289.3
		<u>OKLAHOMA</u>						
13.	13902	Altus	01/61-12/70	432	9.1	30	958	290.1
14.	13975	Gage	01/50-12/54	668	7.6	25	933	287.5
15.	93986	Hobart	01/50-12/54	472	7.6	25	954	289.2
		<u>KANSAS</u>						
16.	13987	Dodge City	01/50-12/54	787	6.1	20	921	285.8
17.	23064	Garden City	01/64-12/73	878	6.1	20	911	285.7

* Computed from U. S. Climatological Data Annual Summary

TABLE 1
DATA STATIONS

The National Weather Service currently installs wind anemometers at 6 to 9 meters above ground on light towers or poles placed in the clear at substantial distances from surrounding buildings, trees, or other objects which might create wind disturbances. These towers are usually located near airport runways. Formerly, however, the anemometers were commonly placed on a short tower or pole above a hanger, control tower, or other building. It is probable that some of the wind records taken under these conditions are grossly inaccurate because of aerodynamic distortions of the wind boundary layer caused by the structure supporting the anemometer. The wind record at Amarillo, Texas provides a case in point. Weather records have been maintained there for the past 38 years, first by the Civil Aeronautics Administration and since May, 1940 by the National Weather Service and U. S. Weather Bureau. Wind data are available on magnetic tape for the period July, 1948 through December, 1974. During that period the anemometer site was changed only once, in May, 1961⁽¹⁾ when it was moved from atop a building at 10.0 meters (33 feet) located amongst trees⁽¹⁷⁾, to its present location near the runways at Amarillo Air Terminal atop a tower at 7.0 meters (23 feet) above ground, free from nearby obstructions. The average wind speed at the 10 meter site from 1951-1960 was 5.81 meters/second⁽¹⁸⁾ whereas at the 10 meter level for the period 1962-1972 the wind speed average was 6.30 meters/second.⁽¹⁹⁾ The inference from this abnormal result is that the surrounding trees and/or the building beneath the higher, pre-1961 anemometer site severely disturbed the wind pattern to the degree that those data must be disregarded in favor of the more recent data at the lower anemometer site. Apparently, less attention was formerly paid to the possibility of interference to the anemometer wind regime than is currently afforded. Records describing the older anemometer sites are available^(20,21), but do not provide adequate descriptions of the supporting structure to allow for reliable evaluation of site quality with respect to wind interference. Thus the credence of the early records must, in general, be considered to be less than that of the later records, without specific information to the contrary.

3. Data Reduction

For each station, the following data reduction scheme has been employed and executed using the IBM 360 computer facility of Texas Tech University.

a. Windspeed-Duration Functions

In order to deal with the different types of boundary layer stability of the atmosphere which occur during night

and day, the hourly wind speed values are segregated into two groups: (1) The day period from 0700 through 1800 hours and (2) the night period from 1900 through 0600 hours. The wind speeds are compiled in terms of percent time duration for which a given windspeed was equaled or exceeded. Because the wind records report integer values of wind speed in knots, that unit of measurement is used in the data compilation and subsequently converted to the more common unit of meters/second. The distribution of wind during the night period is quite different from that of the day period, the average speed being much less at night. A set of windspeed-duration curves is provided in Appendix A.

b. Height Extrapolation

Wind speed normally increases with height as a function of both atmospheric lapse rate and surface roughness. Empirical investigations of the relationship of wind speed with height have demonstrated that the vertical profile data can be adequately treated with only two divisions of atmospheric stability conditions, namely stable and unstable⁽²²⁾. The former consists of inversion, isothermal and adiabatic conditions described by the power law relation⁽⁹⁾,

$$U_s = U_{r,s} (h/h_r)^a \quad \text{for stable conditions.} \quad (1)$$

The latter condition is well described by the logarithmic relation⁽⁷⁾

$$U_u = U_{r,u} \frac{\ln(h/z_0)}{\ln(h_r/z_0)} \quad \text{for unstable conditions.}$$

where

- h = height above ground
- U = wind speed
- z₀ = characteristic roughness length, an empirical parameter
- a = empirical exponent, a function of lapse rate and wind speed
- r = subscript, refers to reference anemometer at height h_r
- s = subscript, refers to stable conditions
- u = subscript, refers to unstable conditions

In the SwPS region, the atmospheric conditions are unstable 70 percent of the time on an annual basis⁽²³⁾. Virtually all of the stable lapse rates occur at night, but the degree of stability is minimal, the annual mean lapse rate in Amarillo, Texas at 0600, CST, being only 0.86 degrees centigrade/100 meters⁽²⁴⁾. Thus the logarithmic wind speed variation with height for unstable atmospheric conditions, equation (2) above, is used for the day period. The night period wind speed extrapolation to various heights is performed using an average of the two expressions (1) and (2) weighted on frequency of occurrence of stable conditions.

Hosler⁽²³⁾ has tabulated frequencies of stable conditions over the United States based on radiosonde data and tower measurements. According to his tabulations, the SwPS service region is assigned a 35 percent of total time inversion frequency as an annual average value. However, the 1800 CST inversion frequency at Amarillo, Texas is given as 7 percent, indicating the very low percentage of time for which stable conditions occur during the day period. The contribution of night period inversion conditions to the total percent frequency is therefore approximated as 30 percent of total time, which implies a 60 percent of night period inversion conditions. Hosler used radiosonde observation times of the set 1000 and 2200 or the set 0700 and 1900. In order to "prepare frequencies of low-level stability as a percent of total seasonal hours from radiosonde data, the following hypothesis was used for analyzing data from inland stations: The entire nocturnal period was considered stable if an inversion was observed at any time during the night, and the maximum percent frequency of inversions for any one observation time within a nocturnal period was assumed applicable to the entire nighttime period."^(23a) Even if there is only one night for which stable conditions, once having appeared, do not continue all night, then this method of estimating nocturnal inversion frequencies is an overestimation, a conclusion agreed with by Hosler^(23b). A crude correction is therefore applied to the night period inversion frequency tabulation. It is assumed that one-half of the nocturnal period, rather than the entire period, is considered stable if an inversion is observed at any time during the night. This correction factor halves the Hosler frequency, resulting in an annual average night period inversion frequency of 30 percent.

The night period wind speed, U_N , being inversion frequency weighted, is given by the following relation for the purpose of height extrapolation.

$$U_N = 0.7 U_u + 0.3 U_s \quad (3)$$

The day period wind speed, U_D , is height extrapolated using the following equation

$$U_D = U_u \quad (4)$$

Both day period and night period reference height wind speeds are compiled using a wind speed-duration tabulation, and each are separately height extrapolated. For those purposes for which a daily average speed-duration function is required, the day period and night period percent durations are linearly averaged for each wind speed value.

The characteristic roughness length z_0 is an empirical constant which should be locally evaluated because it is a function of the local terrain geometry and type of ground cover. However, the only longterm wind data in the region at two significantly different heights at the same location is from the National Weather Service Stations at Lubbock Regional Airport. The Lubbock anemometer was located atop the airport control tower free from surrounding obstructions at a height of 20.7 meters from June, 1950 to September, 1965, when it was lowered to its present height of 7.6 meters and placed on a tower adjacent to the airport runway. The annual wind speed average at the 20.7 meter height was 8.55 m/S and 7.67 m/S at the 7.6 meter height. Fitting these data to the logarithmic relation (2) yields a value of 6 cm which corresponds to a surface covered by long to medium height grasses from data compiled by other investigators^(7,25). The natural cover for the Lubbock area is Buffalo Grass and the farm land crop in the region is short staple cotton. Both are comparable in ground cover height to medium to long grasses. Inasmuch as that description fits most of the SwPS service region, the z_0 value of 6 cm computed at Lubbock is used for all data stations.

The exponent a of equation (1) is a function of both wind speed and lapse rate⁽⁷⁾. The lapse rate is taken as the 0600 CST average Amarillo, Texas value of $0.18^\circ\text{C}/100$ meters. Using that lapse rate, the empirical tower data of Rijoort⁽²⁶⁾ for the exponent are well fit by the following set of linear equations.

$$a = 0.557 - 0.0316 U_r \quad 1 \text{ knot} \leq U_r \leq 11 \text{ knots} \quad (5)$$

$$a = 0.325 - 0.01 U_r \quad 11 \text{ knots} \leq U_r \leq 18 \text{ knots} \quad (6)$$

$$a = 0.15 \quad U_r \geq 18 \text{ knots} \quad (7)$$

By these methods, wind speeds are compiled as speed-duration tabulations for both night and day periods and extrapolated to heights of 30, 45, 60 and 75 meters. At each height, the average night period, day period, and daily wind speed averages are computed and a daily average speed-duration tabulation is made.

c. Windpower

The kinetic energy flux of the wind, named the windpower density, is given by

$$E = 1/2 \rho U^3$$

where ρ is the air mass density, and is computed from the perfect gas equation of state using the annual average values of dry bulb temperature and barometric pressure given in Table 1. Wind power-duration tabulations are computed by substituting the wind speed levels of the wind speed-

duration functions directly into equation (8) above. By numerical integration of the tabular wind power-duration functions, the average windpower density $\bar{E}$ is obtained for each station and each height above ground according to

$$\bar{E} = \frac{1}{T} \int_0^T E dt \quad \begin{array}{l} \text{where } t = \text{time} \\ \text{and } T = \text{total period} \\ \text{of record} \end{array} \quad (9)$$

d. Wind Velocity-Frequency and Power-Frequency Distribution

For the original anemometer height at each wind measurement station and for each of the extrapolated heights calculated, wind data have been arranged by velocity-frequency and power-frequency distributions as shown in the example in Table 2. This Table shows the average percentage of the time (day, night and total) that the wind velocity exceeds a given velocity value, and that the available power exceeds the equivalent power value. In this example, data are presented from the Amarillo Airport station. The Amarillo wind regime is taken as representative of the study region, with some wind stations reporting less and some reporting higher available power density in the wind. It can be seen from Table II that the probability of calm conditions, (winds less than 4 knots), is less than 2.5% at a height of 45M. This value is extremely low, and gives rise to the possibility of machines with high capacity factor. Statistically, this may enhance the possibility of crediting capacity value to WTG installations, particularly those with geographic diversity (both these concepts remain unproven, however). Capacity factor is here defined as the total annual energy converted by a wind machine in kWh per annum, divided by the rated energy available (rated power x 8760 Hrs./annum). For example, in the Amarillo wind regime, a WTG with the characteristics of the NASA MOD "Zero" machine (Plumbrook), at the 45M height, would exhibit a capacity factor of nearly 0.8 at its 8M/sec. rated wind speed. From Table II it can be seen that this machine would deliver its rated power 41% of the time. A similar machine rated at 10M/sec. would exhibit a capacity factor of about 0.6, and at 13M/sec. a capacity factor of 0.38. Machines rated at these velocities are used in further calculations made in this report. In a later section, it is reported that in the Amarillo wind regime, the most cost-effective machine of 1,000 kW capability was found to be one rated at a wind velocity of 10M/sec. Such a machine would exhibit a capacity factor of 0.59 and would deliver full rated power about 26% of the time at the Amarillo location.

STATION # 23047 AMARILLO, TEXAS													
TOTAL NUMBER OF YEARS 11.0													
EXTRAPOLATED HEIGHT IS 45.0000 METERS (147.6 FT)													
PERIOD FROM 1950 THROUGH 1960													
V.W.EE KNOTS	V.W.EE M/SEC	V.DAY KNOTS	V.DAY M/SEC	POWER KW/M**2	% DAY	V.NITE KNOTS	V.NITE M/SEC	POWER KW/M**2	% NITE	TOTAL PERCENT	TOTAL KW/M**2	V.TOTL M/SEC	V.TOTL KNOTS
0	0.0	0.0	0.0	0.0	100.00	0.0	0.0	0.0	100.00	100.00	0.0	0.0	0.0
1	0.515	1.28	0.67	0.0002	98.60	0.56	0.875	0.0003	98.57	98.58	0.0002	0.736	1.63
2	1.030	2.59	1.33	0.0013	98.43	1.07	1.570	0.0021	98.42	98.42	0.0017	1.456	2.83
3	1.545	3.88	2.00	0.0043	97.51	1.51	2.324	0.0067	97.51	97.51	0.0055	2.161	4.20
4	2.059	5.17	2.66	0.0101	97.83	2.03	3.042	0.0151	97.86	97.86	0.0126	2.853	5.54
5	2.574	6.47	3.33	0.0198	96.61	2.75	3.734	0.0279	96.93	96.93	0.0239	3.532	6.86
6	3.089	7.76	3.99	0.0342	86.31	3.55	4.403	0.0458	84.87	85.59	0.0499	4.199	8.16
7	3.604	9.05	4.66	0.0543	81.69	4.03	5.050	0.0691	78.81	80.23	0.0617	4.856	9.43
8	4.118	10.35	5.33	0.0811	76.01	4.51	5.677	0.0982	70.93	73.42	0.0996	5.502	10.69
9	4.633	11.64	5.99	0.1154	69.86	5.00	6.286	0.1332	62.42	66.14	0.1243	6.139	11.93
10	5.148	12.93	6.66	0.1583	64.04	5.48	6.877	0.1744	54.37	59.20	0.1664	6.768	13.15
11	5.663	14.23	7.32	0.2108	54.51	5.96	7.471	0.2237	42.11	48.31	0.2172	7.398	14.37
12	6.178	15.52	7.99	0.2736	49.59	6.44	8.112	0.2864	36.04	42.82	0.2900	8.051	15.64
13	6.692	16.81	8.66	0.3479	43.80	6.92	8.748	0.3591	29.88	36.46	0.3535	8.702	16.90
14	7.207	18.11	9.32	0.4345	37.64	7.40	9.378	0.4424	23.92	30.78	0.4384	9.350	18.16
15	7.722	19.40	9.99	0.5344	32.71	7.88	10.002	0.5368	19.78	26.83	0.5326	9.995	19.41
16	8.237	20.69	10.65	0.6486	25.88	8.36	10.621	0.6427	16.64	23.26	0.6457	10.637	20.66
17	8.752	21.99	11.32	0.7780	21.43	8.84	11.235	0.7607	11.51	16.57	0.7694	11.277	21.91
18	9.266	23.28	11.98	0.9235	15.66	9.36	11.870	0.8971	8.00	11.83	0.9103	11.927	23.17
19	9.781	24.57	12.65	1.0861	12.54	9.88	12.529	1.0551	6.16	9.35	1.0706	12.590	24.46
20	10.296	25.87	13.32	1.2668	10.49	10.40	13.189	1.2306	5.11	7.80	1.2487	13.253	25.74
21	10.811	27.16	13.98	1.4664	7.62	10.90	13.848	1.4246	3.53	5.58	1.4455	13.915	27.03
22	11.326	28.45	14.65	1.6861	6.43	11.38	14.508	1.6379	2.89	4.56	1.6620	14.578	28.32
23	11.840	29.75	15.31	1.9266	4.87	11.84	15.167	1.8716	2.13	3.50	1.8991	15.241	29.60
24	12.355	31.04	15.98	2.1890	3.34	12.30	15.826	2.1265	1.53	2.43	2.1577	15.303	30.89
25	12.870	32.33	16.65	2.4742	2.54	12.75	16.486	2.4035	1.21	1.87	2.4368	16.566	32.18
26	13.385	33.63	17.31	2.7831	1.86	13.20	17.145	2.7036	0.84	1.36	2.7434	17.228	33.47
27	13.900	34.92	17.98	3.1167	1.42	13.65	17.805	3.0277	0.67	1.04	3.0722	17.311	34.75
28	14.414	36.21	18.64	3.4760	1.23	14.10	18.464	3.3767	0.56	0.89	3.4264	18.394	36.04
29	14.929	37.51	19.31	3.8619	0.92	14.55	19.124	3.7516	0.43	0.67	3.8068	19.476	37.33
30	15.444	38.80	19.97	4.2754	0.76	15.00	19.783	4.1533	0.36	0.56	4.2143	19.559	38.62
31	15.959	40.09	20.64	4.7173	0.62	15.45	20.442	4.5826	0.24	0.38	4.6499	20.642	39.90
32	16.474	41.39	21.31	5.1887	0.56	15.90	21.102	5.0405	0.20	0.33	5.1146	21.204	41.19
33	16.988	42.68	21.97	5.6905	0.47	16.35	21.761	5.5280	0.16	0.22	5.6092	21.307	42.48
34	17.503	43.98	22.64	6.2236	0.42	16.80	22.421	6.0459	0.12	0.17	6.1348	22.410	43.76
35	18.018	45.27	23.30	6.7891	0.39	17.25	23.080	6.5952	0.10	0.14	6.6922	23.192	45.05
36	18.533	46.56	23.97	7.3878	0.36	17.70	23.740	7.1768	0.07	0.09	7.2023	23.855	46.34
37	19.048	47.86	24.64	8.0207	0.30	18.15	24.400	7.7917	0.05	0.07	7.7406	24.517	47.63
38	19.562	49.15	25.30	8.6888	0.26	18.60	25.060	8.4406	0.05	0.06	8.5647	25.180	48.91
39	20.077	50.44	25.97	9.3929	0.23	19.05	25.719	9.1247	0.03	0.04	9.2588	25.843	50.20
40	20.592	51.74	26.63	10.1342	0.20	19.50	26.377	9.8448	0.03	0.03	9.9895	26.505	51.49
AVERAGE WIND SPEED KNOTS												AVERAGE POWER DENSITY KW/M**2	
M/SEC												KW/M**2	
DAY												16.07	
NITE												0.3250	
TOTAL												0.3578	
7.844												0.4397	

TABLE 2.

Velocity and Power Duration Data at Amarillo, Texas Weather Station,
10 Year Average, Extrapolated to 45M height above Ground.

4. Results of Assessment of Wind Energy Distributions

Wind speed-duration curves for Lubbock and Carlsbad are given in Figures 3 and 4 respectively for a 30 meter height above ground. The curves are typical in shape, and as usual, the night period curve is of lesser magnitude than the day period curve in each case. The ratio of day to night period average wind speeds are nearly identical at each location, being 1.25 at Lubbock, and 1.21 at Carlsbad. The shape of the speed-duration curve reflects the statistical distribution of wind speed with time. This distribution varies significantly from station to station throughout the SwPS region, as demonstrated by the comparison between the average daily wind speed-duration curves of Lubbock and Carlsbad given in Figure 5. The figure shows a crossover of the curves for wind speeds above 10 M/S. This means that Carlsbad experiences high winds (>10 M/S) a greater percentage of the time than does Lubbock, even though Lubbock has a 10 percent higher average wind speed. Because of the cubic relation of power in the wind to wind speed, such a distribution will dramatically effect the average power available in the wind. Figure 6 comparatively displays the wind power-duration curves for the two locations. The average wind power density at Carlsbad is 6 percent higher than that at Lubbock, even though the cube of the wind speed is 23 percent lower at Carlsbad than at Lubbock. Therefore, the average wind speed at a location will not provide reliable assessments of the actual power density of the wind. When possible, statistical distributions should be used.

Figure 6 further displays the energy which could be produced by a wind turbine generator of practical characteristics (1000 kW rated at 10Mps). Such a turbine will not operate below a threshold wind speed named the "cut in" speed and will by some means stabilize at the rated speed of the turbine, thus producing constant power at all speeds above rated. The area under the power density curves of Figure 6 between the "feather" condition and "cut in" condition represents that portion of the windpower which can practically be utilized with the efficiency of the wind turbine generator (WTG). As displayed by the figure, the cross-hatched area represents the excess of windpower which can be used at Lubbock over that which can be utilized by Carlsbad by a similar WTG. This excess is a result only of the shape difference (statistical distribution difference) of the two curves. Thus, even though Carlsbad has an average windpower density 6 percent higher than that of Lubbock, the particular WTG given could produce only 83 percent as much energy at Carlsbad as it could at Lubbock. Therefore, the average power density in the wind will not provide reliable assessments of potential windpower utilization rates. Extremely large errors can result from an assumption of uniformity of wind speed-duration functions or from use of the local wind speed

FIGURE 3

WIND SPEED - DURATION CURVES FOR LUBBOCK, TEXAS
AT A HEIGHT OF 30 METERS ABOVE GROUND

FIGURE 4

WIND SPEED - DURATION CURVES FOR CARLSBAD, NEW MEXICO
AT A HEIGHT OF 30 METERS ABOVE GROUND

FIGURE 5

AVERAGE DAILY WIND SPEED - PER CENT DURATION CURVES
FOR LUBBOCK, TEXAS AND CARLSBAD, NEW MEXICO AT A
HEIGHT OF 30 METERS ABOVE GROUND

FIGURE 6
 AVERAGE DAILY POWER - PER CENT DURATION CURVES FOR
 LUBBOCK, TEXAS AND CARLSBAD, NEW MEXICO AT A HEIGHT
 OF 30 METERS ABOVE GROUND

average alone in estimation of the local potential for windpower generation of electrical energy. Local wind speed averages are not even reliable indicators of the relative magnitude of windpower when used to compare potentials of locations for which those data are known. It is imperative to use statistical distribution functions for all windpower assessments.

The distributions of windpower density at levels of 30, 45, 60 and 75 meters above ground throughout the SwPS service region are displayed in Figures 7 through 10 and listed in Table 3. The contour lines of equal windpower density are drawn by estimation based on linear interpolation among data stations. The SwPS service area is indicated on the maps for reference. The stations names may be identified by referral to Figure 2. The figures indicate a generally increasing average windpower density towards the north within the region with a relative maximum in southwestern Kansas and a fairly broad region of nearly uniform windpower density in the West Texas region south of the Panhandle.

The data of two stations, namely Big Spring, Texas and Hobart, Oklahoma give anomalous results with respect to nearby stations and with respect to the general trend of the data of the region. Because of the severity of the deviations, data from these stations are disregarded in interpolations for isopleths, assessment of energy potentials, and other evaluations, although the values are listed in all other tabulations and are indicated on all maps.

The windpower density at Big Spring is likely influenced by the surrounding relief features, the city being located on the edge of the "caprock" a high plain encompassing most of West Texas including the Panhandle region. As such, the wind data there could represent the surrounding region or only the local airfield wind regime because of topographic influence of the relief features. Without additional information, only speculation is possible, so the data is properly abandoned, being the least biased alternative.

The period of record at Hobart, Oklahoma is during the early 1950's. The station history from the U. S. Dept. of Commerce⁽²⁷⁾ gives only height information about the anemometer during that period. The station exposure is described as follows: "Terrain is flat to gently rolling except for the Wichita Mountains which jut abruptly out of the flat 10 mi. south of the station, consisting of isolated buttes 800-900 ft. high. Few trees except along creeks and section lines." It is unlikely that such terrain features significantly affect the anemometer wind regime from such a distance. Fortunately, Hobart is outside of the region analyzed for windpower utilization so that even if included in the assessment, it would have little influence on the results.

FIGURE 7
ISOPLETHS OF WIND POWER DENSITY
30 METERS ABOVE GROUND, KW/m²
(Extrapolated from actual anemometer heights)

FIGURE 8

ISOPLETHS OF WIND POWER DENSITY
45 METERS ABOVE GROUND, KW/m²

(Extrapolated from actual anemometer heights)

FIGURE 9

ISOPLETHS OF WIND POWER DENSITY
60 METERS ABOVE GROUND, KW/m²

(Extrapolated from actual anemometer heights)

FIGURE 10

ISOPLETHS OF WIND POWER DENSITY
75 METERS ABOVE GROUND, KW/m^2

(Extrapolated from actual anemometer heights)

Station Number	Station Name	Height Above Ground			
		30 m	45 m	60 m	75 m
23047	Amarillo, Texas	0.530	0.643	0.733	0.809
23005	Big Spring, Texas	0.527	0.536	0.613	0.678
23007	Childress, Texas	0.294	0.358	0.409	0.452
93042	Dalhart, Texas	0.480	0.581	0.662	0.729
23042	Lubbock, Texas	0.319	0.388	0.444	0.491
23023	Midland, Texas	0.267	0.325	0.372	0.411
23040	Wink, Texas	0.237	0.288	0.329	0.364
93033	Carlsbad, New Mexico	0.341	0.413	0.471	0.519
23051	Clayton, New Mexico	0.384	0.466	0.532	0.587
23008	Clovis/Cannon, New Mexico	0.281	0.342	0.391	0.433
93034	Hobbs, New Mexico	0.322	0.391	0.446	0.492
23043	Roswell, New Mexico	0.245	0.299	0.343	0.380
13902	Altus, Oklahoma	0.219	0.266	0.304	0.337
13975	Gage, Oklahoma	0.486	0.589	0.671	0.741
93986	Hobart, Oklahoma	0.480	0.583	0.665	0.734
13987	Dodge City, Kansas	0.495	0.601	0.686	0.758
23064	Garden City, Kansas	0.779	0.944	1.075	1.186

TABLE 3
AVERAGE WIND POWER DENSITY, KW/M²

A less serious anomaly but one which may be open to question because of the resulting increase in the windpower density is the station at Garden City, Kansas. Windpower density at 30M here is shown to be .78 kW/M² compared to 0.50 kW/M² at the next closest station of Dodge City, Kansas. However, this data and the general trend produced by utilizing it is confirmed by previous studies, notably the work of Reed⁽³²⁾. Garden City is also outside the Southwestern Public Service Company area and consequently has little effect on the analysis to follow in succeeding chapters.

B. Potential Electrical Energy Generation

1. WTG Performance Characteristics

The maximum mechanical power extractable from the wind by an ideal wind turbine is 59.3 percent of the power within the wind⁽²⁸⁾. A real wind turbine generator (WTG) will deliver substantially less than that, perhaps 40 to 45 percent, depending upon the turbine design and wind regime.

Performance characteristics from existing and projected wind turbines, including all losses, have been compiled by Johnson⁽²⁹⁾ to form a set of composite performance curves for WTG's of 8, 10 and 13 M/S rated wind speeds. These curves are reproduced in Figure 11. The diameter D of a WTG producing the rated power PR at the rated wind speed UR is given by Johnson as,

$$D = 79.7 \sqrt{\frac{PR/\text{Kilowatts}}{(UR/\text{meters per second})^3}} \quad \text{meters} \quad (10)$$

For a uniform wind speed, the power in the wind is given by,

$$P_w = \rho \pi D^2 U^3 / 8 \quad (11)$$

The power output P from a WTG can be defined in terms of a mechanical efficiency η as,

$$P = \eta P_w, \quad (12)$$

and, in general, the efficiency is a function of wind speed. Let P* be the ratio P/PR and let U* be the ratio U/UR. Then by combination of equations (10), (11) and (12), the efficiency is given by,

$$\eta = 0.368 P^* / (U^*)^3 \quad (13)$$

The nondimensional power P^* is a function of nondimensional wind speed U^* , as seen in Figure 11. The functional form is independent of rated wind speed, however, as seen in Figure 12, taken from the characteristic curves of Figure 11 and equation (13). Thus, for any designated WTG, the mechanical efficiency is a function only of nondimensional wind speed U^* according to the following set of equations fit to the curve of Figure 12.

$$\eta = 0 \quad 0 \leq U^* \leq 0.5 \quad (14)$$

$$\eta = 2.36 (U^* - 0.5) \quad 0.5 \leq U^* \leq 0.6 \quad (15)$$

$$\eta = 0.15 + 0.225 \sin \pi (1.25 U^* - 0.625) \quad 0.6 \leq U^* \leq 0.9 \quad (16)$$

$$\eta = 0.368 + 0.07 (1 - U^*) \quad 0.9 \leq U^* \leq 1.0 \quad (17)$$

$$\eta = 0.368 \quad U^* \geq 1.0 \text{ and } u < 30 \text{ M/S} \quad (18)$$

2. Assessment of Potential Electrical Energy Generation

For this assessment, three WTG designs are considered. These are the three for which characteristic performance curves are given in Figure 11. They are representative of modern, efficient machines which employ fixed ratio gearing and use either a synchronous or a low-slip induction generator so that the turbine operates at a fixed speed under load⁽²⁹⁾. The three WTG designs are rated at 8, 10 and 13 meters/second respectively and will be designated as WTG-8, WTG-10 and WTG-13, respectively. The standard output capacity (rated power) will be taken as one megawatt. According to equation (10), this would result in WTG's with rotor diameters of 111.4, 79.7 and 53.8 meters for WTG-8, WTG-10 and WTG-13, respectively. The rotor diameters limit the minimum height of the turbine hub so that the rotor would clear the ground. Electrical power assessments are therefore limited to hub heights of 60 and 75 meters for WTG-8, to 45, 60 and 75 meters for WTG-10, and to 30, 45, 60 and 75 meters for WTG-13.

Electric power-duration functions are generated for each of the three WTG design ratings by multiplication of the wind power-duration functions by the appropriate efficiency according to the corresponding nondimensional wind speed using equations (14) through (18). The resulting electric power-duration function tabulations are numerically integrated using the trapezoid rule approximation to obtain annual average production of electric energy by wind turbine generators producing rated power of one megawatt at rated

FIGURE 11
WIND TURBINE GENERATOR CHARACTERISTIC CURVES, ALL LOSSES INCLUDED
MODIFIED FROM C. C. JOHNSON, 1975 [29]

FIGURE 12
EFFICIENCY/WINDSPEED RELATION FROM
WIND TURBINE PERFORMANCE CURVES

wind speeds of 8, 10 and 13 meters per second, variously erected at heights of 30, 45, 60 and 75 meters. These results are listed in Table 4.

Continuous functions of annual electrical energy potential for the various WTG's at the various turbine hub heights are estimated by linear interpolation among data stations. These functions are represented by isopleths of constant electric power generation potential in Figures 13 through 21 drawn on maps of the SwPS service region. These maps show generally increasing potential for electric energy generation in a northerly direction with a relative maximum in southwestern Kansas. The shapes of the isopleths are somewhat different from the windpower density isopleths owing to the variation in statistical distribution of wind speeds, i.e., variation in shape of wind speed-duration curves throughout the region.

The electrical energy generation potential isopleth maps can be used to estimate the annual energy that could be produced by a given WTG at any location within the SwPS service region by selection of the proper map and interpolation between isopleths to the location required. The maps exhibit anomalies at Hobart, Oklahoma and Big Spring, Texas as before and the values at those locations were not used in estimating the placement of contour lines.

3. Daily and Seasonal Power Variability

The availability of wind for production of electrical power varies with the time of day, and the season of the year. The winds are generally expected to be higher in the afternoon and in the spring than at other times. The degree of such hourly and seasonal variation of the average wind is easily quantized using the data accumulated in this study. Amarillo, Texas is selected as a representative site for analysis, being centrally located in the SwPS service region. The following computations were made for the Amarillo wind data.

- a. The 3-hourly wind speeds for the period January, 1962 through December, 1972 were collected and a wind speed-duration function tabulated for each of the hours 0000, 0300, 0600, 0900, 1200, 1500, 1800 and 2100 throughout a given month over the 10-year interval. Thus were obtained 8 speed-duration curves (3 hour intervals) for each of the 12 months of the year.
- b. Each speed-duration curve was height adjusted by the usual way to various heights, and by the cubic relation, power-duration functions formed. WTG performance characteristics were applied to each power-duration function and integrated to obtain

	Station	Rated at 8 m/s		Rated at 10 m/s				Rated at 13 m/s		
		60 m	75 m	45 m	60 m	75 m	30 m	45 m	60 m	75 m
23047	Amarillo, Texas	6.89	7.08	5.11	5.47	5.72	2.75	3.22	3.53	3.78
23005	Big Spring, Texas	6.17	6.39	4.50	4.83	5.08	2.25	2.67	2.99	3.24
23007	Childress, Texas	5.33	5.64	3.39	3.69	3.94	1.39	1.70	1.95	2.17
93042	Dalhart, Texas	5.97	6.17	4.31	4.61	4.83	2.28	2.64	2.89	3.09
23042	Lubbock, Texas	5.69	5.94	3.75	4.08	4.36	1.61	1.97	2.25	2.47
23023	Midland, Texas	4.92	5.17	3.28	3.56	3.81	1.42	1.72	1.97	2.17
23040	Wink, Texas	4.17	4.39	2.56	2.83	3.03	1.08	1.33	1.53	1.67
93033	Carlsbad, New Mexico	4.61	4.83	3.06	3.28	3.48	1.50	1.72	1.92	2.09
23051	Clayton, New Mexico	6.06	6.31	4.08	4.44	4.73	1.89	2.28	2.59	2.81
23008	Clovis/Cannon, N. M.	4.58	4.83	2.97	3.25	3.48	1.33	1.61	1.81	2.00
93034	Hobbs, New Mexico	5.31	5.58	3.53	3.83	4.06	1.56	1.89	2.14	2.36
23043	Roswell, New Mexico	4.17	4.44	2.47	2.72	2.97	1.06	1.28	1.45	1.61
13902	Altus, Oklahoma	4.11	4.33	2.61	2.86	3.06	1.08	1.33	1.53	1.70
13975	Gage, Oklahoma	5.61	5.78	4.25	4.47	4.67	2.42	2.81	3.11	3.31
93986	Hobart, Oklahoma	6.56	6.81	4.83	5.14	5.39	2.53	3.00	3.34	3.61
13987	Dodge City, Kansas	7.00	7.25	5.06	5.42	5.73	2.59	3.06	3.39	3.67
23064	Garden City, Kansas	7.64	7.81	5.89	6.22	6.48	3.48	4.03	4.39	4.64

TABLE 4
ANNUAL ELECTRICAL ENERGY POTENTIAL AT ALL STATIONS
FOR A 1 MEGAWATT TURBINE AT VARIOUS RATED WIND SPEEDS
AND TURBINE HUB HEIGHTS, KWH $\times 10^{-6}$

FIGURE 13
 ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
 BY AN 8 m/s RATED TURBINE AT 60 METER HUB HEIGHT
 $\text{KWH} \times 10^{-6}$ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 14
ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
BY AN 8 m/s RATED TURBINE AT 75 METER HUB HEIGHT
KWH x 10⁻⁶ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 15

ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
 BY A 10 m/s RATED TURBINE AT 45 METER HUB HEIGHT
 $\text{KWH} \times 10^{-6}$ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 16
ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
BY A 10 m/s RATED TURBINE AT 60 METER HUB HEIGHT
 $\text{KWH} \times 10^{-6}$ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 17

ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
BY A 10 m/s RATED TURBINE AT 75 METERS HUB HEIGHT
KWH x 10⁻⁶ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 18
ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
BY A 13 m/s RATED TURBINE AT 30 METER HUB HEIGHT
KWH $\times 10^{-6}$ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 19

ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
 BY A 13 m/s RATED TURBINE AT 45 METER HUB HEIGHT
 $\text{KWH} \times 10^{-6}$ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 20
ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
BY A 13 m/s RATED TURBINE AT 60 METER HUB HEIGHT
KWH x 10⁻⁶ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

FIGURE 21

ISOPLETHS OF ELECTRICAL ENERGY GENERATION POTENTIAL
 BY A 13 m/s RATED TURBINE AT 75 METER HUB HEIGHT
 $\text{KWH} \times 10^{-6}$ PER YEAR PER INSTALLED MEGAWATT

(Extrapolated from actual anemometer heights)

the average power output for the machine at each hour of an average day of the month.

- c. These average hourly variation curves were integrated to obtain the expected energy output per installed KW for each month.

The hourly electric power which could be produced by a one megawatt WTG rated at 10 M/S erected to a turbine hub height of 60 meters is given in Figures 22 and 23. The minimum expected power production occurs during the month of July at 0600 when only 398 KW per installed megawatt are produced on the average. The maximum expected power production occurs during the month of April at 1200 for which 798 KW per installed megawatt are produced on the average. It is interesting to note that the hourly distributions generally follow electrical load requirements being maximal during the day period and minimal during the night period. This is illustrated in Figure 24 in which a typical load duration curve (May 1973) for the SwPS system is shown superimposed on the average power curve for May, taken from Figure 22.

The expected monthly variation of electric power production by a one megawatt WTG rated at 10 M/S elevated to 60 meters is given in Figure 25. The minimal energy production month is August for which 0.402 million KWH are expected and the maximum production month is March for which 0.529 million KWH are expected. The mean value for the year is 0.456 million KWH/month, so that the maximal deviation from the mean of the expected monthly windpower is only 16 percent. The extractable energy from the wind of West Texas is therefore quite seasonably reliable and unexpectedly uniform.

4. Effect of Scheduled and Unscheduled Downtime

Actual power generated by a WTG would be affected in a minor way by periods of scheduled maintenance, unscheduled downtime and repair. It is not possible to assess this effect on the basis of experience, since no large systems have operated routinely for long periods of time. Some comparison with existing plants may be useful, and estimates of maintenance requirements are made in a later section of this report ("Design and Cost Study", Appendix A.)

On the present Southwestern Public Service Company system, gas turbines (which may be said to represent equipment of much greater complexity than wind turbine generators), exhibit overall availability of approximately 90%. Unscheduled outages and repair account for less than 1% of the total, the majority of the unavailable time being accounted for by scheduled routine maintenance. It is reasonable

FIGURE 22

HOURLY VARIATION OF POWER PRODUCED BY 1 MW TURBINE RATED AT 10 mps AT 60 m HUB HEIGHT IN AMARILLO, TEXAS DURING AN AVERAGE DAY OF THE MONTH, JANUARY THROUGH JUNE

3739

FIGURE 23

HOURLY VARIATION OF POWER PRODUCED BY 1 MW TURBINE RATED AT 10 mps AT
60 m HUB HEIGHT IN AMARILLO, TEXAS DURING AN AVERAGE DAY OF THE MONTH, JULY THROUGH DECEMBER

FIGURE 24

AVERAGE HOURLY VARIATION OF WIND-GENERATED POWER
AND OF SwPS SYSTEM LOAD FOR MONTH OF MAY. (WTG rated
at 10M/S at 60M hub height).

3740

FIGURE 25
AVERAGE MONTHLY POWER PRODUCED
BY A 1 MW TURBINE RATED AT 10 mps
AT 60 m HUB HEIGHT IN AMARILLO, TEXAS
JANUARY THROUGH DECEMBER

to assign more optimistic values of down-time to WTG than to gas turbines based on the lack of combustion chambers, high temperature components and high speed mechanisms that apply to gas turbines. A maximum figure of one day/month total unavailable time may therefore be realistically assigned to the WTG. This amounts to approximately 3%. Figures for electrical energy generation potential may thus be subject to reduction by 3% of totals given in this report. This figure is insignificant compared to the other uncertainties in wind energy potential projections, and has been disregarded in the preceding paragraphs.

C. Windpower Utilization Potential

The purpose of this part of the study is to determine upper limits on the potential use of practical WTG arrays to produce electrical power, using the SwPS service region as a model area, the latter described in Figure 26. The distribution of wind energy at various heights above ground and its potential convertability to electrical energy have been determined. The calculations have provided estimations of annual electrical energy potential at 17 locations throughout the SwPS region for one megawatt WTG's obtaining rated power at 8, 10 and 13 meters/second wind speed elevated to heights above the ground of 30, 45, 60 and 75 meters. Isopleth maps, representing continuous functions of these calculations are given as Figures 13 through 21 and a tabulation is presented as Table 4. The maps represent the continuous distribution of the electrical energy that could be generated annually by a specified WTG at a specified height at any location throughout the region. These results are to be used to determine the magnitude of electrical energy which could be produced in the SwPS service area with practical wind turbines, without specific regard to other considerations. Practical, short-term utilization potential is discussed in a later section.

1. Wind Farm Regions

The area served by SwPS is displayed in Figure 26 with indications of the major transmission lines. To facilitate estimations of windpower exploitation, the SwPS service area is divided into 5 parts, named wind farm regions (WFR). The division is made so that each WFR is of similar size and such that each contains a major power generation center and hence a major convergence center for power transmission lines. The wind farm regions are defined and numerically designated by the area map given as Figure 27.

WTG's or WTG arrays could be distributed within the SwPS service region in innumerable patterns. One promising choice would be to locate all sites with unusually high potential for power production. These might be sites in canyons, on hilltops, along ridge-

3717

FIGURE 26
AREA SERVED BY SWPSC

3741

FIGURE 27
WIND FARM REGIONS
OF SWPSC SERVICE AREA

lines or other sites with irregularly high wind speeds. The location and evaluation of such sites would require extensive instrumentation and is beyond the scope of this project. Such sites are probably uncommon over much of the SwPS service region owing to the relatively level plain, but over other large areas, such as along the Canadian River Brakes, sites of anomalously high wind conditions may be commonplace.

2. Uniform Deployment of WTG's

A first-cut upper bound can be established by evaluation of the amount of energy that could be annually extracted from the region by maximal employment of WTG's. A separation distance of ten turbine diameters between adjacent turbines is usually taken as an adequate separation to avoid interference or loss of windpower available to downstream turbines. The ten diameter spacing is considered quite conservative by some⁽³⁰⁾, and it may be that spacings as close as 2 or 3 turbine diameters will not cause unacceptable losses or interference.

Golding⁽⁴⁾ states that a "flat-topped hill or ridge might accommodate several (200 ft. diameter machines) with a spacing of about 1/4 mile." This is equivalent to approximately 6 rotor diameters. For purposes of this study, a value of 5 turbine diameters is arbitrarily taken as a lower limit for WTG separation. For uniform deployment, a minimum value of 20 diameters is used for the spacing limit which should produce a very conservative estimate of the total windpower potential, an estimate which may be altered as future definitive work on the spacing of turbines is reported.

Total electrical energy production estimations can be easily made for various spacing distances. The electrical energy generation potential maps are used to estimate the average electrical energy generation potential for each of the five wind farm regions (WFR) for a specified WTG rating and hub height. The standard size of WTG considered for all following analyses is one megawatt, but the results will apply to any size WTG by linear scaling. The number N of WTG's to be located in a given WFR of area A using a turbine spacing distance of Δ is computed according to,

$$N = [1 + (A)^{1/2}/\Delta]^2 \quad (13)$$

The electrical energy that could annually be generated in each WFR is approximated by the product of the number of WTG's with the average electrical energy generation potential of the region. Results of these computations for WTG spacings of 20 to 80 turbine diameters are listed in Tables 5 through 13. Spacing WTG's rated at 8 meters/second elevated to 60 meters would require 24,325 machines which would produce over

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH x 10 ⁻⁶ /YrMW	20 Diameter Spacing		40 Diameter Spacing		60 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹
1	6,651	17,226	4.4	3,612	16.06	927	4.11	426	1.89
2	10,057	26,048	5.3	5,427	28.64	1,384	7.31	633	3.33
3	9,034	23,398	5.6	4,883	27.14	1,247	6.92	571	3.17
4	10,780	27,920	5.8	5,812	33.92	1,481	8.64	677	3.94
5	8,486	21,979	6.7	4,591	30.61	1,173	7.83	538	3.89
Totals	45,008	116,571		24,325	136.37 or 7.8 times SWPSC Capacity	6,212	34.81 or 2.0 times SWPSC Capacity	2,845	16.22 or 0.93 times SWPSC Capacity

TABLE 5
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 8 M/S ELEVATED TO 60 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH x 10 ⁻⁶ /YrMW	20 Diameter Spacing		40 Diameter Spacing		60 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹
1	6,651	17,226	4.7	3,612	17.06	927	4.39	426	2.00
2	10,057	26,048	5.8	5,427	31.64	1,384	8.08	633	3.69
3	9,034	23,398	5.8	4,883	28.47	1,247	7.28	571	3.33
4	10,780	27,920	6.7	5,812	38.75	1,481	9.86	677	4.50
5	8,486	21,979	7.2	4,591	33.17	1,173	8.47	538	3.89
Totals	45,008	116,571		24,325	149.09 or 8.5 times SWPSC Capacity	6,212	38.08 or 2.17 times SWPSC Capacity	2,845	17.41 or 0.99 times SWPSC Capacity

TABLE 6
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 8 M/S ELEVATED TO 75 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH X 10 ⁻⁶ /yr MW	20 Diameter Spacing		50 Diameter Spacing		60 Diameter Spacing		70 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹
1	6,651	17,226	2.78	6,938	19.28	1,148	3.19	810	2.25	600	1.67
2	10,057	26,048	3.61	10,443	37.73	1,717	6.19	1,209	4.36	894	3.22
3	9,034	23,398	3.89	9,392	36.53	1,546	6.00	1,089	4.22	806	3.14
4	10,780	27,920	4.58	11,187	51.28	1,837	8.42	1,293	5.92	956	4.39
5	8,486	21,979	5.14	8,828	45.36	1,455	7.47	1,025	5.28	759	3.89
Totals	45,008	116,571		46,788	190.18 or 10.8 times SWPSC capacity	7,703	31.27 or 1.78 times SWPSC capacity	5,426	22.03 or 1.26 times SWPSC capacity	4,015	16.31 or 0.93 times SWPSC capacity

TABLE 7
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 10 M/S ELEVATED TO 45 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH X 10 ⁻⁶ /yr MW	20 Diameter Spacing		50 Diameter Spacing		60 Diameter Spacing		70 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹
1	6,651	17,226	2.97	6,938	20.61	1,148	3.42	810	2.42	600	1.78
2	10,057	26,048	3.89	10,443	40.56	1,717	6.67	1,209	4.69	894	3.47
3	9,034	23,398	4.17	9,392	39.17	1,546	6.44	1,089	4.53	806	3.36
4	10,780	27,920	4.92	11,187	55.00	1,837	9.03	1,293	6.33	956	4.69
5	8,486	21,979	5.50	8,828	48.62	1,455	8.00	1,025	5.64	759	4.17
Totals	45,008	116,571		46,788	203.96	7,703	33.56	5,426	23.61	4,015	17.47
					or 11.6 times SWPSC capacity		or 1.91 times SWPSC capacity		or 1.36 times SWPSC capacity		or 0.99 times SWPSC capacity

TABLE 8
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 10 M/S ELEVATED TO 60 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH X 10 ⁻⁶ /yr MW	20 Diameter Spacing		50 Diameter Spacing		60 Diameter Spacing		70 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH X 10 ⁻⁹
1	6,651	17,226	3.11	6,938	21.59	1,148	3.58	810	2.52	600	1.86
2	10,057	26,048	4.06	10,443	42.25	1,717	6.95	1,209	4.89	894	3.61
3	9,034	23,398	4.36	9,392	40.92	1,546	6.72	1,089	4.72	806	3.53
4	10,780	27,920	5.14	11,187	57.45	1,837	9.42	1,293	6.64	956	4.92
5	8,486	21,979	5.75	8,828	50.81	1,455	8.36	1,025	5.92	759	4.36
Totals	45,008	116,571		46,788	213.02 or 12.2 times SWPSC capacity	7,703	35.03 or 2.0 times SWPSC capacity	5,426	24.69 or 1.41 times SWPSC capacity	4,015	18.28 or 1.04 times SWPSC capacity

TABLE 9
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 10 M/S ELEVATED TO 75 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH x 10 ⁻⁶ /Yr.MW	20 Diameter Spacing		40 Diameter Spacing		60 Diameter Spacing		80 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹
1	6,651	17,226	1.11	15,150	16.83	3,844	4.28	1,737	1.92	992	1.11
2	10,057	26,048	1.50	22,839	34.25	5,777	8.67	2,603	3.92	1,483	2.22
3	9,034	23,398	1.94	20,531	39.92	5,197	10.11	2,343	4.56	1,336	2.61
4	10,780	27,920	2.50	24,470	61.17	6,187	15.47	2,786	6.97	1,586	3.97
5	8,486	21,979	2.78	19,294	53.59	4,886	13.58	2,204	6.11	1,257	3.50
Totals	45,008	116,571		102,284	205.76	25,891	52.11	11,673	23.48	6,654	13.41
					or 11.7 times SWPSC Capacity		or 2.97 times SWPSC Capacity		or 1.34 times SWPSC Capacity		or 0.77 times SWPSC Capacity

TABLE 10
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 13 M/S ELEVATED TO 30 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH x 10 ⁻⁶ /Yr.MW	20 Diameter Spacing		40 Diameter Spacing		60 Diameter Spacing		80 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹
1	6,651	17,226	1.39	15,150	21.06	3,844	5.33	1,737	2.42	992	1.39
2	10,057	26,048	2.03	22,839	46.31	5,777	11.72	2,603	5.28	1,483	3.00
3	9,034	23,398	2.22	20,531	45.61	5,197	11.56	2,343	5.19	1,336	2.97
4	10,780	27,920	2.78	24,470	67.98	6,187	17.20	2,786	7.78	1,586	4.42
5	8,486	21,979	3.33	19,294	64.31	4,886	16.28	2,204	7.33	1,257	4.19
Totals	45,008	116,571		102,284	245.27 or 14 times SWPSC Capacity	25,891	62.09 or 3.54 times SWPSC Capacity	11,673	28 or 1.6 times SWPSC Capacity	6,654	15.97 or 0.91 times SWPSC Capacity

TABLE 11
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 13 M/S ELEVATED TO 45 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH x 10 ⁻⁶ /Yr. MW	20 Diameter Spacing		40 Diameter Spacing		60 Diameter Spacing		80 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹
1	6,651	17,226	1.67	15,150	25.25	3,844	6.42	1,737	2.89	992	1.67
2	10,057	26,048	2.17	22,839	49.48	5,777	12.53	2,603	5.64	1,483	3.22
3	9,034	23,398	2.64	20,531	54.17	5,197	13.74	2,343	6.19	1,336	3.52
4	10,780	27,920	3.19	24,470	78.17	6,187	19.78	2,786	8.89	1,586	5.06
5	8,486	21,979	3.61	19,294	69.67	4,886	17.64	2,204	7.97	1,257	4.53
Totals	45,008	116,571		102,284	276.74 or 15.8 times SWPSC Capacity	25,891	70.11 or 4.0 times SWPSC Capacity	11,673	31.58 or 1.8 times SWPSC Capacity	6,654	18.00 or 1.03 times SWPSC Capacity

TABLE 12
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 13 M/S ELEVATED TO 60 METERS

Region No.	Area Sq. Miles	Area Sq. KM	Avg. Energy Potential KWH x 10 ⁻⁶ /Yr.MW	20 Diameter Spacing		40 Diameter Spacing		60 Diameter Spacing		80 Diameter Spacing	
				No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹	No. of Turbines	Energy/Yr. KWH x 10 ⁻⁹
1	6,651	17,226	1.72	15,150	26.09	3,844	6.61	1,737	3.00	992	1.72
2	10,057	26,048	2.50	22,839	57.12	5,777	14.45	2,603	6.50	1,483	3.69
3	9,034	23,398	2.78	20,531	57.03	5,197	14.45	2,343	6.50	1,336	3.72
4	10,780	27,920	3.33	24,470	81.56	6,187	20.61	2,786	9.28	1,586	5.28
5	8,486	21,979	3.75	19,294	72.37	4,886	18.33	2,204	8.28	1,257	4.72
Totals	45,008	116,571		102,284	294.17 or 16.8 times SWPSC Capacity	25,891	74.45 or 4.25 times SWPSC Capacity	11,673	33.56 or 1.91 times SWPSC Capacity	6,654	19.13 or 1.09 times SWPSC Capacity

TABLE 13
WIND FARM REGIONS OF SWPSC SERVICE AREA
ENERGY FROM UNIFORMLY SPACED TURBINES
RATED AT 13 M/S ELEVATED TO 75 METERS

136×10^9 KWH, a factor of 7.8 times the 1975 annual energy generation capacity of the Southwestern Public Service Company. In such a configuration, turbines would be located in a uniform grid throughout the region with a spacing of 2.23 kilometers between machines. On the other hand, an amount of energy equivalent to the 1975 SwPS capacity could be produced by a uniform grid spacing of 6.5 kilometers (58 diameters) resulting in annual energy production of 17.5×10^9 KWH, requiring about 3,000 WTG's.

These results are summarized in Figures 28, 29 and 30. The spacing separation distance in either kilometers or diameters is seen to be a nonlinear function of the energy production. As the capacity is approached, the required spacing distance dramatically increases. Figure 30 displays the relationship between numbers of turbines required to produce 100 percent of the SwPS capacity and height of turbine hub above ground for the three ratings of WTG's. Little gain with height is experienced for either WTG-8 or WTG-10 but elevation from 30 to 75 meters of the 13 meter/second rated wind turbine generator improves the requirement by over 30 percent.

Therefore, it is clearly demonstrated that much more than sufficient energy is extractable from the wind than is presently needed. In fact, if WTG's were uniformly placed throughout the region at a spacing of 5 turbine diameters for the 8 M/S rated machines, the amount of energy produced would be 125 times the capacity of SwPS.

3. Wind Farm WTG Arrays

More economical, esthetically pleasing, and environmentally satisfactory turbine array conformations can be utilized than a uniform grid distribution. For example, closely spaced WTG's at 5 or 10 diameters (a spacing chosen as a reasonable compromise of the reported estimates from the literature) can be used to provide turbine farms in more compact units. Placement of turbine farm units in each of the five wind turbine farm regions of Figure 27 could produce an amount of energy equivalent to 100 percent of the present SwPS capacity with relatively small farms, as listed in Tables 14 and 15. At a 5 diameter spacing, this can be accomplished utilizing less than 0.75 percent of the total land area, regardless of the WTG rating or hub height used. The worst case would require the largest wind farm unit to contain 722 WTG's occupying 208 square kilometers for a square farm unit of 14.4 kilometers (9 miles) on a side. Doubling the spacing to 10 diameters would quadruple the areas required for the wind farm units. Such wind farms would likely be located near present generation stations for supplementation so as to require minimal new construction of transmission lines and equipment.

FIGURE 28

ENERGY PRODUCED BY TURBINES UNIFORMLY DISTRIBUTED
AT VARIOUS SPACING DIAMETERS

FIGURE 29

ENERGY PRODUCED BY TURBINES UNIFORMLY DISTRIBUTED
AT VARIOUS SPACING SEPARATION DISTANCES

FIGURE 30

NUMBERS OF 1 MW TURBINES REQUIRED TO
PRODUCE 100 % OF SWPSC CAPACITY

N = Number of Turbines of Specified Rating Required
to Produce 100% of SWPSC Capacity

A = Area Required For N Turbines Uniformly Spaced at
10 Diameter Separation Distance, KM²

Region No.	Area Sq. Miles Sq. KM		Rated at 8 m/s						Rated at 10 m/s						Rated at 13 m/s					
			60 m		75 m		45 m		60 m		75 m		30 m		45 m		60 m		75 m	
			N	A	N	A	N	A	N	A	N	A	N	A	N	A	N	A	N	A
1	6,651	17,226	454	512	426	479	673	395	636	373	601	351	1322	362	1124	306	992	269	903	244
2	10,057	26,048	675	774	632	723	1004	598	947	563	896	532	1978	547	1681	463	1482	407	1348	369
3	9,034	23,398	609	696	570	649	905	537	854	506	808	478	1781	491	1514	416	1335	366	1214	332
4	10,780	27,920	722	831	676	776	1074	641	1013	604	958	570	2117	586	1799	496	1586	436	1442	396
5	8,486	21,979	573	653	537	610	852	505	804	475	760	448	1676	462	1424	391	1256	343	1143	312
Totals	45,008	116,571	3033	3466	2841	3237	4508	2676	4254	2521	4023	2379	8874	2448	7542	2072	6651	1821	6050	1653
				or		or		or		or		or		or		or		or		or
				2.97%		2.78%		2.3%		2.16%		2.04%		2.1%		1.78%		1.56%		1.42%
				Total		Total		Total		Total		Total		Total		Total		Total		Total
				Area		Area		Area		Area		Area		Area		Area		Area		Area

TABLE 14

LAND AREAS REQUIRED FOR WIND TURBINE FARMS WHICH SUPPLY AN AMOUNT
OF ENERGY EQUIVALENT TO 100% OF SWPS CAPACITY. 10 DIAMETER SPACING.

N = Number of Turbines of Specified Rating Required
to Produce 100% of SWPSC Capacity

A = Area Required for N Turbines Uniformly Spaced at
5 Diameter Separation Distance, KM²

Region No.	Area Sq. Miles Sq. KM		Rated at 8 m/s				Rated at 10 m/s				Rated at 13 m/s										
			60 m		75 m		45 m		60 m		75 m		30 m		45 m		60 m		75 m		
			N	A	N	A	N	A	N	A	N	A	N	A	N	A	N	A	N	A	
65	1	6,651	17,226	454	128	426	120	673	99	636	93	601	88	1322	91	1124	77	992	67	903	61
	2	10,057	26,048	675	194	632	181	1004	150	947	141	896	133	1978	137	1681	116	1482	102	1348	92
	3	9,034	23,398	609	174	570	162	905	134	854	127	808	120	1781	123	1514	104	1335	92	1214	83
	4	10,780	27,920	722	208	676	194	1074	160	1013	151	958	143	2117	147	1799	124	1586	109	1442	99
	5	8,486	21,979	573	163	537	153	852	126	804	119	760	112	1676	116	1424	98	1256	86	1143	78
Totals		45,008	116,571	3033	867	2841	810	4508	669	4254	631	4023	596	8874	614	7542	519	6651	456	6050	413
				or		or		or		or		or		or		or		or		or	
				0.74%		0.69%		0.57%		0.54%		0.51%		0.53%		0.45%		0.39%		0.35%	
				of		of		of		of		of		of		of		of		of	
				Total		Total		Total		Total		Total		Total		Total		Total		Total	
				Area		Area		Area		Area		Area		Area		Area		Area		Area	

TABLE 15
LAND AREAS REQUIRED FOR WIND TURBINE
FARMS WHICH SUPPLY 100 PER CENT
OF SWPSC CAPACITY. 5 DIAMETER SPACING

Such farms would create minimal visual irritation, being restricted to only 5 individual farms over the entire SwPS service region.

4. Transmission Line WTG Arrays

Another convenient turbine arrangement would be the placement of turbines along the transmission line rights-of-way. Such an arrangement could minimize costs of land use acquisitions, minimize costs of new transmission line construction associated with WTG's, and could stabilize the wind energy production level by providing the dispersion of WTG's throughout the region.

For the present study only those transmission lines carrying 66 kilovolts, 115 kilovolts, and 230 kilovolts will be considered. A schematic diagram of the distribution of those transmission lines over the SwPS service region is given in Figure 26. The portion of the transmission lines located near cities is neglected. Major cities such as Lubbock and Amarillo have many kilometers of transmission lines within and around the city and these right-of-ways are not suitable for WTG erection. Conservative estimates of lengths of transmission lines useful for windpower conversion are utilized and as a result, the estimation of potential for electrical energy production by WTG's along those transmission lines will be conservative. The useful length of each line segment is estimated from a transmission line map and the potential for electrical power generation is averaged over the line segment, for a specified WTG rating and hub height, using the potential energy generation maps of Figures 13 through 21. A base spacing of one kilometer is chosen and the annual energy production along that transmission line segment computed by multiplication of the segment line length with the average energy potential for electric power generation. These computations are tabulated for 66 KV, 115 KV, and 230 KV lines and listed as Tables 16, 17 and 18 respectively. The computations from those tables are summarized in Table 19.

There are 1909 kilometers of 66 KV lines, 2090 kilometers of 115 KV lines, and 938 kilometers of 230 KV lines that, for this study, are considered useful for windpower production of electrical energy. Spacing WTG's along the lines every one kilometer will provide for annual electrical energy production of 59 to 161 percent of the 1975 SwPS annual capacity of 17.5×10^9 KWH, depending upon the WTG rating and hub elevation used. The numbers of turbines and spacing distances required for the equivalent of 100 percent of present capacity energy production are listed for each combination of WTG rating and hub height in Table 20. As noted in the table, 100 percent of SwPS capacity can be provided by placing WTG's of any of the three rated speeds, at any of the listed hub heights, along the high voltage transmission line right-of-ways with WTG separation spacings of no less than 11 turbine diameters.

Location of Transmission Lines	L	Rated at 8 M/S				Rated at 10 M/S				Rated at 13 M/S			
		60 m		75 m		45 m		60 m		75 m		30 m	
		e	E	e	E	e	E	e	E	e	E	e	E
1 Roswell to Artesia	68	4.31	294	4.58	311	2.64	178	2.92	200	3.06	206	1.11	77.8
2 Artesia to Carlsbad	61	4.44	272	4.72	289	2.92	178	3.19	194	3.33	206	1.17	72.2
3 Artesia to Cunningham	97	4.72	456	5.00	483	3.06	294	3.33	322	3.47	339	1.53	150
4 Carlsbad to Cunningham	88	4.72	417	5.00	439	3.06	267	3.33	294	3.47	306	1.53	133
5 Cunningham to Denver City	63	5.28	333	5.28	333	3.61	228	3.89	244	4.03	256	1.58	100
6 Cunningham to Seminole	64	5.28	339	5.28	339	3.61	233	3.89	250	4.03	256	1.58	100
7 Denver City to Lubbock	98	5.28	517	5.28	517	3.61	356	3.89	383	4.03	61.1	1.58	156
8 Denver City to Whiteface	77	5.28	406	5.28	406	3.61	278	3.89	300	4.03	311	1.58	122
9 Whiteface to Littlefield	74	5.28	389	5.28	389	3.61	267	3.89	289	4.03	300	1.47	111
10 Lubbock to Tahoka	34	5.42	183	5.69	194	3.75	128	4.03	139	4.17	144	1.58	55.6
11 Lubbock to Abernathy	29	5.42	156	5.69	167	3.75	111	4.03	117	4.17	122	1.64	50.0
12 Lubbock to Hale Center	51	5.83	300	6.11	311	4.03	206	4.31	222	4.44	228	1.81	94.4
13 Abernathy to Floyd County	34	5.69	194	5.97	206	3.89	133	4.17	144	4.31	144	1.67	55.6
14 Floyd County to Ralls	24	5.69	139	5.97	144	3.89	94.4	4.17	100	4.31	106	1.67	38.9
15 Floyd County to Floydada	16	5.69	88.9	5.97	94.4	3.89	61.1	4.17	55.6	4.31	66.6	1.67	27.8
16 Hale Center to Plainview	40	5.97	239	6.25	250	4.17	167	4.44	178	4.58	183	1.81	72.2
17 Hale Center to Plant X	48	5.69	272	6.25	300	3.89	189	4.17	200	4.31	206	1.81	88.9
18 Hale Center to Amarillo	122	6.25	766	6.53	795	4.44	544	4.72	578	4.86	594	2.22	272
19 Plant X to Clovis	77	5.00	383	5.28	406	3.33	256	3.61	278	3.75	289	1.81	139
20 Amarillo to Clovis	148	5.83	861	6.11	906	4.17	617	4.44	656	4.58	678	2.08	311
21 Amarillo to Sunray	72	6.39	461	6.68	478	5.28	378	5.56	400	5.97	356	2.78	200
22 Amarillo to Borger (3 lines)	121	6.39	772	6.68	700	5.28	361	5.56	672	5.97	689	2.78	339
23 Borger to Sunray	53	6.39	339	6.68	356	5.28	278	5.56	294	5.97	300	2.78	150
24 Borger to Pampa	51	6.11	311	6.39	328	5.00	256	5.28	267	5.42	278	3.06	156
25 Borger to Gruver (2 lines)	126	6.39	806	6.67	839	5.28	667	5.56	700	5.69	717	3.06	383
26 Sunray to Guymon & branch	106	6.53	695	6.81	722	5.42	572	5.69	606	5.83	617	3.11	328
27 Gruver to Guymon	51	6.53	333	6.81	334	5.42	278	5.69	289	5.83	300	3.11	161
28 Guymon to Beaver & branch	121	6.39	772	6.67	806	5.28	639	5.56	672	5.69	689	3.19	389
29 Guymon to Kansas	76	6.95	528	7.22	550	5.56	422	5.83	444	5.97	456	3.28	250
TOTALS	2090		12023		12512		8912		9490		9756		4584
													5184
													6089
													6551

L = Length of Transmission Line
Estimated to be Useful For
Wind Power Production, km

e = Average Energy Potential
for Turbine at Location of Line
KWH $\times 10^{-6}$ /Yr Installed MW

E = Energy Produced by 1 MW Turbines
Spaced Every 1 km Along Line
KWH $\times 10^{-6}$ /Yr

TABLE 16
ENERGY PRODUCED BY WIND TURBINES LINEARLY
SPACED ALONG 115 KILOVOLT TRANSMISSION LINES

Location of Transmission Lines	L	Rated at 8 M/S				Rated at 10 M/S				Rated at 13 M/S									
		60 m		75 m		45 m		60 m		75 m		30 m		45 m		60 m		75 m	
		e	E	e	E	e	E	e	E	e	E	e	E	e	E	e	E	e	E
1 Roswell to Artesia	60	4.31	261	4.58	278	2.64	161	2.92	178	3.06	183	1.11	66.7	1.31	77.8	1.50	88.9	1.67	100
2 Artesia to Carlsbad	51	4.44	228	4.72	239	2.78	144	3.19	161	3.33	172	1.17	61.1	1.33	66.7	1.53	77.8	1.72	88.9
3 Carlsbad to Caverns	34	4.44	150	4.72	161	2.78	94.4	3.19	111	3.33	111	1.17	38.9	1.33	44.4	1.53	55.6	1.72	61.1
4 Seminole to Denver City	43	5.14	222	5.14	222	3.47	150	3.75	161	3.89	167	1.44	61.1	1.72	72.2	2.00	83.3	2.28	100
5 Denver City to Seagraves & branch	97	5.14	500	5.14	500	3.47	339	3.75	361	3.89	373	1.44	144	1.72	167	2.00	194	2.28	222
6 Seagraves to Brownfield	51	5.28	267	5.28	267	3.61	456	3.89	200	4.03	206	1.58	83.3	1.86	94.5	2.14	111	2.42	122
7 Brownfield to Post	82	5.28	433	5.28	433	3.61	294	3.89	317	4.03	328	1.58	128	1.86	150	2.14	178	2.42	200
8 Brownfield to Morton	68	5.28	361	5.28	361	3.61	244	3.89	267	4.03	272	1.58	106	1.86	128	2.14	144	2.42	167
9 Brownfield to Levelland	32	5.28	167	5.28	167	3.61	117	3.89	122	4.03	128	1.58	50.0	1.86	61.1	2.14	66.7	2.42	77.8
10 Post to Lubbock	55	5.28	289	5.28	289	3.61	200	3.89	217	4.03	222	1.58	88.9	1.86	100	2.14	117	2.42	133
11 Lubbock to Ralls	45	5.42	244	5.69	256	3.75	167	4.03	183	4.17	189	1.64	72.2	1.92	88.9	2.22	100	2.50	111
12 Levelland to Whiteface	31	5.28	161	5.28	161	3.61	111	3.89	122	4.03	122	1.58	50.0	1.86	55.6	2.14	66.7	2.42	72.2
13 Levelland to Littlefield	31	5.28	161	5.28	161	3.61	111	3.89	122	4.03	122	1.58	50.0	1.86	55.6	2.14	66.7	2.42	72.2
14 Littlefield to Muleshoe	55	5.28	289	5.28	289	3.61	200	3.89	217	4.03	222	1.58	88.9	1.86	100	2.14	117	2.42	133
15 Littlefield to Hale Center	48	5.69	272	5.97	289	3.89	189	4.17	200	4.31	206	1.67	77.8	1.97	94.5	2.28	111	2.64	128
16 Hale Center to Plainview	39	5.97	233	6.25	244	4.17	161	4.44	172	4.58	178	1.81	72.2	2.11	83.3	2.42	94.5	2.78	111
17 Plainview to Silverton	51	5.97	306	6.25	317	4.17	211	4.44	228	4.58	233	1.81	94.5	2.11	106	2.42	122	2.78	144
18 Hale Center to Abernathy	27	5.97	161	6.25	167	4.17	111	4.44	122	4.58	122	1.81	50.0	2.11	55.6	2.42	66.7	2.78	77.8
19 Abernathy to Plainview	43	5.97	256	6.25	267	4.17	178	4.44	189	4.58	194	1.81	77.8	2.11	88.9	2.42	106	2.78	122
20 Hale Center to Dimmitt	100	5.97	600	6.25	628	4.17	422	4.44	444	4.58	461	1.81	183	2.11	211	2.42	244	2.78	278
21 Muleshoe to Clovis	47	5.00	233	5.28	250	3.33	156	3.61	172	3.75	178	1.81	83.3	2.11	100	2.42	111	2.78	133
22 Dimmitt to Plant X & Hereford	80	5.69	456	5.97	478	3.89	311	4.17	333	4.31	344	1.67	133	1.97	156	2.28	183	2.64	211
23 Dimmitt to Hereford	39	5.97	233	6.25	244	4.17	161	4.44	172	4.58	178	1.81	72.2	2.11	83.3	2.42	94.5	2.78	111
24 Amarillo to Vega	63	6.11	383	6.39	400	4.86	306	5.28	333	5.42	339	3.06	194	3.36	211	3.67	233	4.03	256
25 Amarillo to Channing	72	6.11	439	6.39	461	5.00	361	5.28	378	5.42	389	3.06	222	3.36	244	3.67	267	4.03	289
26 Amarillo to near Lela	121	6.11	739	6.39	772	5.00	606	5.28	639	5.42	378	3.06	372	3.36	406	3.67	444	4.03	489
27 Jericho to Wilcox	35	5.83	206	6.11	217	4.72	167	5.00	178	5.14	178	2.78	100	3.08	106	3.39	117	3.75	133
28 Wilcox to Kelton	76	5.56	422	5.83	444	4.44	339	4.72	361	4.86	372	2.50	189	2.81	211	3.11	239	3.47	267
29 Magic City to near Allison	66	5.28	350	5.56	367	4.17	278	4.44	294	4.58	300	2.22	144	2.50	167	2.78	183	3.19	211
30 Borger to Pampa	60	5.83	350	6.11	367	4.72	283	5.00	300	5.14	311	2.78	167	3.08	183	3.39	206	3.75	228
31 Dumas to Dalhart	61	5.83	356	6.11	372	4.72	289	5.00	306	5.14	311	2.78	172	3.08	189	3.39	206	3.75	228
32 Guymon to Keyes and Elkhart	98	6.39	622	6.67	656	5.28	517	5.56	544	5.69	556	2.78	272	3.08	300	3.39	333	3.75	367
33 Guymon to Hooker	48	6.94	333	7.22	344	5.56	267	5.83	278	5.97	289	3.28	156	3.61	172	4.03	194	4.44	211
TOTALS	1909		10684		11068		8101		8384		8617		3923		4439		5023		5639

L = Length of Transmission Line Estimated to be Useful for Wind Power Production, km

e = Average Energy Potential for Turbine at Location of Line, $\text{KWH} \times 10^{-6} / \text{Yr}$, Installed MW

E = Energy Produced by 1 MW Turbines Spaced Every 1 km Along Line, $\text{KWH} \times 10^{-6} / \text{Yr}$

TABLE 17
ENERGY PRODUCED BY WIND TURBINES LINEARLY
SPACED ALONG 66 KILOVOLT TRANSMISSION LINES

Location of Transmission Line	Length KM	Rated at 8 M/S				Rated at 10 M/S				Rated at 13 M/S									
		60 m e	60 m E	75 m e	75 m E	45 m e	45 m E	60 m e	60 m E	75 m e	75 m E	30 m e	30 m E	45 m e	45 m E	60 m e	60 m E	75 m e	75 m E
1 Cunningham to near Whiteface	134	5.28	706	5.69	761	3.61	483	3.89	522	4.03	539	1.39	189	1.94	261	2.08	278	2.36	317
2 Near Whiteface to Jones Station	64	5.42	344	5.83	372	3.75	239	4.03	256	4.17	267	1.53	100	2.08	133	2.22	144	2.50	161
3 Near Whiteface to Plant X	72	5.42	389	5.83	422	3.75	272	4.03	289	4.17	300	1.53	111	2.08	150	2.22	161	2.50	178
4 Plant X to Abernathy	71	5.69	406	5.94	422	3.89	278	4.08	289	4.36	311	1.61	117	2.17	156	2.28	161	2.56	183
5 Plant X to Amarillo	167	6.11	1022	6.67	1111	4.44	745	4.86	700	5.00	833	2.22	372	2.50	417	2.92	489	3.06	511
6 Abernathy to Jones Station	53	5.69	300	5.94	317	3.89	206	4.08	217	4.36	233	1.61	83.3	2.17	117	2.28	122	2.56	133
7 Abernathy to Amarillo	164	6.11	1000	6.67	1094	4.44	728	4.86	800	5.00	822	2.22	367	2.50	411	2.92	478	3.06	500
8 Amarillo to Kelton	163	6.25	1017	6.81	1111	4.58	745	5.00	817	5.14	839	2.36	383	2.64	428	3.06	500	3.19	522
9 Amarillo to Borger	50	6.67	333	7.22	361	5.14	256	5.56	278	5.69	283	2.78	139	3.33	167	3.47	172	3.89	194
Totals	938		5517		5973		3950		4278		4428		1861		2239		2506		2700

e = Average Energy Potential for Turbine at Location
of Line KWH x 10^{-6} /Yr Installed MW

E = Energy Produced by 1 MW Turbines Spaced Every
1 km Along Line KWH x 10^{-6} /Yr

TABLE 18
ENERGY PRODUCED BY WIND TURBINES LINEARLY
SPACED ALONG 230 KILOVOLT TRANSMISSION LINES

		Total Energy Produced by 1 MW Turbines of Indicated Rated Wind Speed and Hub Height Spaced at 1 kilometer Intervals Along Line, KWH x 10 ⁻⁹ /Yr.								
Type of Transmission Line	Estimated Useful Length, Kilometers	Rated at 8 m/s		Rated at 10 m/s			Rated at 13 m/s			
		60 M	75 M	45 M	60 M	75 M	30 M	45 M	60 M	75 M
66 KV	1909	10.68	11.07	8.10	8.38	8.62	3.92	4.44	5.02	5.64
115 KV	2090	12.02	12.51	8.91	9.49	9.76	4.58	5.18	5.67	6.55
230 KV	938	5.52	5.97	3.95	4.28	4.43	1.86	2.24	2.51	2.70
Totals	4937	28.22	29.55	20.96	22.15	22.80	10.37	11.86	13.20	14.89
		or	or	or	or	or	or	or	or	or
		1.61	1.69	1.20	1.26	1.30	0.59	0.68	0.75	0.85
		times	times	times	times	times	times	times	times	times
		SWPSC	SWPSC	SWPSC	SWPSC	SWPSC	SWPSC	SWPSC	SWPSC	SWPSC
		capacity	capacity	capacity	capacity	capacity	capacity	capacity	capacity	capacity

TABLE 19

TOTAL ENERGY PRODUCED BY 1 MW TURBINES
SPACED AT 1 KILOMETER ALONG HIGH VOLTAGE TRANSMISSION LINES

Turbine Specification		Number of Turbines Required	Spacing Distance, Kilometers	Spacing Distance in Number of Turbine Diameters
Rated Wind, Speed, M/S	Height Above Ground, Meters			
8	60	3066	1.61	14.5
8	75	2921	1.69	15.2
10	45	4114	1.20	15.1
10	60	3918	1.26	15.8
10	75	3798	1.30	16.3
13	30	8368	0.59	11.0
13	45	7260	0.68	12.6
13	60	6583	0.75	13.9
13	75	5808	0.85	15.8

TABLE 20
NUMBERS OF TURBINES AND SPACING
REQUIRED ALONG HIGH VOLTAGE TRANSMISSION
LINES TO PRODUCE 100 % OF SWPSC CAPACITY

D. Practical Windpower Utilization

It has been demonstrated that wind-generated electrical power of an amount at least as great as the present total generating capacity of the Southwestern Public Service Company could be achieved by large scale deployment of relatively small (1000 kW) machines in configurations that appear generally reasonable in terms of overall land use. However, it can immediately be suspected that there are other considerations that would limit practical utilization of this potential to values far less than the limits just described. Some of these practical considerations are discussed in this section, and estimates made of realistic useage potential over the period of the next twenty years. Projections beyond 1995 depend to such an extent on relative unknowns as to make them largely futile. Prominent among these unknowns is the fuel supply situation generally, and in particular the development of the nuclear power industry, the ability of the coal industry to keep pace with expanded production requirements, and off-shore petroleum exploration results.

1. Present SwPS Fuel Situation

Traditionally the Southwestern Public Service Company generation requirements have been met by gas-fired steam and open-cycle gas turbine plants. A small amount of fuel oil is used as backup. Low-cost natural gas is available throughout the area, the Panhandle region once being the site of the largest known gas deposits in the world. This situation has undergone dramatic change since the early 1970's. Not only are the Panhandle gas reserves being depleted rapidly (the original Amarillo gas field was discovered prior to 1920) but the fuel supply situation generally throughout the United States has made such demands on the existing gas supplies, as to create a seller's market in fossil fuel, particularly gas. In order to alleviate this situation, SwPS has embarked on a program of coal-fired plant construction, based on a supply of low-sulfur coal from Wyoming. The first of these plants, of 360 MW capacity, was placed in service in the summer of 1976, after the principal work of this study was complete. For all practical purposes, the system can be said at the time of this report to be fueled by natural gas and fuel oil.

2. Take-or-Pay Fuel Contracts

A very real factor in the immediate and near-term fuel situation in the southwest is the "take-or-pay" gas contract. This arrangement, now beginning to affect all fossil fuels, requires that contracted fuel be paid for whether burned or not. Ironically, contracts of this kind seriously limit the capability of a utility to save fossil fuel, even if the technological means were available to do so. Southwestern

Public Service Company executives estimate that the effect of these contracts on the operation of that utility would limit to approximately 3 to 5% the energy that could be supplied by windpower on the SwPS system, without regard for other considerations. Present gas contracts containing take-or-pay provisions will limit the flexibility of that utility until the late 1980's.

3. Deployment along Distribution Lines

For illustrative purposes, the installation of WTG along the transmission lines of Southwestern Public Service Company has been explored. From a practical standpoint, however, such machines could best be utilized on the lower voltage distribution network. Here the worth of windpower is likely to be maximized by eliminating some of the distribution losses (approximately 8% total over all the SwPS system), and problems of transmission line peak-loading and high-voltage matching would not occur. This subject is explored further in Section V of this report, "Technical and Operational Requirements". Each distribution circuit would necessarily be limited to a total WTG capacity less than the minimum circuit loading.

Excluding the urban distribution circuits, which would generally be inappropriate for the installation of WTG, the SwPS system has a total of at least 3,000 kilometers of distribution circuits available for possible direct use of WTG generated energy. The current minimum load represented by this rural distribution system is estimated at approximately 200 MW, or 10% of the present total SwPS capacity. Along the distribution network there is more than an adequate number of windpower sites for capacity of this amount. This figure may be interpreted as an upper bound on the practical network usage of wind generated power in the foreseeable future. Thus, within the practical limits of current fuel contracts and the bounds of power demands by the service outside the immediate urban areas of the utility, practical utilization estimates range from 3 to 10% of present generating capacity.

4. Reserve Capacity

A more serious constraint on the use of wind-generated energy on the SwPS system is the necessity of accounting for reserve capacity during peak loading conditions.

It is well known that the wind has only statistical reliability. The practical fact is that a wind generator which may be operating at rated capacity at one instant, can suddenly find its output drastically reduced in a short period of time. The wind may in fact stop blowing. Some other generating capability must then pick up the load

exactly as though the machine had experienced an outage for any other reason. Because of the potentially rapid nature of the wind-induced fluctuations in power output, they can only be accounted for by "spinning" reserve, or generating capability actually in operation. During off-peak periods, and for small numbers of WTG, base-load generating plants can "swing" over a sufficient range to encompass the slight total variations. But in order to achieve its greatest value, windpower, particularly when connected in large blocks, must be supplied during peak load periods. Then the limitation on total windpower capacity on a system cannot exceed the spinning reserve on the system. When operating "on the grid" (interconnected with other utilities), the spinning reserve capability must be at least 3% of load. This places an upper limit on the amount of windpower that could be accommodated by the SwPS system to 3% of total capacity, or approximately 60 MW.

It can be seen that there are three practical constraints affecting the utilization of windpower by SwPS in the next twenty years. These three constraints are (1) the limited flexibility of the system within existing long-term fossil fuel supply contracts which serve to limit the total windpower potential to approximately 5% of generating capacity (100 MW); (2) the minimum load requirements of the non-urban distribution system, which would limit WTG capacity to about 10% (200 MW); and, most important, (3) the limitation of required spinning reserve capacity to pick up sudden generating loss due to fluctuations in wind velocity. This latter factor tends to limit the total WTG capacity to 3% of load, or 60 MW total. This constraint conceivably could be eased as long operating experience with WTG systems confirms that a significant geographic diversity factor exists over a large network of wind systems. Total practical windpower utilization of 3% of total capacity appears to be realistic for the SwPS system within the next twenty years.

E. Limited Duration Wind Measurement Experiments

1. Background

A significant requirement for implementation of wind energy systems is prediction of performance based on accurate wind data. In previous sections, the wind potential of the study region has been evaluated, based on data from 17 weather stations with long-term wind measurement records. It can be immediately recognized that in site selection for specific WTG installations greater accuracy than can be obtained by the interpolation between existing wind stations would be required.

Putnam⁽⁶⁾ discusses this problem at some length and, indeed, the disappointing results of the Grandpa's Knob experiment of the

early 1940's was at least partially the result of insufficient wind data. Putnam was concerned with the period of data sample required to determine the long-term velocity at any site, and assumed that a period of one year was adequate. However, he learned that the power output calculated from wind speed records of a single year departed from the 5 year average output by ± 26 percent. He found a short-cut method to reduce the sample period required, by comparison of on-site data records with a nearby long-established meteorological station. He described his method as follows: "Determine the ratio between the velocity recorded at the survey station and that recorded at the control station in the same period of time. Multiply the long term mean velocity of the control station by this ratio to obtain the long-term mean velocity at the survey station". Putnam performed such an analysis on a sequential basis for a number of stations in his network. He would take data for a period of 24 hours and compute the average of the 24 hourly values of the speed ratio and note the maximum deviation of hourly values from the mean. He would then extend the sample period to 48 hours and collect the data into 6 hour averages and found the maximum deviation to decrease. By sequentially increasing the total sample period and averaging intervals, the average speed ratio approached a constant and the maximum deviations approached zero. By this means, he could project the mean speed at any site to a long-term value to any desired degree of accuracy. Putnam found that the length of record required at the survey station to establish the ratio of the velocity there to that of the control station, with a specified accuracy, varies with the slant distance between the stations. In one example, Putnam shows that a period of 30 days of data at a point 10 miles away and 400 ft. higher than the control station, was required to establish the ratio within 5 percent of the mean value.

The objective of this part of the present study has been to attempt to estimate the potential for wind energy generation in the foothills region of the Guadalupe Mountains southwest of Carlsbad, New Mexico and in the Lake Meredith Valley walls north by northeast of Amarillo, Texas, based on short-term data. Both of these regions are thought to offer promising windpower sites, the former because of the topographical nature of the foothills, being smooth and rounded high hills with bold relief, and the latter because of the possible funneling effect of the valley which is alligned in the direction of the prevailing winds.

To properly apply the short data-sample periods allotted to this study, Putnam's method for time scaling the results to long-term estimates was employed. Run-of-the-wind anemometers, which automatically provided a recording of the average hourly wind speed were designed and constructed for data acquisition, and the wind measurements at each site, for periods approximating one month, were attempted.

Unfortunately only one of these tests - that at Lake Meredith - was completely successful. The Guadalupe Mountain site was plagued by equipment failure and the results were inconclusive. They are, however, included in the interest of completeness.

2. Anemometer Construction

The anemometer is a three cup contact type (C. F. Cosella & Co., London) with 12.7 cm diameter, beaded edge cups which magnetically key a constant speed reed switch every 0.1 statute mile of run-of-wind. The quoted accuracy is within 1.6 kilometers/hour (kph) up to 100 kph. The anemometer and instrument box are shown in Figure 31. Each 0.1 mile pulse is electronically counted and displayed on a 6 digit LED assembly mounted on a 35 mm camera back for photographic recording. The counter and display units are shown in the photograph of Figure 32. A solenoid operated spring clock of the type commonly used in automobiles is utilized as a one hour timer to key the camera advance solenoid once per hour after initiating the current LED display for film exposure. The timer, camera back, and advance solenoid are shown in Figure 33. In this manner the 0.1 mile pulses of the contact anemometer are counted and photographically recorded each hour when the LED display is momentarily switched on by the electric clock, which subsequently advances the film to ready the device for the next hourly record. The system is powered entirely by a 12 volt wet storage battery and all enclosed in a light and water tight box. The anemometer is mounted on a telescoping mast which is supported by guy wires. The entire unit is portable and can operate unattended for at least one week. Two units were constructed and utilized for this study.

3. Methodology

Both the Lake Meredith and the Carlsbad site are reasonably close to long term weather record stations, the former being 59 kilometers from the Amarillo National Weather Service Station and the latter being 11 kilometers from the Carlsbad Air Terminal FAA Station. The synoptic winds of the respective regions will strongly influence both the test sites and the weather station locations so that correlation between the two could be expected. That is, if the wind is high in Amarillo, it is probably being driven by atmospheric pressure cells on such a large scale that the winds will similarly be high in the Lake Meredith Valley and thus correlatable, each with the other. Certainly this will not always be so nor will local effects be negligible but data from other stations within the general region have shown such a general correspondence.

3710

FIGURE 31

ANEMOMETER AND RECORDING UNIT

3711

FIGURE 32

PULSE COUNTER AND LED DISPLAY UNITS

3712

FIGURE 33

CLOCK AND CAMERA UNITS

Hourly run-of-the-wind data were taken at each test site and correlated with data from the local weather station for extrapolation to an estimate of long term average wind speed. This was done by the ratio method of Putnam, abridged for use with limited data samples. The long term annual wind speed is known at each weather station. An estimate of the long-term annual wind speed at the test site is made by forming the ratio of the average speed at the test site to that at the weather station during the test sample period. This ratio is assumed to be representative of the ratio of long term averages of the two locations. Thus an estimate of the long term wind speed of the test site is made by multiplication of the sample ratio with the long term average wind speed of the weather station. The method of Putnam employs seeking of convergence of numerous such estimates but owing to the shortness of the current sampling period only one estimate is made and is taken only as a first order quantitative approximation of the average test site wind speed and resulting wind power density.

4. Results at Lake Meredith Valley

Data were recorded at Lake Meredith during the period January 14 to February 13, 1976. The data were analyzed and reported by V. Nelson and E. Gilmore, and summarized and interpreted herein. The Lake Meredith Station was located on the north side of the Lake about 1 kilometer west of the northwest end of the dam. The anemometer was raised 9.1 meters above ground and placed on a small knoll which rises about 15 meters above the surrounding area which is itself about 24 meters above the lake level. The anemometer is placed therefore about 48 meters above the lake and at an elevation of approximately 960 meters above sea level. The site is located in an area of sharp relief at the northeast end of the lake which is alligned from southwest to northeast and as such is situated to receive the prevailing south-westerly wind after it traverses the lake and the valley walls. Photographs of the site are given as Figure 34. As seen, the approach to the site is reasonably smooth and might provide aerodynamic speed-up.

Wind speed histograms for the Amarillo National Weather Service Station and the test site are listed in Table 21 for the sample period. The Lake Meredith site clearly experienced higher winds during the sample period than did the Amarillo National Weather Service Station, 6.49 to 5.26 m/s and experienced a higher wind power density, 0.339 to 0.151 kw/m², a factor of 2.2. The increased wind speed, however, is not so great as to be significant. Using the empirical wind speed-height relation appropriate for the region, the wind speed difference between the NWS station at Amarillo and the test site corresponds to an increase in height above ground of only 14 meters. Thus because the Lake Meredith anemometer is effectively elevated above the surrounding

3713

APPROACH TO LAKE MEREDITH TEST ANEMOMETER SITE

3714

VIEW TO THE SOUTHWEST FROM LAKE MEREDITH TEST ANEMOMETER SITE

FIGURE 34. PHOTOGRAPHS OF SITE

TABLE 21

WIND SPEED HISTOGRAMS FOR AMARILLO NWS AND
LAKE MEREDITH TEST SITE, JANUARY 15-FEBRUARY 12, 1976

Wind Speed Meters Per Second	Number of Hours Amarillo NWS	Speed Recorded Lake Meredith Site
0	8	4
1	8	16
2	41	58
3	114	72
4	156	92
5	127	90
6	66	72
7	54	64
8	32	60
9	30	41
10	31	31
11	10	27
12	9	18
13	3	8
14	4	4
15	3	12
16	0	12
17	0	8
18	0	3
19	0	2
20	0	1
720	0	1
Total	696	696

	<u>Calculated Averages</u>	
	Wind Speed Meters per Second	Wind Power Density kw/m ²
Amarillo NWS	5.26	0.151
Lake Meredith Site	6.49	0.339

terrain by at least that amount, its increased wind speed and windpower density is taken as insignificant on the average with respect to a valley funnel effect or aerodynamic speed-up effect. The canyon walls could however play a minor role in providing a naturally occurring boost in height for a wind turbine generator, thus reducing the required height of the supporting structure to yield a specified energy output. For the limited direction of wind from 210-230 degrees, however, there was a greater energy ratio factor of 3.9 compared to the average factor over all directions of 2.2. Thus a slight speed-up factor is possible for this narrow range of directions, but does not appear sufficiently great to warrant further investigation.

5. Results at Guadalupe Mountain Foothills

Data were recorded at Carlsbad during the period 28 February 1976 through 17 March 1976. Two stations were erected, one at the Cavern City Air Terminal 9 kilometers southwest of Carlsbad (Civic Center), New Mexico, and the other on a ridge line called the Ocotillo Hills located within the Living Desert State Park 11 kilometers north by northwest of the air terminal.

The Air terminal site is on a gently sloping plain open to the north, east, and south, but bounded by foothills of up to 150 meter relief to the southwest, west, and extending to north by northwest at a range of 6 to 15 kilometers. A photograph of the site is shown in Figure 35. The anemometer was placed at a height above ground of 6.1 meters and compares to the FAA spot readings from the nearby FAA anemometer at 6.1 meters. The two anemometer locations were approximately 25 meters apart. Long term wind records are available from the site, taken during the period 1950 through 1954 from an anemometer elevated to 15.2 meters above ground.

The Guadalupe Mountain foothills site is atop a 9.14 meter water tank at an above ground elevation of 11.5 meters. The site is on a small knoll on the southern extreme of the Ocotillo Hills ridge line at a sea level elevation of 1060 meters with an exposed relief of about 90 meters and an approach slope from the southwest of 1 to 5 (1 meter elevation per each 5 meters approach). Despite repeated trials only 16 hours of continual data were recorded at this site due to instrument malfunction. A photograph of the installation is given in Figure 36.

The data collected at the air terminal are given on a daily integrated average basis in Table 22 and as a wind speed histogram in Table 23. The average windpower density during the sampling period, as calculated from the histogram, is 0.26 kw/m^2 . The ratio of the average wind speed measured by the TTU anemometer to that at

the FAA anamometer is 1.45.

During the short data sample at the foothill site the average wind speed was 7.15 meters per second as compared to an average wind speed at the FAA anamometer of 1.7 meters per second. The number of these latter measurements is too small from which to draw conclusions about the Guadalupe Mountain area. It does appear to offer a worthwhile region for additional study at a later time.

3715

FIGURE 35

VIEW TO THE WEST FROM CAVERN CITY AIR TERMINAL TEST ANEMOMETER SITE

3716

FIGURE 36

GUADALUPE MOUNTAIN FOOTHILLS TEST ANEMOMETER INSTALLATION SITE

TABLE 22

CAVERN CITY AIR TERMINAL WIND SPEEDS
 FOR THE PERIOD FEBRUARY 28 THROUGH MARCH 17, 1976
 DAILY AVERAGES

Date	Wind Speed Average, Meters per Second	
	FAA Anemometer	TTU Anemometer
Feb. 28	3.3	4.2
29	5.9	7.0
Mar. 1	4.3	6.4
2	5.8	7.2
3	6.1	8.4
4	8.9	12.6
5	1.7	3.9
6	1.7	2.5
7	2.1	2.4
8	2.0	3.0
9	2.7	4.1
10	1.3	2.6
11	6.7	9.8
12	3.4	4.4
13	2.4	3.3
14	2.1	3.0
15	3.4	3.9
16	3.5	5.1
17	1.7	-
Average	3.63	5.21

TABLE 23

WIND SPEED HISTOGRAM FOR CAVERN CITY AIR TERMINAL
FEBRUARY 28 THROUGH 17, 1976

Wind Speed Meters per Second	Numbers of Hours of Occurance
0	1
1	30
2	44
3	54
4	56
5	49
6	29
7	21
8	15
9	17
10	19
11	8
12	2
13	8
14	6
15	3
16	6
17	5
18	2
19	1
20	0
> 20	0
	<hr/>
	394

Average Wind Power Density
for Histogram = 0.26 kw/m^2

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III. ENERGY STORAGE ASSESSMENT

A. Introduction to Energy Storage Investigation

The question of energy storage is of great concern to the large-scale use of windpower. Within the regions of even the most favorable wind conditions, the wind is, at best, an unreliable source of power. It is known to vary in energy content from day to day, and even from moment to moment, depending upon meteorological factors of the most complex nature. But energy storage of a type useful to electric utility networks can be considered an established technology by only one or, at the most, two methods, both of large scale. The first of these is pumped hydro storage, and the second, which may eventually be useful but is so far unproven, is pumped compressed air. Other techniques, including storage batteries, inertial storage by means of large flywheels, and chemical storage including the production and storage of hydrogen, are as yet only subjects of research study. Thus, attention in this work was concentrated in three areas: First, the use of the wind without storage (or more accurately, network storage); consideration of the regional potential for pumped hydro storage; and because of general lack of large surface water sources and previous effort by Southwestern Public Service Company, the potential of pumped compressed air.

Consideration of energy storage potential in the Texas Panhandle region drew heavily upon prior studies by SwPS of energy storage facilities to be used for future peak-shaving purposes. Because of the heavy commitment on surface water stored in the two existing man-made lakes, pumped compressed air was believed to represent the best storage potential. The Utility had conducted preliminary study of a specific air storage site in southeastern New Mexico, and the technical aspects of this study were used as the basis for further detailed studies of this particular facility. The work was also extended to an examination of the use of natural aquifers as the air storage medium. Consideration of the two potential pumped-hydro sites was also included.

B. Concept of Energy Storage by a Utility

An electric utility is a complex mixture of generating plants, transmission and distribution lines, and electrical loads. Operation of a utility system consists of careful balancing of generation capability with loads which vary from hour to hour and minute to minute. Generally speaking, during certain periods of the day more energy is used than during others, and this variation in demand is balanced by (1) dispatching additional reserve generating capacity during the periods of peak loading and (2) allowing the plants on line to "swing" with variations

in output accounted for by variations in fuel consumed. Some types of generating plants have greater capability for accommodating changes in load than others. The most versatile are the gas-fired steam and gas turbine plants, with coal-fired plants less flexible, and nuclear plants the least flexible of all. The concept of energy storage to assist in handling peak demand periods has long been recognized by utility engineers, and many pumped hydro plants, designed to perform this function, are in routine operation. In general, an energy storage facility makes use of low-cost base-load power to create a reservoir of energy to be used to reduce the dependence on high-cost less efficient peak generating capacity such as gas turbines.

The addition of wind-powered generating systems to a network, adds a new variable to the operation. The wind cannot be called upon when desired, but must be accepted at all times when it is available, regardless of demand factors. While this appears to place new requirements on energy storage, some reflection shows that windpower requirements can be easily handled within the conventional concept of utility storage. Wind generated power can most efficiently be utilized by applying it directly to the network load when possible, while storage can best be handled by dispatching energy to storage, based on criteria other than available windpower alone. This removes the restriction of storage facilities located in intimate association with wind generator systems.

The use of some type of energy storage to account for the unpredictable nature of the wind, has been termed by previous workers "firming" windpower. One or two wind generators might be firmed with local energy storage capability (for example, storage batteries), but for only a small fraction of the total wind system power rating. The reason for this is that even in regions of very good winds, relatively long periods during which the wind is calm can occur unpredictably. No matter how much storage capacity is provided (within reason) at an individual wind site, eventually it will prove insufficient for a particular period of calm and an outage will result. On the other hand, excess storage capacity, unused most of the time, would be economically unacceptable.

A stand-by generator such as a diesel electric or gas turbine unit will not qualify to "firm" wind power. In order to supply capacity during periods of peak demand, auxiliary power capacity equivalent to the full rated windpower capacity would be required. Then energy generated by the wind has value equivalent only to the cost of the fuel saved, since the peak load could always be supplied by the auxiliary plant alone by simply burning fuel. No further saving would accrue to the wind generators, since windpower would in no way extend the capacity of the gas turbine or diesel equipment.

In the case of an existing hydro or air storage facility, however, the addition of wind generating plants can indeed effect savings in capital expenditure. In this case, the existing capacity of the hydro (or compressed air) plant can be extended by simply adding turbines, a small part of the total cost of the hydro-electric facility. The amount of capacity value that can accrue to the windpower system will be dependent upon many factors and must be determined for each increment of windpower added and for the parameters of the storage system itself.

Pumped compressed air has been a recognized utility storage concept for at least twenty years, although still largely unproven. The analysis of a specific potential compressed air system particularly suited to the requirements of the study region, is included in following sections of this report. It follows the concept of (1) a central network-storage facility, with or without windpower (2) separate, dispersed WTG, located to conform to separate and unrelated requirements. The worth of wind generated energy applied to the compressed air storage plant studied is explored in a following section of this report, "IV, Cost Goal Analysis".

C. Description of Compressed Air Systems Considered

A schematic drawing of a basic compressed air energy storage system is shown in Figure 37. Any such system as considered here requires these elements:

- . A storage volume
- . A compressor system
- . A turbine or expansion system
- . A fuel chamber for heating the compressed air
- . A generator (alternator) capable of operating as a motor

The elements of this system have been studied in detail in several configurations and these will be discussed in the following pages.

The concept of pumped compressed-air storage is based on the fact that conventional gas turbines (which operate by compressing air, heating it with fuel and expanding it through a power turbine) require nearly 2/3 of shaft power developed to compress the air necessary for operation. Thus, if a source of compressed air were available, all the shaft power

FIGURE 37.
SYSTEM SCHEMATIC

developed by the turbine could be converted to the generation of electricity, and the electrical output of the system increased by nearly a factor of 3. By combining such a system with a system of wind turbine generators, it was postulated that, during periods of excess wind or reduced demand, power from the WTG could be used to compress storage air. Then during periods of low wind or high peak demand, the compressor could be de-clutched, and the turbine could turn the generator directly, operating from compressed air in storage.

1. Cavern

The particular storage volume first considered, is a sealable cavern in the form of an abandoned potash mine near Carlsbad, New Mexico. The most significant characteristics of this mine for the purpose of the analysis made here are its volume, surface area and the thermal properties of the walls, which are rock salt. The mine is about 1000 ft. below ground level. Preparation of the storage volume would essentially consist of a sealing system through which the mine could be pressured and the compressed air removed. Sealing the mine was found to be a significant element in the storage installation cost.

The volume of the mine has been estimated to be $7 \times 10^7 \text{ ft}^3$ ($2 \times 10^6 \text{ m}^3$); the surface area inside the mine has been estimated to be $4 \times 10^7 \text{ ft}^2$ ($3.7 \times 10^6 \text{ m}^2$). The walls of the mine are rock salt with the following property values: mass density - $135.2 \text{ lb}_m/\text{ft}^3$ ($2166 \text{ Kg}/\text{m}^3$), specific heat = $0.204 \text{ Btu}/\text{lb}_m\text{-}^\circ\text{F}$ ($854 \text{ J}/\text{Kg-}^\circ\text{K}$), and thermal conductivity = $4.16 \text{ Btu}/\text{hr-ft-}^\circ\text{F}$ ($7.20 \text{ W}/\text{m-}^\circ\text{K}$).

Because of the deterioration of the strength of the rock salt at high temperatures and in an environment of high relative humidity, a major design constraint on the system design is to have the mine temperature remain near ambient and the air relative humidity be about 50 percent. In addition, the maximum air pressure should remain well below the over-burden pressure of 1000 psia ($6.9 \times 10^6 \text{ N}/\text{m}^2$).

2. Compressor System

During periods in which there is excess power, either from wind power generation or base power plant generation, a set of compressors are run which absorb the excess power. For the purpose of this study, these compressor units are assumed to be commercially available units with multiple stages and intercooling. The maximum exit temperature of any stage is taken to be 350°F (450°K) to avoid the necessity of using high temperature materials within the compressor. Each compressor stage is assumed to be well insulated with an isentropic

efficiency of 75 percent. The motor which drives the air compressors (and the refrigeration compressor discussed below) is assumed to have an efficiency of 96 percent.

The compressed air is cooled by intercoolers between each stage of compression and by an aftercooler following the last stage. For each of these heat exchangers it is assumed that the capacity rate ($\dot{m} c_p$) on the hot, compressed air side is less than the capacity rate on the cold side. It is also assumed that the heat exchanger effectiveness of the intercoolers is 85 percent, the effectiveness of the aftercooler is 80 percent, and that each heat exchanger has a pressure drop of five percent of its respective inlet pressure.

In order to insure that there would be no degradation of the physical properties of the salt caused by excess moisture carried into the cavern by the compressed air, the compressor system also contains necessary equipment to de-humidify the compressed air. The mathematical model of this portion of the system is developed assuming that a standard vapor-compression refrigeration cycle using Freon-12 is used to cool the compressed-air and entrained water vapor to a temperature of 57°F (287°K), condensing whatever water vapor necessary to reach this condition. The resulting saturated mixture of air and water vapor may then be reheated to a temperature of 70°F (294°K) prior to injection into the mine; the relative humidity of this reheated stream will be about 50 percent. Reheating may be done using the cooling media of the intercoolers and/or aftercooler. Both the de-humidifier and the reheater are assumed to have a pressure drop equal to five percent of the respective inlet pressure.

The exit pressure of the last stage of the compressor system is chosen to be about 2 psi (13800 N/m²) above the maximum pressure at station 4D. This value is determined by trial-and-success runs of the mathematical model and is tabulated in a later section for each turbo-expander considered. The number of these compressor systems is determined by the flow rate required. This is, in turn, determined by the operating schedule and the turbo-expander size.

3. Turbine System

Three different turbo-expanders are considered in this study. Each turbo-expander is, at most, a slightly modified version of a commercially available unit, so that an economic analysis of the results of this study may be performed with a reasonable degree of accuracy. Three turbo-expanders are considered; one is a high inlet temperature turbine, the second is an intermediate temperature turbine, and the third

is a low temperature (steam) turbine. The cost per MW is expected to be proportional to the inlet temperature; therefore, these three turbo-expanders are successively less expensive. The subsequent economic analysis of the results of this study will, then, cover a wide diversity of capital cost.

The three types of turbo-expanders are as follows:

1A: General Electric, Series 7000, 100 MW nominal

Inlet pressure = 138 psia ($9.51 \times 10^5 \text{ N/m}^2$)

Inlet temperature = 1950°F (1339°K)

Mass flow rate = $1.71 \times 10^6 \text{ lb}_m/\text{hr}$ ($7.76 \times 10^5 \text{ Kg/hr}$)

1B: Solar Centaur, three 7 MW units nominal

Inlet pressure = 120 psia ($8.27 \times 10^5 \text{ N/m}^2$)

Inlet temperature = 1600°F (1144°K)

Mass flow rate = $3.53 \times 10^5 \text{ lb}_m/\text{hr}$ ($1.60 \times 10^5 \text{ Kg/hr}$)

2 : Worthington Steam Turbine, two 12.5 MW units nominal

Inlet pressure = 490 psia ($3.38 \times 10^6 \text{ N/m}^2$)

Inlet temperature = 645°F (614°K)

Mass flow rate = $5.50 \times 10^5 \text{ lb}_m/\text{hr}$ ($2.50 \times 10^5 \text{ Kg/hr}$)

A regenerator heat exchanger is used with turbo-expanders 1A and 1B. The heat exchanger effectiveness is taken to be 80 percent; the pressure drop on both sides is taken to be 5 percent of the respective inlet pressure. Each turbo-expander is assumed to be adiabatic with an isentropic efficiency of 84 percent. The driven electric alternator is taken to have an efficiency of 98 percent.

Finally, it is assumed that the fuel used in the combustion process is natural gas with the following composition by volume: 83.4 percent CH_4 , 15.8 percent C_2H_6 , and 0.8 percent N_2 (1). The (dry) air with which the fuel is reacting is assumed to have the following composition by volume: 20.99 percent O_2 and 79.01 percent apparent N_2 (2).

4. Schedule

A detailed examination of the Southwestern Public Service Company demand curve (Figure 38) was made. In order that the comparison of the three systems may be made consistently, they are each simulated as being run on the following schedule:

DAY OF WEEK	COMPRESSORS			TURBINE(S)		
	OFF	ON	HRS	ON	OFF	HRS
Sunday	7 am	11 pm	8			0
Monday	7 am	11 pm	8	11 am	10 pm	11
Tuesday	7 am	11 pm	8	11 am	10 pm	11
Wednesday	7 am	11 pm	8	11 am	10 pm	11
Thursday	7 am	11 pm	8	11 am	10 pm	11
Friday	7 am	11 pm	8	11 am	10 pm	11
Saturday	7 am	12 m	<u>7</u>			<u>0</u>
			55			55

5. Environment

The environmental conditions are the average values over a five year period for Carlsbad, New Mexico as determined by computer analysis of Weather Bureau data. These conditions are: Temperature = 56.8°F (287°K), pressure = 13.1 psia (9×10^4 N/m²), and relative humidity = 48.5 percent. In order to determine any effects of running a system at environmental conditions removed from the yearly average, average conditions were also determined for 13 four week periods. A simulated operation of one of the systems (1A) over the year was then obtained using these 13 environmental conditions. The environmental condition data are:

4 Week Period	Temperature		Pressure		Relative Humidity, %
	°F	°K	psia	N/m ² x 10 ⁻⁴	
1	42.1	279	13.1	9.03	42.9
2	42.4	279	13.1	9.03	43.5
3	46.4	281	13.1	9.03	36.5
4	53.2	285	13.1	9.03	42.7
5	60.0	289	13.1	9.03	41.7
6	68.1	293	13.1	9.03	50.6
7	74.7	297	13.1	9.03	54.6
8	74.7	297	13.1	9.03	57.6
9	72.5	296	13.1	9.03	58.4
10	65.7	292	13.1	9.03	54.1
11	55.4	286	13.1	9.03	56.0
12	44.6	280	13.1	9.03	48.2
13	38.6	277	13.1	9.03	43.7

FIGURE 38. TYPICAL DEMAND CURVES FOR SwPS SYSTEM.

D. Mathematical Model

1. Compressor System

The mathematical model of the compressor system is divided into five segments: (1) state relations for air-water vapor mixtures, (2) analysis of the compression process, (3) analysis of the intercooler/aftercooler process, (4) analysis of the de-humidification process, and (5) the determination of the design pressure rises per stage.

Because of the design constraint of having the relative humidity of the air in the cavern approximately 50 percent, it is necessary to provide equipment to de-humidify the compressed air. This, in turn, requires the treatment of the air to be made as a mixture of the non-reacting substances, "dry" air and water vapor. The usual psychrometric approach is taken using the Biggs-Dalton non-reacting mixture approximation and assuming that both dry air and water vapor are perfect gases with constant specific heats. Thus, the partial pressure of the water vapor is given by

$$P_w = \phi P_{\text{sat}}(T)$$

where

ϕ is the relative humidity and

$P_{\text{sat}}(T)$ is the saturation pressure of water

The absolute humidity is given by

$$\omega = (R_a/R_w) P_w/P_a$$

where (R_a/R_w) is the ratio of gas constants, $0.622 \frac{\text{lb}_m\text{-water}}{\text{lb}_{\text{H}_2\text{O}}\text{-air}}$

P_w is the partial pressure of water vapor, and

P_a is the partial pressure of air, $P_a = P - P_w$

It may be recalled that the absolute humidity, ω , is defined as the ratio of the mass of water vapor to the mass of dry air in any given volume.

The specific heats of the mixture may be calculated knowing the absolute humidity, as follows:

$$\begin{aligned}
M c_p &= M_a c_{pa} + M_w c_{pw} \\
c_p &= \frac{M_a}{M_a + M_w} c_{pa} + \frac{M_w}{M_a + M_w} c_{pw} \\
&= \frac{1}{1 + (M_w/M_a)} c_{pa} + \frac{(M_w/M_a)}{1 + (M_w/M_a)} c_{pw} \\
&= (c_{pa} + \omega c_{pw}) / (1 + \omega) \\
c_v &= (c_{va} + \omega c_{vw}) / (1 + \omega)
\end{aligned}$$

The isentropic exponential, k , is taken to be the ratio of the mixture specific heats, c_p/c_v , for each compressor stage. Condensation, which may occur in any of the intercoolers, could change this ratio of specific heats from stage-to-stage.

Each compressor stage is modeled in the usual thermodynamic manner. It is assumed to be an adiabatic device with a known isentropic efficiency; thus

$$\begin{aligned}
T_{e,s} &= T_i (P_e/P_i)^{\frac{k-1}{k}} \\
T_e &= T_i + (T_{e,s} - T_i) / \eta_c
\end{aligned}$$

where the inlet state is given by the subscript, i , and the exit state by the subscript, e . The isentropic efficiency of the compressor stage is η_c .

All heat exchangers are modeled using the heat exchanger effectiveness concept of Kays and London⁽³⁾. As stated above, it is assumed that the cooling side of each intercooler and the aftercooler has a larger capacity rate, $\dot{m} c_p$, than the compressed air side. Thus, the temperature of the exit, compressed air side of each heat exchanger is given by

$$T_e = T_i - \epsilon(T_i - T_o)$$

where the subscript, i , refers to the inlet of compressed air; the subscript, e , refers to the exit; and the subscript, o , refers to the inlet state of the cooling media. It is assumed that cooling media enters all heat exchangers at environmental conditions.

A standard vapor-compression, Freon-12 refrigeration cycle, is assumed for the de-humidification process. A fairly extensive thermodynamic analysis has been performed for this segment of the system because it was feared that it would consume a substantial amount of electric power. However, the results of the analysis indicate that less than two percent of the input power is used for de-humidification. As a result, the details of this section of the mathematical model are not repeated herein.

The de-humidification heat-exchanger is to be designed to reduce the compressed air stream temperature to 57°F (287°K) and to condense all excess water vapor. The air is then expanded through a control valve to approximately the cavern pressure and reheated to a temperature of 70°F, at which temperature the relative humidity is about 50 percent.

The exit pressure of each compressor stage has been determined in the following manner: the complete system simulation is run at various exit pressures from the final compressor stage (station 4A on Fig. II-1). The desired value of this pressure is chosen to be that which results in the pressure at station 4D to be about 2 psia (13,800 N/m²) above the maximum pressure at station 5A; and the minimum pressure at station 5B to be the same amount above the pressure at station 6. This latter pressure is fixed by the required inlet pressure to the turbo-expander plus applicable pressure drops through the regenerator. The result of this procedure is the overall pressure rise requirement of the compressor system.

Once the overall compressor pressure rise has been determined, a large number of computer simulations of just the compressor system was performed. Each run used a different set of intermediate pressures. The set which resulted in the least amount of input power while not having an exit temperature of any stage greater than 350°F (450°K) was the set used for the final computer simulation. The results are as follows:

SYSTEM	1A	1B	2
P ₀ , psia	13.1 (90.3)	13.1 (90.3)	13.1 (90.3)
P _{1A} , psia	33.9 (234)	36.0 (248)	45.0 (310)
P _{2A} , psia	70.5 (486)	80.0 (552)	108.0 (745)
P _{3A} , psia	146.6 (1011)	-	260.0 (1793)
P _{4A} , psia	305.0 (2103)	178.0 (1227)	625.0 (4309)

Figures shown in parenthesis are in units of thousands of N/m²

2. Cavern

The mathematical model of the cavern is divided into two topics. One topic is the thermodynamic analysis of the transient charging/discharging process. This analysis results in the calculation of pressure, temperature, and relative humidity within the cavern as a function of time for the weekly period. The second topic is the analysis of the transient heat conduction into/from the salt surrounding the cavern.

The transient analysis of the cavern consists of a conservation of mass statement for both the dry air and the water vapor, a conservation of energy statement for the two substances, and state relations for each substance.

The conservation of mass statements are

$$\frac{dM_{a5}}{dt} = \dot{m}_{a5A} - \dot{m}_{a5B}$$

$$\frac{dM_{w5}}{dt} = \dot{m}_{w5A} - \dot{m}_{w5B} - \dot{m}_{wc}$$

where the flow rates are inflow at station 5A, outflow at station 5B, and water vapor condensation at the wall surface of the cavern. The inflows are, respectively,

$$\dot{m}_{a5A} = \dot{m}_{5A} / (1 + \omega_{5A})$$

$$\dot{m}_{w5A} = \omega_{5A} \dot{m}_{a5A}$$

These values are determined from the compressor system section. The outflow rates are determined from the absolute humidity in the cavern and the required mass flow rates for the turbo-expander:

$$\dot{m}_{a5B} = \dot{m}_{5B} / (1 + \omega_5)$$

$$\dot{m}_{w5B} = \omega_5 \dot{m}_{a5B}$$

The condensation rate expression was developed following the method presented in Eckert and Drake⁽⁴⁾. This portion of the analysis was done prior to the decision to have de-humidification. The mathematical model predicted a considerable amount of condensation (as well as an almost perpetual fog or rain in the cavern). As a result of these

predictions and concern regarding the deterioration of the rock salt structure, the de-humidification equipment was added to the compressor system. Once de-humidification was added, no condensation was predicted. Thus, the details of the condensation analysis are no longer important to the over-all model and are not included in this report.

An energy balance on the cavern indicates that the rate at which the total internal energy of the air and entrained water within the cavern changes depend on energy fluxes entering from the compressor system, leaving to the turbo-expander system, or leaving to the rock salt in the form of heat or condensation:

$$\frac{dU_5}{dt} = \dot{m}_{a5A} h_{a5A} + \dot{m}_{w5A} h_{w5A} - \dot{m}_{a5B} h_{a5} - \dot{m}_{w5B} h_{w5} - \dot{m}_{wc} h_c - \dot{Q}$$

The internal energy, U , is made up of the internal energy of the dry air and of the water,

$$U_5 = M_{a5} u_{a5} + M_{w5} u_{w5}$$

Thus,

$$\frac{dU_5}{dt} = u_{a5} \frac{dM_{a5}}{dt} + M_{a5} \frac{du_{a5}}{dt} + u_{w5} \frac{dM_{w5}}{dt} + M_{w5} \frac{du_{w5}}{dt}$$

Two significant cases may be considered. One is that no change of phase occurs and the second is that some of the water entrained in the air may condense forming a fog, or perhaps rain. Both of these cases were included in the model, but only the first case became applicable once the de-humidification equipment was added to the compressor system. Thus, only the first case is discussed in this report and the condensation rate, $\dot{m}_{wc}$, is taken to be zero.

The combination of the energy equation with the two mass balances and the assumption that both air and water vapor behave as perfect gases with constant specific heats results in a differential equation for the rate of change of cavern temperature.

$$(M_{a5} c_{va} + M_{w5} c_{vw}) \frac{dT_5}{dt} = r_1 + r_2 - r_3 - r_4 - \dot{Q}$$

The rate terms are, respectively,

$$r_1 = \dot{m}_{a5A} c_{pa} (T_{5A} - T_5/k_a)$$

$$r_2 = \dot{m}_{w5A} c_{pw} (T_{5A} - T_5/k_w)$$

$$r_3 = \dot{m}_{a5B} c_{pa} T_5 (1 - 1/k_a)$$

$$r_4 = \dot{m}_{w5B} c_{pw} T_5 (1 - 1/k_w)$$

$$\dot{Q} = H_o A (T_5 - T_{So})$$

The integrated values of the two masses M_{a5} and M_{w5} , and the temperature, T_5 , determine the pressures,

$$P_{a5} = (R_a/V) M_a T_5$$

$$P_{w5} = (R_w/V) M_w T_5$$

$$P_5 = P_{a5} + P_{w5}$$

The transient heat conduction into/from the rock salt is determined from a six node model. The temperatures of each node is indicated by T_{S1} , T_{S2} , etc. The last node is taken to have a constant temperature, $T_{S6} = 70^\circ\text{F}$ (294°K). The differential equation for the temperature of node i is

$$\frac{dT_{Si}}{dt} = \frac{1}{C_i} \left[\frac{T_{S(i-1)}}{R_i} - \left(\frac{1}{R_i} + \frac{1}{R_{i+1}} \right) T_{Si} + \frac{T_{S(i+1)}}{R_{i+1}} \right]$$

Where C_i is the thermal capacity of node i , R_i is the thermal resistance between node $i-1$ and node i , and R_{i+1} is the thermal resistance between node i and node $i+1$.

The spacing between nodes has arbitrarily been selected to be as follows:

Location	Distance Between Locations, ft (m)		Distance Included In Node, ft (m)	
Cavern Surface	0.125	(0.038)		
Node 1	0.375	(0.114)	0.25	(0.076)
Node 2	0.875	(0.267)	0.50	(0.152)
Node 3	2.125	(0.648)	1.25	(0.381)
Node 4	4.0	(1.219)	3.0	(0.914)
Node 5	2.5	(0.762)	5.0	(1.524)
Node 6			-	

E. Cost Estimates

Rough cost estimates in current dollars for the three systems, including subsurface costs for sealing the mine were prepared, and are summarized in Table 24. Total costs are

System 1A	\$360/kw	(100 mw)
System 1B	\$448/kw	(20 mw)
System 2	\$350/kw	(25 mw)

These costs are considerably higher than those for simple cycle gas turbine peak-shaving plants, which cost in the range of \$130/kw, and result because of (1) the relatively small turbine sizes; (2) the separation of compressor and turbine elements; (3) the incorporation of various intercoolers, recuperators, etc., and (4) the cost for sealing the mine. Since no manufacturers presently supply separable compressor and turbine equipment (except for Brown Boveri in 280 mw ratings), the cost estimates are only approximate, but indicate a disappointing trend.

F. Evaluation of Aquifer Storage Potential

In assessing the storage potential of the Texas Panhandle, attention has been given to other possibilities for storing large volumes of compressed air since suitable abandoned mines are relatively rare occurrences, and the cost of constructing underground caverns is prohibitively high.

TABLE 24.

Performance and Cost Summary
Compressed Air Storage - Depleted Potash Mine⁽¹⁾

	Gas Turbine 100 MW (System 1a)	Gas Turbine 20 MW (System 1b)	Expander Turbine 25 MW (System 2)
Energy Output, kWh/a ⁽²⁾	33.83×10^7	5.69×10^7	6.58×10^7
Energy Input, kWh/a ⁽²⁾	28.03×10^7	4.78×10^7	11.53×10^7
Equivalent Fuel Energy Input, kWh/a ⁽²⁾	13.82×10^7	2.31×10^7	2.12×10^7
Energy Conversion Efficiency	80.9%	80.3% ⁽⁴⁾	48.2%
Estimated Cost ⁽³⁾ \$/kW (sealed mine)	360	448	350
Estimated Cost \$/kW, (aquifer storage)		425	

(1) Aquifer storage reservoir costs developed for 20 MW Gas Turbine System for comparison purposes.

(2) Based on 11 hours/day, 5 days/week power output.

(3) Cost of sub-surface sealing of mine = $\$10^6$

(4) Can be increased to 88.4% by raising turbine inlet temperature.

Three other types of underground compressed air storage have been mentioned in the literature. The first is depleted and abandoned oil and gas fields, the second is solution-mined salt caverns and the third, porous underground rock strata containing natural water called "aquifers". A general survey of the geology of the study region has been undertaken with a view toward the potential of all three of these possibilities.

One of the systems studied (System 1B) involves a 20 mw peaking plant using gas turbines, the total air requirement for which is 4.2×10^5 lbs/hr, or 5.5×10^6 scf/hr. Since considerable detail has gone into the examination of this size plant, it is used as a base of comparison for other storage concepts.

Coats(5) has given an analysis of historical average costs of storing natural gas in the pipeline and fuel gas industry. Capital costs for suitable storage pressure vessels at that time (1967) ranged from \$0.27/Mcf capacity (total volume stored) for depleted natural gas reservoirs, to \$227./Mcf capacity for large spherical steel storage tanks. Aquifer storage costs, based on averages of 40 successful storage facilities of this kind in the United States, averaged \$0.41/Mcf capacity, slightly higher than for depleted gas fields. No figures are given by Coats for solution-mined salt caverns, but he estimates that these costs would be lower than for depleted gas fields, and probably represent the lowest cost storage, outside possible existing caverns that can be easily sealed.

It is important to note that these cost figures, for natural gas, included the cost of "cushion gas", or the gas necessary to maintain pressure, but which is undeliverable to the system. Of this cushion gas, 50 to 60% is considered nonrecoverable and is depreciated. In the case of compressed air, of course, the cost of the raw material is zero and the cost of the depreciated product is negligible, although the energy required to initially compress the cushion air is for all practical purposes not recoverable. This will tend to reduce the total cost of compressed air storage over pipeline peak-shaving storage.

Of equal importance to the total storage capacity is the gas (or air) deliverability rate, generally given in thousands of standard cubic feet per day (Mcf/d). In the natural gas industry, one is frequently faced with the requirement for delivering virtually all the deliverable gas in storage over a very short time period. While this is not the case in compressed air energy storage applications, the flow rate during the turbine duty cycle can be very high, signifying a high deliverability rate. This is evidenced by the deliverability requirement for the SwPSC study system of 21 Mw capacity, for example, of 5500 Mcf/hr.

Ayers and Hoover⁽⁶⁾, in a detailed analysis of aquifer storage in conjunction with gas turbine peaking plants, have given a good description of the significant geologic parameters involved in natural underground storage, i. e. rock porosity, permeability and depth. Permeability, the controlling parameter in deliverability under a given pressure condition, governs the number of wells for a given requirement. The depth, which determines the operating pressure, is an important factor in drilling and development cost. Porosity is the fluid-filled (or occasionally void) interstitial space in the rock matrix, directly affecting the total storage capacity.

Cost factors affecting aquifer and abandoned petroleum reservoir storage are intimately connected with the two parameters, total storage capacity and daily (or hourly) deliverability. Ayers and Hoover apparently disregarded the former in their cost analysis. In practice, pressurizing the "bubble" or air cushion, represents a significant capital cost, since development of such storage may take several years of operating time and thousands of kilowatt hours of pumping energy (non-recoverable) before full operation can be achieved.

In order to determine the number of wells required under given reservoir conditions, principles of petroleum reservoir engineering may be applied. The deliverability of a gas well is given by the following empirical equation:

$$Q_b = \frac{19.88 k h (P_e^2 - P_w^2)}{\mu P_b \ln \frac{r_e}{r_w}}$$

where

- Q_b = deliverability, Mcf/d at base pressure, P_b
- k = permeability, Darcies
- h = formation thickness, feet
- P_e = formation pressure, undisturbed, psi
- P_w = well pressure, flowing, psi
- P_b = delivered pressure, at surface, psi
- r_e = radius of reservoir (or air bubble) feet
- r_w = well radius, feet
- μ = viscosity of gas (or air), centipoise

All the Panhandle region represents sedimentary deposition, and, as such, the reservoir storage possibilities, including depleted gas fields and aquifers, are numerous. In addition, there is widespread, almost general, occurrence of salt deposits at various relatively shallow depths over much of the region which would lend themselves to solution mining.

The Panhandle is the site of the largest gas field in the world. It lies along the eroded slope of an ancient buried mountain chain known as the "Amarillo Range". The area of primary interest is shown on the map in Figure 39. The reservoirs in this field, along with the adjacent oil deposits, have produced heavily since the 1920's and many of the wells have been abandoned. Geology is favorable for high deliverability storage wells throughout this area. Typical reservoir parameters, based on the original oil and gas production, indicate that reservoirs should be operated at pressures of about 400 psi. Flowing at a rate which will yield a 200 psi draw-down, a single Panhandle well should produce about $Q_b = 10,500$ Mscf/day,

$$\begin{aligned} \text{given, } k &= 0.1 \text{ Darcies} \\ h &= 50 \text{ ft.} \\ P_b &= 200 \text{ psi} \\ \mu &= 0.01 \text{ centipoise} \\ r_w &= 1000 \text{ ft.} \\ r_e &= 0.5 \text{ ft.} \end{aligned}$$

For a daily deliverability rate of $5.5 \times 10^6 \times 24 \text{ hours} = 132,000$ Mscf/day for the 21 MW study system, a total of

$$\frac{132,000}{10,500} \cong 13 \text{ wells would be required.}$$

These wells are now estimated (1975) to cost \$24,000 each, for a total investment of \$312,000 or \$15/installed kw.

In addition, the daily total deliverability, $5.5 \times 10^6 \text{ scf/hr} \times 11 \text{ hr cycle} = 60.5 \times 10^6 \text{ scf}$ should be 10% or less of the total stored volume to prevent excessive pressure drop during a cycle. The total bubble volume should then be

$$\frac{60.5 \times 10^6}{.10} = 605 \times 10^6 \text{ scf.}$$

Careful analysis of the cost of developing a bubble of this size is beyond the scope of this study but estimates by Coats indicating aquifer storage costs for natural gas of \$0.41/Mcf may be applicable (while these cost figures may not be current, they include the cost of cushion gas, not applicable to compressed air storage). On that basis, one may estimate a volume storage cost of $605 \times 10^3 \times \$0.41 = \$248,000$. or approximately \$12/kw, in addition to the \$15/kw deliverability cost. The total, \$27 per installed kw, is considerably higher than the \$7 quoted by Ayers and Hoover. This is partially due to the development cost neglected by the latter authors, and partially to the Panhandle reservoir parameters which are poorer than those assumed by them.

a. Main Geologic Features of Region.

b. Cross-section showing Main Formation Lithology across buried Amarillo Mountains.

FIGURE 39.

The remainder of the costs (turbine, generator, compressors, etc.) are relatively fixed regardless of the type of air storage, and are discussed in the overall air storage cost analysis. It is likely that these costs may be affected seriously by the small size of the turbine peaking plant (21 Mw). If so, aquifer storage may actually provide a more practical storage facility than the abandoned mine, since it does not suffer the upper size limitation inherent in a vessel with fixed volume.

G. Results of Compressed Air Storage Study

The significant results of the study are presented in this section. The first set of results is for each of the three turbine systems operating at the average climatological conditions for Carlsbad, New Mexico. The second set of results is those resulting from the year-long simulated operation of System 1A. Finally, the conclusions regarding the technical feasibility of the proposed Compressed-air Energy Storage System are presented.

The output of the computer model gives hour-by-hour results of the power input, power output, fuel flow rate, cavern pressure, cavern temperature, cavern relative humidity, stack temperature, and the values of other less significant variables. Of these, only the cavern pressure has a substantial variation with time (except, of course, the off-on nature of the powers and fuel flow). Therefore, only the cavern pressure is presented graphically in Figure 40; all other results are tabulated in Table 25.

As indicated in Section III. C. 5 (page climatological data were averaged over 13 four-week periods as well as for the whole year using five years' weather data for Carlsbad, New Mexico. These data were used as input to the computer model for 13 successive runs, where the ending conditions of one run are the initial conditions for the next run. The results of this year-long simulation do not indicate any significant variation in any variable shown in Table 25, except for the compressor power input. The variation in this quantity is given as follows:

FIGURE 40.

CAVERN PRESSURE
DURING A TYPICAL WEEKS OPERATION

	System		
	1A	1B	2
Nominal turbine power, MW	100	21	25
Turbine inlet pressure, psia N/m ²	138 9.51x10 ⁵	120 8.27x10 ⁵	490 3.38x10 ⁶
Turbine inlet temperature, °F °K	1950 1339	1600 1144	645 614
Turbine mass flow rate, lb _m /hr Kg/hr	1.71x10 ⁶ 7.76x10 ⁵	3.53x10 ⁵ 1.60x10 ⁵	5.50x10 ⁵ 2.50x10 ⁵
Compressor exit pressure, psia N/m ²	305 2.10x10 ⁶	178 1.23x10 ⁶	625 4.31x10 ⁶
Electric power output, MW for 55 hr/wk	118.3	19.9	23.0
Electric power input, MW for 55 hr/wk	98.0	16.7	40.3
Fuel consumption, lb _m /hr for 55 hr/wk Kg/hr for 55 hr/wk Scfm for 55 hr/wk Btu/hr for 55 hr/wk* MW for 55 hr/wk*	2.38x10 ⁴ 1.08x10 ⁴ 8800 5.00x10 ⁸ 146.4	3975 1800 1460 8.35x10 ⁷ 24.5	3660 1660 1350 7.69x10 ⁷ 22.5
Cavern temperature, °F °K	70 ± 1 294 ± 0.5	70 ± 1 294 ± 0.5	70 ± 1 294 ± 0.5
Cavern relative humidity, %	50 ± 20	55 ± 10	55 ± 10
Stack temperature, °F °K	250 394	216 376	49 283

* based on a fuel heating
value of 21,000 Btu/lb_m

TABLE 25. RESULTS FOR AVERAGE CLIMATOLOGICAL
CONDITIONS AT CARLSBAD, NEW MEXICO

Period	$\dot{w}_{k_M}$, MW
1	94.3
2	94.3
3	94.9
4	96.5
5	98.2
6	99.8
7	102.1
8	102.1
9	101.5
10	99.8
11	97.6
12	94.3
13	93.7

Thus, there is a 4.2 percent variation in the power input over a year.

A rational method of comparing these systems and with other energy storage systems must be developed. A pumped-hydro efficiency may be defined as the ratio of the power output to power input over an input/output cycle. This ratio is not applicable to the compressed-air energy storage system, however, because fuel is used in the power output process. An efficiency which would be applicable to both of these systems uses, as the denominator, the sum of the actual power input plus the power equivalent of the heat rate.

The work equivalent of heat may be taken as the thermodynamic efficiency of a base power plant, which is currently about 33 percent. Thus,

$$\eta_{\text{recovery}} = \frac{\dot{w}_{k_{\text{out}}}}{\dot{w}_{k_{\text{in}}} + \frac{\dot{Q}_{\text{in}}}{\eta_{\text{base}}}}$$

Using this definition, the following are the recovery efficiencies of the three systems:

System	Recovery Efficiency, %
1A	80.9
1B	80.3
2	48.2

It may be seen that both systems 1A and 1B have higher recovery efficiencies than the typical values of 60 to 70 percent for pumped-hydro energy storage systems.

The reason why both systems 1A and 1B have approximately the same values of recovery efficiency is the result of offsetting effects. The first of these is the relative value of the energy loss caused by having to operate the compressor exit pressure well above the turbine inlet pressure. Table 25 clearly indicates that these losses are much greater for system 1A than for system 1B. The second major difference in the two systems is that the turbine inlet temperature is much higher for system 1A than for system 1B resulting in much better performance of the turbine system.

The foregoing observation leads to a conclusion that the smaller machine (based on mass flow rate) "fits" the given cavern better than the larger machine. It also suggests that the recovery efficiency of the smaller system (system 1B) might be substantially improved if the turbine inlet temperature were increased. To investigate this possibility, an approximate analysis has been made using system 1B, except increasing the turbine inlet temperature to that of system 1A. The results of this analysis, which does not affect the compressor system or the cavern dynamic behavior, are as follows:

Modified System 1B

Turbine inlet pressure, psi (N/m ²)	120	(8.27x10 ⁵)
Turbine inlet temperature °F (°K)	1950	(1339)
Turbine mass flow rate, lb _m /hr (Kg/hr)	3.53x10 ⁵	(1.60x10 ⁵)
Compressor unit pressure, psia (N/m ²)	178	(1.23x10 ⁶)
Electric power output, MW for 55 hr/wk	23.2	
Electric power input, MW for 55 hr/wk	16.7	
Fuel consumption based on 21,000 Btu/lb of fuel, MW ^m for 55 hr/wk	28.9	
Stack temperature, °F (°K)	258	(399)
Recovery efficiency, %	88.4	

Thus, an improvement of the recovery efficiency is, indeed, realized by using the smaller system with a higher turbine inlet temperature.

The overall technical conclusion of this study is that compressed-air energy storage systems utilizing the abandoned potash mine in New Mexico are feasible, and that it is effective to match the size of the turbine to the size of the cavern with a turbine designed to maximize the thermodynamic efficiency of a Brayton cycle which used that turbine.

The cost results show the economic weakness of small capacity systems. Many of the costs of an air storage system are fixed. The existence of a significant scale factor in overall installation capacity is obvious, and indicates that high-capacity over a shorter peaking period might be a much more attractive scheme.

The attractiveness of the expander turbine (System 2) was slightly surprising, and appears to warrant more detailed investigation.

A serious drawback of the compressed-air storage system is the requirement for natural gas for fuel for the turbines. At this time, commitment of gas for any new generation or storage plan is extremely doubtful.

H. Review of Regional Pumped-Hydro Storage Potential

Because of climate and topography, the Texas Panhandle is not generally considered a prime candidate for pumped-hydro storage potential. However, this is not to say that such potential does not exist, for in fact two sites have been explored and are considered as having some promise particularly in concert with wind generated pump-up capability. The two sites are Lake Meredith, 40 miles northeast of Amarillo, Texas and Ute Reservoir, 20 miles northeast of Tucumcari, N. M. Either of these sites would permit the installation of 100 mw of pumped-hydro storage. Details are presented in the following.

1. Lake Meredith

The lake is formed behind Sanford Dam on the Canadian River and is located in Hutchinson County, Texas some 40 miles northeast of Amarillo.

Effective drainage area	16,040 sq. mi.
Earth fill dam	6,400 ft. long
	200 ft. high

Elevations in feet above M.S.L. and storage area
in acre feet:

Top of dam	3,011.0 ft.
Top of controlled storage	2,965.0 ft.
	(1,407,600 AF)
Top of conservation pool	2,935.0
	(864,400 AF)
Usable storage	821,300 AF
Invert of flood control	2,894.0
outlet works	(313,700 AF)
Invert of lowest gate in	
outlet works	2,850.0
	(43,100 AF)

(AF = Acre Feet)

Discharge for flood control through three conduits, each 15.5 feet in diameter. These ducts now discharge at elevation 2882.9 ft. (bottom) into open flume. By addition of 600 feet length pressure conduit to each duct, the effective discharge would be at 2748.5 feet (bottom).

Water input to the project, to date, has been barely adequate to satisfy water demands by member cities of the Canadian River Municipal Water Authority. The water level ahead of the dam is now at elevation 2907.48 feet and has been slowly dropping from an all-time high of 2920 feet approximately 3 years ago. Water, now stored ahead of the dam, is approximately 10,000 acres in surface area and 400,000 acre feet in volume.

The Lake Meredith project would appear to offer at least two alternatives for installation of pumped-hydro generation storage, subject, of course, to concurrence by the Canadian River Municipal Water Authority, which operates and owns the project; landowners in the immediate area of the project; environmental agencies; the Bureau of Reclamation, which built the project in 1965, and the continued availability of water flow into the lake sufficient to satisfy contractual and State compact water supply demands plus any increased water loss by seepage and evaporation from the pumped-hydro energy storage.

a. Alternative I

A technically feasible pumped-hydro energy storage project could be constructed utilizing the hydraulic head of the water stored

above the dam and a small, 10,000 acre feet volume, storage reservoir in the stream bed of the Canadian River below the dam. This plan would be relatively simple to implement, relatively low in cost, and should not incur major environmental objections. With silt build-up ahead of the dam, the hydraulic head available for future operation, would actually increase within the permitted stored water volume limits.

Lake Meredith Dam would serve to protect the downstream storage reservoir from flood damage, thus permitting a relatively low cost reservoir to be constructed, assumed to be an earth-fill, concrete-capped dam some 10 feet high approximately 2 miles downstream from Lake Meredith. This downstream reservoir would be in position to store runoff from two major tributaries to the Canadian River below Lake Meredith, and, of course, this reservoir would, under flood conditions, store about 10,000 plus acre feet of water which otherwise would be lost to the Lake Meredith project.

To illustrate the energy potential of this plan, assume a minimum hydraulic head of 27m (90 feet), a water discharge rate of $450 \text{ m}^3/\text{s}$ ($16,000 \text{ ft}^3/\text{sec}$), water density of 1000 kg/m^3 (62.4 lb/ft^3), and a turbine efficiency of 0.85. The generated power would be

$$P = \frac{27 \times 450 \times 1000 \times 9.807 \times 0.85}{1000} = 101,281 \text{ kw}$$

If on-peak hydro generation is limited to 2 hours per day this plan would deliver approximately 200,000 kwh each day into the nearby, existing transmission facilities. The discharge of $450 \text{ m}^3/\text{s}$ of water for 2 hours would require about 2700 acre feet of storage volume in the downstream reservoir.

b. Alternative II

The Lake Meredith area also offers the possibility of installation of a high level water storage reservoir which would operate in conjunction with a low level (stream bed) reservoir. The high level reservoir would be built on top of the bluffs along the river at an effective elevation of 2975 feet. The river bed reservoir, at effective elevation of 2810 feet, would permit pumped-hydro turbine units operating with a head of 50 m (165 feet). Once the low level reservoir had been filled with water, by purchase from the Lake Meredith project, this facility could be operated relatively independently of Lake Meredith and thereby avoid the daily lake level change of 6 inches to one foot, which would result from Alternative I operation. The installed cost of Alternative II would be higher than Alternative I. To develop 100,000 kw and 200,000 kwh/day from this plan, would require a water flow rate of $240 \text{ m}^3/\text{s}$ ($8478 \text{ ft}^3/\text{s}$) and water storage reservoir volume of 1400 acre feet.

The electric utility serving this area could utilize 100,000 kw of hydro storage capacity at this location for a 2-hour period each day, 5 days a week, 50 weeks a year, for peak shaving for a total of 50×10^6 kwh/year. Or this capacity could be maintained as "spinning" reserve of limited duration capability. As is well known, the recharge energy required is larger than the generated energy because of turbine and pump losses. Assuming turbine efficiency of 0.85 and pump efficiency of 0.75, the overall or turn-around efficiency is the product of the two, or 0.64. Consequently, recharge energy of 78×10^6 kwh per year would be required to accommodate 50×10^6 kwh per year of hydro generation.

Obviously, this recharge energy could be supplied during the off-peak load valleys by thermal base plants, and indeed this would be the economic choice taking current fossil fuel energy costs at face value. However, because of uncertainties in projecting future fossile fuel economies coupled with the evident national need for fostering fuel conservation, the purpose here is to examine the feasibility of employing wind power to recharge the hydro storage.

To illuminate this particular case, the following assumptions will be made:

New coal-fired capacity installed	\$275/kw
Annual capital carrying charges	20%
Coal-fired plant fuel and production costs (present day average)	\$0.01/kwh
Pumped-hydro capacity installed (assuming no major dams or extensive pressure conduit construction)	\$200/kw
Wind generation installed	\$500/kw
Wind generation availability factor	0.5

To generate 78×10^6 kwh/year will require $78 \times 10^6 \div 0.5 = 17,810$ kw, say 18,000 kw of installed wind generation capacity.

Annual cost of wind generating plant

$$\$500 \times \frac{18,000}{100,000} \times 0.2 = \$18/\text{kw}$$

Annual cost of pumped-hydro storage facility

$$\$200 \times 0.2 = \$40/\text{kw}$$

Total \$58/kw

An economic alternative is to supply this same amount of energy with new coal-fired plant capacity. Thus:

Annual cost of coal-fired plant	
$\$275 \times 0.2 =$	\$55/kw
Annual cost of energy production	
$\$0.01 \frac{x 50 \times 10^6}{100,000} =$	<u>\$ 5/kw</u>
Total	\$60/kw

This exercise indicates that the pumped-hydro, wind generation facility compares favorably with new coal-fired capacity on an economic basis, with the additional feature of providing 50×10^6 kwh of fuel-free energy per year to the utility network.

The question as to whether such a facility should be operated in the peak shaving mode, in a reserve mode, or in some appropriate combination of the two, would require further study. The 100 mw hydro generation plant could be implemented in 25 mw steps; only the first unit need be a combination turbine-pump machine. Alternatively, the initial 5 mw pumping capacity could be separately implemented and increments added as needed.

2. Ute Reservoir

Ute Reservoir is located on the Canadian River in Quay County, New Mexico, approximately 20 miles northeast of Tucumcari, New Mexico; the earth-fill dam is 2050 feet long, 121 feet high. Elevations in feet above M.S.L. and storage in acre feet are indicated below:

Top of Dam	3801.0 feet
Top of active storage	3760.0 feet (59,700 AF)
Top of inactive storage	3741.6 feet (29,200 AF)
Dead storage	3725.0 feet (20,700 AF)
Total	109,600 AF

The original dam (Logan Dam) was constructed in 1963. The Amarillo office of the U. S. Bureau of Reclamation advises that plans are being made to install control gates on this dam and to increase the

spillway height by 27 feet to permit increased storage of water. U. S. Bureau of Reclamation estimates completion of the municipal water supply system pipeline out of this dam within the next 10 years. This project is known as the Eastern New Mexico Water Supply Project.

The combination of relatively low dam height and relatively small storage volumes of the dam appear to rule out any on-site pumped-hydro storage projects proposed like Alternative I for Lake Meredith.

A two-reservoir pumped-hydro facility, similar to Alternative II for Lake Meredith, might be installed with effective hydraulic head of approximately 225 feet. However, approximately 30 miles south-southeast of the dam is an abrupt escarpment (The Caprock) where a two-reservoir pumped-hydro facility could be installed with up to 168m (550 feet) hydraulic head. This site will be traversed by the proposed water supply system pipeline, and offers a preferred location for pumped-hydro storage. This site could provide up to 100 mw of storage, and should be seriously considered when the water supply pipeline facility is designed and built. A 110 mile transmission line would be required to link this facility with the utility network. This is a major cost item associated with this particular site, and in fact, was a dominant factor in an adverse economic analysis performed by the utility in 1968. Future fossil fuel economics could radically change the results of such a study.

J. Results of Pumped Hydro Storage Studies

The potential for pumped hydro storage in the region of this study is limited and is mainly restricted to two sites. These include the existing facility at Lake Meredith on the Canadian River in Texas, and potential associated with the Ute Reservoir on the Canadian River in Quay County, New Mexico. Lake Meredith could now support a 25 MW pumped hydro facility which might eventually be expanded to 100 MW. The 25 MW system would be suitable for connection with 5 MW of installed WTG, dedicated to the pump-up storage operation. Such a facility could provide two hours/day peak shaving capability, or could be carried as effective spinning reserve of limited duration. The economics of this system compares favorably to that of providing comparable generating capacity with a new coal-fired steam plant.

The Ute Reservoir presently does not have adequate dam height or storage volume for an effective on-site pumped hydro storage project. However, 30 miles southeast of the dam is an abrupt escarpment

where a two-reservoir pumped hydro facility could be constructed with as much as 550 feet of hydraulic head. Such a facility could provide up to 100 MW of storage, but would require a 110-mile transmission line to link the facility with the present utility network.

While the Panhandle is generally not considered suitable for hydroelectric development, these two facilities could eventually provide a total of perhaps 200 MW of storage for future development.

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IV. COST GOAL ANALYSIS

A. Worth of Wind Generated Energy

In general, wind generators can be expected to have less value to a utility than conventional plants because of the inherent lack of reliability of the wind. Quantifying this intuitive view has been the subject of study throughout the history of modern windpower experiments. In the first comprehensive report of serious consideration of the economic viability of windpower systems, Putnam⁽¹⁾ carried out a careful, detailed analysis of the economics of windpower with the help of the Stone and Webster Company. Putnam enumerated the worth of wind generated electrical energy in terms of four components: (a) energy value, (b) reactive value, (c) capacity value, and (d) predictability value. Putnam, Golding⁽²⁾ and later workers have stated that capacity value is present only when wind energy systems are associated with a means of energy storage, such as pumped hydro or natural hydro reserve. It is likely that some capacity value can be obtained through the natural geographic diversity of a wide-spread wind energy system, although the extent to which this capacity value exists remains to be proven.

Reactive value accrues to synchronous generators operating both at no-load as synchronous condensers, and under load at favorable power factors. Induction machines, on the other hand, represent a substantial inductive load and are therefore likely to be of no reactive value, but rather suffer a penalty.

Predictability value has to do with the ability to predict the availability of wind energy systems some hours in advance. It is possible that some value could be attached to a windpower system under sufficiently accurate wind prediction conditions but this aspect, like the diversity factor, remains to be proven.

The most straightforward and obvious value of wind generated energy on a large network is its energy value. Connected to a utility network and free to operate in a run-of-the-wind mode, the WTG can make use of the flexibility of the system to absorb power when wind conditions are favorable, and at other times, to allow the energy deficiency to be made up by other generators on the system. The result of wind generated energy, then, is a saving in fuel consumed by the other plants.

The fuel saving, in general, will be a function of the time of day during which the wind energy is actually available. If a utility were equipped, for example with a large nuclear base-load plant backed up by fossil-fueled units, wind generated energy would have much

higher value during periods when fossil fuels were being burned (peak load), than during other periods, since nuclear fuel cost is very low. But on the SwPS system, all units, both base-load and peak-load, are fired by natural gas. This means that very little difference in energy value accrues to wind energy, regardless of when it occurs.

The potential fuel and other possible savings that windpower promises to a utility, permits consideration of additional capital investment to achieve it. The purpose of this part of the present study is to determine the value of WTG in various configurations, with and without storage, to the Southwestern Public Service Company. This value represents the cost goal for windpower systems under the specific operating parameters and in the wind regime of the Texas Panhandle.

Obviously the number of unfirmed wind generators that could be operated on a given network is limited by the flexibility of the network, and its other generating capacity. The Southwestern Public Service Company network would experience no foreseeable difficulties in accepting the unfirmed energy from a number of WTG amounting to as much as 3% of load, 3% representing the minimum "spinning reserve" requirements of the network.

B. Energy Value

The purpose of this task is the evaluation of windpower energy value benefits to Southwestern Public Service Company, and the determination of the investment which could be justified to achieve these benefits.

This evaluation involves several factors:

1. Wind turbine-generator output vs. wind velocity characteristics. (Developed in Section II of this report.)
2. Average wind velocity at various times of the day and for each month of the year. (Section II)
3. Predicted power output from the wind generator for various times of the day for each month of the year, and total annual energy generated. (Section II)
4. Load pattern characteristics and corresponding generation cost for Southwestern Public Service Company.

5. Annual value of the kWh of expected generation using actual 1975 generation costs and expected future fuel costs.
6. The amount of investment that could be justified to provide the annual savings equal to the value of the kWh generated.

Factors 1, 2 and 3 have been determined by Southwest Research Institute and Texas Tech University in other tasks in the study, and reported in Section II of this document, "Wind Assessment Analysis".

Factor 4 was determined from operating department data of Southwestern Public Service Company.

C. Run-of-the-Wind Operation without Storage

This task consists of two parts, the first of which is to develop a methodology, and to determine the annual dollar value of the fuel savings which can be expected from a given WTG installed on the SwPS system. This figure can be established by first computing the total fuel cost for the year without WTG, and subtracting from this figure the total fuel cost with WTG operating in the system.

1. Yearly Fuel Cost for SwPS System (without WTG)

SwPS has developed a computer program for optimizing and determining fuel costs on its system. A description of this program is given in Appendix A. The program input consists of -

- a. a system model of the SwPS network and generation plants;
- b. the fuel consumption rates and raw fuel costs for each of the generating stations of the system;
- c. the values of the expected and actual load on the system for each hour of the day.

By iterative calculation, the computer arrives at the mix of generation output for all units, such that the load is met and system total fuel cost in dollars per year is minimized.

To establish a rational methodology with minimum computer time, data for the 1974-1975 period was used, but for selected sample periods comprising only 12 weeks of the year. These included the first two weeks of the months of December 1974, February 1975, April, June, August and October 1975. Each of these periods was assumed to be typical of the longer two-month interval in which it was imbedded. A check on actual system results for the year, reflected in Table 26 showed this assumption to be valid.

For each day of the above periods the actual hourly integrated load of the system was programmed together with the fuel rates and heat rates of each generating station. The computer then calculated the total fuel cost on the basis of dispatching generation to minimize fuel cost. Table 26 shows the results of the computer simulation, together with the actual figures as recorded in SwPS records. It is seen that there is good agreement between the calculated values and the actual values. The rapid increase in cost of generation is, of course, caused by the corresponding rise in the price of fuel during this period of time.

The foregoing analysis establishes a basis of comparison for conventional systems and WTG in terms of fuel savings.

2. Yearly Fuel Costs for System with WTG

In IV.C.1 (above) the fuel costs for a conventional system supplying a known load, in an optimum dispatch mode have been established; that is, fuel costs have been minimized. It remains to determine the fuel costs for the same system and load schedules, except with a single WTG added to the system. For illustrative purposes, a specific example is presented along with the explanation.

Consider a 1000 kW WTG, rated at a wind velocity of 8M/second, at a 60M tower height. In Section II of this report, the power output of such a machine was established, on average, at various locations in the study region, as a function of hours during the day. Typical curves appear in Figures 22 and 23. These curves are subtracted, on an hourly basis, from the known load schedules of the utility system. The resultant curves are the load demand curves which must be met by the conventional generation units of the system. These "net" demand curves are entered into the optimal dispatch program to yield a new total fuel cost for the system. This new fuel cost is, of course, lower than the one computed in IV.C.1 because the WTG output has been fully utilized to reduce the demand upon the conventional units.

TABLE 26

Comparison of Results of
Load Scheduling Computer Program to Actual Operation

<u>Month</u>	<u>Predicted kWh/ 2 wks.</u>	<u>Predicted kWh/ 2 mos.</u>	<u>Predicted Mills/kWh</u>	<u>Actual kWh</u>	<u>Actual Mills/kWh</u>
November 74 - December 74	388 498.3	1, 553, 993	5. 64	1, 485, 710	5. 69
January 75 - February 75	355 514.5	1, 422, 058	6. 34	1, 405, 667	6. 52
March- April	385 982	1, 543, 928	6. 74	1, 521, 455	6. 75
May- June	401 230	1, 604, 921	7. 53	1, 651, 777	7. 72
July- August	462 689	1, 850, 755	8. 18	1, 613, 304	8. 23
September- October	<u>386 449</u>	<u>1, 545, 795</u>	<u>9. 81</u>	<u>1, 609, 679</u>	<u>9. 46</u>
Total Year		9, 525, 864	7. 4136	9, 652, 457	7. 85

November 1974 - Generation Cost = 5.48 mills/kWh

October 1975 - Generation Cost = 10.11 mills/kWh

It should be noted that the kW output curves of the WTG can be adjusted to allow for planned maintenance shut-down periods, although these periods were not included in the numerical example. Thus, the numerical results in this respect are overly optimistic by a small amount (estimated at 3% maximum down-time).

For the example at hand, the difference between the two annual fuel costs (with and without WTG) is approximately \$53,000, which represents the fuel saving. The significance of this figure is only evident in the context of the particular WTG considered, together with the fuel costs of the system for the year 1975, as shown in Table 26. Obviously, for a different WTG design and under different operating conditions, the numerical value of fuel savings can vary widely. Nevertheless, the procedure given here is valid for any WTG design for which energy generation functions at a particular location are known and for all utility systems for which fuel and heat rates are established.

To check on the validity of representing yearly WTG output data by 6 selected two-week periods, the total calculated yearly kWh output for the WTG selected (6,848,000) has been multiplied by the average annual fuel cost, in dollars/kWh (\$0.0785) for the year 1975. This product, \$53,800. is in excellent agreement with the previously calculated differential fuel cost. Thus, it has incidentally been shown that for the SwPS system it is sufficiently accurate, at this time, to calculate WTG fuel savings by simply multiplying WTG yearly energy output by average fuel costs. Clearly this short-cut procedure must not be used for other systems without first validating it by means of the general methodology given above. The fundamental reason for the success of the short method on the SwPS system is the uniformity of the heat rates and fuel costs in that region. This will not generally be true of many utility systems, and indeed will not be true for SwPS as other fuels and other generation systems are brought on stream.

3. Potential Reduction in System Losses

For conventional systems, the analysis of system losses as they affect optimal dispatching has been carried out and implemented in a number of optimal-dispatch loss-penalty computer programs. In these simulations the system network with its associated lines is represented along with the loads and sources of generation to first determine transmission and distribution losses, represented as so-called loss, or "B", coefficients. Once determined, the loss coefficients can be used in conjunction with the basic optimal dispatch program to modify the uncorrected dispatch schedules; that is, to correct for system losses. Since WTG will undoubtedly be of small rating compared to conventional generating units, it may be advantageous to deploy them at distribution subsystem levels throughout the system

(discussed in other sections of this report). If this were done, the WTG would not suffer a loss penalty for transmission, nor perhaps for distribution in some instances. Thus, the wind generated energy could be credited with an additional value to account for the reduction in transmission and distribution losses. In modern systems these losses range from 5 to 15 percent of total generation; on the SwPS system, they average 8%. Thus, although system transmission and distribution losses were not included in the simulation just described, when more precise WTG siting data warrants, refinement of the previously described basic methodology can be accomplished in a straightforward manner.

4. Summary of Energy-Value Determination

In summary, in this subtask a methodology for determining the worth of fuel savings accruing to WTG installed on an existing utility system has been established. The developed methodology uses a base of computer-oriented technology and system methodology generally available to utility system planners and management. Finally, as numerical data for design and operation of WTG becomes more precisely defined, the methodology proposed allows for refinement to include transmission and distribution loss "credits" to WTG by means of established methods, such as the "B coefficient" approach.

D. Windpower with Compressed Air Storage

1. Fuel Savings and Equivalent Capacity

The three compressed air storage systems discussed in Section III of this report have each been evaluated by the following method which has general applicability.

It was assumed that a sufficient number of wind generators would be installed (throughout the SwPS system) to provide total kilowatt hours of energy, on average, equivalent to that required for operating the air compressors, on an annual basis. The wind generators would supply energy to the utility system at any time wind energy was available.

A study of the weekly load characteristics showed that the optimum use of compressed air storage to the utility would result when the compressed air generating unit was operated 11 hours/day, Monday through Friday, or 55 hours/week.

According to the storage study task, reported in Section III, the 100 MW compressed air storage unit identified as System 1A (page 116) would deliver 328,900 MW hours of energy per year. If 1000 kW WTG, each generating an average of 6848 MWh/year were

used in conjunction with this system, 41 wind generators would be required to furnish energy equivalent to the "pump-up" energy to the utility system. Similar data for the other alternate arrangements are tabulated in Table 27 which also shows the number of wind generators of various rated characteristics required to support the compressed air storage units, had they been available during the 12 months ending November 1975 to replace equivalent conventional generation. The results of these computations are listed in Table 28.

2. Cost Benefits

The cost benefits of the alternatives discussed above and listed in Table 27 are tabulated in Table 28. The value assigned to the WTG generation capacity is based on the levelized annual carrying charges of the most competitive alternate peaking capacity, open-cycle gas turbines.

From the total of fuel savings plus equivalent capital value, the total benefit in mills/kWh of wind energy generated is calculated. For example, the 21 MW compressed air storage unit has a total annual value of \$751,186 for 55 hours/week operation or \$463,960 for 15 hours/week operation which results in a total benefit of 15.72 mills/kWh and 35.62 mills/kWh respectively.

E. Allowable Investment

1. Economic Analysis Program

In order to develop a methodology for establishing the investment which could be justified by the energy value of WTG we have drawn upon a second computer program developed and used by Southwestern Public Service Company for economic evaluation of given investments. This program is suitable for use in developing the relationships between allowable investment for WTG based on calculated energy value. In Appendix B is presented a detailed description of this program, but a brief summary is presented here.

The program calculates depreciation, taxes, interest and other fixed charges annually, and together with revenue (fuel savings plus capacity value) and expenses, calculates cash flow and earning each year. These annual results are then discounted and accumulated to produce the earnings rate (fuel savings in dollars/year) on investment. By iterating the calculations, the investment that can be justified by a given annual revenue (fuel savings) can be determined. In all of the calculations made here, this iteration was carried out on the basis of a 6% return on investment.

TABLE 27

Operating Summary, WTG Systems with Compressed Air Storage

a. Air Storage Operating Parameters

<u>System (from Task 2)</u>	<u>1A</u>	<u>1B</u>	<u>1B-Alt.</u>	<u>2</u>
Nominal Turbine Power MW	100	21	21	25
Operating Hours/Week	55	55	15	55
Elec. Power Output MW ave.	115	19	19	22
Weekly energy Output MWh	6 325	1 045	285	1 210
Annual energy Output MWh	328 900	54 340	14 820	62 920
Compressor Power Input MW	98.0	16.7	16.7	40.3
Weekly energy Input MWh	5 390	918.5	250.5	2216.5
Annual energy Input MWh	280 280	47 762	13 026	115 258

b. Annual Generation from 1000 kW Wind Generators

1.) Rated Wind Velocity, m/s	8	8	8	8
Tower Height, meters	60	60	60	60
Annual MWh Generated	6 848	6 848	6 848	6 848
Number Wind Generator Required	41	7	2	17
2.) Rated Wind Velocity, m/s	10	10	10	10
Tower Height, meters	45	45	45	45
Annual MWh Generated	5 100	5 100	5 100	5 100
Number Wind Generator Required	55	10	3	23
3.) Rated Wind Velocity, m/s	13	13	13	13
45 Meter Tower Height				
Annual MWh Generated	3 200	3 200	3 200	3 200
Number Wind Generator Required	88	15	4	36

TABLE 28.

Cost Comparison Compressed Air Storage (1975 Costs)

	<u>No Wind Power</u>	<u>No Storage; 1000 kW Wind Power</u>	<u>System 1A 100 MW Storage with Wind Power</u>	<u>System 1B 21 MW Storage with Wind Power</u>	<u>Syst. 1B-Alt 21 MW Storage with Wind Power</u>	<u>System 2 25 MW Storage with Wind Power</u>
1. Net Generation from Storage (MW)			115	19	19	22
2. Hours per Week	0	55	55	55	15	55
3. MW Hours Wind Power (From Table II.2)	0	6 848	280 280	47 762	13 026	115 258
4. Total 1975 System Fuel Cost, dollars	70 621 055	70 567 796	69 316 892	70 208 081	70 513 345	70 242 887
5. 1975 Fuel Savings from Wind Power, dollars	0	53 259	1 304 162	394 936	107 710	378 167
6. Savings, Mills/kWh Wind Power generated, 5/3	0	7.78	4.65	8.27	8.27	3.28
7. Equivalent Capacity Capital Value/Year at 18.75/kW/year		0	2 156 250	356 250	356 250	412 500
8. Total Value Wind Gen/Year, dollars	0	53 259	3 460 412	751 186	463 960	790 607
9. Total Benefit Mills/kWh 8/3		7.78	12.34	15.72	35.62	6.86

The costs of capital used include 9% interest on bonds, 9% preferred dividends, 48% federal income tax, 1.39% local taxes on investment and 9% discount rate. These values are those currently in use by SwPS in economic evaluation.

2. Cost Goal Nomograph

a. Explanation of Nomograph

The results of the computer methodology just described, are summarized in nomograph form and presented in Figure 41. Explanation of its use follows.

On the horizontal axis of the chart, to the left of center, appears a scale marked "MW Hours per Year". Here is plotted the result of the application of windpower-duration data for a given site, to the performance characteristics of the specific WTG under study. The vertical dotted line to the extreme left, for example, originates on the axis at a point representing the total average annual energy, 6848MWh, that would be generated by a modern WTG of 1000 KW rating, rated at a wind speed of 8 meters per second at 60 meter hub height in Amarillo, Texas wind regime.

The vertical axis of the chart is labeled "Fuel Savings in Dollars per Year (Levelized)". Along this axis are plotted the energy values as calculated by the previously developed methodology, using the optimal dispatch computer technique. The word "levelized" signifies that in certain instances the basic fuel costs for the system have been allowed to escalate at a given rate over the total life of the WTG, in this case 30 years. In order to levelize these costs, the computer sums the yearly cost for fuel over the 30-year period, and divides by 30 to produce an annual levelized energy value or savings.

The diagonal straight lines originating at the zero intercept of the X and Y axes extending to the left, are labeled "Fuel Costs in Cents per Kilowatt Hour". The intersection of lines erected vertically from the proper "MWh per year" point on the X axis, with these "fuel cost" lines permits fuel savings in dollars per year to the SwPS system, for any WTG energy output and any fuel cost, to be determined. This is accomplished by moving horizontally on the chart from the intercept of the appropriate lines, to the Y axis in the center of the nomograph.

The horizontal axis of the chart on the right-hand side of the vertical axis is labeled "Dollars per Kilowatt Investment". Along this axis appears the dollar investment which can be justified by a given fuel saving value in accordance with SwPS cost of capital,

FIGURE 41. ALLOWABLE INVESTMENT vs WTG ANNUAL GENERATION. (a) Enter WTG annual generated energy, MWh per installed MW, on horizontal axis; (b) move vertically to appropriate "Fuel Cost" line; (c) move horizontally to "Fuel Saving" axis to read total annual dollar fuel saving; (d) continue horizontally to appropriate "Maintenance Cost" line; (e) move downward to horizontal axis to read allowable investment per kW for the WTG installation. Nomograph is applicable where average fuel costs reflect overall fuel cost picture.

preferred dividends, federal income tax, etc. This "allowable investment" is found by extending the horizontal line to the right from the "Fuel Savings per Year" axis, to the appropriate right-hand diagonal line marked "Annual Investment Cost plus Operation and Maintenance". On the figure, these diagonal lines have been drawn to conform to zero, \$10,000 and \$20,000 per year fixed operation and maintenance costs. Obviously, other values could be chosen as well, since the lines are parallel, and their dollar amount is derived from the "fuel savings" axis.

b. Use of Nomograph; Example without Storage

Three illustrative examples are shown on the figure. The dotted line to the extreme left represents the annual energy output of an 8M per second, 1000 kilowatt WTG, as previously described, without storage. This line, originating at 6848 MWH per year, is shown intersecting the "one cent per KWH" fuel cost line at a point which, when projected horizontally, intersects the "Fuel Savings per Year (Levelized" line at \$68,000. This line, extended from the vertical axis further to the right, intercepts the "Annual Investment Cost Plus \$10,000 Operation and Maintenance" line at a point which, when projected vertically back to the X axis, intercepts the "Dollars per KW Investment" line at approximately \$410/KW.

If the original line extended vertically from 6848MW hours per year is permitted to intercept the "two cents per KWH" fuel cost line, (top left corner) the resultant fuel savings per year is shown to be \$138,000. Extending this line horizontally to the investment cost plus \$10,000 operation and maintenance line, produces an allowable investment of \$890/KW. All costs are normalized to 1975 dollars.

The two allowable investment values in the example, \$410 to \$890 graphically demonstrate the importance of fuel costs to the long term worth of wind generated energy to a utility.

c. Use of Nomograph: Example with Storage

with any storage subsystem used in conjunction with WTG, the allowable investment is determined as follows:

1. Utilizing the optimal-dispatch computer technique, the value of the total energy delivered by the WTG system to the network is calculated, in terms of an equivalent fuel saving (actual fuel saving plus capacity value) for each installed MW of WTG in the system*.

*It is important to realize that this "equivalent fuel saving" must be calculated and not derived from the nomograph. Any specific storage subsystem will exhibit losses of various types between the input point of the wind generated energy, and the peak-load output from storage, peculiar to that subsystem. In the pumped-compressed air plant, for example, the plant not only consumes energy for charging storage, but consumes fuel at the turbines. Thus the net fuel conserved is always less than the total energy generated by the WTG for any practical storage subsystem.

2. Entering the Nomograph at the vertical axis, plot the calculated equivalent fuel saving per megawatt of installed WTG capacity.

3. Move horizontally to the right, intersecting the appropriate "Investment Cost plus Operation and Maintenance" line. Note that this includes operation and maintenance costs for the storage subsystem, prorated among each MW of WTG comprising the system.

4. Move vertically from the intersection point to the horizontal axis. This is the total allowable investment for the WTG and its share of the storage subsystem cost.

An example is shown by the dashed line on the Nomograph for the 100 MW compressed air storage plant (System 1A on page 116) previously described.

In Table 28 the results of the computation of the fuel saving accruing to the wind-generated energy delivered to the system is shown to be \$1,304,162. at 1975 SwPS fuel costs. To this is added an amount equal to the capacity value of the system (\$18.75/year x 115,000 kW actual storage plant capacity) or \$2,156,250. The equivalent fuel saving is the sum, or \$3,460,412. The energy subsystem is supported by 41 WTG of 1000 kW capacity, and the total equivalent fuel saving per MW of WTG is thus $\$3,460,412. / 41 = \$84,400$.

The equivalent fuel saving per MW, \$84,400 is entered on the Nomograph on the vertical axis, and a line extended horizontally to the right. Its intersection with the "Investment Cost plus Operation and Maintenance" line for an assumed fixed cost of \$10,000/year/MW of WTG indicates a point which, projected to the horizontal axis, gives an allowable investment of \$520 per installed kW of WTG plus its proportionate share of the storage subsystem cost.

F. Reactive Value

For WTG with synchronous generators, the reactive capability is primarily a function of the synchronous machine KVA rating and its design power factor. In addition, the actual amount of reactive KVA available from a synchronous machine will depend upon the real power output at any given time. In the case of induction machines, however, the inductive reactive capability is in fact negative; that is, an induction generator is actually a consumer of inductive volt amperes. Therefore, the induction generator would generally suffer a penalty with respect to reactive KVA, except under unusual conditions when the requirements are for capacitive volt amperes at the point where the machine is installed. This would be a rare situation.

With respect to the synchronous machine, typical reactive values might be as follows: a machine rated at 1000 KVA would normally carry a 0.8 power factor lagging design rating. This means that at full KVA load the machine can actually supply 800 kilowatts of real power and 600 KVA of inductive power to the load. Present costs of sources of inductive volt amperes (static capacitors) cost roughly \$6 per KVA. Thus, when the synchronous generator WTG is operating at rated conditions, the value of its reactive volt ampere capacity is about \$3600, or roughly \$4 per KVA rating. It would be possible to increase this amount somewhat as the machine real power loading decreases, which of course would be the case in normal operation. However, the minimum continuous inductive reactive KVA available would be roughly 600 per 1000 KVA ratings. In any case, it is seen that the reactive capability dollar value is relatively small compared with energy values associated with WTG.

G. Capacity Value

1. Forced Outage Rate

The determination of capacity value for conventional energy conversion units of electric utilities has been a subject of numerous investigations and publications over the past 30 years. As these studies have evolved and been refined, it has become clear that a probability-type analysis is the most realistic representation of the actual situation to be thus far devised. The usual assumptions for such an analysis include using integrated hourly peak loads for the system, and two states of operation (full load or zero) for the various fossil-fueled generating units within the system. The question of integrated peak load period and number has been discussed in the literature⁽³⁾, which recommends that a minimum integrated peak load of one hour should be considered and, if sufficient computer capacity is available, this should be reduced to a 15 minute integrated peak load period.

The number of capacity states for the individual generation plants of the system could also be increased to more than two, particularly for the case of WTG, where it appears that it would be very desirable to have a fairly large number of capacity states available to thoroughly represent the machine. These might include zero output, and $1/4$, $1/2$, $3/4$ and full rated kilowatt output.

Historically, the values of forced outage for fossil-fuel plants have been well established through careful recording and documentation of the experiences of hundreds of utilities throughout the United States. These records have indicated that on an overall basis, the average forced outage rate is 0.03 at the present time.⁽⁴⁾ The definition of "forced outage rate" is the number of days a generating unit has been forced off the line during the heavy load period (usually 7 a. m. to 10 p. m.) of weekdays, divided by the total number of days in operation plus the

outage days. As unit size has increased during the past 20 years, this rate has slowly risen from approximately 0.02 to the present value of .03. It is interesting to note, however, that the Southwestern Public Service Company has been able to maintain this rate at a value one tenth of the national average - that is, at 0.003. It should further be noted that the definition of the forced outage rate includes not only the generator but also the turbine and the boiler connected together as a unit.

2. WTG Capacity Value

Unfortunately, values for forced outage rates of WTG are unknown and it will be a number of years before these quantities can be established with any confidence. It is recognized, however, that the forced outage rate will be very heavily dependent upon the detailed statistics of the wind at the actual site location. As has also been recognized by authorities in the windpower field, there is a possibility of the diversity of WTG installations contributing to the statistical values in a favorable fashion.

The means for calculating the capacity value of a given WTG has not been dealt with in previous literature, no doubt because the pertinent numerical data have not been available to carry out meaningful calculations. It is worthwhile, however, to propose a methodology by which capacity value for WTG can be established once sufficient statistical data have been accumulated, based on operating results over the next 5-10 years. The method is outlined below.

a. Outage Probability

The procedure would begin by utilizing the probability of outages of the existing (conventional) units already on the system and combining them with the outage states and probabilities of the WTG to be considered for addition to the system. Using these various probability figures, one can calculate and prepare a table of cumulative probability, which would be a listing of increments of capacity out of service (in megawatts) for the entire system as a function of the probability that a given number of megawatts, or more, would be out of service.

b. Daily Peak Load Variation

The second step would be to develop a definition of the daily peak load variation curve for the system. It is recommended that the hourly or perhaps even shorter, time period integrated load data be used for each day of the year. The data can then be arranged so that the largest load is shown as occurring on day number one, the next largest

load on day two, etc., to develop what will be called the "daily peak load variation curve", as a function of time in days. These values can be normalized, for example, by dividing by the maximum peak integrated hourly load.

c. Maintenance

Maintenance is, of course, a reduction of capacity, but it has been shown by many authorities that it can be considered, without significant error, as an increase in load. The inclusion of maintenance periods will then simply alter the shape of the peak load variation curve.

d. Loss-of-Load Probability

Having tabulated all the probability-capacity values and the daily peak load variation curve with maintenance considered, it is then possible to perform a calculation (which normally would be done with the use of a computer) to determine the loss-of-load probability with any particular assumed value of maximum annual peak daily hourly load. (The calculation must, of course, eventually be repeated for a number of assumed maximum peak hourly integrated loads to obtain the loss of load probability as a function of the annual peak hourly integrated load in megawatts.) The calculations would begin, for the assumed maximum peak annual load, by subtracting this maximum peak load for "day number one" from the installed capacity. This result would show the capacity that could be lost without incurring a loss of load for that day. Next, a search of the capacity outage table for the smallest listed capacity outage that equals or exceeds the above amount, would be made and the time determined for which an outage of this amount would cause loss of load. This might be for the entire day period considered, or only for a fraction of that time should the load decrease sufficiently so that an exact outage of the above amount would not cause the loss of load.

From the corresponding probability values initially tabulated in the program, one can read the probability of an outage equal to or greater than the capacity value above. We can then compute the product of this probability and the corresponding time computed from these steps.

The previous three steps above would then be repeated, if necessary, for the next period of time within the first day. The calculations are repeated again and again for successive days and their corresponding peak loads until the total time interval to be considered (usually one year) is covered.

Having done all computations for the total time interval, one can then sum up all the probability-time products to obtain the probability of loss of load (in days per year) during the year being considered, for the initial annual peak load assumed. Having summed up these products, the resulting loss of load probability in days per year can then be plotted as a point against the maximum specific peak load considered.

The entire set of calculations is repeated for another annual peak hourly integrated load, and continued until all possible annual peak hourly loads have been covered. In this manner a curve of loss of load probability versus annual peak hourly loads can be generated.

All of the above calculations would then be redone with the WTG replaced by an assumed steam turbine generator and its associated forced outage rate, and the result of this new set of calculations compared with the previous ones; that is, the loss of load probability curves for each of these two situations would be compared. The computer would iterate through a range of steam turbine generator ratings until a rating is found which produces a loss of probability curve in essential agreement with the first. Then the equivalent capacity of the WTG can be directly equated to the kilowatt rating of the steam turbine generator which replaced it.

It should be noted in this discussion that the data needed to produce the forced outage rates for WTG are not those which are generated from available records from various weather stations and airports. These historical records have been taken as hourly or three hourly point readings, and do not give an indication of the number or length of intervals during which the WTG would produce various power levels, needed to develop the forced outage probability data. These records give only gross values of the product of the number of intervals and the length of time of those intervals during a one year period. Further it is likely that if a number of WTG are installed throughout a system, the various probabilities of forced outage will vary somewhat from one WTG site to another depending upon the inherent diversity of the wind itself.

In Figure 42 is shown a representative loss of load probability curve such as might be expected from a dispersed system of WTG, installed in conjunction with a mix of conventional power plants on a utility network. The hypothetical steam turbine plant which could replace the system of WTG would produce the second loss-of-load curve in the figure and permit determination of actual capacity value of the WTG.

FIGURE 42. LOSS-OF-LOAD PROBABILITY CURVE SUCH AS MIGHT BE EXPECTED FROM 50 MW OF WTG COMBINED WITH A HYPOTHETICAL SYSTEM OF CONVENTIONAL GENERATION PLANTS. Capacity value of the wind system is determined by the rating of a steam turbine whose system performance is calculated to be approximately equivalent.

H. Discussion of Cost Goals

In the previous paragraphs of this section, the various components of the total cost benefits of WTG have been addressed, including energy value, capacity value and reactive KVA value.

Reactive KVA value was shown to be insignificant compared to the other values, being a maximum of only about \$4/KVA. Capacity value has not yet been determined numerically for WTG because of a lack of appropriate statistical data. Some authorities are hopeful that as much as 15 percent of nameplate rating may be ascribed to a widely dispersed WTG network, if full advantage of diversity is possible. If, as expected, maintenance requirements are very low, capacity value will be determined almost entirely by the wind regime statistics.

To be conservative, neither reactive value, which is really insignificant, nor estimates of capacity value, which depend heavily upon data not yet available, have been included in the final numerical examples, except for the case of WTG with storage. Here a methodology has been developed and applied for establishing an equivalent capacity value based upon costs per KW for alternative gas turbine sources and average power output available from the WTG-storage system. Methodology has also been suggested for evaluating capacity value of WTG without storage subsystems, based upon accepted "loss-of-load probability" concepts.

No provision has been included for a general inflationary rate where general inflation is defined to be the decrease in the value of money as evidenced by general price increases. On the other hand, provision has been made for a range of expected increase in the real cost of fuel, where these costs may in fact accompany general inflation, but are independent of general price increases since they may be the result of entirely different economic forces.

This approach is sound for the valid comparison of economic values, as is the case for other valid comparisons of the relative merits of alternatives. Then it is required that comparisons be of or among the same kinds of things and in this case of the same size dollars. It is well recognized, for example, that the application of present worth factors to future costs is of value because it does reduce all costs to the same time reference.

In Table 29, cost goals are summarized for the representative WTG designs discussed throughout this report. These machines are rated at 1000 kW, at rated wind speeds of 8, 10 and 13 M/S. Conditions included are current fuel costs of \$.01/kWh electric, and fuel cost escalation rates of 3% and 6% annually for the lifetime of the machines (assumed 30 years).

TABLE 29
Examples of
Wind Generator Cost Goals

Size Wind Generator KW	1 000	1 000	1 000
Design Wind Velocity for Full Capacity Output Meters/Second	8	10	13
Tower Height, Meters	60	45	45
Annual MWh Generated; from Task 2	6 900	5 100	3 200
Annual Fuel Savings at \$.01/kWh (no escalation)(Fig. 41)	69 000	51 000	32 000
Annual Maintenance Expense (assumed)	10 000	10 000	10 000
Investment, Max. Allowable with no Fuel Escalation (read from Fig. 41)	412 500	286 000	153 800
With 3% Fuel Escalation	590 000	410 000	220 000
With 6% Fuel Escalation	863 500	600 000	324 000

I. Comparison of Goals and Present Estimates

Extreme caution must be exercised in making close comparison between present cost goals and cost estimates because of the rapidly changing fuel cost picture, as well as the dearth of actual production experience for WTG. These factors cause considerable uncertainty in numerical values. With this caveat in mind, some of the results of the sample calculations are listed here (all costs relate to 1975 dollars).

1. WTG without Storage

a.	Machine	Two blade rotor, 1000 KW,
10m/sec, 60m. height,
Amarillo wind regime
b.	Cost Goal	
	(1) (no fuel cost
escalation)	\$286/kW (using 1975
SwPS data)
	(2) (6% annual fuel
cost escalation)	\$600/kW
c.	Cost Estimate	\$659/kW (at total pro-
duction of 1000, pro-
duction rate 200/year.

2. 100 MW WTG with Storage (SwPS System 1A)

a.	Machine	Two blade rotor, 1000 KW,
8m/sec, 60m. height,
(41 machines required for
a 100 MW system)
b.	Cost Goal	
	(1) (1975 fuel costs)	\$20,000,000.
	(2) (\$.02/kWh fuel
costs)	\$36,000,000.
c.	Cost Estimate	\$36,000,000 for sealed
cavern storage subsystem;
\$34,500,000 for 41 WTG -
Total \$70,500,000.

For the 100 MW WTG with storage, costs were calculated as follows:

- (1) from line 8 of Table 28 read \$3,460,412 equivalent value per year, or per WTG, $3,460,412/41 = \$84,400$;
- (2) from the chart, Figure 41, read \$520/kW allowable investment goal, for 1975 costs, based on \$84,400 equivalent fuel saving.

Thus each 1000 kW machine and its share of the total storage subsystem can support an investment of $1000 \times 520 = \$520,000$. For the entire 100 MW system, 41 machines of the type selected are required (1000 kW, 8m/sec, 60m hub height). The total allowable investment is $41 \times 520,000 \cong \20×10^6 , which is item (1) in line 2b above. If fuel rates rise to 2 cents/kWh, a similar calculation, using \$875/kW rather than \$520/kW, indicates a goal of $\$36 \times 10^6$, which is item (2).

The cost estimates are taken from Table 24, Section II, \$360/kW for the storage subsystem, and from the Boeing-Vertol cost estimate of \$840/kW for the WTG (\$820/kW from Table 30, Section VII plus \$20/kW for siting and connection costs).

3. 21 MW WTG with Storage (SwPS System 1B)

a.	Machine	1000 kW, 8m/sec; 60m. height, 7 required
b.	Cost Goal (1975 costs)	\$4,800,000
c.	Cost Estimate	
	(1) Storage Subsystem	\$9,000,000
	(2) Seven (7) WTG	<u>5,900,000</u>
	Total	\$14,900,000

Costs were calculated as follows:

- (1) from line 8, Table 28, read \$751,186 equivalent value per year, or per WTG, $\$751,186/7 = \$107,312$ per machine
- (2) from chart, Figure 41, enter \$107,312 on Fuel Saving (vertical) axis, and read \$690/kW as allowable investment goal. The total allowable investment, $\$690 \times 1000 \times 7 = \$4,800,000$.
- (3) The storage subsystem cost, from Table 24, $\$448/\text{kW} \times 20 \times 1000 \cong \$9,000,000$.
- (4) The WTG cost, from Table 30, Section VII, is \$820/kW plus \$20/kW for siting. For 7 machines, total cost, $\$840 \times 1000 \times 7 = \$5,900,000$.

The foregoing sample calculations illustrate the obvious great significance of conventional fuel prices in establishing the economic viability of windpower. They also illustrate the enormous importance of storage subsystem costs to the practical use of energy storage in conjunction with WTG. For SwPS, storage certainly increases the value of wind generated energy to the system, but not so significantly as to warrant large additional investment to achieve it.

Perhaps a more succinct way of stating the energy storage case is as follows: a utility can consider energy storage as one solution to a peak-shaving requirement in which case it must stand on its own merits. Wind generated energy for storage charging will inevitably find itself in direct competition with the lowest cost off-peak energy available on the system.

J. Results of Cost Goal Analysis

In the analysis of cost goals, a methodology for determining the allowable investment in WTG systems has been developed and applied, based upon accepted economic principles and established utility operating procedures. Basic data required for applying the methodology are WTG energy capacity output-probability distributions and average hourly kW electrical output versus hours of the day, along with conventional unit fuel rates, heat rates, system load schedules and utility economic data-base parameters such as depreciation rates, interest rates, return on investment, tax rates, etc. Numerical calculations have been carried out for that part of the methodology which applies to the fuel saving value of WTG without storage, and to the fuel plus capacity value of WTG with pumped-compressed air storage subsystems. Numerical data for determining the capacity value of WTG without storage is not yet available, but a proposed methodology has been included.

Reactive capability value of WTG does not exceed about \$4/KVA, which is insignificant compared to other WTG costs and savings on a KVA basis.

Results of numerous iterative calculations, using an economic investment program described in Appendix B have been summarized in a Nomograph shown on Figure 41. This Nomograph was developed to enable a rapid determination of annual fuel savings for a WTG knowing its annual energy output in MWh, and the system average fuel cost. With the annual fuel saving, assumed maintenance cost, and average cost of capital, taxes and return on investment (corresponding to those values in use by SwPS), the investment that a given WTG system can justify may be determined. Sufficient guidelines are given on the use of the Nomograph to permit accurate interpolation over a broad range of the pertinent variables, including at least two fuel escalation projections.

For representative WTG designs combined into systems with and without storage, numerical values of allowable investment have been calculated. In comparing these numerical illustrations, one must remember to view them within the context of the constraints and assumptions of this study.

As an illustration of the use of the Nomograph, a 1000 KW WTG which can deliver 6900 MWh per year into the network of a utility with a fuel rate of 1 cent per kWh, would produce a fuel savings of \$69,000 per year. This saving could justify an investment of about \$410/kW, based upon SwPS economic parameters. At an assumed real increase in fuel costs of 3% per year, the same WTG will produce a levelized annual saving of \$92,000 per year, which would justify an investment of approximately \$590/kW.

Analysis of a particular pumped compressed air storage subsystem does not indicate that storage subsystems will contribute substantially to the economic benefits of WTG unless these storage subsystems can be implemented at relatively low cost. Such examples might include in-place pumped-hydro installations. Final determination of capacity value accruing to WTG, however, must await the gathering of detailed data not presently available.

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V. TECHNICAL AND OPERATIONAL REQUIREMENTS

A. Summary

Exploration of various operational and technical factors associated with the implementation of WTG on the SwPS system failed to uncover any fundamental limitations or unusual requirements with which the implementation would be faced. Several factors were delineated that would require detailed consideration prior to final design and installation. These have to do with siting, security, hazard protection, and maintenance, as well as assessment of performance, rating, and technical problems associated with electrical circuit tie-in on each specific distribution installation.

Suitable locations for all large WTG are certainly rural. So far as the utility is concerned, the installation of a number of units in close proximity has desirable aspects on the basis of inspection, maintenance and security. Site consideration should include not only wind data but also accessibility for personnel and equipment, reasonable proximity to existing electric lines, and public acceptability. All sites should give consideration to future installation of multiple units.

Operating economics would dictate automatic unattended operation. This will make particular attention to protective relaying and lightning protection a necessity. A matter of some concern is the operation of automatic synchronization equipment and synchro-acceptors on isolated synchronous generating equipment. Such equipment is ordinarily operated only rarely, whereas frequent separations and restarts may be common in wind generator applications. Induction machines may have highly favorable aspects in this regard.

WTG of sizes from 1 to 3 megawatts would best be located on rural and industrial distribution systems on lines of 15 kV class ranging from 12.5 kV to 13.8 kV. Each distribution circuit must be carefully assessed to make certain that it is designed to receive rated generator output during periods of maximum winds and to take full load during periods of no wind. WTG in larger blocks, for example 10,000-15,000 kVA, could be designed to feed into 69 kV subtransmission circuits throughout the Southwestern Public Service Company network. In any event, detailed consideration would have to be given to load distribution, fault isolation, stability and synchronization under unsteady wind conditions.

A problem with serious implication is repair and maintenance of large WTG of 1 to 3 megawatt capacity. It seems unavoidable that eventually means must be provided for dismantling and replacing the WTG components, including rotor assemblies, by utility maintenance crews. Present concepts make this difficult at best.

The most significant finding in this part of the study is the failure to identify special or unusual requirements. Normal power equipment engineering can easily encompass these small (from a utility generating standpoint) machines. Their large physical size compared to their power output, however, dictates high reliability and relatively troublefree operation.

B. The Use of WTG on Utility Networks

This task in the study reviewed the application requirements anticipated for wind generating systems, as they apply to the Southwestern Public Service Company System.

At present, large wind generators of a type suitable for use by electric utilities are undergoing preliminary study. These machines, which prototype design will undoubtedly follow, are horizontal axis, propeller type wind turbines with two (or at the most three) blade rotors, coupled through gears to standard synchronous or induction generators in the size range from 100 to 1500 kW. Although to an electric utility they appear very small from a power standpoint, mechanically they will be extremely large. A 1000-kW windpower generator (WTG) would have a rotor diameter of perhaps 200 ft., and its machinery would be located atop a large steel or concrete tower about 150 ft. high.

On the Southwestern Public Service Co., network, WTG in the 1- to 3-MW range could be located on rural and urban lines throughout the entire system. These distribution lines are 15-KV, 22-KV and 34-KV class. In some cases, especially with industrial customers, the 15-KV class voltage is the utilization voltage. Location of wind-generating equipment on these lines would supply power to the system at the point where maximum efficiency would be realized by reducing or eliminating losses associated with the transmission and subtransmission systems. Locating generators on the lines that are always loaded (such as industrial lines) would minimize power fed back into the system, although during periods of good winds and low system load, power could feed back into the transmission system for use elsewhere with no difficulty. The distribution system would necessarily be designed to take full load from the system during periods of no wind, and should be capable of receiving rated generator output into the system during periods of maximum winds and low load. With proper sizing and location of the generators, there should be very little increase in system investment to accommodate the wind-driven generators.

The power delivered to the power system from the wind-driven generators would displace power being generated with high cost fuel. Savings of a valuable energy resource would thus be realized, and in the future, this saving is likely to be more beneficial than at present, as oil and gas

resources continue to decrease in supply, and fuel generally becomes more valuable with time. The average annual system losses represent approximately 8 percent of total system load, but savings realized from the power produced by the wind-driven machines could reduce this number by assuming that on many occasions peak loads and normal wind conditions would occur at approximately the same time.

C. General WTG Requirements

In order to be of use as commercial generating stations, wind-generator systems must meet certain general, as well as specific requirements. In the first category are those items dealing with utility operating practice, maintenance, and service. Among these are the following:

1. The wind-generator unit should be arranged with all controls in a control house at ground level for convenient access of operating personnel.
2. Hoisting equipment should be designed into the tower to permit removal of the wind turbine or the generator and other machinery from the tower, as required for repair or maintenance. (Mobile cranes with sufficiently long booms for a unit of this height are not readily available and would increase the cost and downtime associated with repairs.)
3. The proposed plant site should be protected with adequate fencing to insure against the intrusion of unauthorized persons, both for the protection of the public and of the wind-generator equipment.
4. Site locations should be selected such that in the remote event of a tower collapse, due to tornado or other destructive occurrence, the property of other parties would not be damaged.
5. Sites should be chosen so that the location of several turbines within minimum distance is possible.
6. The wind-generator unit and its supporting tower should be designed for wind velocities of at least 120 miles per hour with 2 in. of ice loading without damage.
7. TV interference may be a difficult obstacle to circumvent. This observation comes from the fact that a low-flying propeller-driven aircraft does cause significant and distinctive TV interference (although in this case only for a short-time duration). It is likely that a wind turbine could cause a similar interference. If study indicates this to be the case, site selection must include consideration of this fact.

D. Electrical Requirements

Due to the large physical nature of the WTG, and further assuming a small generator size of 1500 kW or less, a suitable location is certainly rural. To economize on maintenance facilities, routine inspections, metering, control, etc., it would be desirable to locate a number of units in close proximity. For single units the degree of control and protection would necessarily, for economic reasons, be at lower level than for a group of machines, particularly of larger unit sizes. For large systems of many such units, supervisory control for monitoring operation of units may be justified.

One might envision a mini-power park somewhat according to the schematic in Figure 43.

Consider first a WTG, either singly or in a group, feeding into a rural distribution circuit of 12.5-KV to 34-KV rating. The wire size probably will be between #24A1 to #4/0 ACSR. The circuit may or may not be shielded.

The operating parameters of the distribution circuit must be considered critically. It is a small system in itself, tuned to accommodate a certain load cycle, load distribution along the line, and allowable voltage regulation limits combined with a voltage gradient along the line. Fault clearing and reclosing apparatus is carefully coordinated. Therefore connecting a WTG into the distribution circuit could create a complex set of variable operating conditions. A detailed study will be required for each proposed location to establish and/or define specific problems and operating limits of the distribution facilities, as well as to determine the maximum capacity of WTG that can be accommodated, probably in the range of 3000 to 5000 KVA. In some cases the complexity of the operating conditions, together with the additional circuit monitoring equipment, may eliminate the feasibility of adding WTG to an existing distribution circuit. In this event a separate distribution class line from the WTG to the distribution substation may be the better and simpler choice.

The alternative to a distribution voltage tie from the WTG to the utility system is a tie into the sub-transmission system. This would be a particularly attractive arrangement where a group of generators of 10- to 15-MW total capacity is contemplated. This arrangement offers advantages in operational control and monitoring, communication facilities, maintenance, inspection and security. Also it may present certain advantages to the research and study phase in that different designs, control systems, etc., could be concentrated at one location. Moreover, potential distribution system stability problems may be avoided.

FIGURE 43. PROPOSED ELECTRICAL LAYOUT FOR CONNECTING WIND-POWERED GENERATORS TO AN ELECTRICAL UTILITY SYSTEM.

Assuming that conventional AC electrical generators are employed, and that they are clustered together at one location, then all of the usual site-specific studies must be conducted to determine performance under abnormal conditions. The end result must produce a design for (1) a coordinated protective relaying system and (2) generators and excitation systems designed to produce electrically stable operation under steady-state and transient system conditions for all non-feathered WTG operating conditions.

If non-conventional generators are considered, such as direct current generators, or non-synchronous high-frequency generators, many new and interesting possibilities are presented. However, the end design must be capable of integrating into the utility electric system in a stable and controllable manner. The matter of cost of these unconventional systems is a source of concern.

E. Control Requirements

Individual wind-generating plants must be designed for completely automatic, fail-safe, unattended operation. The controls should include variable pitch or other speed control to enable automatic synchronizing of the generating unit to the electrical system, and should include a synchro-accepter to protect against malfunction of the auto synchronizer.

Voltage-regulating equipment should have provisions for automatic voltage matching to the system voltage at the time of synchronizing. In addition, fluctuations of voltage caused by starting, stopping and power changes produced by wind gusting, must be limited in magnitude and frequency to minimize the annoyance of incandescent lighting flicker.

For synchronous generators, it would be desirable that speed control be capable of maintaining frequency within ± 0.5 cycles of 60 cycles with the wind generator running isolated from the utility company's electrical system.

Hourly readings of kilowatt hours generated could be transmitted to a remote point for recording, and instantaneous values of watts and vars could be available to the remote control center personnel on demand for the larger systems.

It is most desirable that the wind-generating unit be designed to operate over as wide a range of wind velocities as possible to minimize the number of separations and resynchronizing operations, to minimize disturbances to the system and to maximize generated energy.

Protective monitoring of variables such as unit vibration, bearing temperature, hydraulic control pressures, etc., in addition to electrical values such as volts, amps, and excitation should be included and alarmed where necessary. These protective relay operation and alarm conditions should be indicated at a remote control center of the utility company through supervisory control circuits, if justified by plant capacity.

Data logging and recording equipment located at the wind-generator site should be designed for operation unattended for periods of at least one week or longer without intervention by any operator for chart replacement, etc. It would appear desirable to include wind data as well as unit performance in the operating records.

Because of the size and location of WTG, lightning protection will be necessary, including low tower grounding resistance, arresters, and undoubtedly shielding as well.

F. Maintenance and Spare Parts Requirements

Careful consideration should be given in the design of a wind-generator plant to provisions for maintenance with a minimum of people. Suitable means of access, working platforms and hoisting equipment are very important.

Rapid availability of repair parts will shorten the duration of unit outages and improve the utilization of the available wind energy. This will be a highly significant item in overall cost analysis.

VI. INSTITUTIONAL CONSIDERATIONS

A. Regulatory Restrictions

Texas has an unusually favorable regulatory climate for the development of new energy sources, including windpower systems. With the exception of nuclear plants, for which the requirements have been set by the Federal Government, there are no regulatory agencies with direct cognizance of utility plant construction in the State. Only within the past legislative session has Texas provided for a Utilities Commission.

Typically, a privately owned electric utility in Texas is responsible only to local rate setting bodies, and to its financial sources. Municipally controlled utilities generally operate in a similar manner, responsible to a governing body analogous to a board of directors, under varying degrees of control of municipal authorities, who must authorize the issuance of bonds and, in some cases, approve new construction. Control of all electric utilities in the State is largely limited to the rate structure, in which public interest is balanced against legal recognition of an allowable rate of return on investment.

At the Federal level, the Federal Power Commission and the Securities and Exchange Commission accounting and reporting requirements apply to interstate utilities. Most of Texas' intrastate utilities choose to operate within FPC and SEC guidelines which are not generally restrictive, certainly not in the matter of power sources. The unreliable nature of wind generated power has been cited by others as the basis for possible FPC concern, but this is totally unfounded. It is the ability of a utility to meet its system demand requirements that is of interest, not the ideosyncracies of a particular generating method. Overall generation reliability, with wind machines integrated with other generators and/or storage would certainly have to be achieved, or no utility would use them.

The Federal Energy Administration now has broad powers in the fuel supply area, most of which have not yet been exercised on any but an emergency basis. Even prior to FEA, Texas utilities fuel gas suppliers limited and curtailed electric utility fuel use by exercise of the "interruptible" clauses in supply contracts. Nothing in this area poses any limitation to windpower development.

There are no general requirements in Texas that bind a utility to obtain approval from any environmental authority for siting or construction of a particular type of power plant, other than those requiring nuclear fuel or discharging effluent into navigable waterways. State and Federal regulations limit air and water pollution, but with the exception of nuclear plants these requirements have not acted to prevent the construction or operation of new

generating facilities. Zoning restrictions are within the powers of municipal and county governments in Texas; however, since most generating facilities are located outside of municipal limits, only county zoning restrictions apply and these are easily satisfied in most cases.

Much more restrictive are the requirements of good business practice, for which the utility must answer to its stockholders and financial sources. These of course, have to do with the rate of return on investment and the general ability of the utility to meet its financial obligations. At the present time there is nothing within State or Federal statutes that would proscribe Southwestern Public Service Co. (or any other Texas utility) from installing several megawatts, or even several hundred megawatts of wind generator plant capacity if it was economically justified and if funds could be made available. Certainly no responsible utility could expand windpower plants to include a sizeable share of total generating capacity without long-term experience, and hard proof that such installations would be both technically and economically viable.

Implementation of plants funded by the Federal Government, poses the added statutory requirement for the filing of environmental impact statements, and this may apply to windpower machines. This can be as serious as the Courts allow it to be. There are at least 31 identifiable Federal agencies having some area of jurisdiction or special interest in environmental matters, under certain circumstances. Probably all or most are eager to assume regulatory authority over anything including wind generators. Most of their connection to windpower is farfetched, but some could be troublesome. The Environmental Protection Agency, the Federal Energy Administration and the Federal Aviation Administration are among those certain to at least take note of wind conversion machines, and a number of others are vaguely connected through reference to "land use and management". The latter cover a range of agencies from the Bureau of Land Management of the Department of the Interior, to the Bureau of Outdoor Recreation, the National Park Service and the Bureau of Reclamation.

There are sixteen state agencies in Texas having some jurisdiction or official interest in either environmental protection or land use and management. These range from the Texas Air Control Board, through the Environmental Protection Division of the Texas Attorney General's Office, all the way to the Texas Antiquities Committee. Many of these are merely advisory bodies (e. g., the Energy Resources Council of the Office of the Governor) and one, the newly formed Utilities Commission, has not yet had its duties fully defined. The most experienced and powerful regulatory body in the State, the Texas State Railroad Commission, has for years been both the principal representative of the petroleum industry in the State, and its regulatory and control body. That Commission now has a "Renewable Resources Department" which easily could stand first in line before the State Legislature, to accept any jurisdictional control that may develop over windpower at the state level. This is particularly the case should some question arise about the ownership of the energy in the wind above a land area.

Whatever the regulatory impact at the State level turns out to be, it will more than likely involve questions of land use. Compared with other generating systems, the land requirement for siting large wind generator systems (likely in the range of from one to five acres/megawatt) together with access roads and transmission line rights of way, would appear to be reasonable. The difficulty is likely to arise in the number of individual sites required. If it becomes necessary to site one windmill on five acres in each square mile of land area, for example, land procurement may become such a troublesome matter as to preclude large scale implementation. The experience of the pipeline industry in Texas indicates that land requirements can generally be met only through rights of eminent domain. Condemning the large number of small plots of land required to implement several hundred megawatts of wind generators, is likely to provide a formidable task compared to the return. However, existing generating plant and substation sites and transmission line rights of way could accommodate a number of wind generating units, and may solve a large part of this problem. Beyond that, questions of wind energy captured from adjacent property could conceivably lead to a system of leasing "wind rights" over a sizeable area of land. For detailed treatment of all of these issues and more, see Taubenfeld*.

B. Weather and Natural Hazards

The Panhandle is in the Great Plains tornado belt, and catastrophic tornado damage to WTG installations is a statistical possibility, just as it is to power lines and other installations. Protection from tornado damage is not amenable to design solutions, but the statistical probability of damage to a specific installation is extremely low. Long-term loss experience eventually accruing to a windpower network will simply become part of the operating cost of the system, just as does the cost of damaged power line towers.

Severe thunderstorms also occur in the Panhandle, as do occasional snow and ice storms. Generally speaking, however, icing conditions are not severe, as compared to sections of the country farther north and east.

Earthquake damage, rockslides and large-scale flooding are unknown.

*Taubenfeld, H. J., "Barriers to the Use of Wind Energy Machines: The Present Legal/Regulatory Regime and a Preliminary Assessment of Some Legal/Political/Societal Problems", Final Report, NSF Grant AER75-18362, 1976.

C. Other Environmental Considerations

Very large areas of the study region are devoted to range-land, and the remainder to large-area crop farming, including wheat, grain sorghum and dry-land cotton. Small farms are rare, and farming is generally accomplished on at least quarter-section (160 acre) blocks. Population density in the rural areas is extremely low, and interference with existing activities by large WTG would be minimal. Petroleum development has been extensive over the entire region for a half century, and drilling structures, tank farms, lease roads, and other development associated with oil and gas production are commonplace. At various times during the development of the petroleum reserves, literally hundreds of drilling rigs have operated simultaneously. People in the region are accustomed to such activity and, indeed, structures of this kind go largely unnoticed on the monotonous, generally uninteresting landscape. The Great Plains, including particularly the Texas Panhandle, could be expected to present minimal environmental constraints.

In spite of the low population density, the region is well equipped with an extensive electrical distribution system to service both the farm population, and more significantly perhaps, the oil field installations. One could locate wind farms or other WTG installations near distribution lines with minimum difficulty for utilization of wind-generated energy.

Because of the large scale of the farming and ranching activities, there appears to be no reason for an individual WTG site to require more than the minimum amount of land necessary to site the tower and associated ground equipment. Thus, an individual WTG installation might consist of a one or two acre fenced ground plot, plus an easement for a distribution line and service road to the nearest connection point on the network. Particularly in the case of rangeland, the land immediately surrounding the ground installation could be used for its normal purposes.

D. Vandalism

Possible vandalism, particularly involving the use of hunting rifles, has been mentioned as a source of concern to large WTG installations. Such a contingency certainly exists. However, indiscriminate use of firearms in the Panhandle is rare, primarily because of the tight posting restrictions on the rangeland. Unauthorized hunters are not welcome, trespassing is vigorously prosecuted, and the low population density and large farms and ranches make rural vandalism an uncommon occurrence. Cases of vandalism to SwPS service installations are presently so infrequent that separate accounting of costs resulting from them are not maintained.

VII. WTG DESIGN AND COST STUDY

A. Summary

Cost estimates of six separate WTG designs were prepared: single and two-blade horizontal axis machines rated at 1000 kW at 8 M/S, 10 M/S and 13 M/S. Both the single and two-blade models showed cost optimization based on the minimum cost of generated energy, at a rated wind speed of 10 M/S in the Amarillo, Texas wind regime. The capital cost estimates for these 10 M/S machines, not including land, site preparation, and connecting lines, amount to \$531 per installed kW for the single blade design, and \$619 for the conventional two-blade design. Estimated costs of land, site preparation and 1/2 mile of distribution line in the rural vicinity of Amarillo, bring the total estimated costs to \$551 and \$639 per kW, respectively. All figures are in terms of 1975 dollars.

Referring to the Cost Goal Analysis (Section IV), it can be seen that the present (1975) worth of unfirmed WTG on the SwPS system, based on the energy generated by 1000 kW machines rated at 10 M/S, is \$286 per installed kW. At a projected continuous fuel escalation rate of 6% per year (above the normal inflation rate), the cost goal (\$600/kW) and the estimated cost (\$551 to \$639/kW) approximately coincide.

B. Historical Basis for Cost Estimation

A sufficient number of large wind turbine generators has been constructed since 1930 to form some historical basis for the estimation of costs. Horizontal-axis, propeller type WTG of conventional design consist of a limited number of major components either readily obtainable (e.g., gear boxes, electrical generators) or for which the design is well understood (towers). Rotor blade construction is still open to some engineering uncertainty, but rotors have been constructed in the past, and their manufacture is sufficiently well related to aircraft practice to permit reasonable cost estimates to be made, although with lower confidence than for some other elements. Cost histories of a number of machines have been analyzed by several authors⁽¹⁾, and attempts made to update them in light of current technology and economic conditions.

In addition to the historical data, two detailed design studies^(2,3) have been completed within the framework of the present Federal Wind-power Program. The purpose of the design and cost study task in this program has been twofold: (1) to generate a critical evaluation and comparison of the two current studies by an independent manufacturer,

and (2) to evaluate equipment specifically designed to match the wind regime of the Texas Panhandle area. The design and cost study was performed under subcontract by the Boeing-Vertol Company, an aerospace manufacturer with experience in large helicopter design and construction, and commercial experience in the manufacture of rail cars and other large devices. The Boeing-Vertol report on this subcontract is included in its entirety as Appendix C.

C. Design Parameters

The general operating elements of a wind generating plant are shown in Figure 44. Operation may be described as follows: A wind turbine, consisting of aerodynamic elements combined into a rotor, delivers torque through step-up gearing to a generator. The electrical output of the latter is transformed and matched to the network rotational frequency ω . In both vertical axis, and in particular in conventional horizontal axis machines, the various components of these operating elements are understood.

Such a machine will exhibit a basic turbine characteristic curve, such as that shown in Figure 45, in which the power coefficient, C_p , is related to the turbine rotor tip speed ratio, λ , at the optimum turbine rotor blade pitch angle, β . In general, it is possible to operate the rotor blade at its optimum pitch angle at only a single wind velocity, V_D .

The power coefficient, C_p , for a practical machine is given by the expression

$$C_p = P / 1/2 \rho \pi R^2 V^3$$

where

P is the power output generated,

ρ is the mass density of the ambient atmosphere,

R is the radius of the turbine rotor and

V is the wind velocity.

Johnson⁽⁴⁾ has shown the relationship between the various design parameters (a) rated power level, (b) rated wind velocity, (c) design wind velocity and (d) the number of generator poles, which parameters in turn define wind turbine radius, turbine speed, rated torque and set-up gear ratio. When these are combined with site-specific wind data, appropriate wind plant cost functions, and criteria by which to compute annual cost of ownership, the result yields the cost of produced energy for the several design variations. One basis of selecting the optimum design is to choose that one for which the cost of produced energy is minimum (other considerations may come

FIGURE 44

OPERATING ELEMENTS OF WIND GENERATING PLANT

Fig. 2. Basic turbine characteristic curve.

FIGURE 45

BASIC TURBINE CHARACTERISTIC CURVE (from Ref. 4)

into play, in particular the desirability of high capacity factor).

The process of optimization is necessarily an iterative one in which cost functions are developed for all elements of the wind generating plant. These include turbine, drive train, generator, switch gear, transformer and transmission equipment, instrumentation, land, site development, transportation and erection costs, etc.

The optimum wind velocity at which to rate a WTG is not an obvious choice. Both Putnam⁽⁵⁾ and Golding⁽⁶⁾ discuss the issue, but not independently of other design parameters. Both show the effect of average wind velocity on rated windspeed, the optimum ratio of rated to average velocity becoming lower as average wind velocity increases. The Kaman study⁽³⁾ further develops this thesis. For optimization at a rated velocity of 1000kW, the choice of rated wind velocity for minimum cost of generated energy is shown to be virtually constant over the range from 11 to 13 M/S, at an average wind velocity of 8 M/S.

While a complete optimization study was beyond the scope of the present program, six separate designs of 1,000 kW WTG rated at three separate wind velocities were examined, and cost estimates made by Boeing, applied to the wind regime of Amarillo, Texas (representative of the region under study). The average wind velocity at the Amarillo station is 7.33M/sec. at 30M hub height; 7.84M/sec. at 45M hub height; and 8.21M/sec. at 60M hub height. The designs studied, all horizontal axis machines rated at 8, 10 and 13 M/sec., included both two-blade and single blade rotors. The results of these cost studies, details of which are given in Appendix C, are summarized in Table 30 which shows performance and cost data for the six machines. In Table 31 are shown the itemized major component costs for each design. All costs are estimated production costs, based on a total of 1,000 units produced at a rate of 200 units per year. Included are estimated transportation and erection costs, but not cost of land or site preparation.

Boeing found that for both the single blade and two-blade rotor 1,000 kW machines, cost optimization, in terms of generated energy cost in the Amarillo wind regime, occurred with a machine rated at 10M/sec. However, as shown in Figure 46, the cost penalties for rating at wind velocities either higher or lower than 10M/sec. are not severe. In the lower part of the same figure, the capital cost in \$/installed kW vs. capacity factor is shown.

In terms of final cost trade-off, it may be desirable to operate at an even higher capacity factor (lower rated wind velocity) at the expense of increased capital cost, beyond the 10M/sec. range. If experience shows that a diverse array of wind generators over a large

MODEL CLASS (ONE OR TWO BLADES)	MODEL SW-1						SPECIFIED PRELIMINARY GOALS		
MODEL SUB-CLASS (PER RATED WIND)	SW-1-8	SW-1-10	SW-1-13	SW-2-8	SW-2-10	SW-2-13	RATED WIND, METERS/SEC		
RATED WIND VELOCITY METERS/SEC	8	10	13	8	10	13	8	10	13
Wind Spectra Height, Meters	60	60	45	60	60	45	60	60	45
Max. Efficiency Velocity, MPH	15	17.3	20.2	15	17	19.8			
Rated Wind Velocity, MPH	17.9	22.4	29.1	17.9	22.4	29.1	17.9	22.4	29.1
Rated Watts/Sq.Ft.	10	17.5	35.2	10.5	18.8	38.5			
KW HR/Sq.Ft./Yr.	63.2	90.5	117.5	67.5	99.0	127.5			
Efficiency (Machine)	.35	.35	.35	.38	.38	.38			
Rotor Diameter, Ft.	356	270	190	348	260	182			
Diameter Rotor Area, Sq.Ft.	100,000	57,140	23,410	95,240	53,190	25,975			
HP Output (Rotor)	1,440	1,440	1,440	1,460	1,460	1,460			
Max. Efficiency Tip Speed to Wind Ratio	13.3	13.3	13.3	9.43	9.43	9.43			
Rotor Solidity/Mean Blade Lift Coeff.	.015/1.0	.015/1.0	.015/1.0	.030/1.0	.030/1.0	.030/1.0			
Mean Rotor Blade Chord, Ft.	8.42	6.34	4.48	8.21	6.13	4.28			
Rotor Tip Speed, Ft./Sec.	293	338	394	208	235	274			
Rotor RPM	15.72	28.87	39.56	11.41	17.26	28.77			
Generator RPM	1,200	1,200	1,200	1,200	1,200	1,200			
Step Up Ratio	76.3	50.3	30.3	105.1	69.5	41.7			
Input Torque (Rotor), FT/LB	482,000	316,800	191,430	671,000	443,600	266,150			
Hub Height, FT.	197	197	148	197	197	148	197	148	148
Rotor Drag, LB	51,100	38,800	26,250	57,230	34,970	23,210			
KW HR/YR	6,330,000	5,171,100	3,338,000	6,428,700	5,265,800	3,311,800			
Installed Capital Cost, \$	677,930	530,750	410,190	821,150	619,080	477,950			
Unit Cost, \$/KW	678	531	410	821	619	478	410/900	290/640	160/380
Cost of Electricity, ¢/KW. HR.*	2.14	2.05	2.46	2.55	2.35	2.89			
Capacity Factor	.72	.59	.38	.73	.60	.38	.79	.58	.37
Plant Life, Years	30	30	30	30	30	30	30	30	30

*Based on 20% annual carrying charge

TABLE 30

Design Characteristics & Cost Summary, 1000 KW Models SW-1 & SW-2
(Single Blade & Two-Blade Rotor)

SUBSYSTEMS & COMPONENTS	MODEL SW-1 (Single Blade)			MODEL SW-2 (Two-Blade)		
	RATED WIND - m/sec			RATED WIND - m/sec		
	8	10	13	8	10	13
Rotor Subsystem	155,000	96,000	63,000	242,500	150,000	106,500
Transmission Box	181,000	137,000	103,000	220,000	169,000	124,500
Shafting, Couplings	24,500	19,500	15,800	30,000	23,300	18,000
Induction Generator	21,500	21,500	21,500	21,500	21,500	21,500
Capacitors	3,000	3,000	3,000	3,000	3,000	3,000
Gen. Protection, Electr. Contr., Switchgear, Transformer, etc. }	45,000	45,000	45,000	45,000	45,000	45,000
Nacelle Assembly	65,500	54,000	41,600	71,500	50,000	39,000
Tower Struct. & Found.	123,500	106,000	80,000	113,000	101,000	77,000
SUBTOTAL-\$	616,300	482,000	372,900	746,500	562,800	434,500
ERECTION & ASSEMBLY 10%	61,630	48,250	37,290	74,650	56,280	43,450
TOTAL-\$	677,930	530,750	410,190	821,150	619,080	477,950

TABLE 31

Model SW-1 & SW-2 Component Cost Summary

FIGURE 46. CAPITAL COST AND BUSBAR COST OF ELECTRICITY AS FUNCTIONS OF CAPACITY FACTOR, 1000 KW WTG IN AMARILLO, TEXAS, WIND REGIME

area gives sufficient firm generating capacity to permit some capacity credit for the wind system, then the higher the capacity factor, the higher is likely to be the capacity credit that can be allowed. The door should not be closed to this possibility, until geographic diversity can be determined by large scale, time-correlated wind measurements.

D. Comparison with Design Studies in Progress

In order to evaluate the cost estimates made in the previously referenced GE and Kaman design studies, design parameters from reports of these two programs were used in conjunction with Boeing cost estimation methods to normalize the results, based on the same production quantities of 1,000 total units, produced at a rate of 200 per year. Performance of the machines was then analyzed by applying the characteristics of the Amarillo wind regime. These results, summarized in Table 32, are in general agreement, and further show the slightly lower cost of electricity (but higher capital cost) from machines rated at lower wind velocity.

E. Cost of Land and Site Preparation

Land costs in the vicinity of Amarillo, Texas range from \$200 to \$400 per acre. The amount of land required for a single 1,000 kW WTG installation could range from a minimum of one acre, to as much as fifteen acres, depending upon factors which cannot yet be accurately evaluated. As a basis of comparison, typical high-voltage transmission line easements in the panhandle presently average only 100 feet in width. The only land consideration beyond immediate tower enclosure for a large WTG, would presumably relate to general public safety and hazards associated with WTG should be no greater than those posed by high-voltage lines. Land cost for each site, at the \$400/acre figure, could range from \$400 to as much as \$6,000 (\$0.40 to \$6 per installed kW).

Distribution line costs, to connect the WTG to existing lines, average \$10,000 to \$12,000 per mile, with minimal all-weather service road costs of another \$5,000 per mile. Assuming site locations averaging 1/2 mile from existing distribution circuits, the land cost (maximum of \$6,000), plus connection and service road costs, should not exceed \$15/installed kW. Site preparation, including fencing, should be less than \$5/kW.

The total siting cost for a single, isolated WTG installation of 1 MW capacity should not exceed \$20/installed kW in the rural Amarillo vicinity.

ITEM	MACHINE		
	GEN. ELEC.	KAMAN	SW-2-13
Mean Wind, mph	18.9	18.9	18.9
Rated Power, KW	1500	1500	1000
Rated Wind, mph	32.5	34.2	29.1
Rotor Dia., ft.	190	180	182
Specific Power, w/sq. ft.	53	59	38.5
Specific Energy, KW Hr/Yr/Sq. Ft.	139	142	127.5
Energy Output, KW Hr/Yr. (Amarillo, Tex.)	3,940,650	3,613,900	3,311,800
Capital Cost, \$	619,795	620,345	477,950
Unit Cost, \$/KW	412	413	478
Energy Cost, ¢/KW Hr.	3.14	3.43	2.88

TABLE 32

Comparison of GE, Kaman, and Boeing Designs Normalized by
Boeing Cost Methods to Same Production Quantities

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VIII. CONCLUSIONS AND RECOMMENDATIONS

A. Summary of Results

1. Wind Assessment

Reduction of long-term wind data from seventeen weather stations in the study region confirms that the Texas Panhandle is within the Great Plains belt of consistently high winds. The area of most favorable wind conditions for the extraction of wind energy was found to lie in an area approximately 100-miles wide, extending north-northeastward from near Lubbock, Texas on the south, into southern Kansas and beyond.

The region consists largely of flat, featureless prairie, broken mainly by the transverse course of the Canadian River, north of Amarillo. The river has eroded a broad, gently sloping valley some 30 miles wide across the region during recent geologic time. Here the topology is marked by numerous plateau-like projections and gently rising hills, from 100 to 200M in height. These may offer sites of higher than average wind velocity.

The windpower density in the Panhandle was found to range from $.32 \text{ kW/M}^2$ at Lubbock, to $.53 \text{ kW/M}^2$ at Amarillo, to a high of $.78 \text{ kW/M}^2$ at Garden City, Kansas, these values being normalized to an extrapolated height above ground level of 30M.

Means of extrapolating wind velocity and power values from recorded anemometer height to various heights above ground were developed from the literature, and the wind-energy potential estimated at heights of 30, 45, 60 and 75M above ground.

Reliability of the wind was found to be relatively high, with calm conditions (wind velocity less than 4 knots) occurring at the Amarillo weather station, on average, only 2-1/2% of the time.

Utilizing realistic WTG characteristics, including all losses, the electrical generation potential for machines rated at wind velocities of 8M/sec, 10M/sec and 13M/sec were calculated at the 17 weather station locations, based on wind velocity-frequency data from the long-term wind records. This potential in the Amarillo wind regime (considered representative of the region) ranges from $6.89 \times 10^6 \text{ kWh}$ per year for an 8M/sec rated turbine at 60M hub height, to $3.22 \times 10^6 \text{ kWh}$ per year for a 13M/sec turbine at 45M hub height, all machines rated at a power of 1000 kW.

The study region is largely served by the power network of the Southwestern Public Service Company. Investigation of practical implementation of systems of wind turbine generators of various deployment configurations on the SwPS system was made. It was found that an amount of energy equal to the total present generating capacity of the Utility could easily be supplied by either a "grid" of WTG, uniformly spaced at approximately 60 rotor diameters; by five relatively small wind "farms" utilizing a total land area considerably less than 1% of the total, with a WTG spacing of 5 turbine diameters; or by a line array of machines along rural transmission lines, with a spacing between turbines of 16 rotor diameters.

Practical considerations limiting the usefulness of windpower to SwPS over the period of the next twenty years were found to include "take-or-pay" provisions of present fossil fuel contracts, minimum off-peak loading of the rural distribution system (where implementation would show greatest value to the utility) and most significantly, the spinning reserve requirements of the network. The latter constitutes the limiting factor, and would preclude implementation of unfirmed WTG capacity beyond 3% of total generating capacity. Based on the present system, this is equivalent to 60 MW of WTG.

2. Energy Storage

Three separate compressed air storage systems were analyzed in detail, and two potential pumped-hydro facilities were identified and given preliminary consideration.

In no case was a unique combination of wind machines and storage components found that presented a cost-effective overall system. Rather, the favored approach from all aspects is the separate consideration of WTG, implemented throughout the system at locations determined by the wind and factors other than storage, and storage facilities, considered as separate entities. The latter, when conditions warrant, can then be operated off network power by whatever dispatch process is most effective.

A serious, current limitation of conventional compressed air storage systems utilizing gas turbines is the requirement for natural gas to operate the turbines. An expander turbine system examined in this study showed unexpected promise, and merits further study.

Lack of suitable low pressure turbines and separate turbine-compressor combinations is a further impediment to pumped-compressed air storage.

The high cost of all the air storage systems was disappointing and occurred for three principal reasons: (1) the relatively small size of the systems considered, preventing significant benefit from the scale factor applicable to gas turbine installations; (2) the complexity of the required components, including separation of turbines and compressors, extra intercoolers, regenerators, and other peripheral equipment; (3) the lack of a hydrostatic leg in the air storage volume. This last reason presents a serious limitation in "sealed cavern" storage reservoirs.

The two pumped-hydro sites in the region show promise, and the costs appear significantly lower than those for compressed air storage.

3. Cost Considerations

Southwestern Public Service Company's economic analysis and optimal dispatch computer programs were used to analyze the operation of the SwPS system, with and without WTG in various configurations and with and without energy storage. The purpose was to develop cost goals that would express the investment WTG installations could support. The results of the study show that under fuel conditions existing in March 1976, 1000 kW WTG installed on the SwPS system in the Amarillo, Texas wind regime could support investment costs ranging from \$153/installed kW for a machine rated at 13M/second; \$286/installed kW for a machine rated at 10 M/S; to \$412/installed kW for a machine rated at 8M/second. To generalize these results, functions were developed for expressing allowable investment costs for various fuel costs and total annual energy generated.

The Boeing-Vertol Company, in a separate analysis of manufacturing costs, developed designs optimized for the Amarillo wind regime, utilizing six basic machine configurations: single blade and two-blade rotor machines of 1000 kW capacity, each rated at wind speeds of 8, 10 and 13M/second. The study showed that for both the single and two-blade designs, the most cost-effective WTG of 1000 kW rating is the design rated at a wind speed of 10M/second, at a hub height of 60M in the Amarillo wind. Installed cost of a machine of this type including land, site preparation and line connection, would range from \$551/installed kW to \$639/installed kW, the lower figure representing Boeing's estimate of the cost of a single-blade model.

The cost goal analysis indicates that estimated WTG costs and their value to the utility approximately coincide at a fuel cost of \$.02/kWh, a rate approximately double the SwPS fuel cost in early 1976 (many Texas utilities are less fortunate with fuel costs already exceeding \$.02).

4. Institutional and Environmental Considerations

Study of the regulatory requirements in effect in the State of Texas indicate that no legal restrictions within the State are likely to impede development of WTG, and that future questions in an expanding use of this resource are likely to mainly involve questions of land use. Acquisition and maintenance of numerous small (1 to 4 acres) ground sites, possible problems associated with TV and microwave interference, and some concern for possible vandalism, could present problems. Questions of "wind rights" could eventually require clarification by the courts or by legislation.

Tornado damage represents a catastrophic hazard to WTG in the Panhandle region, but the statistical probability of such damage at a specific site is extremely low. Thunderstorm activity is common, with hail and turbulent winds occurring with some frequency. Earthquakes, mud and rock slides and wide-area flooding are unknown.

The study region historically represents an area of extensive petroleum development, and the appearance of structures such as drilling rigs, oil derricks and tank farms is commonplace. Population density is extremely low, much of the land is devoted to ranching, and establishment of an extensive system of WTG could be accomplished without serious interference to normal activities over much of the region.

5. Technical and Operational Requirements

Study of the technical factors involved in implementation of WTG on the SwPS network, discloses no unusual requirements or fundamental limitations posed by the use of the wind resource. Machines of the sizes considered (1 to 3 MW) would best be located on rural and industrial distribution systems, with WTG in larger configurations (e. g. "farms" of units totaling 10 to 15 MW) designed to feed into sub-transmission circuits located throughout the SwPS network. Detailed consideration would have to be given to load distribution, fault isolation, stability and synchronization under unsteady wind conditions. Repair and maintenance of large WTG, particularly replacement of the rotor assembly and other major components, presents concern. Large-scale implementation of WTG would require careful attention to provisions for maintenance of these assemblies by regular utility crews.

The large physical size of WTG compared to their power output dictates that each must operate automatically with high reliability and trouble-free operation.

B. Conclusions

Based on the results of this study the following conclusions can reasonably be drawn:

1. The Texas Panhandle, largely served by the Southwestern Public Service Company electrical network, represents a region of broad areal extent exhibiting consistently high winds. Windpower density ranges from 0.4 to 0.8 kW/M² at a height of 45 meters across the region, recommending it as a prime windpower area. The large geographic size and low population density further enhance the prospects of successful siting of large (1 to 3 MW) WTG.

2. WTG of modern design could be deployed in realistic configurations along transmission or distribution lines, or in a few concentrated "wind farms" capable of supplying an amount of wind-generated energy many times greater than the present SwPS network could practically accommodate.

3. The energy storage potential in the region consists of two possible pumped-hydro sites, and a number of potential pumped-compressed air storage sites. Costs of practical compressed air storage plants based on an existing abandoned potash mine were found to range from \$360 per installed kW to \$448 per installed kW, depending upon generation capacity. These costs are considerably higher than preliminary cost estimates of storage facilities implemented at either of the two potential hydroelectric sites in the region.

4. The principal identifiable value of windpower to a utility is its energy value. Energy storage may enhance this value by making the energy available during periods of high demand. Methodology does not now exist for determining possible capacity value of windpower systems without storage.

5. Cost goals for large WTG to the SwPS system, are below cost estimates by a factor of approximately two. The cost goals and estimates appear to coincide at a fuel cost of \$.02/kWh, a cost now being borne by many utilities. For SwPS, this corresponds to a fuel cost escalation rate of approximately 6% per year, in constant 1975 dollars.

C. Recommendations

Several specific recommendations are warranted by the conclusions of this study:

1. The Texas Panhandle region is recommended as a promising site for serious large-scale windpower experiments, because of its good wind potential, favorable regulatory and societal climate, and the existence of substantial electrical energy demand.

2. A program of "prospecting" for specific sites of highest windpower potential is recommended. Even with rather fine-grain data from a grid of weather stations in this essentially level locale, there is sufficient local variation, because of topographic anomalies, to produce significant enhancement of average power density. This enhancement is highly desirable.

3. The inherent "diversity-capacity" factor of windpower may be an important consideration for WTG without storage subsystems. Such effects would serve to add some equivalent capacity value at no added investment cost. We recommend that a program of continuous, time-correlated wind measurements over an extensive area in the Panhandle be undertaken to establish the worth of wind energy on a real-time basis.

APPENDIX A

SUMMARY DESCRIPTION OF SWPSC ECONOMIC
DISPATCH COMPUTER PROGRAM

Southwestern PUBLIC SERVICE Company
System Control Center

SPS installed an IBM 1800 process control computer in a new System Control Center in January 1972. The computer was installed in conjunction with the move of Company offices and System Dispatching facilities to the new location. The primary function of the computer installation is to perform Load Frequency Control and Economic Dispatch. Secondary functions are to provide the System operator with System security analysis data that will guide him in making the decisions necessary on a minute to minute basis to operate the power system, and as an aid in energy accounting.

There will be 12 generating units under direct control with the completion of the new Harrington Station No. 1 coal unit. This represents 77% of the gross capability. Another 24 units are dispatched manually on an area reserve and economic basis. The total gross capability with the completion of testing of the Harrington unit will be about 2746 MW.

The scope of the software to accomplish the primary and secondary functions above includes the following:

1. Data acquisition, verification and alarming.
2. Economic Dispatch and Load Frequency Control.
3. Dispatchers interface.
4. System Operation and analysis.
5. Energy accounting.

The method of economic dispatching of system generation has been altered in the last 24 months to account for constraints imposed by new fuel contracts. Fuel contracts requiring high use on a take or pay basis require special handling. Preliminary off line calculations for the contract period are used to estimate daily, weekly and monthly volumes. Factors in the 1800 programs are used to schedule the generation so that the minimums can be met.

The basic economic dispatch equation states that all plants should be operated such that their incremental fuel cost plus the incremental cost of line loss equals the "incremental cost of delivered power" (or Λ). All plants should operate at equal Λ to give best economy. Special conditions of fuel curtailments or fuel minimum "take or pay" quantities are scheduled by introduction of "factors" to alter the incremental cost. These factors give a solution to the economic dispatch for optimum cost-but not minimum cost. This meets the constraints imposed in the most economical manner.

Each unit in our system is represented in these programs by an equation for the incremental heat rate of that unit. Unit maximum load, minimum load, fuel cost, special limits and adjustable performance factors are all readily changeable from the dispatchers console.

The Load Frequency Control Program consists of three basic parts: 1. Calculation of Area Control Error and Unit Corrections, 2. Unit Controller, 3. Pulse output drivers. The Area Unit Correction Calculation operates basically as a permissive control system. Control action is taken in response to ACE such that units will almost always be economically loaded. ACE can be calculated for either flat frequency, flat tie line or tie line bias control. Expected load changes as well as generation changes anticipated from previous control moves are used in the program.

Operator Interface - The operating status is presented to the Dispatcher, and operating directions are transmitted from the Dispatcher, through the Operators Interface. The Interface includes Operator Control Stations (alphanumeric CRT's), Trend Recorders, and Line Printers.

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Southwestern Public Service Company
Linear Programming Applications

MPSX:

The term MPSX is derived from the expression Mathematical Programming System, Extended. This is the title of a family of computer programs that, taken together, form a general purpose mathematical tool that can solve some types of optimization problems. In particular, MPSX is designed to solve three classes of optimization problems:

1. Linear Programming
2. Non-linear But Separable
3. Mixed Integer

One specific SPS application of MPSX is in the development of a generation budget for each calendar year. The production facilities of SPS are modeled in the form of a Linear Program tableau containing 601 equations or inequalities that express the relationships between 776 variables. The model can be illustrated with the following diagram.

Other applications of MPSX now being studied are:

1. Optimization of generating unit commitment on a daily and weekly basis to minimize cost.
2. Optimization of the annual overhaul schedule to minimize fuel costs.
3. Refine generating unit input-output curve equations to minimize the error between calculated and actual fuel use.

MWR
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APPENDIX B

SUMMARY DESCRIPTION OF SWPSC ECONOMIC ANALYSIS COMPUTER PROGRAM

PROGRAM ABSTRACT

TITLE: Economic Analysis (Cash Flow and Earnings)

PURPOSE/DESCRIPTION: This program is designed to give a detailed analysis of an investment plan to be studied by calculating the effect that the investment has on the income statement of the company. Although the design of the program is such as to accommodate the capital structure of Southwestern Public Service Company, certain capitalization segments may be omitted for use in investment plan comparison by individuals or companies more simply financed. The program computes each of the following:

- Book Value of Assets
- Federal Income Tax Assets
- Book Value Depreciation
- Double Declining Balance Depreciation
- Guide Line Depreciation
- Straight Line Depreciation
- Liberal Depreciation Reserves
- Income Before Tax
- Income Tax
- Income After Tax
- Investment Related State Tax
- Preferred Stock Dividends
- Cash Flow
- Earnings and Discounted Earnings
- Discounted Cash Flow
- Revenue Required to produce desired return to Common

Investment, revenue and expenses may be entered on the same input card and they may be made in any year of the study. Any number of investments can be made in one year.

The cash flows are assumed to be computed at the end of the year and the investments are assumed to be made at the beginning of the year. A plan must result in total, positive cash flow for the program to be able to compute an earnings rate.

Two different plans for the same project may be compared by changing the cash flow values in the plan with the largest total investment to all negative values. This should give a positive cash flow to compute an earnings rate comparison.

The program may be used to check the desirability of an investment where revenue and expense can be computed. It will compute an earnings rate that equals discounted cash flow and discounted investments.

ECONOMIC ANALYSIS (CASH FLOW AND EARNINGS)

CAPABILITY

The program is designed around a loop process that repeats the loop for the life of the investment.

THE ECONOMIC ANALYSIS PROGRAM WILL:

1. Calculate the F.I.T. depreciation, guide line (straight line) depreciation, and the book (straight line) depreciation.
2. Calculate the interest and preferred stock dividends using the book value of the asset.
3. Calculate income before taxes, income taxes, and income after tax.
4. Calculate liberal depreciation reserves.
5. Calculate annual cash flow.
6. Calculate earnings.
7. Calculate book value of assets and F.I.T. assets.
8. Calculate state tax using book asset.
9. Calculate earnings rate. (IF cash flow is positive)
10. Calculate discounted present value cash flow using an input earnings rate.
11. Calculate discounted earnings.
12. Calculate annual cash flow for the common stockholder.
13. Calculate revenue to produce common stockholder earnings rate equal to input discount rate.

METHOD:

Loop process

RESTRICTIONS/RANGE:

Will accept any number of items. The range of the study is from one to 100 years (to be specified in input data) and thus the depreciation time limit on equipment is limited to fifty years. Each item of the study is listed, but the output is the sum of the individual items. Annual totals only are printed in the output.

EQUIPMENT:

I.B.M. 370 , Model 135

ECONOMIC ANALYSIS (CASH FLOW AND EARNINGS)

DESCRIPTION

I

General

The Cash Flow Program was designed to give as much flexibility as possible in the type of Investments and depreciation methods that may be used by the program. Any undepricated assets at the end of the study are transferred into cash flow just as if they had been sold at the end of the study and the study time limit is 100 years. There is an option in the program that will allow for early retirement of equipment as well as an option that will allow equipment to be transferred out of the study before the end of its useful life and it is assumed that this equipment can be used elsewhere in the company. A cost escalation factor can be used for increasing present day cost for future Investments.

The output of the program is in three sections: Section I - Compiles a list of input data, lists the year, company book value, revenue, expense, book depreciation, income tax, liberal depreciation reserves, interest, preferred stock dividends and earnings. This output is listed year-by-year for the life of the study.

Section II - Output is for total company cash flow and includes the year, assets for federal tax, federal tax depreciation, income before tax, income after tax, cash flow, cumulative cash flow, discounted cash flow, cumulative discounted cash flow, cumulative earnings and discounted cumulative earnings. Each of these are listed year-by-year for the life of the study.

Section III - Is the common stockholder section. It lists the year, common assets, common depreciation, cash flow for common, cumulative cash flow, and discounted cash flow. Each of the above are listed year-by-year for the life of the study.

II

Calculation for depreciation using different types of Investment

1. Investments that Internal Revenue Service will not allow to be depreciated, such as land or salvage value of equipment.

The program holds this asset at the input amount. It by-passes depreciation and computes the interest, preferred stock dividends and state taxes for each year for the life of the asset. At the end of life, the asset is assumed sold at the value of the original investment. This amount goes into cash flow, no gain or loss assumed.

2. Investments that do not qualify for double declining balance depreciation.

An investment of this type would be used property such as the purchase of an existing power plant in a small town.

The program uses straight line depreciation based on the Internal revenue guide line life for federal income tax. It uses straight line company life for calculation of interest, preferred stock dividends and state taxes. (State taxes are investment related taxes.)

3. Investment that qualify for double declining balance depreciation for federal income tax.

The program calculates tax depreciation using double declining balance with Internal revenue guide line rate. The program changes from double declining balance to straight line depreciation when the double declining balance divided by remaining years of life is greater than declining balance depreciation. This allows the asset to be fully depreciated. Straight line depreciation using company life is used for calculation of interest, preferred stock dividends and state taxes.

Depreciation Options In the Program:

1. There is an option that will allow for a full year or a half year depreciation the first year.
2. There is an option that will allow choice of straight line depreciation, double declining balance depreciation or no depreciation.
3. There is an option that will allow equipment to be retired early. The normal depreciation is taken until the year specified for retirement. At the end of that year the remaining amount in the asset accounts is used for depreciation in that year.
4. There is an option to allow a transfer out of the study, equipment that has useful life left. It is assumed that this equipment can be used elsewhere on the system. Normal depreciation is taken until the year transfer is specified, then, the equipment is transferred to cash flow at the company book asset value.

Calculated Cash Flow and Earnings

After all input data has been read in and depreciation calculated, the program starts on the output. Annual income before tax, annual income tax, annual income after tax, liberal depreciation reserves and earnings are calculated. Annual cash flow is equal to income after tax + tax depreciation - investment + investment transfer credits - preferred stock dividends.

To determine a basis for economic comparison of the investment plan under analysis, its earnings rate must be compared to the current company earnings rate which is considered satisfactory. To do this, the present value of annual cash flow quantities, without investments, for the plan under study, is computed at the earnings rate which equates the total sum of these quantities to the present value of the total investment, involved in the plan, computed with the same earnings rate but from time starting at the beginning of the year. (Note: Cash flow is computed at the end of each year). The program finds the earnings rate that equates the two and prints it out.

The common stock holder cash flow is then computed. It is assumed that as an asset is depreciated the book value depreciation that applies to debt and preferred stock is used to pay off the asset and reduce the interest and preferred stock dividends. However, this is not available for the cash flow to the common stock holder.

The common cash flow equals income after tax + (tax depreciation - book depreciation) + (book depreciation + transfers - investments) X (ratio of common capital to total capital) - preferred stock dividends.

The program zeroes the asset accounts at the end of the last year of the study. All the assets are put in cash flow in that year as if they were sold.

Revenue and expense are added to the annual revenue and expense in the year they are made.

ECONOMIC ANALYSIS (CASH FLOW AND EARNINGS)

COMPUTER PROGRAM METHOD

Read and print title card.
Read and print second card.

CONTENTS OF SECOND CARD:

- A. Starting year of study
- B. Number of years in study
- C. Federal income tax rate
- D. State tax rate (Investment related)
- E. Bond ratio (bond capital to total capital)
- F. Preferred ratio (preferred capital to total capital)
- G. Bond interest rate
- H. Preferred dividend rate
- I. Current earnings rate
- J. Number of items in study
- K. Required revenue code (optional)
- L. Cost escalator (if desired)
- M. Investment tax credit rate

Read and print third item card.

CONTENTS OF THIRD CARD:

- A. Title of investment or description
- B. Type of investment (depreciable or non-depreciable)
- C. Type of depreciation (Double declining balance or straight line)
- D. Depreciation rate for company
- E. Depreciation rate for federal tax
- F. Year investment is made (1 is first year of study)
- G. Investment amount (all investment cost is at present day values)
- H. Annual revenue
- I. Annual expense
- J. Half or full year depreciation the first year (Optional)
- K. Year retirement is made if less than life of asset
- L. Year investment transfer is made if less than life
- M. Code to calculate investment tax credit on this investment.

The first investment data is now in the computer. The program checks the first year to see if there is an investment. If no investment was made, the depreciation routine is by-passed and the revenue and expense in the item card are added to the expense and revenue for that year. Each item card is counted as the computer returns to read the next input card. If there was an investment, the program checks to see if it is to be depreciated. If not, it will by-pass the depreciation routine and go to a routine that calculates the interest preferred stock dividends and state tax for the number of years specified. At the end of the specified life, the investment amount is placed in the cash flow as a sale (no gain or loss assumed). The investment

revenue and the expense are added to the Investment, revenue and expense of that year. The Item is counted and the program returns to read the next input card. If there was depreciation for this asset the program goes to the depreciation routine.

DEPRECIATION ROUTINE:

This routine calculates three types of depreciation: double declining balance guide line rate, straight line guide line rate and straight line company rate. The straight line company rate is used to decrease the book assets. Each year the book assets are decreased by that year's depreciation. The interest, preferred stock dividends and state tax are calculated using the book assets.

The straight line guide line depreciation is calculated and used when an asset is not qualified for double declining balance. It is also used to calculate the liberal depreciation reserves.

The double declining balance guide line rate is used for all new equipment that qualifies for accelerated depreciation. There is an option that will allow half year or full year depreciation the first year of the Investment.

One change in the method of depreciation is allowed. The double declining balance is converted to straight line when the declining balance divided by the remaining life depreciation is greater than the declining balance depreciation. This allows an asset to be fully depreciated. The assets are reduced by the depreciation each year. The amount of each asset and each depreciation is added to a total for that account for each year. In the last year, the depreciation is calculated and compared with the amount in the asset account. If the asset account is less than depreciation for that year, the amount in the asset account is used as the depreciation. This can happen when the life of an asset is not an integer.

There are three exits from the depreciation routine; the normal exit that runs out the full life of the equipment; a transfer which allows an Investment to be transferred to cash flow at the company book value after a specified number of years; and a retirement that allows an Investment to be used for a specified number of years and then retired the last year. The amount in this asset account is charged as depreciation for that year.

If an Investment is to be depreciated, the program checks the type of depreciation to use in the depreciation routine, the life of the Investment (It uses both company life and Internal revenue guide line life), checks for a retirement date, checks for a transfer date and checks for full or half year depreciation. It calculates the first year depreciation, half or full year as specified, then proceeds to calculate annual depreciation until it comes to an exit. The retirement exit and transfer exit override the normal exit. If the life of an asset plus the year installed is longer than

the number of years in the study, the program will go to the transfer routine in the last year. Except in the case of a non-depreciable asset where the asset remains in the asset account without cashflow benefit.

For the normal exit, the program adds investment, revenue and expense for that year and returns for the next item in the study.

For a transfer exit, the program transfers the amount in the asset account to cash flow in the year the transfer was specified. The investment, revenue and expense are then added to total investment, revenue and expense for that year.

For the retirement exit, the amount in the federal tax asset is used for tax depreciation, the book asset amount for book depreciation and the straight line guide line asset for its depreciation. This zeroes the asset accounts and full depreciation is taken. Then the program adds the investment, revenue and expense for the year the investment was made and continues to process the item cards until the number specified in the input is reached. Then, calculation for the output begins.

CALCULATIONS FOR CASH FLOW AND EARNINGS:

Annual totals for depreciation, investment, revenue, expense, state tax, interest, preferred stock dividends and transfers are all complete.

The program now calculates the income before tax, federal tax, income after federal tax, liberal depreciation reserves and earnings. These are calculated for each year of the study. A list of the equations used for calculating the above is shown in the program write-up under "equations in the program".

SECTION I OUTPUT:

The program lists the input as it is read in and records and increases the investment if the escalation factor is used. It reads all input cards and does the required calculations. It prints out the headings: the year, book value, revenue, expense, book depreciation, income tax, liberal depreciation reserves, interest, preferred stock dividends and earnings. Each of the above items are listed for the life of the study. The cash flow and the total cash flow are calculated next. If total cash flow is negative, it will by-pass the routine to calculate discounted cash flow and go on to Section II output. When cash flow is positive, the program proceeds to the discount routine.

THE DISCOUNT ROUTINE:

It is assumed that Investments are made in the first part of year and cash flow is computed in the last part of the year. The equation for annual discounted cash flow is $(1.0/(1.0+R))^k \times \text{cash flow}$. Since cash flow includes Investments, it is necessary to remove the investment portion prior to performing the foregoing discount calculation. The same equation is used to calculate the discounted investment but the year used is $(k-1)$.

Annual cash flow (without investments) and investments are discounted and then added together. The range of the discount factor, used in this iterative process, may be from 0 to 200% and is considered sufficient to cover the requirement of any study that needs to be made. This routine will start with the assigned discount factor of 1.0 (or 100%), then compute half the difference between the current (or starting) value and the previous value (where previous value begins at 0.0). The routine then adds this quantity, if the discounted cash flow is positive and subtracts if it is negative. It then takes half the difference in the current calculated discount rate and the previous discount rate for the next incremental change. It will continue to decrease the interval by half, usually requiring about twenty iterations to find the required discount rate which is within the \$1.00 difference tolerance limit assigned in equating the discounted (present value) cash flow to zero. A maximum of forty iterations is set for the termination of this routine should the discount factor go to 200%.

The total present value cash flow and computed earnings rate are printed as they are calculated. This evolution can be omitted by removing one write statement in the program.

The program is now ready to calculate and print out Section II output.

SECTION II OUTPUT: (Based on Total Investment)

Column headings for this output are: the year, federal income tax assets, federal income tax depreciation, income before tax, income after tax, cash flow, cumulative cash flow, discounted cash flow, cumulative discounted cash flow & cumulative earnings. Each is listed for the life of the study. The quantity used to compute the discounted cash flow is the input earnings rate. This earnings rate is the minimum acceptable rate of return on the investment. If bonds and preferred stock rates are included in the input, this factor is the rate of return to common for the total investment, but if bonds and preferred are not included, the factor represents total rate of return. The input earnings rate and the calculated earnings rate are printed at the bottom of Section II output if the total cash flow is positive. "Total Cash Flow is Negative" is printed when total cash flow is negative.

SECTION III OUTPUT: (Based on Equity Investment)

Section III output is the common stockholders section. It lists the year, book assets, book depreciation, cash flow, cumulative cash flow and discounted cash flow for each year of the study. Some assumptions are made for this section:

1. The book depreciation that applies to bonds and preferred stock would not be cash flow to the common stockholder but it is used to retire the debt as it is accumulated.
2. The difference between the federal income tax depreciation and book depreciation goes into cash flow to common.
3. The book depreciation that applies to common goes to common cash flow.
4. For a retirement or investment transfer, only that portion of the remaining investment derived from equity would return to common cash flow.

When the annual cash flows are calculated, the program returns to the discount routine only if total cash flow is positive and then a new discount factor is calculated. The annual totals for the life of the study are then printed followed by the calculated earnings rate.

The program has now completed this study and is ready for the next study. The first card is checked to see if it is a blank card and if so, the program calls "exit". The program will continue to execute any number of studies until a blank title card is read but will stop if the first two cards are blank or if they are out of order. The program will take up to 999 item cards and is capable of running the study for a maximum of fifty years.

EQUATIONS IN PROGRAM

1. Guide line rate = $1/\text{Internal revenue life of asset}$
2. Federal Income tax depreciation = $2 \times \text{guide line rate} \times \text{declining balance of assets}$
3. Guide line depreciation = $\text{Guide line rate} \times \text{Investment}$
4. Company rate = $1/\text{company life}$
5. Book depreciation = $\text{company rate} \times \text{Investment}$
6. Preferred stock dividends = $\text{book assets} \times \text{preferred ratio} \times \text{preferred rate}$
7. Interest = $\text{book assets} \times \text{bond ratio} \times \text{bond rate}$
8. Ins/Advaloren tax = $\text{book asset} \times \text{Investment related tax rate}$
9. Liberal depreciation reserves = $(\text{F.I.T. depreciation} - \text{guide line depreciation}) \times \text{federal tax rate}$
10. Cash flow = $\text{Income after tax} + \text{F.I.T. depreciation} - \text{preferred stock dividends} - \text{Investment} + \text{Investment transfers}$
11. Earnings = $\text{Income after tax} - \text{preferred stock dividends} + (\text{F.I.T. depreciation} - \text{book depreciation}) - \text{liberal depreciation reserves}$
12. Discounted Investment = $\text{Investment} (I) (1/(1+R))^K$; where $K=(I-1)$;
 I = year Investment is made from starting year
13. Discounted cash flow = $\text{cash flow} (I) \times (1/(1 + R))^I$
14. Common cash flow = $\text{Income after tax} + \text{F.I.T. depreciation} - \text{preferred stock dividends} - (\text{Book depreciation} \times (1 - \text{common equity ratio})) - (\text{Investment} \times \text{common equity ratio}) + (\text{Investment transfer} \times \text{common equity ratio})$

APPENDIX C
BOEING VERTOL DESIGN AND COST STUDY
FINAL REPORT

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**DESIGN AND COST CHARACTERISTICS
OF A SERIES OF WIND TURBINE GENERATORS
FOR TEXAS WIND SPECTRA**

WAYNE WIESNER

ADRIAN KISOVEC

APRIL 1976

**IN RESPONSE TO CONTRACT NO. 05060 SW
SUBMITTED TO
SOUTHWEST RESEARCH INSTITUTE
SAN ANTONIO, TEXAS**

BOEING VERTOL COMPANY

A DIVISION OF THE BOEING COMPANY

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FOREWORD

This document was prepared for Southwest Research Institute, San Antonio, Texas, by Boeing Vertol Company under P.O. 05060 SW during the period December 1975 thru April 1976.

The Southwest Research Institute program and technical direction was provided by Robert Swanson and Craig Johnson respectively. Boeing Vertol program management was provided by Franklin D. Harris, Director of Research and Development.

The principle investigators for this study were:

Wayne Wiesner, Project Engineer, and Adrian Kisovec, Research Staff Engineer, and Gerald Walsh, Research Technician. Technical contributions were also made by the following Boeing Vertol personnel: Structural Analyses - Joseph Baskin, Dynamic Analyses - Louis Mirandy, Rotor Technology - Glidden Doman, and Computer Assistance - Kenneth Eagle.

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1.0 INTRODUCTION

This report summarizes the study conducted by Boeing Vertol for Southwest Research Institute under Contract No. 05060 SW. The major requirements of the study were to develop an engineering description and related costs for a series of advanced, 1000 KW, wind turbines rated at specified wind velocities of 8, 10 and 13 meters/sec that are optimized to extract maximum energy from the wind spectra near Amarillo, Texas.

Emphasis has been placed on developing designs that will approach the preliminary cost goals as specified by Southwest Research Institute. These designs have been developed from Boeing Vertol's experience in the technology and development of large rotors (helicopter) and drive systems coupled with good knowledge of commercial construction (rail cars). Test data from several wind turbine models has been obtained and forms the basis for performance analyses. Cost data base stems from Boeing experience plus data obtained from well known U.S. manufacturers.

In general, this report presents a design summary, a presentation of the approach used to develop and size the designs, and a design description and capital and operating cost estimates. Further development areas are identified. Supporting data are included in the Appendices. G.E. and KAMAN study results are compared.

Both one and two blade configurations were equally considered as the design progressed. Based on the several advantages of the one blade configuration, especially lower capital and energy output costs and inherent gust alleviation ability, the one blade, Model SW-1, was selected.

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2.0 DESIGN SUMMARY

This section summarizes the major design and cost data and operating characteristics of both the selected single blade Model SW-1 and the comparative two blade Model SW-2.

2.1 SPECIFIED DESIGN AND COST GOALS

Both models are rated 1000 KW as specified by Southwest Research Institute. Table I shows the design, cost and operating goals as specified by SWR at the start of the program. Figure 1 shows the specified wind spectra used in sizing and calculating the respective performances. All production costs are based on a total of 1000 units manufactured at a rate of 200 units per year.

2.2 DESIGN CHARACTERISTICS

The selected one blade, baseline design, Model SW-1-10*, is shown in Figure 2 with equivalent two blade design shown in Figure 3. Table II summarizes the major design and cost characteristics of both models sized for the specified rated wind velocities and wind spectra and equipped with induction generators. Figure 4 shows the effect of the prescribed rated winds on the capital costs and comparison with the prescribed cost goals.

In comparing the cost and operating goals of Table I with the calculated values shown in Table II, it is clearly evident that the single blade Model SW-1 most nearly complies with such goals. Figure 4 shows that the Model SW-1 costs are well within the prescribed cost range goals if the costs are further reduced by R&D recommended in this report. (See Section 6.0, page 119)

*The designations used throughout this report are as follows:
The first dash number denotes the number of blades. The
second dash number denotes the rated wind velocity in meters/sec.

Based on such cost goals and consideration of practical lengths of objects that can be transported by rail, we have selected the one blade Model SW-1 sized for optimum energy output in a 10 meter/sec wind as the baseline configuration (designated Model SW-1-10). This model provides for excellent performance, maintainability and gust characteristics as well as low capital and operating cost.

Some of the most advanced features are:

- o The built in 'delta three' hinge arrangement of the teeter axis of the rotor automatically compensates for rotor gust loadings and will reduce tower and rotor fatigue loads and blade loads.
- o The articulated (teetering) hub external to the blade structure provides for lower capital and maintenance costs and blade loads.
- o Rotor characteristics selected to maximize electrical energy output per year by efficiently converting wind energy especially for the low wind velocities below rated power.
- o Blade material of common, low cost fiberglass impregnated with formable thermoplastic material enabling automated, low labor cost fabrication.
- o Soft-in-torsion shafting designed to obtain high power quality by minimizing the alternating torque harmonics resulting from rotor and wind loads.
- o Proven tower construction formed from steel plates and welded into a semi-cantilever conical shell with dynamic characteristics minimizing the interaction with rotor vibratory loads, and a cost effective shell construction for longer dimensions to reach higher wind velocities.

- o An advanced planetary gear drive for improved efficiency, and reduced weight and competitive cost.
- o Induction generator installed because of its lower cost even with capacitors to provide leading power factor. The soft drive characteristics are more compatible with turbine rotor and the power regulation controls are simpler.

The general data on Configuration, Fabrication Methods and Material selected for the respective subsystems are shown in Table III.

TABLE I.

PRELIMINARY WGS COST GOALS FOR AN UNFIRMED
1000 KW RATED PLANT IN THE AMARILLO WIND REGIME

WGS Configuration			Annual Energy Produced kwh x 10 ⁻⁶	Plant Utilization Factor	Yearly Average Fuel Cost \$/kwh	WGS Cost Goal \$/kw
Rated Wind, m/s	Hub Height, m	Plant Life, yrs.				
8	60	30	6.89	0.79	0.01	410
8	60	30	6.89	0.79	0.02	900
10	45*	30	5.11	0.58	0.01	290
10	45*	30	5.11	0.58	0.02	640
13	45	30	3.22	0.37	0.01	160
13	45	30	3.22	0.37	0.02	380

Notes: (1) Investment cost based on following:

6% equity earnings on book value (straight line depreciation)
9% interest on bonds and preferred stock
48% Federal income tax (accelerated depreciation)
10% investment tax credit

(2) Operating and maintenance costs (O & M):

Arbitrary \$10,000 per year, fixed

(3) Analysis does not include price inflation effects

* Changed to 60 meters, Feb. 1976

FIGURE 1. WIND FREQUENCY, CURVE, AMARILLO, TEXAS

FIGURE 2. BOEING MODEL SW-1-10 GENERAL ARRANGEMENT

FIGURE 3. BOEING MODEL SW-2-10 GENERAL ARRANGEMENT

TABLE II. DESIGN CHARACTERISTICS & COST SUMMARY, 1000 KW MODELS SW-1 & SW-2

MODEL CLASS (ONE OR TWO BLADES) MODEL SUB-CLASS (PER RATED WIND)	MODEL SW-1			MODEL SW-2			SPECIFIED PRELIMINARY GOALS		
	SW-1-8	SW-1-10	SW-1-13	SW-2-8	SW-2-10	SW-2-13	RATED WIND, METERS/SEC		
RATED WIND VELOCITY METERS/SEC	8	10	13	8	10	13	8	10	13
Wind Spectra Height, Meters	60	60	45	60	60	45	60	60	45
Max. Efficiency Velocity, MPH	15	17.3	20.2	15	17	19.8			
Rated Wind Velocity, MPH	17.9	22.4	29.1	17.9	22.4	29.1	17.9	22.4	29.1
Rated Watts/Sq.Ft.	10	17.5	35.2	10.5	18.8	38.5			
KW HR/Sq.Ft./Yr.	63.2	90.5	117.5	67.5	99.0	127.5			
Efficiency (Machine)	.35	.35	.35	.38	.38	.38			
Rotor Diameter, Ft.	356	270	190	348	260	182			
Diameter Rotor Area, Sq.Ft.	100,000	57,140	23,410	95,240	53,190	25,975			
HP Output (Rotor)	1,440	1,440	1,440	1,460	1,460	1,460			
Max. Efficiency Tip Speed to Wind Ratio	13.3	13.3	13.3	9.43	9.43	9.43			
Rotor Solidity/Mean Blade Lift Coeff.	.015/1.0	.015/1.0	.015/1.0	.030/1.0	.030/1.0	.030/1.0			
Mean Rotor Blade Chord, Ft.	8.42	6.34	4.48	8.21	6.13	4.28			
Rotor Tip Speed, Ft/Sec.	293	338	394	208	235	274			
Rotor RPM	15.72	28.87	39.56	11.41	17.26	28.77			
Generator RPM	1,200	1,200	1,200	1,200	1,200	1,200			
Step Up Ratio	76.3	50.3	30.3	105.1	69.5	41.7			
Input Torque (Rotor), FT/LB	482,000	316,800	191,430	671,000	443,600	266,150			
Hub Height, FT.	197	197	148	197	197	148	197	148	148
Rotor Drag, LB	51,100	38,800	26,250	57,230	34,970	23,210			
KW HR/YR	6,330,000	5,171,100	3,338,000	6,428,700	5,265,800	3,311,800			
Installed Capital Cost, \$	677,930	530,750	410,190	821,150	619,080	477,950			
Unit Cost, \$/KW	678	531	410	821	619	478	410/900	290/640	160/380
Cost of Electricity, ¢/KW. HR.*	2.14	2.05	2.46	2.55	2.35	2.89			
Capacity Factor	.72	.59	.38	.73	.60	.38	.79	.58	.37
Plant Life, Years	30	30	30	30	30	30	30	30	30

FORM 10-60 (10-60)

*Based on 20% annual carrying charge

FIGURE 4. EFFECT OF RATED WIND ON CAPITAL COSTS OF MODELS SW-1 AND SW-2

TABLE III

BOEING MODEL SW-1 AND SW-2 GENERAL DATA

SUBSYSTEM	MATERIAL/HARDWARE	CONFIGURATION	FABRICATION METHOD
BLADE	GLASS & THERMOPLASTIC	D-SPAR	FORMING
HUB	CORROSION REST. STEEL	CASTING	MACHINING
PITCH CONTROLS	ELECTR. ACTUATOR	HUB MOUNTED	N.A.
TRANSMISSION	HIGH QUALITY STEEL	PLANETARY	COMMERCIAL/AIRCRAFT
GENERATOR	—	INDUCTION	—
NACELLE	COMPOSITE - STEEL	SHELL + BEAMS	WET LAYUP & WELDING
TOWER	STEEL PLATE	SHELL	FORMING & WELDING

2.3 OPERATING CHARACTERISTICS (BASELINE CONFIGURATION)

The Boeing Vertol Baseline Model SW-1-10 (Figure 2) has been designed to work in the 60 meter wind spectra for the Amarillo, Texas region (See Figure 1), where the mean average wind at hub height is 19.7 mph. The Model SW-1-10 starts producing useful power at winds near 10 mph. It develops power most efficiently at 17.3 mph and reaches full power (1000 KW) at 22.4 mph. The Model SW-1-10 generates 5,171,100 KWHR per year giving a capacity factor of .59. Cut out wind speed has been assigned as 60 mph. The operating performance characteristics curve is shown in Figure 5 and Figure F-8 of Appendix F.

Model SW-1-10 has excellent gust alleviation characteristics because its rotor is hinged in such a way that the blade feathers toward a load relieving blade pitch when gusts strike the rotor. This was one of the important reasons for selection of a one blade rotor because such blade pitch - blade coning coupling is not mechanically attractive for a two blade rotor. This gust characteristic also simplifies the operation of the rotor control and speed governing system. SW-1-10 also has excellent starting characteristics (allowing starts in lower winds) due to this hinged feature in that the blade will automatically feather to starting pitch when the blade cones toward the downwind flapping stop. Power quality generation is excellent due to the 'soft' drive shaft between the rotor and the gear box. The induction generator offers simplified starting and stopping techniques, simple power engagements to the utility lines, and leading power factor is supplied by 690 KVAR capacitors. Fatigue loads in the

drive system and rotor are much reduced with the use of the induction generator coupled with the 'soft' drive shaft.

Hurricane protection is offered with the one blade configuration since the one blade could be tethered to the tower for the 'once every five years' maximum winds. Blades are designed to absorb without damage large hail stones and operation under normal icing conditions are permissible.

FIGURE 5. PERFORMANCE OF WIND TURBINE MODEL SW-1-10
AT RATED POWER OF 1000 KW

2.4 COMPONENT AND OPERATING COST

Component costs for the Model SW-1 and Model SW-2 series of wind turbine generators are summarized in Table IV. Included are expenditures for erection and assembly, amortization of special manufacturing plants and tooling. Not included are site preparation and land acquisition cost, and transportation. Estimation of the latter cost is presented in section 2.5.

Annual operating costs were determined for the Model SW-1-10 and SW-2-10 units. The analyses contained expenditures for maintenance labor, spare parts, monitoring station operation and amortization, and hand tools.

The most significant item causing variations in annual Unit operating cost is the number of wind generating units that are controlled and monitored by one control station. Therefore, the annual operating costs are summarized in Figure 6 by showing the annual operating costs per unit as a function of the number of units monitored by a single control station. Also shown are these costs in terms of cents per KW HR generated per year.

TABLE IV. MODEL SW-1 & -2 COMPONENT COST SUMMARY

SUBSYSTEMS & COMPONENTS	MODEL SW-1			MODEL SW-2		
	RATED WIND - m/sec			RATED WIND - m/sec		
	8	10	13	8	10	13
Rotor Subsystem	155,000	96,000	63,000	242,500	150,000	106,500
Transmission Box	181,000	137,000	103,000	220,000	169,000	124,500
Shafting, Couplings	24,500	19,500	15,800	30,000	23,300	18,000
Induction Generator	21,500	21,500	21,500	21,500	21,500	21,500
Capacitors	3,000	3,000	3,000	3,000	3,000	3,000
Gen. Protection, Electr. Contr., Switchgear, Transformer, etc. }	45,000	45,000	45,000	45,000	45,000	45,000
Nacelle Assembly	65,500	54,000	41,600	71,500	50,000	39,000
Tower Struct. & Found.	123,500	106,000	80,000	113,000	101,000	77,000
SUBTOTAL-\$	616,300	482,000	372,900	746,500	562,800	434,500
ERECTION & ASSEMBLY 10%	61,630	48,250	37,290	74,650	56,280	43,450
TOTAL-\$	677,930	530,750	410,190	821,150	619,080	477,950

FIGURE 6. EFFECT OF NUMBER OF INTEGRATED WIND TURBINE UNITS ON OPERATING COST

2.5 INSTALLATION AND TRANSPORTATION CONSIDERATIONS

Summarized below are some of the considerations made in arriving at 10% of Capital Costs for installing (erection and assembly) a Wind Generator at a given site.

Installation

Some of the factors which guide such costs are:

- o noise, which should not create serious problems due to a relatively low blade tip speed;
- o plant separation, which should be between 15 to 20 rotor diameters;
- o microwave interference, which requires investigations to determine effect on television and telephone communication
- o Environmental impact, i.e. aesthetics, which can be enhanced by a slender shell type tower with minimum of bracing and a streamlined nacelle.

The following is the estimated erection and assembly time for one unit, whereby it is assumed that the site will be prepared and foundation poured and set ahead of time. The latter requires at least 28 days for complete curing. It is also assumed that the electrical cabling will be in modular sets easily assembled and mounted in the unit. and hooked-up to the line transformer which may be adjacent to the tower.

	<u>Days</u>	<u>Men</u>
<u>Erection Time:</u>		
Tower	2.0	6
Nacelle	1.0	6
Rotor	0.5	4
Electrical Modules	2.0	4
Cabling to the Transformer	2.0	4
Functional Check-out		
o Mechanical	1.0	2
o Electrical	<u>1.0</u>	3
Total	9.5	

Assuming a labor rate of 20 \$/hr. the above effort will amount to the following cost:

	<u>M/H</u>	<u>\$</u>
Nacelle & Rotor Pre-assembly Labor	400	8000
W.T.G. Erection and On-site Assembly Labor	328	6560
Contingencies 10%	33	660
Commuting Time 12%	<u>39</u>	<u>780</u>
Total	800	16,000

However, substantial additional costs will arise from equipment rental and other expenditures for material and services such as:

o Cranes	}	Total Equipment = \$12,000
o Compressors		
o Welding Equipment		
o Trucks & Fuel		
o Drivers & Crane Operators' Salaries	}	Total Additional Salaries & Overhead = \$6,000
o Supervisory Personnel Salaries		
o Inspection and Service Approval		

Based on the above values and allowance for other contingencies, it was conservatively estimated that total erection expenditures may reach 10% of capital cost as summarized below:

Labor	\$16,000
Equipment	12,000
Additional Salaries & Overhead	6,000
Contingencies	<u>14,000</u> (1)
	\$48,000

(1) Contingency factor of 1.4 recommended by the tower manufacturer, Bruce Lake Co., Coatesville, Pa.

Transportation Limitations and Cost

Limitations

Transportation by rail was investigated and the following limitations were imposed on the W.T.G. components:

- a) Maximum length - regular car: 60 ft.
- b) Maximum length - special arrangement (spread over 3 flat cars): 150 ft.
- c) Maximum width and height: 13 ft. (incl. packaging)
- d) Maximum weight (depending on car type): to 100,000 lb.

Taking into account above limitations, the following comments are appropriate:

- o Blades - Single components should not be longer than 150 ft. with a maximum chord of 14 ft. (this requirement necessitated a splice at the counterweight arm joint). The baseline Model SW-1-10 blade and arm stub length is 148 ft. long and weighs about 9000 lbs. This length is transportable by rail. This was one of the reasons for selecting the Model SW-1-10 for the baseline configuration. (Model SW-1-8 requires a blade splice at about 3/4 radius.)
- o Tower - is built in three sections, each 60 ft. long which is quite practical for rail transportation. However, the maximum width or diameter, including supports and harness, should not exceed 13 ft.

The model SW-1 tower has a maximum diameter of 12 ft. and the heaviest (bottom) section weighs about 50,000 lbs. The

sections are bolted together during erection. (Cement for foundation is delivered by truck and poured into the formed ground excavations that have had steel work preparation.)

- o Nacelle - is a cylindrical, streamlined fiberglass shell reinforced with steel beams. The Model SW-1-10 structure is about 60 ft. long with a 15 ft. long detachable nose section. It has a diameter of 10 ft. Total weight of the nacelle assembly, including turntable structure, transmission and shafting, induction generator and electrical equipment, is about 70,000 lbs. This assembly can be transported and erected as a single unit.

Cost

Transportation cost could vary considerably depending on different means of locomotion. In this study only rail transport was considered because of its ability to haul long components. It was assumed that all parts will be manufactured in the Philadelphia, Pennsylvania, metropolitan area and transported to an Amarillo, Texas site.

The following approximate costs have been identified for the base-line Model SW-1-10 unit:

Freight Cost	\$19,900
Special Handling and Packaging	<u>40,000</u>
Total	\$59,900

The special handling cost includes packaging, loading and unloading, and securing and off-road transportation to the Amarillo site, as well as miscellaneous preparatory and administrative work.

0 DESIGN AND FABRICATION METHODS DEVELOPMENT

This major section reports the approach used to size and select the design features of the Models SW-1 and the comparative Model SW-2.

Standard Selection procedures of wind turbine components are not yet well developed so Boeing Vertol has devised methods such as the computation of maximum energy output to aid in such work. In other areas (for example) Vertol's computer programs developed for the structural analyses of helicopter blades have been used in this study to verify the structural integrity of the blades reported herein.

3.1 GENERAL DESIGN REQUIREMENTS AND CRITERIA

The principle design considerations made as the various designs progressed are listed below. Actual quantification of such requirements can be made and should be the subject of future design analyses. However, these listed considerations were used in the design analyses especially where in a great impact on cost was evident.

The overall structural design criteria used to size the rotor components, the drive system components and the tower are shown in Table V.

PRINCIPAL DESIGN CONSIDERATIONS

ROTOR

Blades

Low Cost Fabrication Without Compromising Performance

Infinite Fatigue Life (no deterioration of mechanical properties)

Structural Redundancy

Anti-Corrosive Properties

Ease of Assembly, Handling, Transportation

Easy Repair in the Field

Erosion (rain and sand) Protection

Lightning Protection & De-icing Features

High L/D Airfoil

Hail Impact Resistance

Hub

Design and Fabrication Simplicity - Low Cost

Infinite Fatigue Life and Corrosion Resistant

Cocked Hinge for Gust Alleviation

Sealed for Life (annual lubrication, i.e. purging acceptable)

Pitch Control and Yaw Control

(Electric actuators to avoid hydraulic leakage problems, redundant arrangement)

High Reliability

Failure Warning & Detection

Automatic Feathering or Azimuth Setting

Auxiliary System or Redundancy

Low Maintenance Requirements

Sealed for Life (annual lubrication, i.e. purging acceptable)

Low Power Requirements

NACELLE

Turntable

Suitable Stiffness to Match Rotor Frequency Characteristics

Suitable Stiffness to Ensure Shafting Alignment

Adequate Fatigue Life

Corrosion Resistance

Minimum Maintenance (annual)

Transmission

Long Service Life (Low Transmissibility of Torque Pulses)

Low Weight and Cost

Sealed for Life (annual maintenance, i.e. oil change acceptable)

Chip Detection and Warning System (coupled with pitch controls for shut down)

Generator and Accessories

Low Sensitivity to Torque and RPM Fluctuations

High Reliability and Low Maintenance

Enclosure Structure

Lightweight, Low Cost

Corrosion Resistant, Weather-Proof

No Maintenance

Low Aero-Drag

TOWER

Low Fabrication and Erection Cost

Stiffness to Match Rotor & Drive Natural Frequencies

Infinite Fatigue Life

Corrosion Resistance

Minimum Maintenance

Appealing Looks

TABLE V. STRUCTURAL DESIGN CONDITIONS

LOAD PARAMETER	DESIGN CONDITION				
	STATIC LOADING			FATIGUE LOADING	
	CASE 1	CASE 2	CASE 3	CASE 4	CASE 5
WIND VELOCITY, MPH	125	RATED	3 x RATED	AVERAGE	RATED
CROSS FLOW ANGLE, °	0	45°	0	20	0
RPM	0	NR	2 x NR	NR	NR
GUST, %	0	+200 -100	0	0	±10 @ 100/HR
WIND GRADIENT, %	0	0	0	15	15
TORQUE VARIATION, %	±200	±100	± 50	± 20	±30
BLADE ANGLE OF ATTACK STALLED		STALLED	NORMAL	NORMAL	NORMAL
NO. HOUR LIFE	—	—	—	100,000	50,000
LOADING DESCRIPTION	HURRICANE	LARGE GUST AT ANGLE	OVERSPEED	NORMAL OPERATION	RATED OPERATION WITH GUST

3.2 BASELINE SIZING AND PERFORMANCE

This section describes the method used to select the characteristics and performance of the series of wind generators described in this report and summarized in Table II, page 10. In order to reduce the length of this section, only the selection of the Baseline SW-1-10 characteristics will be described. Data for the other models are contained in Appendix F.

Blade Characteristics and Tip Speed

For lowest cost, the blade chord has been selected on the basis of the probable highest radius to mean chord ratio that is structurally sound. This ratio is believed to be near 22. For the configuration selected, this ratio is 21.4 for chord taken at 3/4 radius point, which gives a solidity of .015 per blade. A taper of 3:1 (root chord to tip chord) has been selected to give efficient structural arrangement and to permit (when combined with the 10° twist) a constant disk loading over the swept area of the rotor. Further, the root chord is such that it does not exceed the maximum dimensions that can be transported. The airfoil selected to date is the NASA GAW-(1) with 18% thickness. It was selected because of its high L/D at lift values near $C_L = 1.0$. Future design refinement may reduce the thickness in the outer 1/4 blade radius region. The tip speeds for the one and two blade configurations have been selected to that which for the respective solidities produces a blade lift coefficient near 1.0 at the design wind speed, V_o , (maximum efficiency wind speed) - 17.3 mph for the Model SW-1-10 Baseline at the prescribed rate velocity of 22.4 mph (See Figure 7).

The design ratio of tip speed to wind velocity for the one blade configuration is 13.3 and 9.4 for the two blade models. Thus at

the design wind velocity of 17.3 mph a tip speed of 338 ft/sec. is required for operation at maximum efficiency and the lift coefficient of 1.0 for the Baseline Model SW-1-10. (Refer to Table II, Page 10 for tip speeds for other models.)

Diameter and Maximum Energy Output

The diameter of Model SW-1-10 was selected as follows: from Figure 7 for the prescribed (by SWRI) rated wind velocity of 10 meters per sec. (22.4 mph), the specific power, P_s , is 17.5 watts/sq.ft. Thus, for the prescribed machine rating of 1000 KW, the rotor area is 57140 sq. ft. and the rotor diameter is 270 ft. For the specific rating of 17.5, Figure 7 shows that the maximum output specific energy is 90.5 KW HR/YR/SQ.FT. or a total of 5,171,100 KW/HR/YR for the 270 ft. rotor. (This data and data for other models are summarized in Table II, page 10)

Development of Generalized Design Chart

The generalized design chart of Figure 7 was obtained as follows: A generalized machine power output performance curve, Figure 8, was developed from Boeing test data and computer analyses as described further in Appendix F. The efficiencies used to obtain the machine efficiency, C_{p_m} , are shown in Table VI. Following the

TABLE VI. EFFICIENCIES OF COMPONENTS

	GEARBOX	GENERATOR	BLADE CONING	ROTOR	MACHINE, C_{p_m}
SW-1	.985	.95	.95	.39	.35
SW-2	.975	.95	.95	.43	.38

FIGURE 7. GENERALIZED DESIGN CHART FOR MODEL SW-1-10
FOR 60 METER HUB HEIGHT

FIGURE 8. GENERALIZED MACHINE POWER OUTPUT PERFORMANCE FOR MODELS SW-1 AND SW-2

establishment of the machine power output generalized curve and component efficiencies, the method outlined in Reference 1 was used to compute the specific energy output, E_s , versus design velocity, V_o , for various specific power ratings, P_s , as shown in Figure 9. The design velocity for each specific power rating was selected as that value where the specific energy is maximum for the given specific rating and these values were plotted in Figure 7. Corresponding rated wind velocity for the peak energy output is shown plotted in Figure 9 and these values are also plotted in Figure 7. Thus Figure 7 is a generalized design chart from which for a given rated wind velocity, the design velocity, the specific power output, and the maximum energy output can be conveniently determined. Similar design charts are shown in Appendix F for the other models for their respective wind frequency curves.

FIGURE 9. GENERALIZED SPECIFIC ENERGY - POWER RELATIONSHIPS FOR MODEL SW-1 AT 60 METERS HUB HEIGHT

Determination of Other Physical Characteristics

Other parameters, as presented in Table II, page 10 were derived as follows:

Step Up Ratio: For a generator output rpm of 1200, the step up gear ratio of the gear box is

$$G.R. = \frac{1200}{\left(\frac{\Omega R}{2\pi R}\right) 60} = 125.7 = \left(\frac{R}{\Omega R}\right)$$

Where R = rotor blade radius, ft.

ΩR = tip speed velocity, ft/sec.

Rotor Horsepower

$$HP_R = \frac{(1.341) (1000)}{(\eta)}$$

η = product of gear and generator efficiencies from Table VI.

Rotor Torque , ft.lb.

$$Q = \frac{(HP_R) (550) (R)}{(\Omega R)}$$

Rotor Drag, lb.

$$D_R = C_L \rho / 6 A (\Omega R)^2 \sigma$$

σ = solidity = .015 for SW-1 Models and .030 for SW-2 Models.

C_L = lift coefficient = 1.0

A = rotor area, sq.ft.

(ΩR) = rotor tip speed, ft/sec.

Capacity Factor

$$= \frac{\text{Annual Energy Output}}{(\text{KW}) (\text{hours per year})}$$

$$= \frac{E}{(1000)(8760)}$$

3.3 CONFIGURATION SELECTION

This section summarizes the major reasons for selection of components or arrangement of the single blade Model SW-1 with Induction Generator. This Advanced Technology Wind Generator arrangement has the potential of achieving the lowest generating cost possible for horizontal axis rotor types. Table VII presents this data in a concise form reporting only the most important reasons for selection.

The major differences between the individual models of each series are shown in Figure 12 (SW-1 series) and Figure 13 (SW-2 series). It should be noted that the rotor diameters of the SW-2 series are slightly less than the SW-1 series due to the higher machine efficiency of the SW-2 series (See Table VI, page 28). The overhang of the rotor from the tower is greater for the SW-1 series in order to allow for the clearance of the 'drooped' counterweight. This extra overhang requires a slightly longer nacelle.

TABLE VII. CONFIGURATION SELECTION TRADES

COMPONENT OR ARRANGEMENT	REASON FOR SELECTIONS
1. One blade rotor	Fewer parts, lower capital cost, easier to transport and erect, can withstand hurricane, no centrifugal force on feather bearings.
2. Underslung counter-weight arm	Provides less coning of main blade and thus higher rotor efficiency. Permits inexpensive and accessible hub arrangement.
3. High Fineness Ratio Steel Shell Tower	Frequency less than rotor rpm, proven construction, no inside maintenance required (depressurized and sealed). Less tower shadow effect.
4. Low Solidity Blade	Permits high rpm for least step up ratio in gearbox and is easier to transport. Lower blade area, thus lower cost.
5. Low Specific Power Rated Rotor	Allows efficient operation in lower winds

TABLE VII. CONFIGURATION SELECTION TRADES

(continued)

COMPONENT OR ARRANGEMENT	REASON FOR SELECTIONS
6. Drive Shaft soft in torsion	Does not transmit rotor torque pulses and thus provides good power quality.
7. Thermoplastic Composite Material for Blades	Provides for low manhour fabrication with minimum facilities and is corrosion resistant.
8. Teeter Hinge Instead of Rigid Hub	Greatly decreases the flapping bending moment on the blade to provide for long life blade. (See Figure 10). Allows for relatively slender blade root section, i.e. efficient, moderate thickness airfoils.
9. Cocked Teeter Hinge (δ_3)	Provides for self-alleviation of gust loads and permits good starts in low winds.
10. Induction instead of Synchronous Gen.	Induction generator one half the cost (See Fig.11) even with capacitors to provide leading power factor. 'Soft' drive characteristics much more compatible with rotor. Regulation and starting controls much simpler.

TABLE VII. CONFIGURATION SELECTION TRADES

(continued)

COMPONENT OR ARRANGEMENT	REASON FOR SELECTIONS
11. Planetary Gears instead of Spur Gear Arrangement	Much less weight and space provides for easier erection. Self-alignment of planets provide for even loading and long life. Higher efficiency.

FIGURE 10. EFFECT OF HUB TYPE ON ALTERNATING FLAP BENDING STRESS IN WIND GRADIENT AT 19 MPH, MODEL SW-2-10

FIGURE 11. ELECTRIC GENERATOR COST VS. RATED POWER

FIGURE 12. BOEING MODELS SW-1 SERIES CONFIGURATIONS

SW-2-8

SW-2-10

SW-2-13

FIGURE 13. BOEING MODELS SW-2 SERIES CONFIGURATIONS

3.4 SUBSYSTEMS DESIGN & FABRICATION METHODS

This section describes the basic steps in development of all the major subsystems and components such as rotor, controls, drive system, electrical power system, tower and nacelle.

The main considerations underlying design trade studies were to achieve the cost goals as outlined by SWR as well as to satisfy operational requirements with an efficient, practical design.

The design effort was also directed to comply with the following requirements established for this study:

- o Rated power output: 1000 KW
- o Wind spectra @ 45 and @ 60 m
- o Machine power coefficient - single blade: 0.35
- two blades: 0.38
- o Maximum wind speed: 125 mph for stopped rotor design
- o 30 year operating life
- o Components to be transportable by rail

Based on above constraints, the Boeing Vertol WTG designs were configured for high performance, low loads, low capital and operating cost, and simple, commercial type fabrication.

Component design selection was approached from two main directions:

- o System materials selection and configuration options
- o Determination of fabrication methods and cost

The above two tasks are so intimately interfaced and dependent on corresponding design criteria that, as a rule, several iterations were required to arrive at a practicable compromise providing a viable basis for final design optimization.

The often conflicting requirements between cost, performance, and reliability imposed varied solutions for different subsystems, involving materials, design approaches and fabrication methods.

3.4.1 ROTOR SUBSYSTEM

The selected rotor configuration for the Boeing Model SW-1 series is a single-bladed, "underslung" and counterbalanced rotor shown in Figure 14. The articulation joint is on the outside of the blade root section, thus enabling easy access for inspection and maintenance. Such configuration makes it possible to reduce the size of all hub components, especially pitch housing and corresponding bearings. There is no need for large blade pitch control bearings to carry blade centrifugal loads as required in two-bladed designs.

The drooped counterweight also functions as a coning angle reducer to minimize performance loss due to high coning angle.

The rotor comprises one blade with a 1.5% solidity made from glass-reinforced thermoplastic material. The hub is made from corrosion-resistant steel casting, and the counterweight is a cast lead shape suitably attached to blade spar extension for teeter balance adjustments.

Total weight of the model baseline SW-1-10, Figure 12b, page 40 rotor system including blade, hub, counterweight and pitch controls is about 19,000 lbs.

The Boeing Model SW-1-10 rotor was designed to the following major criteria:

FIGURE 14. MODEL SW-1 SERIES ROTOR CONFIGURATION

- o Low solidity for least cost and highest RPM for minimum step-up ratio.
- o Teetering concept for low blade root hub and tower loads.
- o Minimum coning to reduce disc area loss, i.e. power loss.
- o Inherent gust load alleviation by means of δ_3 .
- o Structural redundancy and corrosion resistance.
- o Simple, cost effective construction.
- o Easy maintenance and high reliability.

Selection of the single blade configuration was based on comparison of performance, design and cost analyses.

Comparison was conducted with other configurations such as the two-bladed Model SW-2-10, Figure 13b, page 41 and another single-bladed Model SW-1A-10, Figure 15, variant. Comparison of all designs was based on identical ground rules, especially with respect to performance, structural criteria and fabrication cost. For instance, the coning angle was intentionally limited to 12 degrees for reasons of minimizing loss of disc area due to coning. Rotor coning power loss was thus kept to less than 5% (see Table VI, page 28).

Model SW-2-10, Figure 13b, was run through the same design and cost analysis as Model SW-1-10. As shown in Table II, Page 10, the single-bladed Model SW-1-10, generates electricity for the least cost based on 20% annual carrying charges as well as offering important advantages regarding simplicity of hub design and service accessibility. These lower costs and reduced complications makes the one blade SW-1 series more attractive than the equivalent SW-2 series.

FIGURE 15. BOEING MODEL SW-1A-10 GENERAL ARRANGEMENT

Model SW-1A-10, Figure 13 was eliminated for reasons of higher cost and weight brought about by substantial tip and counterweight penalties amounting to about 2800 lbs. for the tip weight and an additional 6500 lbs. for the counterweight to reduce the coning to the required 12°.

The major advantages of the selected single-bladed rotor configuration (SW-1 series) can be summarized as follows:

- o Single blade will result in --
 - Lower capital cost and cost of electricity.
 - Much simpler hub design (no C.F. on pitch change bearings).
 - Less maintenance time.
 - Lower transportation cost.
 - Easier erection and assembly.
 - Simple securing behind the tower in hurricane winds.
- o Canted teeter hinge (δ_3) will help to --
 - Alleviate gust loads.
 - Initiate rotor starting.
- o Drooped counterweight, which is located at the same distance as the blade's center of percussion, will reduce coning angle to the required amount with no tip weight needed.

It should be noted that the problem caused by alternating torque harmonic loads, which always occur in teetering rotors (Coriolis geometry), was solved by "soft" shafting which reduces the torsional natural frequency well below the rotor one per rev. Thus the rotor and generator are "decoupled" and the latter will feel only a small fraction of torque fluctuations. (See discussion in Section 3.4.2 "Drive System".)

Thoughts were also given to adverse environmental conditions such as icing and erosion. The proposed solution by application of a polyurethane blanket riding on a silicone lubricant paste and covering the blade leading edge area is shown in Appendix C.

3.4.1.1 Rotor Blade Design

Description

Boeing has conducted a number of studies of WTG blades with the goal to reduce cost and allow an efficient mass production with automated equipment. Some of the composite designs (glass-epoxy) investigated and proposed in the past by Boeing and others are summarized in Table VIII-A. Reasons for selecting a composite material rather than metal are shown in Table VIII-B.

The selected design blade cross-section is shown in Figure 14 and rotor geometry in Figure 15. The composite selected for blade fabrication is phenoxy resin reinforced with E-glass filaments. The reason for this choice is the ease of manufacture due to post-forming capabilities of the procured material, therefore eliminating the need for time consuming curing of glass-epoxy structures.

Figure 16 illustrates the selected blade cross section of reinforced thermoplastic material. The "D" spar is composed from consolidated internal uni-fiber sheets and one $\pm 45^\circ$ crossply layer for the transfer of torsional shear from the aft skin sandwich plates. A channel web completes the D-section. Toward the tip, the number of uni-fiber layers is gradually reduced, and the gap between the channel web flange and the uni-fiber sheets is filled with appropriate filler strips, which contribute to the spar moment of inertia. Trailing edge section is constructed from an upper (curved) and a lower (flat) sandwich plate connected by a trailing edge wedge strip from crossply.

The trailing edge box skins are of $\pm 45^\circ$ crossply with the thickness sized to resist damage and/or penetration by a one-inch diameter hailstone impacting normal to the surface at free fall terminal velocity.

Structural Criteria

The blade was designed to meet structural criteria presented in Table V (Page 26). Case 1 proved to be the most critical and, when the blade elements were sized for this case, it was found that the structure would meet the fatigue loadings of the other conditions.

Results of structural analysis indicate that if the rotor blades are designed to meet the limit wind condition, and the lg alternating weight moment as the design fatigue condition, theoretically, an unlimited operating life can be achieved. Therefore, the limit static load was developed for a 125 mph wind, acting along the drive shaft axis, and on a stationary blade. In additon, the spar shell was not permitted to buckle when subjected to the limit bending load amplified by a factor of 1.25. The aft skins, supported by honeycomb, have to resist bending stresses resulting from the elemental chordwise air load shears of the 125 mph wind condition.

The dynamic response characterisitcs of the blade-hub system can be tuned through a wide range of frequencies in order that the harmonic response loads resulting from the impulsive gust and tower shadow flow conditions, as well as the primary one and two per rev loads generated by the wind shear and yawed flow conditions, do not impair the structural life.

TYPE	SECTION	WEIGHT	STRUCTURAL INTEGRITY	TOOLING COST	AUTOMATION POTENTIAL	MACHINE TIME	LABOR	ESTIMATED COST
1. MONOCOQUE SHELL - Filament Wound		HEAVY	GOOD	LOW	EXCELLENT	VERY HIGH	LOW	MAY BE HIGH BECAUSE OF SLOW WINDING & HIGH MATERIAL WEIGHT
2. SEMI-MONOCOQUE Glass-epoxy		MODERATE	GOOD	HIGH	FAIR (Filam. wound tubes machined core)	MODERATE TO HIGH	HIGH	MAY BE HIGH BECAUSE OF MANY PARTS & REQD ASSEMBLY LABOR
3. D-SPAR E.T.E.Box Filament Wound spar built-up box		LOW	VERY GOOD	MODERATE TO HIGH	FAIR (D-spar filam. wound, machined H/comb)	MODERATE	MODERATE TO HIGH	MODERATE TO HIGH
4. MULTIPLE TUBE-SPAR & SKIN & CORE		MODERATE TO HIGH	VERY GOOD	MODERATE TO HIGH	FAIR TO GOOD (Filam. wound tubes, machined core)	MODERATE TO HIGH (Many tubes)	MODERATE TO HIGH	MODERATE TO HIGH

TABLE VIII-A. COMPOSITE BLADE TRADE STUDY

Discipline	Item	Metal	Composite (a)
Structures	Fatigue life Notch sensitivity Structural damping Weight		Best Lowest Best Lowest
Fabrication	Tooling requirements Size limitations Parts count Labor and Q. C. required Shape forming Contour accuracy Scrap incidence		Lowest None Lowest Lowest Easiest Best None
Operation	Handling damage vulnerability Corrosion resistance Surface wear Maintenance required Field repair	Lowest	Lowest Best Lowest Easiest
Cost	Material Labor Transport and handling Installed cost	Lowest	Lowest Lowest Lowest

(a) Glass reinforced thermoplastics

TABLE VIII-B. SELECTION OF BLADE MATERIAL

FIGURE 16. MODEL SW-1-10 GLASS-REINFORCED THERMOPLASTIC BLADE SECTION

FIGURE 17 BOEING MODEL SW-1-10
ROTOR GEOMETRY

To reduce blade weight, the blade is not balanced about the quarter chord in the outboard (tip) section. Because of the inherent high torsional stiffness and the very low rotational speed, there is no anticipation of classical flutter problems.

In order to balance the blade aerodynamic shear force at average power (700 KW), the counterweight is swept forward 2.1° as shown in Figure 17. The aerodynamic shear force is due to the in-plane forces which produce the power output torque. For the design condition of 1000 KW, this force is 3130 lbs. and is felt as a one per rev force on the hub unless the counterweight is swept as stated above.

Fabrication

Blade manufacturing methods were studied in detail to arrive at low cost procedures. These studies are summarized in Section 4.1 and Appendix B.

3.4.1.2 Rotor Hub Design and Fabrication

Description

Figure 18 illustrates the selected hub configuration for the selected Model Series SW-1 single bladed, "underslung" and counterbalanced rotor. The very simple hub amounts basically to a universal joint between the rotor shaft and the blade, allowing for blade flapping and pitch motions. This configuration is very accessible, lighter and less expensive to make than any of the previous designs. The teeter axis, (not shown), is 'cocked' to allow blade pitch-coning coupling for excellent gust alleviation characteristics. The hub parts are made from stainless steel to eliminate corrosion problems.

Design Studies

To obtain comparative cost of different configurations using different materials and fabrication methods, two typical design approaches for a two-bladed hub (representing Model SW-2) series) were analyzed first as follows:

- o aluminum casting
- o corrosion resistant steel weldment

In both cases the pitch shaft with the blade grip was assumed to be made from cast corrosion resistant steel.

The critical load condition for sizing the components was the 125 mph wind acting against a stationary blade (See Table V).

The accompanying Figures 19 through 22 illustrate the pertinent configurations and indicate progression during the initial design process.

Since the single bladed rotor (Model SW-1 Series) proved to be more cost effective than the two bladed design (Model SW-2 Series), the design effort was concentrated in the former (See Weight and Cost Comparison below)

Figure 23 shows a hub configuration corresponding to the Model SW-1A-10 rotor with a straight counterweight arm straddled by the hub pitch housing. This model was discarded, due to high coning angles requiring substantial counterweight and tip weight penalties to reduce the blade coning to 12° to minimize performance loss.

The following is a weight and cost comparison for the configurations shown in Figures 18 thru 22. It should be noted that the selected single blade hub is configured as a universal joint and does not feature an actual housing or pitch shafts:

HUB CONFIGURATION						
Item	Single Blade - St.Steel Casting		Two Blades - Alum.Casting		Two Blades - St.Steel Weldment	
	(Figure 18)		(Fig. 19 & 20)		(Fig 21 & 22)	
	Weight lb.	Cost \$	Weight lb.	Cost \$	Weight lb.	Cost \$
Hub Housing	-	-	3,780	10,700	7,320	8,900
Pitch Shaft/ Grip (1)	-	-	6,400	23,00	6,400	23,200
Hub Assembly	5200	18,640 (2)	10,180	33,900	13,720	32,120

(1) From stainless steel; weight and cost for two units

(2) Includes: blade articulation lugs, pitch actuator support, cardan joint hardware and rotor shaft clevis end.

NOTE:

FOR CLARITY REASONS THE BLADE ARTICULATION
IS SHOWN WITHOUT A CANTED TEETER AXIS (δ_3)

FIGURE 18. HUB CONFIGURATION, MODEL SW-1 SERIES

FIGURE 19. MODEL SW-2 SERIES HUB (ALUMINUM CASTING VERSION)

FIGURE 20. TYPICAL TWO BLADE
TEETERING ROTOR HUB
CONFIGURATION

FIGURE 21. WELDED STEEL ROTOR HUB CONCEPT (TWO BLADES)

FIGURE 22. WELDED STEEL HUB DETAILS (TWO BLADES)

FIGURE 23. MODEL SW-1A ROTOR HUB CONFIGURATION

3.4.2 DRIVE SYSTEM

Gear Box

The rotor torque is transmitted to the generator through a three-stage planetary step-up gear. The gear box is connected to the rotor hub by means of a short tubular steel shaft and a long, concentric "soft" composite shaft transmitting rotor torque only.

The three-stage planetary configuration was selected based on a joint design and cost study with Cincinnati Gear Company.

A parametric study of planetary gear configurations was conducted by Boeing Vertol and Cincinnati Gear Company based on criteria enumerated in Table IX. and on parameters summarized in Table XII. (Page 90). The resulting cost trends are shown in Figure 31 (Page 91). For comparison of parallel shaft and planetary gear boxes, shown below are size, weight and cost comparisons using data obtained from the Falk Co. (Note: Parallel shaft box does not fit into nacelle.) As a result of such studies, the gear box of the planetary type as shown in Figure 24 was selected for the Models SW-1 and SW-2.

GEARBOX WEIGHT & COST (MODEL SW-1-13)

<u>Parallel Shaft *</u>	<u>Planetary</u>
94,500 LB.	20,000 LB.
\$96,000	\$124,500

* Falk Co. Data

TABLE IX. ADVANCED TRANSMISSION DESIGN CRITERIA

- Data is based upon max. Hertz K-Factor equal to 365. Higher K-Factor can reduce size and cost at the expense of gear reliability. The 365 K-Factor is based upon max KW rating.
- Fatigue life loadings are (% Power - % Time); (100 - 35) (60 - 25), (30 - 25) and (15 - 15).
- For this study, The Cincinnati Gear Company used a gearbox cost optimizing program which compares various ratios for both parallel shaft and planetary gears. The program then selects the lowest cost gearbox design for a particular application. Therefore, the data for this study is based on the 10 lowest cost gearboxes of over 500 total designs considered.
- The gear designs are based upon commercially proven hardware and would not require extraordinary development costs. Also, there are existing machines and time available to manufacture the large internal gears.
- For three stage gearboxes, the last stage nearest the generator was a parallel shaft gear. The first stage was always a planetary gear with five planets.
- The impact of the K-Factor is important. At 3000000 in-lbs. of torque and a K-Factor = 300, the cost would be 1.37 higher and the weight would be almost doubled.
- A large production was assumed, i.e. not less than a total of 1000 gearboxes at a production rate of 200 per year.

FIGURE 24. ADVANCED PLANETARY GEAR BOX

Drive Shaft

During initial stages of this project it became increasingly clear that the drive system design will be greatly affected by the selected rotor configuration. The teetering rotors are preferred for reasons of lower blade flapping loads and greatly reduced shaft moments. However, because such rotors develop significant Coriolis forces causing substantial torque fluctuations when flapping, the design of the drive system should enable elimination of these torque harmonics to the maximum extent possible. Such drive system should also alleviate torque variations due to wind gusts.

Due to tower shadow and wind gradient the alternating one per rev torque of the selected single bladed teetering rotor may amount conservatively to as much as 40% of steady torque. Such magnitude of torque fluctuations would be unacceptable in a synchronous generator system and it would not be practicable even in an induction generator.

Therefore, ways must be conceived to decouple the rotor from the generator and to minimize torque harmonic pulsations due to blade flapping.

Such decoupling can be achieved with a "soft" drive system with the torsional natural frequency well below rotor one per rev. The first attempt to achieve this goal with a conventional metal shaft proved unsuccessful; therefore a design as shown schematically in Figure 25 was conceived.

FIGURE 25. FLEXIBLE DRIVE SHAFT ARRANGEMENT

The outer tubular shaft is from steel and it takes bending due to the rotor overhang. The inner shaft, which is attached to the outboard end of the tubular steel shaft is a filament wound E-glass/epoxy tubular structure. The available length of about 200 in. and the low shear modulus of elasticity of such structure (about 1.7×10^6 psi according to extensive Boeing Vertol test data) resulted in a very low spring rate of 18.7×10 in.lb/rad. which enables a substantial reduction of alternating rotor torques as shown in Figure 26. The composite shaft itself was sized by means of the Goodman diagram based on Boeing Vertol testing and shown in Figure 27. It was conservatively assumed that the ratio of steady torque vs. alternating torque is 1.5.

The alternating torque alleviation will be also enhanced by the transmission since the latter is by no means infinitely rigid. According to Boeing-Vertol experience, the transmission contribution may extend as far as the cross hatched area in Figure 26.

Therefore it can be expected that about 92-94% of the rotor alternating torque loads will be eliminated through the shaft and transmission by a proper selection of the overall structural stiffness.

FIGURE 26. DRIVE SYSTEM SPRING RATE EFFECT

FIGURE 27. FATIGUE PROPERTIES OF COMPOSITE TUBES IN TORSION (S-GLASS)
(BOEING VERTOL TEST DATA)

3.4.3 Electric Power System

e proposed wind turbine generator is a constant speed type. Therefore only such electrical systems compatible with this design will be considered.

The two types of generators that are available are (a) synchronous and (b) induction. The synchronous generator, incorporating a rotating dc field, is the type commonly used by utilities, ships, aircraft and mobile ground power supplies. Generator field excitation is supplied by a regulating unit which serves as a voltage regulator during isolated generator operation and as a reactive power (KVAR) control during parallel generator operation. During parallel generator operation, which includes the case of the wind-mill supplying power to the electric utility, reactive power is controlled by the excitation regulating unit and real power (KW) is proportional to generator torque. The synchronous generator would function only in synchronism with the utility system. Thus the start-up control would have to provide for automatic synchronizing of the generator prior to connecting the generator to the line.

An induction generator can consist of a standard squirrel-cage induction motor. This type machine functions as a generator when it is connected to an energized ac line and is driven at higher than synchronous speed. For a commonly available type of induction machine, rated output is produced by 103% of synchronous speed, with output approximately proportional to difference between synchronous and operating speed in the range from zero to double rated output. A generator excitation controller is not required since the generator automatically takes its excitation from the

power line. Real power (KW) output would be controlled as a function of windmill blade pitch and its consequent effect on torque.

The induction generator is simpler and more rugged than the synchronous type; and since it needs no black box controller, it is an appreciably more economical approach than the synchronous. However, it requires additional magnetizing kilovars which may be conveniently provided by capacitors. Thus the induction generator will generate, continuously, the same kilovars as a synchronous machine.

The only significant shortcoming on the induction generator-capacitor combination may be that the kilovars delivered by capacitors decrease as the square of the voltage. Therefore, in case of sudden overloading, when the generator needs more kilovars, capacitors will provide less instead of more power. On the other hand, because isolated wind turbine generators are not considered in this study, which treats suitably large "farms" of interconnected units, the aforementioned shortcoming is not considered to present a major problem and does not seem to outweigh other advantages of the induction system, especially regarding cost and simplicity.

Besides, the induction generator is rather insensitive to torque oscillations as compared with the synchronous machine. This is important because, in the described teetering rotor configuration, two major problems have to be considered as potential impediments to the quality of electrical energy:

- a. Harmonic torque oscillations due to Coriolis effects of a teetering rotor.

b. Sudden torque changes due to gusts.

The Coriolis forces could be substantially reduced with a fixed gimbal integrated in the rotor hub. However, as described in Section 3.4.2, a simpler and more cost effective approach was found in a suitable spring rate of the rotor shaft and transmission. Such "soft" drive system, when combined with the cocked (δ_3) teeter axis, will reduce the effects of the anticipated gust conditions.

Based on torque oscillation alleviation capabilities of the selected drive system, the synchronous generator might be used; however, the induction generator with corresponding capacitors was selected because of its inherent insensitivity to torque variations and much lower cost. (See Figure 11, Page 39)

Appendix E gives vendor's (General Electric) technical information on both the induction and synchronous generators.

3.4.4 CONTROL SYSTEM

The blade pitch control system consists of an electrical actuator mounted on the underside of the blade root end. Blade pitch change is accomplished via a worm gear drive as shown in Figure 18 (Page 57). Such electro-mechanical system is simple and requires only a slip ring device for power supply. It eliminates all leakage and maintenance problems of a hydraulic drive.

The required control power (pitch rate) will be greatly affected by gust induced loads and potential electrical failures.

One of the critical transient loading conditions is a sudden generator failure, causing torque surge and subsequent rotor acceleration. This condition will govern the selection of the pitch control rate.

Since acceleration is proportional to torque and inversely proportional to rotor mass moment of inertia, i.e. diameter and weight, these parameters will greatly influence the pitch rate requirements.

The following is a diagram showing the basic relationship between rotor overspeed as a function of available pitch rate and rotor diameter:

The advantage of a large, slowly rotating and high inertia rotor is quite apparent. It is also obvious that a rapid pitch change greatly attenuates the hazards of an overspeeding rotor. Since the pitch control mechanism does not represent a significant cost item, a slightly higher investment is recommended for achieving a pitch rate of at least 5 deg./sec.

The total blade pitch travel is about 90 degrees from the operating low pitch angle to the fully feathered position for shutdown.

The rotor yaw control system also consists of an electrical actuator with its pinion engaging the outer ring gear of the turntable bearing. The actuator is mounted on the cylindrical steel structure on top of the tower. The desirable pitch rate is about 3 degrees per second and the sensitivity to wind direction changes should be no less than 10 degrees starting from the cut in wind velocity. A time averaging circuit will be used to prevent continuous operation of this system.

3.4.5 TOWER, NACELLE AND FOUNDATION

Tower

The tower structure is a steel shell pole braced at the lower construction splice at about $1/3$ of the pole height by means of four tubular struts. Diameter at the ground level is 12.0 ft. and 8.0 ft. at the top. The structure is made in three sections with end flange plates bolted together for assembly. (See Figure 2, Page 8). The tower sections are fabricated from two to four longitudinal sections bent to shape on a large press brake and seam welded. This is the type of construction developed by the Bruce Lake Co. of Coatesville, Pennsylvania, and is widely used for utility cantilever power poles. The base plate is preferably bolted to a concrete foundation; however the actual foundation type will depend on terrain characteristics.

For Models SW-1-8 and -10, the tower supports the hub at a height of 197 ft. as defined by S.W.R. for rated wind velocities of 8 and 10 m/s.

For the smaller Model SW-1-13, the tower is fully cantilevered because of the lower hub height of 147 ft. as defined by S.W.R. for a rated wind of 13 m/s. (See Figure 12c page 40)

The tower was designed according to AISC-Steel Construction Criteria to withstand moments resulting from rotor limit drag loads (twice the maximum operational loads) as well as static and alternating loads and moments caused by the rotor and nacelle assembly (See Appendix G).

Exterior of the tower is protected by a zinc rich primer and a suitable surface coat.

After assembly, the tower interior is depressurized to check sealing between the end plates. Thus the interior is protected against corrosion without further maintenance.

Electrical conduits run along the outside tower surface and through a suitable protective, accessible tubular shaft. This will enhance maintainability and eliminate need for access to tower interior. Slenderness of the tower results in low bending and torsional frequencies which can be substantially below rotor one per rev, thus dynamically decoupling the rotor-nacelle assembly from the tower.

A portable service elevator-cart rides on a rail welded to the outside of the tower and travels by means of an integral winch winding up a cable attached to the top of the tower. A small platform and corresponding ladder enables access to the nacelle interior.

Nacelle

The nacelle, of identical size for all models, rotates on a large turntable bearing such as KAYDON T-24-88E (P.D. = 88.50 in.) with external ring gear capable to carry radial and axial loads, as well as the substantial weight moment of the rotor. Nacelle structure itself features two main load carrying I-beams from steel embedded in a structural fiberglass shell. The upper enclosure is made from a light fiberglass structure. The total nacelle cross section is circular with a large "funnel" accommodating the turntable structure.

Figure 28 shows the inboard profile of the nacelle arrangement with upper tower end including the turntable, electrical yaw actuator, service elevator and access platform.

The rotor shaft arrangement is shown in Figure 25, Page 67 .

The generator is driven via a double coupling to allow for some shaft offset and misalignment. The rotor brake is an integral part of the 3-stage planetary transmission.

Longitudinal axis of the nacelle body is inclined by 6° tail up to improve the rotor-tower clearance. Thus the blade and counterweight can flap 28 and 22 degrees respectively toward tower from the operating 12 degrees coning angle. (See sketch below)

An electro-mechanical yaw actuator (engaging the turntable ring gear) is mounted on the vertical tubular steel structure which is also provided with an access door for servicing the slipring assembly. Said structure is bolted to the upper tower flange plate.

FIGURE 28. NACELLE INBOARD PROFILE (ALL MODELS)

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4.0 CAPITAL COST & WEIGHT ANALYSES

General Considerations

A major effort was focused on achieving the cost goals outlined in Table I, as well as to provide lightweight and cost effective structures for **all** subsystems and components to reduce transportation and assembly costs.

To develop realistic cost trends and equations, certain basic cost data were compiled for materials and fabrication methods. Principal values based on our manufacturing experience and on current prices of raw materials as well as castings and forgings are summarized in Appendix A. Generator, transmission and tower costs trends are presented in this section. A sample cost calculation is included.

Manhours and machine time required for machining and welding of parts were estimated from Boeing studies on "Design to Cost". Each component or subsystem was analyzed separately.

Advanced fabrication processes were studied for improved cost effectiveness because it became quite clear that such methods should be applied especially to the rotor system for reducing cost of produced electric energy. For research for further cost reduction see Section 6.0.

Blades: Special attention was given to blade fabrication cost since traditionally blade costs are high for the large and sophisticated high performance wind turbines developed in the past.

For this reason two conventional methods of fabricating composite structures were compared with the advanced forming approach using reinforced thermoplastics.

Hub: Similar philosophy was applied to the hub construction by comparing aluminum casting and weldment from stainless steel.

Drive System: Conventional, parallel shaft gear drive was discarded because of very high weight and low efficiency. Advanced, low weight and low cost planetary transmissions were examined and proved to be more cost effective when installation and operating costs are considered.

Electric Power System: Cost of electrical system components, including induction and synchronous generators, were partly obtained from vendors and from estimates from other similar projects by GE and KAMAN.

Tower & Nacelle: Tower costs were obtained from Bruce-Lake Company in Coatesville, Pa. The proposed design is a widely used steel shell built up from prebent sections welded together into conical tubes in lengths limited by transportation requirements. These sections are then bolted together to form the tower of selected height.

Nacelle costs were estimated from material weight and labor cost for the selected configuration, combining steel truss and structural composite shell.

On the following pages the basic cost and weight trends are developed for each of the above subsystems. To arrive at the final capital cost, the following specified criteria were applied:

- Total production - 1000 units
- Annual production rate - 200 units/yr

At the end of this section a sample cost calculation is presented to show the detail procedure used to calculate the cost of the baseline model SW-1-10.

4.1 ROTOR SYSTEM

Blade

Past studies have confirmed that blade costs represent a substantial part of investment required for erection of a Wind Turbine Generator. Therefore, special attention was given to a cost saving design without sacrificing performance and structural integrity.

As mentioned previously, two conventional fabrication methods, i.e., filament winding and tape laying have been compared with the advanced forming process of glass reinforced thermoplastics.

Based on Hercules' Inc. estimate of a maximum winding speed of 270 lbs per hour (glass filaments and resin) and a stipulated production rate of 200 units per year, the filament winding technique required 3 machines for the single blade configuration. The turn-around time for assembling the complete blade was estimated at 30 hours. It was (optimistically) assumed that the same rate could be achieved with the tape laying method.

To double the production rate for the filament winding and tape laying (thermosetting) fabrication methods, a minimum of five machines would be required. Cost comparisons of the three fabrication methods is given in Table X.

EXPENDITURE - 1975

	FILAMENT WINDING		TAPE LAYING		FORMING	
A. Capital Investment (Non-recurring Engrg. written off)						
Production Rate - Units per year	200	400	200	400	200	400
Building & Site	2,575,000	3,550,000	2,575,000	3,550,200	2,075,000	2,075,000
Machines (A)	2,250,000	3,750,000	5,625,000	9,400,000	750,000	750,000
Heating or Curing Equipment	250,000	415,000	250,000	415,000	150,000	150,000
Resin Mixing & Fiber Heads	50,000	83,000	25,000	42,000	-	-
Handling & Stripping Equipment	145,000	240,000	145,000	200,000	70,000	70,000
Utility Equipment	50,000	83,000	50,000	83,000	20,000	40,000
TOTAL	5,320,000	8,121,000	8,670,000	13,730,200	3,065,000	3,085,000
B. Fabrication						
Material (See Table 4)	18,647	18,647	27,427	27,427	28,252	28,252
Tooling - Labor (2)	60,000	85,000	60,000	85,000	53,000	53,000
- Material	40,000	67,000	40,000	67,000	40,000	40,000
Fabrication Labor (2)	37,500	37,500	37,500	37,500	26,000	(5) 21,000
Machine Operating Cost (3)	3,000	3,000	3,000	3,000	200	200
Machine Operating Time Spar: To Assy:	15 hrs. 15 hrs. 30 hrs.	15 hrs. 15 hrs. 30 hrs.	15 hrs. 15 hrs. 30 hrs.	15 hrs. 15 hrs. 30 hrs.	6 hrs.	6 hrs.
Curing Cost (3)	1,600	1,250	1,600	1,250	-	-
Curing Time (Spare & Other)	16 hrs.	16 hrs.	16 hrs.	16 hrs.	-	-
Moving & Storing Cost	500	390	500	390	500	390
C. Amortization (No Interest, Site Cost Included)						
Plant Investment (1000 Blades)	5,245	8,050	8,595	13,655	2,990	3,010
Tooling (100 Blades)	1,000	1,520	1,000	1,520	930	930
D. Final Product Cost						
Material	18,647	18,647	27,427	27,427	28,252	28,252
Fabrication	42,600	40,140	42,600	42,140	26,700	21,490
Amortization	6,245	9,570	9,595	15,175	3,920	3,940
Production Cost	67,492 (~67,500)	70,357 (~70,400)	79,622 (~80,000)	84,742 (~85,000)	58,872 (~59,000)	53,680 (~53,700)

NOTES:

- (1) Some tape storing and feeding equipment required.
- (2) A rate of 20\$/manhour was assumed.
- (3) Machine operational cost (including labor) was \$100\$/hr.
- (4) Using a winding rate of 270 lb/hr per Hercules Inc. quote, it was assumed that three machines will be required for 200 blades per year and five for 400 blades per year. (No additional machines are needed for forming.)
- (5) It was assumed that by doubling the production rate, labor will be reduced by 20%.

TABLE X, BLADE FABRICATION COST (DETAIL BREAKDOWN)

Since thermoplastic forming process turn-around time was only 6 hours (due to the fast and simple method which eliminates bonding and curing) one machine sufficed even for the higher production rate. It was also assumed that higher production rate will reduce the labor time by 20% since only one machine is used.

Table XI summarizes the impact of production rate increase on all three fabrication methods.

Due to the need for a substantially higher capital investment for filament winding and tape laying and distributing the amortization over the same amount of 1000 blades, the cost trend in the two conventional processes is unfavorable, i.e, blade costs are increasing. On the other hand the forming process shows a decline in blade cost with higher production rates.

These manufacturing costs plus an 8% profit margin are presented in Table XI. It should be noted that the cost analyses apply to individual blades. For the selected Model SW-1 rotor, 20% blade cost was added for the counterweight and arm.

TABLE XI. EFFECT OF PRODUCTION METHODS - ON BLADE COST

Hub

the Model SW-1 series hub was simplified to such an extent that it represents only a minor cost item in the entire rotor cost and it is included in Table XIII, page 98 in the rotor subsystem showing the example cost breakdown for various subsystems of Model SW-1-10.

Total Rotor Subsystem Cost

For obtaining total single and two blade rotor system cost variations for constant power output with a varying blade radius, the blade cost was divided into a variable and constant cost (fabrication labor) cost portion. The variable consists of material, handling, tooling amortization and some fabrication costs. It was estimated that this variable cost will amount to between 45 to 50% of total blade cost and vary as the cube of radius. (See Figures 29 and 30)

4.2 DRIVE SYSTEM

A parametric study of various gear drives such as parallel shaft design and planetary gear configuration was conducted based on criteria enumerated in Section 3.4.2 and on parameters summarized in Table XII. The resulting cost trends are shown in Figures 31 and 32, whereby Figure 32 relates to cost adjustments for gear ratio changes. The cost trend applies basically to 1000 KW inputs, however for first approximations it can be used for a range from 500 to 2000 KW. As mentioned before, an advanced planetary gear drive was selected for low weight and cost, and high efficiency. Although the design was not optimized, it shows promising cost trends when compared with the existing commercial transmissions.

is interesting to notice that the single bladed rotor requires a less expensive transmission because of its inherently higher tip speed. The cost of shafting was estimated from transmitted torque and weight of components.

FIGURE 29. SINGLE BLADE ROTOR COST TREND VARIATION WITH BLADE RADIUS

FIGURE 30 . TWO BLADED ROTOR COST TREND VARIATIONS WITH BLADE RADIUS

TWO BLADE INPUT

Option Number	HP Rated	KW Rated	Generator Speed RPM	Input Speed RPM	Step-Up Ratio	Input Torque lb-inch	Input Torque ft-lbs	Output Torque lb-inch	HP Rotor
1	670	500	1200	28.57	42	1,651,200	137,600	39,314	740
2	1341	1000	1200	20.00	60	4,656,000	388,000	77,600	1470
3	2011	1500	1200	16.44	73	8,568,000	714,000	117,369	2230
4	2682	2000	1200	14.12	85	13,200,000	1,100,000	155,294	2950
5	4023	3000	1200	11.65	103	24,000,000	2,000,000	233,009	4430

ONE BLADE INPUT

Option Number	HP Rated	KW Rated	Generator Speed RPM	Input Speed RPM	Step-Up Ratio	Input Torque lb-inch	Input Torque ft-lbs	Output Torque lb-inch	HP Rotor
1	670	500	1200	40.00	30	1,179,600	98,300	30,320	740
2	1341	1000	1200	28.57	42	3,324,000	277,000	79,142	1500
3	2011	1500	1200	23.08	52	6,120,000	510,000	117,692	2240
4	2682	2000	1200	20.00	60	9,432,000	786,000	157,200	2990
5	4023	3000	1200	16.22	74	17,280,000	1,440,000	233,513	4440

TABLE XII. TRANSMISSIONS FOR WIND TURBINE GENERATOR APPLICATION
(PARAMETRIC ANALYSIS BY CINCINNATI GEAR COMPANY)

FIGURE 31. TRANSMISSION WEIGHT & COST TRENDS

FIGURE 32. GEAR RATIO COST EFFECTS

4.3 ELECTRICAL POWER SYSTEM

The cost and weight trend curves in Figure 33 and 34 for induction and synchronous generators respectively were developed from data obtained from the General Electric Company as shown in Appendix E. Other electrical equipment cost was obtained from the same source for a typical generator and then varied with the power rating.

4.4 CONTROL SYSTEM

Estimation of control system cost (pitch and yaw) was based on control power requirements and previous studies such as the ERDA studies conducted by General Electric and Kaman.

The pitch control actuator and drive is included in the rotor cost. The yaw actuator and drive system cost is included in the turntable structure cost.

4.5 TOWER & NACELLE

The tower cost trends are based on manufacturer's (Bruce-Lake Co., Coatesville, Pa.) data and presented in Figure 35 where cost is plotted vs tower root moment, i.e, product of rotor drag and tower height. Foundation cost will vary depending on site conditions. An average 25% cost of tower structure was used for cost of foundations.

Nacelle costs are based on the cost and weight of raw materials such as glass and resin (either glass/epoxy or glass/phenoxy), metal structure, estimated fabrication labor and assembly cost. Due to the rotor drag variations in the Model SW-1 and SW-2 design series the material costs were developed as a function of rotor drag. The total cost trend developed is shown in Figure 36.

FIGURE 33. INDUCTION GENERATOR WEIGHT AND COST VARIATION WITH OUTPUT POWER

FIGURE 34. SYNCHRONOUS GENERATOR WEIGHT AND COST VARIATION WITH OUTPUT POWER

FIGURE 35. EFFECT OF DRAG MOMENT ON STEEL SHELL TOWER COST.

FIGURE 36. EFFECT OF ROTOR DRAG ON NACELLE ASSEMBLY COST

4.6 MODEL SW-1-10 COMPONENT WEIGHT & COST SUMMARY

The following summarizes component weight and cost for the baseline Model SW-1-10 wind turbine generator. The costs were derived as described in the preceding sections relating to corresponding subsystems.

	WEIGHT-LB	COST-\$	\$/LB
ROTOR SUBSYSTEM (1)	18,750	96,000	5.12
ALL SHAFTING, COUPLINGS, ETC.	5,730	19,500	3.40
TRANSMISSION	22,100	137,000	6.20
INDUCTION GENERATOR	8,750	21,500	2.68
ALL ELECT. EQUIPMENT & TRANSFORMER (2)	--	48,000	--
NACELLE ASSEMBLY (INCL. TURNABLE)	21,600	54,000	2.50
TOWER STRUCTURE	149,000	85,200	0.57
FOUNDATION	--	21,300	--
PORTABLE ELEVATOR (3)	--	8,000	--
NOTES: (1) INCLUDES PITCH ACTUATOR (2) INCLUDES CAPACITORS (3) USED FOR NUMBER OF W.T.G.'s			

TABLE XIII. MODEL SW-1-10 COMPONENT WEIGHT AND COST

4.7 PRODUCTION RATE EFFECTS ON COST

To estimate effects of various annual production rates on capital cost of individual wind turbine generators, the following learning process was assumed:

1. A 85% learning curve was used for rotor fabrication labor.
No improvement was considered for material cost.
2. A 90% learning curve was used for total cost of the following systems:
 - o Transmission and shafting
 - o Nacelle and yaw drive
 - o Tower
 - o Erection and assembly
3. No improvement was considered for:
 - o Generator and transformer
 - o Turntable bearing

Figure 37 shows the results of above analysis. It is indicated that unit capital cost for the base rate of 200 units per year could be noticeably reduced with an accelerated production. This figure also shows that production rates should be at least 200 units per year because any lower rate rapidly increases the unit cost.

FIGURE 37. EFFECT OF ANNUAL PRODUCTION RATE ON MODEL SW-1-10 WIND TURBINE COST

4.8 SAMPLE COST CALCULATION FOR MODEL SW-1-10

The following is a sample derivation of Model SW-1-10 capital cost. The procedure makes use of the cost trends developed in previous sections for the major subsystems and components.

1. ROTOR SUBSYSTEM

Rotor cost development is described in Section 4.1, page 83.

Rotor cost for a radius of 135.0 ft. from Figure 29, (page 88) = \$96,000. If a more detailed cost breakdown is desired, for instance to determine blade cost only, then use the following approximate per cent of total rotor cost.

Blade Cost	=	65
Counterweight & Arm	=	13
Hub and Related Parts	=	19
Pitch Controls	=	3

Numerical example:

Total from Cost from Figure 27	=	\$96,000
Blade Cost @ 65%	=	\$62,400
Counterweight & Arm @ 13%	=	\$12,400
Hub & Related Parts @ 19%	=	\$18,300
Pitch Controls @ 3%	=	<u>\$ 2,900</u>
Totals		\$96,000

2. TRANSMISSION GEARBOX

From Table II for Model SW-1-10 the gear ratio is 50.3. From Figure 31 for 1000 KW and one blade configuration, the cost is \$125,000 for a gear ratio of 42 (quoted in Table XII). For the actual gear ratio of 50.3, adjust this cost upward by determining the difference between these two ratios. This difference is about 1.2. From trend in Figure 32, read the cost factor = 1.095. Therefore the adjusted cost of the SW-1-10 gearbox is:

$$1.095 \times 125,000 = \$137,000.$$

3. SHAFTING & COUPLINGS

From Table II page 10, the rotor shaft torque is 316,800 ft. lb. Boeing studies have shown that for rotor shafts of the type shown for Model SW-1-10, the cost is approximately .03 dollars per ft. lb. of torque. Therefore the rotor shaft cost is $.03 \times 316,800 = \$9500$.

The cost of the shafts and couplings between the gear box were estimated to be \$10,000 for all models because all are rated at the same generator rpm and power output.

Thus, total shafting and coupling costs are $\$9500 + \$10,000 = \$19,500$.

4. ELECTRICAL POWER SYSTEM

From the General Electric data in Appendix E and other sources, the following applies to all models of SW-1 and SW-2 series wind turbine generators:

1000 KW Induction Generator	\$21,500
690 KVAR Capacitors	3,000
All Electrical Equipment (including Line Transformer)	<u>45,000</u>
Totals	\$69,500

5. NACELLE ASSEMBLY

From Table II, the rotor drag for Model SW-1-10 is 38,800 lb. Figure 36, page 97 shows that for this drag the nacelle cost, which includes the turntable and yaw control and drive system is \$54,000.

6. TOWER STRUCTURE AND FOUNDATION

As mentioned in Section 4.5, basic cost data were received from the manufacturer Bruce-Lake Company, Coatesville, Pa. In the course of this study a tower cost of \$90,000 was calculated for a base design having a root moment of about 5.3×10^6 ft.lbs. In the design criteria, allowance was made for diameter changes with constant shell thickness to keep the root stress at the same level for various tower heights or moments. Therefore, within the height variations of this study, cost should be essentially proportional to the square root of the bending moment resulting from rotor drag.

Further, it was assumed that about 10% of the cost would not vary (this includes the support system such as platform and elevator components). The resulting trend is shown in Figure 35, page 96.

Example:

For the 38,800 lb. rotor drag and the tower height of 197 ft. for Model SW-1-10, the tower root moment is 7,650,000 ft. lb. and from Figure 35, the tower cost is \$106,500.

It should be noted that bracing of the bottom third of tower would reduce the amount of shell material and therefore the cost as well. In this study it was assumed that additional cost of bracing will be offset by the reduced cost of the tower shell.

7. TOTAL MODEL SW-1-10 COST - \$

a. Rotor Subsystem (incl. Controls)	\$ 96,000
b. Transmission Gear Box	137,000
c. Shafting & Couplings	19,500
d. Electrical Power Subsystem and Controls	69,500
e. Nacelle Assembly	54,000
f. Tower, Yaw Controls & Foundation	<u>106,500</u>
Subtotal	\$482,500
g. Erection and Assembly 10%	<u>58,250</u>
Total	\$530,750

5.0 OPERATING COST ANALYSES

5.1 MAINTENANCE

GENERAL CONSIDERATIONS

The individual wind generator unit should be designed and built to a level of reliability which requires minimum scheduled and unscheduled maintenance. For achieving that goal the system must be rugged and fully automated, and equipped with diagnostics, feeding their information into a remote data collection center which will contain all required monitoring display and check-out panels or instruments. This will enable the required preventive measures well ahead of any major failures.

MAINTENANCE REQUIREMENTS

Requirements will vary for each subsystem, however, the basic philosophy should be not to let potential failures of one subsystem damage another. This must be ensured by the diagnostic and warning system, and an appropriate automatic separation and/or isolation of the respective components. The following is a breakdown of requirements for each of the major subsystems.

Rotor Assembly

- Blades are formed from glass reinforced thermoplastic material. Their structure is inherently redundant and failsafe. They will be designed for infinite life. The only anticipated maintenance may be required in the following areas:
 - a) Paint, which may erode toward the tips (Opaque paint is needed for protection against damaging effects of the ultraviolet rays.) Some retouching may be necessary on occasion.

- b) Deicing leading edge blanket (See Appendix C.)
should be visually checked for potential tears.
- c) Root end fitting and bolts should be visually
checked for condition.
- Hub from corrosion resistant steel casting should be
annually visually checked for condition of weld seams, pitch
bearings, seals, etc. Development of fatigue cracks is not
anticipated because the structure will be stressed well below
normal fatigue allowables. Maintenance should therefore relate
mainly to an annual purging of the pitch bearings.
- Pitch control actuator and drive system will be lubricated
and sealed for life. Diagnostics system will monitor any
incipient malfunction to prevent potential complete component
failures. Maintenance will be limited to periodical (remote)
checking of the electrical warning system circuitry.

Drive System

- The transmission will be equipped with electrical chip detec-
tors monitoring potential accumulation of debris to warn of
incipient internal failures. As a back-up measure, after
accumulation of a certain, predetermined amount of debris, an
electrical signal will cause the pitch control actuator to
feather the blades. Subsequently the brake will be actuated
to lock the rotor in a predetermined azimuth position. At
the same time the generator will be disconnected from the
utility grid.

All above preventive sequences will be automated and monitored via the remote control center. Therefore the only scheduled maintenance may consist of remote checking the diagnostic, warning and shut-down system. Same applies to monitoring of rotor shaft and high speed shaft bearings and rotor brake temperatures. An annual oil change and filter replacement will also be required.

Electrical Generator and Equipment

- Maintenance of the generator, switchgear, transformer, controls, etc. will be based on manufacturer's recommendations. All electrical subsystems and components must be tightly enclosed to prevent dirt, moisture and other foreign objects to impair operation or degrade performance.

With respect to diagnostics and warning devices, same philosophy will be applied as in the case of the drive system.

Nacelle with Turntable

- Nacelle structure should not require any maintenance, except for the external paint which may be retouched as required. The usual wear of the interior (passageways, steps, etc.) may require an occasional minor repair.
- The turntable bearing may require periodical purging and relubrication, however, not more than once a year.
- The yaw actuator and gear drive will also have diagnostics connected with the monitoring center. Only periodical warning system circuitry check out from the center is required.

Tower

- o Tower structure should not require any major maintenance, except for occasional paint repair. The usual wear of service platform and elevator rail may also require periodical, minor repairs.

- o The elevator car will serve several wind generator units depending on the number of units monitored by the remote collection center.

5.2 RELIABILITY CONSIDERATIONS

The highest achievable reliability of all major subsystems and components is desired. Such requirement implies a rugged and relatively simple unit design and avoidance of over-sophistication. Selection of materials, structural considerations and environmental protection approaches must be oriented to achieve this reliability. Besides, development tests should be structured to identify potential problems and allow corrective actions before the operational use.

By following the described development path the diagnostics or condition monitoring system may be limited to only such essential areas as:

In the Mechanical System

- o Rotor shaft RPM and torque indicator.
- o Rotor shaft bearings temperature and debris monitor.
- o Transmission main bearings, temperature indicators and housing vibration pick-ups and debris monitor.
- o Oil level, pressure and temperature indicators.
- o Generator main bearings temperature indicators.

In the Electrical System

- o Check out circuitry for:
 - Generator and its protective equipment.
 - Transformer, switches and relays.
 - Cabling and miscellaneous sensors, and controls.
 - Pitch and yaw actuators.
 - Emergency power system.
- o Complete display of the typical electrical power output system.

In the Airstream

- o Wind velocity indicator/sensor (real time)
- o Wind velocity - time history computer (desirable in certain typical sites)
- o Wind direction indicator/sensor and averaging circuit

OUTLINE OF RELIABILITY PARAMETERS DEFINITION

The above list may not be quite complete, however it contains the salient items relating to operation reliability. To obtain a better insight into the reliability requirements, an in-depth study would be required as outlined below:

1. Principal Considerations

- o System Safety.
- o Operational Reliability
- o Maintenance Malfunction Reliability

To optimize the above, the specific operator/customer system requirements must be determined. This involves especially the required system cost effectiveness.

2. System Requirements

Reliability analysis requires definition and understanding of the following:

- o System operational cycle/time frame.
- o Operational environment
 - Natural (Temperature, humidity, precipitation, pollution, etc.)
 - Induced (Vibration/gusts, service, radiation, FOD, etc.)
- o Cost Criteria

- o Failure Criteria
 - Safety requirements (Personnel and equipment)
 - Performance (output) requirements
 - Service Life
- o Maintenance Plan
 - Scheduled maintenance (inspection and repair frequency)
 - Unscheduled maintenance
 - Maintainability
 - Maintenance skills

The above requirements are necessary for understanding the design requirements and the definition of a carefully prepared "Development Test Plan".

The next section on "Maintenance & Overhaul Cost" follows in principle the preceding outline, whereby the limited scope of this program required certain broad assumptions.

5.3 ESTIMATION OF MAINTENANCE & OVERHAUL COST

As mentioned in the previous paragraph, reliability of systems and their major components directly affects operating cost, which in turn contain maintenance and overhaul expenditures. The final service requirements will be developed over a certain time period needed for familiarization with the equipment and correction of problems identified through the accumulation of operating experience. It may be reasonable to assume that this time period will not exceed one year. (This time will depend on the extent of the development program.)

The following is a breakdown of estimated operating cost, whereby in some areas certain assumptions had to be made because more accurate data were not available at the present time. It will be, for instance, assumed that the unscheduled maintenance refers only to replacement of major components cited under spares. A one to two day shutdown period and 32 to 64 manhours will be allotted for such repairs in five percent of the units.

W.T.G. MONITORING CENTER

As described in Section 5.1 several wind generator units will be connected individually to a remote data collection center or monitoring **station**. Costs of such monitoring station and the required equipment is difficult to assess accurately without a

separate in-depth study. It will be therefore, arbitrarily assumed that the cost will amount to \$80,000 (\$30,000 for the building, \$50,000 for equipment), and amortized over the entire unit life span of 30 years. 50% of that amount will be added for spares over the same time span. Maintenance cost includes the operator's salary.

A 24 hours supervision of the station by three operators will be conservatively assumed. The possibility of reducing the manpower by a suitable connection of all sites to a major hub station may be examined in the future for exploring possible favorable cost trade-offs.

ROTOR SYSTEM

Blades - The scheduled maintenance should not exceed 2 man-days per year. It is further assumed that additional 5% of blades will be replaced with spares during the unit's life of 30 years. (This will obviously favor the single bladed design.)

Hub and Pitch Shaft are considered to last for the full life span of 30 years without replacement.

Pitch Controls - Maintenance is included in the blade time. 5% of spares for the entire subsystem will be stocked.

DRIVE SYSTEM

The Transmission should require no more than one man-day of maintenance per year after the first year, in which four man-days are assumed.⁽¹⁾ From past experience with commercial transmissions it can be also assumed that only 5% of transmissions will be replaced in 30 years.

Of those that fail only 50% of the components need replacing. Thus, based on higher costs of spare parts, a failed transmission will cost 75% of the original cost when overhauled.

ELECTRICAL SYSTEM

Generator, Transformer, Switchgear and corresponding electrical equipment traditionally requires little maintenance and only minor stock of spares. It may therefore be assumed that the same maintenance time and spares stock will be required as for the transmission.

SUPPORT STRUCTURE

Nacelle with Turntable and the interior structure will be inspected only during the mechanical and electrical subsystems maintenance period, when the turntable bearing will also be purged.

⁽¹⁾ This minor manhour increase was neglected in the annual operating costs.

(no more than annually). At the same time it is assumed that 5% of spare yaw actuators will be stocked.

Tower will be visually inspected during regular maintenance periods of other subsystems. No spares are required.

Service elevator will be replaced every ten years, i.e. amortized over that time period (present price for the item is about \$8000).

OPERATIONAL COST SUMMARY

Based on the preceding considerations the annual operating costs per unit for Model SW-1-10 and SW-2-10 were compared for a typical small generating system (15 units) and a large generating system (90 units), and summarized in Table XIV. The effect of the number of units, connected to a joint monitoring station on operating cost per unit and on energy cost (¢/KW HR/Unit/YR) is shown in Figure 38.

The slightly lower operating costs for the single bladed Model SW-1-10 W.T.G. are offset by a somewhat higher annual output of the two bladed Model SW-2-10 configuration. Thus the operating cost per annual energy output is about the same for both designs.

Subsystem	Monitoring Station		Rotor & Controls		Drive System		Electrical System	Nacelle & Turntable	Tower Elevator (4)	
	15 Units	90 Units	Single Blade	Two Blades	Single Blade	Two Blades			15 Units	90 Units
Required Skill	Techn.	Techn.	Mech	Mech	Mech.	Mech.	Techn/Mech	Mechanic	Serviceman	
Sched. Maint.-M/H	(3)	(3)	16	16	8	8	8	4	4	4
(1) Sched. Maint.-\$	4000 ⁽³⁾	670 ⁽³⁾	400	400	200	200	200	100	100	100
Unsched. Maint.-\$	(3)	(3)	40	40	80	80	80	-	-	-
(2) Spares - \$	89	15	165	220	190	226	125	35	-	-
Amortization - \$	178	30							53	9
Subtotal	4,267	715	605	660	470	506	405	135	153	109

SUMMARY OF TOTAL OPERATING COST

No. of UNITS	15		90	
No. of blades	1	2	1	2
Subtotal \$	6,035	6,126	2,439	2,530
Tools (5)	67	67	11	11
Annual DOC - \$	6,102	6,193	2,450	2,541

NOTES:

- (1) Assumed 20 \$/hr + 25% for travel
- (2) 5% of major subsystems replaced in 30 years (75% of unit cost affected)
- (3) Three operators 20,000 \$/year each, also performing maintenance tasks
- (4) Service elevator costing 8000\$ replaced every 10 years and amortized over the respective number of towers.
- (5) Assumed 5000\$ and replaced every 5 years for respective number of units.

TABLE XIV. MODEL SW-1-10 & SW-2-10 OPERATING COST SUMMARY

FIGURE 38. EFFECT OF NUMBER OF INTEGRATED WIND GENERATOR UNITS ON OPERATING COST

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6.0 DEVELOPMENT EFFORT REQUIRED FOR FURTHER ECONOMICAL IMPROVEMENTS

During the design studies, many areas where Capital Costs could be reduced were noted but limitations of budget did not permit further study to quantify the savings. These major areas for further study and development are presented in Table XV. It should be noted that with a total R&D expenditure in the order of \$5,000,000 potential reduction in Capital Costs could be near \$100/KW. If this value is applied to the 1000 KW Model SW-1-10, the Capital Cost would be reduced from \$530,750 to \$430,000 - a 20% Capital Cost reduction. The Energy Cost* would be reduced from 2.05 to 1.66 ¢/KW HR. or lower as the maintenance and reliability studies could give payoffs even greater than shown.

It is highly recommended that such studies be given high priority in the ERDA Wind Energy Program.

*Based on 20% annual carrying charges for total operations cost.

SYSTEM OR COMPONENT	RESEARCH REQUIRED	ESTIMATED DE- VELOPMENT COST	PROBABLE \$/KW SAVED
1. ROTOR BLADE FROM REINFORCED THERMO- PLASTIC MATERIALS	<ul style="list-style-type: none"> DEVELOP INEXPENSIVE MANUFACTURING METHODS FOR CURED SEMI-PRODUCTS DEVELOP ECONOMICAL POST-FORMING METHODS OF SAID SEMI-PRODUCTS DETERMINE STRUCTURAL AND FABRICATION CONSTRAINTS OF BLADES DEVELOP MOST ECONOMICAL BLADE DESIGN 	\$800,000	15
2. DRIVE SYSTEM	<ul style="list-style-type: none"> DETERMINE RELIABILITY & MAINTAINABILITY REQUIREMENTS INVESTIGATE OPTIMUM TRADE-OFFS IN TRANSMISSION CONCEPTS DEVELOP SIMPLIFIED, INEXPENSIVE AND LIGHT WEIGHT TRANSMISSION DETERMINE STRUCTURAL AND DESIGN CRITERIA FOR MAXIMUM SERVICE LIFE AT LOWEST COST 	\$1,500,000	20
3. INDUCTION GENERATOR INSTEAD OF SYNCHRONOUS GENERATOR	<ul style="list-style-type: none"> DETERMINE ANALYTICALLY COMPATIBILITY WITH UTILITY REQUIREMENTS CONDUCT EXPERIMENTS TO PROVE COMPATIBILITY OF INDUCTION GENERATORS WITH USER'S REQUIREMENTS 	\$500,000	20
4. OPTIMIZED DRIVE & GENERATOR SYSTEM	<ul style="list-style-type: none"> ANALYZE AND RECOMMEND THE MOST EFFICIENT SHAFT DESIGN FOR MAXIMUM TORQUE OSCILLATION ALLEVIATION CONDUCT TRADE-OFF STUDIES TO OPTIMIZE SYSTEM'S ECONOMICS (STEP-UP RATIO VS. GENERATOR RPM, ETC.) 	\$200,000	20
5. SINGLE BLADED BOEING ROTOR WITH EXTERNAL TEETER PIVOT	<ul style="list-style-type: none"> DEVELOP AND BUILD BOEING MODEL SW-1 TYPE ROTOR TEST ABOVE ROTOR ON THE MOD O NASA W.T.G. 	\$1,500,000	10

TABLE XV. SUMMARY OF DEVELOPMENT EFFORT REQUIRED
FOR FUTURE IMPROVEMENTS IN WIND GENERATOR
ECONOMICS

SYSTEM OR COMPONENT	RESEARCH REQUIRED	ESTIMATED DE- VELOPMENT COST	PROBABLE \$/KW SAVED
6. TOWER OPTIMIZATION	<ul style="list-style-type: none"> ○ STUDY ALTERNATE APPROACHES TO MINIMIZE COST WITH HEIGHT INCREASE ○ DETERMINE ENERGY GAINS AND COST REDUCTION, AND OPTIMIZE FOR MINIMUM ENERGY COST 	\$200,000	10
7. OPERATING COST	<ul style="list-style-type: none"> ○ ESTABLISH RELIABILITY CRITERIA BASED ON OPERATING CONDITIONS ○ STUDY FAILURE WARNING AND DETECTION SYSTEMS AND OPTIMIZE FOR MINIMUM COST ○ ESTABLISH OPTIMUM "FARM" SIZE FOR VARIOUS OPERATING CONDITIONS 	\$200,000	5
8. COMPONENT TRANSPORTABILITY & ASSEMBLY	<ul style="list-style-type: none"> ○ ESTABLISH ACCURATE TRANSPORTATION CRITERIA FOR ALL SITES IN QUESTION ○ STUDY TRADE-OFFS BETWEEN FABRICATION AND ASSEMBLY COST FOR VARIOUS W.T.G. SIZES 	\$100,000	10
TOTAL :		\$5,000,000	110

TABLE XV. (continued)

7.0 COMPARISON OF BOEING, GENERAL ELECTRIC AND KAMAN STUDY RESULTS

References 3 and 4 were reviewed. This section summarizes that review and compares some of the results of those studies with data and characteristics developed by Boeing Vertol.

Design Comparison

The KAMAN wind turbine is a hingeless two bladed rotor 180 ft. in diameter.

The General Electric wind turbine also features a hingeless two-bladed rotor 190 ft. in diameter.

Both units are designed for a rated generator power of 1500 KW.

The principal design difference between the above wind turbines and the Boeing turbine is that both KAMAN and G.E. selected a rigid two-bladed rotor as compared with the teetering single bladed Boeing rotor configuration.

Both KAMAN and G.E. designs feature parallel shaft gear boxes as compared with a planetary transmission in the Boeing wind turbine.

A further difference is the use of concrete shell towers by both above companies, as compared with the steel shell design selected by Boeing.

All salient design features are summarized with comments in the following Table XVI.

DESIGN COMPARISON

ITEM	KAMAN (Ref.4)	G.E. (Ref.3)	BOEING MODEL SW-1-10	COMMENT
ROTOR	2-blades, rigid; high flapping stresses; exposed in hur- ricane winds; high cost; heavy and complex hub	2-blades, rigid; high flapping stresses; exposed in hur- ricane winds; high cost; heavy and complex hub	Single blade, teetering: low flapping stresses; protected in hur- ricane winds; low cost; simple and light hub	Flapping freedom of a teetering rotor with δ_3 hinge greatly alleviates gust loads; & lower shadow & wind gradient effects
XMSN BOX	Parallel shaft: very heavy and large	Parallel shaft: very heavy and large	Planetary: light and compact; high efficiency	Advanced planet- ary can be sub- stantially lighter at equal or lower cost
SHAFTING (from rotor to xmsn)	Steel tube: very rigid; potential augmentation of torque harmonics	Steel tube: very rigid; potential augmentation of torque harmonics	Filament wound composite tube: flexible; alle- viates most of the torque har- monics	Torsionally "soft" shaft de- couples dynamic- ally the rotor from transmission and generator
TOWER	Post-tensioned concrete (1): very heavy; many elements requir- ing long erection time	Reinforced concrete: very heavy; many elements requir- ing long erection time	Steel shell in 3 sections; comparatively light; easy & fast assembly	Steel shell tower will have bending and torsional fre- quencies well be- low 10 to dyna- mically decouple the rotor

Cost Comparison

Cost comparison is presented in Table XVII. Since the Boeing Model SW-2-13 is quite similar in size, the same was used in this study to compare capital system cost of all three designs.

The G.E. capital cost appears to follow closely the trend developed by Boeing for two-bladed rotors, whereas Kaman capital costs are somewhat higher

Performance Method Comparison

In order to compare the Boeing performance method results with the results reported in Ref. 3, the energy output of the 1500 KW 190 ft. diameter General Electric wind turbine was computed by the methods used in this report using the spectra for a mean wind of 24 mph as presented on page 2-4 of Ref. 3. The comparative results are as follows:

<u>METHOD</u>	<u>ENERGY OUTPUT (KW Hr/Yr)</u>
G.E. Analysis, Ref. 3, page 5-3	6,620,000
Boeing Analyses	6,000,000

A similar analyses comparing the Kaman data yielded the following

<u>METHOD</u>	<u>ENERGY OUTPUT (KW Hr/Yr)</u>
Kaman Analyses	5,700,000
Boeing Analyses	5,670,000

These values are in good agreement and verify that all three methods give similar results.

TABLE XVII. CAPITAL COST BREAKDOWN COMPARISON WITH
KAMAN AND G.E. WIND TURBINE GENERATORS

ITEM	GENERAL ELEC.		KAMAN		BOEING
	G.E.ANA. Ref.3(b)	BOEING ANA. (c)	KAMAN ANAL. Ref. 4 (a)	BOEING ANA. (c)	SW-2-13
MGT., DESIGN & INTEGR. AMORT. (c)	6,000	-	25,000	-	-
ROTOR SUBSYSTEM	185,000	143,000	194,000	146,000	106,500
DRIVE SUBSYSTEM	162,000	211,400	181,000	219,900	142,500
ELECTRICAL SUBSYSTEM	60,700	} 82,050 (d)	64,800	} 82,050 (d)	} 69,500 (d)
CONTROL SUBSYSTEM	13,600		31,400		
TOWER & FOUNDATION	55,900	86,000	134,600	77,000	77,000
NACELLE ASSEMBLY	36,400	41,000		39,000	39,000
SUBTOTAL	513,600	563,450	631,800	563,950	434,500
OTHER CAPITAL COST OR OPERATING MARGIN	83,955	-	89,000	-	-
ERECTION & ASSEMBLY - 10%	35,100	56,345	-	56,395	43,450
TOTAL	632,655 (d)	619,795	720,800	620,345	477,950
SYSTEM RATING - KW	1500	1500	1500	1500	1000
SYSTEM COST - \$/KW	422	412	480	413	478

NOTES:

- (a) Data taken from page 3-119 of Kaman Design Study dated Feb.1976 (Ref.4).
- (b) Data taken from page 5-13 of G.E. Design Study dated Feb.1976 (Ref.3).
- (c) Cost based on Boeing Cost Methods but using the parameters of the respective G.E. and Kaman machines.
- (d) Cost of land and control building omitted.

Comparison of Performance in Texas Wind Spectra

Wind turbines of the same size and rating as the General Electric and Kaman machine of Ref. 3 and 4 were analyzed using the 45 meter, Amarillo Wind Spectra (Figure 1) and compared to the performance of equivalent Model SW-2-13 as follows (all winds are ref. to hub height):

ITEM	MACHINE		
	GEN.ELEC.	KAMAN	SW-2-13
Mean Wind, mph	18.9	18.9	18.9
Rated Power, KW	1500	1500	1000
Rated Wind, mph (Fig. 39)	32.5	34.2	29.1
Rotor Dia., ft.	190	180	182
Specific Power, w/sq.ft.	53	59	38.5
Specific Energy, KW Hr/Yr/Sq.Ft. (Fig. 39)	139	142	127.5
Energy Output, KW Hr/Yr.	3,940,650	3,613,900	3,311,800
Capital Cost, \$ (Table XVII)	619,795	620,345	477,950
Unit Cost, \$/KW	412	413	478
Energy Cost ¢/KW Hr. *	3.14	3.43	2.88

The conclusions from the results of the above comparison are:

- (a) In the Texas 45 meter wind spectra the General Electric and Kaman machines would generate about 60% of the yearly energy as they do in the wind spectra which was used in their respective studies.
- (b) A rating of 1000 KW for the sizes of machines compared above seems to be slightly better than the 1500 KW rating on the basis of cost of electricity.

* Based on 20% Annual Carrying Charge.

WIND SPECTRA - 45 METER, AMARILLO, TEXAS

FIGURE 39 SPECIFIC PERFORMANCE OF GENERAL ELECTRIC AND KAMAN WIND TURBINES
(BOEING ANALYSES METHOD)

8.0 REFERENCES

1. Peter G. Sulzer, A Direct Method for Selecting Wind-Turbine Generator Parameters for Maximum Energy Output; Wind Energy Society of America Newsletter #9.
2. Helicopter Technology Aids Wind Effort, Aviation Week and Space Technology, Oct. 13, 1975.
3. NASA CR 134935, Design Study of Wind Turbines - 50 KW to 3000 KW for Electrical Utility Applications, Analyses and Design, General Electric Company, Feb. 1976
4. NASA CR 134937, Design Study of Wind Turbines - 50 KW to 3000 KW - For Electric Utility Applications, Kaman Aerospace Corp., Feb. 1976

APPENDIX A

RAW MATERIAL COST DATA

TABLE A - RAW MATERIAL COST DATA

MATERIAL	SOURCE OF INFORMATION	LB/IN ³	\$/LB	NOTES
<u>GLASS & PLASTICS</u>				
E-Glass - raw	Owens-Corning		0.42 - 1.00	
- tape	Fiberglass Corp.		2.80	(Uncured)
	J. Schurb - 3M	.069		
E-Glass - Crossply			3.15	(Uncured)
Epoxy			.80 - .90	
Phenoxy	J. Hoggatt, Boeing		.59	
E-glass Woven Roving	Owens-Corning Fiberglass		.60	
E-glass Phenoxy Uni-sheet	J. Schurb - 3M		3.10	Consolidated, including 0.30 \$/# for Facility
E-glass Phenoxy Crossply	J. Schurb - 3M		3.45	Consolidated, including 0.30 \$/# for Facility
<u>HONEYCOMB</u>				
Paper WR-2 Hexcel	BV-- R. Spitko	.00214	2.67	Fatigue not clear yet
Commercial Alum	"	.00300	4.26	Potential Lightning Problem
Commercial Alum	"	.00300	11.00	Potential Lightning Problem
5056 Aluminum	"	.00300		
Nomex	"	.00173	27 - 28.0	
<u>FOAM</u>				
Poly-urethane, Rigid	Hydramatic Co.	.00104	1.65	
	Ed Kenna	.00121	1.55	
	"	.00173	2.08	
	"	.00230	2.25	
	H. Gullberg, Inc.	.00290	3.0 - 3.60	

TABLE A (Cont'd)

RAW MATERIAL COST DATA

MATERIAL	SOURCE OF INFORMATION	LB/IN ³	\$/LB	NOTES
<u>STEEL</u>				
4340 Plate	BV - Design to Cost (F.Sauter)	0.283	.75	
15-5 Vac		0.277	1.00	
Forged Billet				
• 4340			1.50	
• 15-5 Vac			2.00	
Closed Die Forging				
• 4340			5.0 - 8.0	
• 15-5 Vac			6.0 - 9.0	
Casting				
• 4340			2.00	
• 15-5 Vac	Ditto		2.50	
<u>ALUMINUM</u>				
2024 Plate		0.101	1.00	
Forged Billet			1.75	
Closed Die Forging			7.0 - 10.0	
Casting	Ditto		2.50	

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APPENDIX B

MODEL BV-1 BLADE FABRICATION METHOD

W.T.G. BLADE FABRICATION

With the mounting experience in composite blade manufacture and inherent fail/safety combined with superior mechanical properties and corrosion resistance of such structures, it was decided to eliminate metal structures and to concentrate on the advanced, cost effective composite blade configurations.

Besides, the advent of advanced, thermoplastics, reinforced with glass filaments, offered new avenues of approach for cost reduction.

Previous work conducted by the Boeing Company on reinforced thermoplastic materials was reviewed to establish whether such materials may lend themselves to application in W.T.G. blade structures and whether they offer any significant cost savings. According to the Boeing study, which also included extensive testing of materials and finished structural components, it was concluded that glass reinforced thermoplastic materials may be the natural choice for this specific application. (See Appendix D "Summary on Reinforced Thermoplastics").

To obtain an objective comparison of the aforementioned materials and to substantiate the advantages of reinforced thermoplastics against the existing glass-epoxy structures, the initial design studies were based on the existing helicopter blade fabrication experience in which the glass filaments, tapes or rovings were combined with epoxy resin. An automated fabrication method

by means of filament winding or tape laying techniques was examined. A typical blade construction made by the filament winding technique is shown in Figure B-1.

Based on these studies, it was concluded that the glass reinforced thermoplastic structure lends itself to a substantially faster, simpler and more cost effective fabrication process. Besides, no significant cost or structural drawbacks were identified. The proposed fabrication sequence is shown in Figures B-2 & B-3 and it proceeds along these general lines:

- Forming of the spar is done by means of a mandrel moving upwardly between a split table plate covered by the consolidated spar sheets. As the mandrel moves up, the two table plates separate, allowing the mandrel to gradually raise and form the sheets.
- To achieve the required forming temperature of 450°F, the mandrel is covered by carbon heating elements which heat the sheets from inside.
- Since at the root end the spar material may be about 1.0 inch thick, another layer of carbon heating elements is laid over the uppermost spar sheet to minimize the required heat penetration.

- Since the spar sheets were already consolidated, only a moderate pressure against the sheets and mandrel is required for forming. This can be accomplished by the conventional vacuum bag method. (A sealing plate seals off the gap between table plate halves to allow for air evacuation).
- The mandrel carries a preformed channel web at its bottom flat surface, which is automatically inserted between the spar sheets in the final forming stage.

Temporary slot strips are attached to the side of spar sheets in order to secure the required slot for inserting the trailing edge box plates (See details A of Fig. 1). The mandrel can now be removed.

Inside the channel web flanges, additional carbon heating element strips are installed. These are used, in conjunction with the outer aft portion of the spar heating system (preferably configured as a separate spanwise strip), for fusing the trailing edge plates to the spar after their insertion into the aforementioned slots (See Fig.12 , Detail A).

Such assembly of spar and boxes may be accomplished by a simple tool as shown in Fig.33 whereby simultaneously the trailing edges of the plates may be fused together by a similar method.

FIGURE B-1

W.T.G. BLADE DESIGN

(GLASS-EPOXY STRUCTURE- FILAMENT WOUND SPAR)

FIG. B2 BLADE SPAR FABRICATION
FROM REINFORCED THERMOPLASTICS

FIG. B3. W.T.G. BLADE ASSEMBLY
FROM PREFORMED THERMOPLASTIC
COMPONENTS

APPENDIX C

DE-ICING PROVISION

APPENDIX C
DE-ICING PROVISION

electronics

PENNSYLVANIA
Tech Mart-2730

De-icing system for fiberglass radomes prevents shutdown of radio navigation equipment from ice formation on the enclosure. The system originally was developed to prevent ice buildup on the leading edges of aircraft wings. It consists of a thin close-fitting polyurethane sleeve that slips over the fiberglass dome as illustrated. Between sleeve and dome is a special low-temperature silicone lubricant. Mobility of sleeve plus lubricant prevents ice from accumulating. In addition, the sleeve protects the dome from sand and weather erosion. Typical installation uses J. P. Stevens' 0.010-0.30 in. polyurethane. About 10,000 such de-icing systems for aircraft have operated without failure since 1967. A test installation on a TACAN radome has operated successfully for 4½ years in Utah. License is open in some areas.

Patent rights are owned by H;SON GULLBERG, Inc. in Media, Pa.

APPENDIX D

SUMMARY ON REINFORCED THERMOPLASTIC MATERIALS

SUMMARY ON REINFORCED THERMOPLASTICS

Thermoplastic resins have been used extensively in industry, primarily in unreinforced molded assemblies or reinforced with chopped glass fibers or mat; both are considered essentially non-structural or secondary structural applications. The thermoplastics are selected for these applications for their low cost, ease of formability and processability and good environmental resistance. Their entrance into the structural composite field had been hampered by their low heat distortion temperature, low mechanical properties and poor creep characteristics. In recent years, however, the development of several new thermoplastic resins has minimized these disadvantages, while retaining the processability and other favorable attributes.

Preliminary work by Boeing indicates that structural glass fabric laminates could be fabricated with thermoplastic resins which were competitive in mechanical properties with thermosetting resin laminates.

Basic savings with the reinforced thermoplastic materials result from post-forming capability, fewer production operations, ease of damage repair, ease of bonding, amenability to lower cost and more reliable quality assurance procedures, and reprocessing capability, thereby reducing scrappage.

However, in order to establish cost effective fabrication methods of W.T.G. blades, the following additional developmental steps are envisioned:

(Continued)

1. Develop inexpensive manufacturing methods for semi-products such as:
 - Consolidated unifiber or crossply sheets.
 - Consolidated flat or curved sandwich panels from paper honeycomb and crossply.
 - Various beams or stringers (angles, channels, etc.).
2. Develop economical post-forming methods of above semi-products and especially determine acceptable minimum temperatures and pressures.
3. Determine by testing effects of various combination of temperature and pressure on structural properties of post-formed parts.
4. Investigate environmental effects on various thermoplastic materials.

The following Figures D1 and D2 show alternate approaches to the fabrication of structures from glass reinforced thermoplastic materials and the good fatigue properties of such structures respectively.

FIGURE D1 : FABRICATION CONCEPTS FOR REINFORCED THERMOPLASTIC COMPOSITES

FIGURE D2 FATIGUE LIFE OF 181 GLASS FABRIC LAMINATES (+70°F)

APPENDIX E

GENERAL ELECTRIC GENERATOR DATA

APPENDIX E

GENERAL ELECTRIC GENERATORS WEIGHT AND COST DATA

RATED KW	RPM	SYNCHRONOUS (CUSTOM 8000)			INDUCTION (SQUIRREL CAGE)		
		WEIGHT-LB	COST-\$	FRAME	WEIGHT-LB	COST-\$	FRAME
500	600	8,000	47,000	8407	4,600	11,500	8210
	1,200	6,000	35,000	8309			
	1,800	4,700	26,000	8210			
1,000	1,200	11,500	55,000	8411	8,100	21,500	8311
	600	20,000	85,000	8608			
1,500	1,200	15,300	65,000	8509	10,100	25,500	8409
	1,800	11,300	55,000	8411			

FOR ESTIMATING ONLY

Fig. 1. Frames 8100-8200, dripproof.

Fig. 2. Frames 8100-8200 TEFC (Double Shell)

FRAME	FIG.	A	B		C		D	E	F	H	M	Q		P		EG		EA	
		Fig. 2	Fig. 1	Fig. 2	Fig. 1	Fig. 2						Fig. 1	Fig. 2	Fig. 1	Fig. 2				
8143S	1		22.0		36.95		12.5	10.0	8.0	.937	15.2	25.0		26.8		23.0	25.0	29.0	5.5
8144S	2	25.0		21.0		44.75	12.5	10.0	8.0	.937	16.2		27.20		23.0		29.0		5.5
8155S	1, 2	25.0	23.0	23.0	40.45	47.25	12.5	10.0	9.0	.937	17.2	25.0	27.20	26.8	23.0	25.0	29.0		5.5
8188S	1, 2	25.0	30.0	30.0	47.45	54.25	12.5	10.0	12.5	.937	20.7	25.0	27.20	26.8	23.0	25.0	29.0		5.5
8110S	1, 2	25.0	37.0	37.0	54.45	61.25	12.5	10.0	15.5	.937	24.2	25.0	27.20	26.8	23.0	25.0	27.0		5.5
8266S	1		32.1		48.40		14.5	11.5	11.0	.937	20.6	29.0		32.1		27.0		10.0	
8283S	1, 2	36.5	38.1	32.0	55.40	66.25	14.5	11.5	14.0	.937	23.6	27.0	32.80		27.2	36.0	36.5		10.0
8210S	1		46.1		63.40		14.5	11.5	15.0	.937	27.6	29.0		32.1		29.0		10.0	
8211S	1, 2	36.5	50.1	44.0	67.40	75.25	14.5	11.5	23.5	.937	29.6	29.0	32.80	32.1	27.2	27.0	36.5		10.0

FRAME	FIG.	KEY LENGTH	KEYWAY		SHAFT				AB		AC		AD		AE		WEIGHT	
					N	N-W	U	V.										
			Wide	Deep					Fig. 1	Fig. 2	Fig. 1	Fig. 2	Fig. 1	Fig. 2	Fig. 1	Fig. 2	Fig. 1	Fig. 2
8143S	1	3.5	.625	.312	6.55	5.25	2.625	5.00	21.0	...	17.0	...	...	...	11.5	...	17.0	...
8144S	2	3.5	.625	.312	5.55	5.25	2.525	5.00	...	26.3	...	21.3	...	...	...	...	...	2570
8155S	1, 2	4.0	.750	.375	6.55	5.75	2.875	5.50	21.0	26.3	17.0	21.3	...	6.56	11.5	14.5	2450	3120
8168S	1, 2	4.0	.750	.375	6.05	5.75	2.875	5.50	21.0	26.3	17.0	21.3	...	7.56	11.5	14.5	2650	3240
8110S	1, 2	4.0	.750	.375	6.05	5.75	2.875	5.50	21.0	26.3	17.0	21.3	...	11.06	11.5	14.5	2650	3240
														14.56	11.5	14.5	3250	4520
8266S	1	4.5	.875	.438	7.15	6.75	3.375	6.50	23.6	...	19.5	...	...	...	13.5	...	3190	...
8288S	1, 2	5.5	1.000	.500	8.15	7.75	3.675	7.50	23.6	29.9	19.5	24.9	...	12.50	13.5	17.0	3670	6500
8219S	1	5.5	1.000	.500	8.15	7.75	3.675	7.50	23.6	...	19.5	...	...	...	13.5	...	4580	...
8271S	1, 2	5.5	1.000	.500	8.15	7.75	3.675	7.50	23.6	29.9	19.5	24.9	...	18.50	13.5	17.0	4960	7600

Weights and Dimensions For Horizontal Motors

FOR ESTIMATING ONLY

Fig. 5. Frames 83-8600, Dripproof.

Fig. 6. Frames 83-8600, Dripproof with Top Hat.

FRAME	FIG.	A	B	C	D	E	F	H	M	V O		P		EG		SA
		Fig. 5	Figs. 5 & 6	Figs. 5 & 6						Fig. 5	Fig. 6	Fig. 5	Fig. 6	Fig. 5	Fig. 6	
8307S	5	...	33.6	63.6	17.0	13.5	16.0	1.06	27.1	33.9	...	36.8	...	34.0	...	11.5
8309S	5, 6	34.0	46.6	71.6	17.0	13.5	20.0	1.06	31.1	33.9	53.00	36.8	46.0	34.0	42.0	11.5
8311S	5, 6	34.0	56.6	81.6	17.0	13.5	25.0	1.06	36.1	33.9	53.00	35.8	46.0	34.0	42.0	11.5
8407S	5	...	46.6	74.6	20.0	17.0	18.0	1.31	31.6	39.7	...	43.3	...	40.0	...	12.0
8409S	5, 6	40.0	55.6	83.6	20.0	17.0	22.5	1.31	36.1	39.7	65.00	43.3	54.5	40.0	50.0	12.0
8411S	5, 6	40.0	66.6	94.6	20.0	17.0	28.0	1.31	41.6	39.7	65.00	43.3	54.5	40.0	50.0	12.0
8507S	5	...	52.1	83.2	24.0	21.5	20.0	1.56	35.2	47.6	...	51.7	...	48.0	...	16.0
8509S	5, 6	48.0	62.1	93.2	24.0	21.5	25.0	1.56	40.2	47.6	66.70	51.7	64.5	48.0	60.0	16.0
8510S	5	...	68.1	99.2	24.0	21.5	26.0	1.56	34.2	47.6	...	51.7	...	48.0	...	16.0
8511S	5, 6	48.0	75.1	106.2	24.0	21.5	31.5	1.56	46.7	47.6	66.70	51.7	64.5	48.0	60.0	16.0
8512S	6	48.0	83.1	114.2	24.0	21.5	35.5	1.56	50.7	...	66.70	...	64.5	...	60.0	16.0
8606S	5	...	52.1	86.2	30.0	27.0	20.0	1.56	35.2	59.6	...	64.0	...	60.0	...	16.0
8607S	5	...	57.1	91.2	30.0	27.0	22.5	1.56	37.2	59.6	82.50	64.0	...	60.0	...	16.0
8608S	5, 6	50.0	62.1	96.2	30.0	27.0	25.0	1.56	40.2	59.6	82.50	64.0	76.8	60.0	72.0	16.0
8609S	5, 6	60.0	68.1	102.2	30.0	27.0	28.0	1.56	43.2	59.6	82.50	64.0	76.8	60.0	72.0	16.0
8610S	5, 6	60.0	75.1	109.2	30.0	27.0	31.5	1.56	46.7	59.6	82.50	64.0	76.8	60.0	72.0	16.0
8611S	5, 6	50.0	83.1	117.2	30.0	27.0	35.5	1.56	50.7	59.6	82.50	64.0	76.8	60.0	72.0	16.0
8612S	6	60.0	92.1	126.2	30.0	27.0	40.0	1.56	55.2	...	82.50	...	76.8	...	72.0	16.0
8613S	6	60.0	102.1	136.2	30.0	27.0	45.0	1.56	60.2	...	82.50	...	76.8	...	72.0	16.0

FRAME	FIG.	KEY LENGTH	KEYWAY	SHAFT				AB	AC	AD	AE	WEIGHT	
			Wide Deep	N	N-W	U	V	Fig. 5	Fig. 6	Fig. 5	Fig. 6	Fig. 5	Fig. 6
8307S	5	6.5	1.0 .500	9.15	8.75	4.375	6.50	25.3	21.1	6.62	15.5	59.50	...
8309S	5, 6	6.5	1.0 .500	9.15	8.75	4.375	6.50	25.3	21.1	10.62	15.5	63.00	...
8311S	5, 6	6.5	1.0 .500	9.15	8.75	4.375	8.50	25.3	21.1	15.62	15.5	81.00	...
8407S	5	8.5	1.25 .625	11.15	10.75	5.375	10.50	28.3	24.1	10.62	18.5	75.00	...
8409S	5, 6	8.5	1.25 .625	11.15	10.75	5.375	10.50	28.3	24.1	15.12	18.5	10.500	11.000
8411S	5, 6	8.5	1.25 .625	11.15	10.75	5.375	10.50	28.3	24.1	19.12	18.5	13.250	14.000
8507S	5	9.0	1.5 .750	12.55	11.75	5.875	11.50	32.3	28.1	12.62	22.5	14.500	...
8509S	5, 6	9.0	1.5 .750	12.55	11.75	5.875	11.50	32.3	28.1	17.62	22.5	16.000	17.000
8510S	5	9.0	1.5 .750	12.55	11.75	5.875	11.50	32.3	28.1	20.62	22.5	18.500	...
8511S	5, 6	9.0	1.5 .750	12.55	11.75	5.875	11.50	32.3	28.1	24.12	22.5	19.500	20.500
8512S	6	9.0	1.5 .750	12.55	11.75	5.875	11.50	32.3	28.1	22.62	22.5	20.500	22.000
8606S	5	12.0	1.5 .750	15.55	14.75	7.375	14.50	38.3	34.1	11.00	28.5	22.000	...
8607S	5	12.0	1.5 .750	15.55	14.75	7.375	14.50	38.3	34.1	13.50	28.5	23.000	...
8608S	5, 6	12.0	1.5 .750	15.55	14.75	7.375	14.50	38.3	34.1	16.00	28.5	24.000	25.000
8609S	5, 6	12.0	1.5 .750	15.55	14.75	7.375	14.50	38.3	34.1	19.00	31.5	25.000	26.000
8610S	5, 6	12.0	1.5 .750	15.55	14.75	7.375	14.50	38.3	34.1	22.50	31.5	26.000	27.000
8611S	5, 6	12.0	1.5 .750	15.55	14.75	7.375	14.50	38.3	34.1	26.50	31.5	28.000	30.000
8612S	6	12.0	1.5 .750	15.55	14.75	7.375	14.50	44.3	40.1	25.12	31.5	30.000	31.000
8613S	6	12.0	1.5 .750	15.55	14.75	7.375	14.50	44.3	40.1	30.12	31.5	34.000	35.000

SYNCHRONOUS GENERATORS HORIZONTAL

Dripproof • CUSTOM 8000⁽¹⁾

With Brushless Exciters

DS-2

GEM-2382

Type AT1
Frames 8407 to 8411

Ring-lubricated Sleeve, or
Antifriction Bearings

Oct. 9, 1967

DIMENSIONS

Port No. Conduit Box		Frame	Dimensions in Inches										
Fig. 1	Fig. 2		KEYWAY		Key Length	SHAFT				MOUNTING	B	M	AD
			Wide	Deep		N	N-W	U	V†	F			

SLEEVE BEARINGS □ OR ANTIFRICTION BEARINGS §

001	021	8407S	1.250	0.625	8.500	11.150	10.750	5.375	10.500	18.000	46.600	31.600	10.620
002	022	8409S	1.250	.625	8.500	11.150	10.750	5.375	10.500	22.500	55.600	35.100	15.110
003	023	8411S	1.250	.625	8.500	11.150	10.750	5.375	10.500	28.000	66.600	41.600	20.620

Part No. Conduit. Box		Frame	Dimensions in Inches														
			C								XH			ZS		ZC	
			AR421	AR422	AR423	AR424	AR531	AR532	AR533	AR534	AR421, -422, -423, -424	AR531, -532, -533, -534	All AR420 Series	All AR530 Series	All AR420 Series	All AR530 Series	
Fig. 1	Fig. 2																
001	021	84075	91.950	93.950	95.950	97.950	99.550	97.550	98.550	100.550	33.800	41.200	43.200	2.440	5.125	13.700	15.400
002	022	84095	100.950	102.950	104.250	106.950	104.550	106.550	107.550	109.550	38.300	45.200	47.200	2.440	5.125	13.700	15.400
003	023	84115	111.950	113.950	115.950	117.950	115.550	117.550	118.550	120.550	41.800	51.200	53.200	2.440	5.125	13.700	15.400

- † "V" dimension represents the length of straight part of shaft.
- Sleeve-bearing motors are supplied with 0.250-inch end play, unless otherwise specified.
- § For antifriction bearings, refer to the Company.
- ◇ If a coupling is mounted at the factory, the face of a flange coupling or the hub of a flexible coupling will be flush with the end of the shaft unless otherwise specified on the order.
- ‡ All 420 series exciters have 3/4-inch pipe tap.
- All 530 series exciters have 1-inch pipe tap.
- The suffix letters "S" and "SU" indicate standard short shaft for direct connection only.

CONDUIT-BOX DIMENSIONS

Fig.	Dimensions in Inches						
	AA	AE	AC	AF	AG	XL	XH

By relocation of conduit entrance plate and the rotation of the conduit box, entrance can be made upward, downward, or from either side. The front cover plate is removable for accessibility. Front-end bearing is insulated against shaft currents. Any instrument inserted into the bearing must be insulated.

For ESTIMATING ONLY unless endorsed for construction.

GENERAL ELECTRIC
SCHENECTADY, N. Y. 12305

APPENDIX F

PERFORMANCE ANALYSES PROCEDURES

APPENDIX F

PERFORMANCE ANALYSES PROCEDURES

The procedures used to predict the performance of the Wind Turbine described in this report are as follows:

1. The operating rotor blade lift coefficient was selected for the $C_L = 1.0$ where the max L/D_0 for the (GAW) -1 airfoil is reached. (See Figure F-1)
2. The generalized machine power output of Figure 8 (Section 3.2) was developed from a Boeing Windmill Rotor Computer Program (SR-1BR) which calculates full scale rotor power data such as shown in Figure F-2 and from the model rotor test data shown in Figure F-3. This test data was developed from six-foot model windmill rotors tested on a rig mounted on a boat (see Reference 2). After the full scale rotor performance is developed, the efficiencies from Table VI (Section 3.2) are applied to get the machine power output of Figure 8.
3. To get the Annual Energy output and the design and rated wind velocities, the method of Reference 1 has been computerized. Data computed from this program is read out in the form as shown in the following Table F-a, and results are then plotted as shown in Figure F-4. From this type of chart, the charts such as F-5, F-6 and F-7 are developed and from these the physical characteristics and annual energy output of a given wind turbine generator can be calculated and displayed as shown in Table II (Section 2) for the Model Series. Performance Charts such as shown in Figure F-8 can be plotted directly from the data charts such as example Table F-a.

FIGURE F-1. AIRFOIL LIFT-DRAG CHARACTERISTICS

NOTES:
 1. NACA 23018 AIRFOIL
 2. $b = 2$
 3. $c = 0.033$
 4. $\mu = 0.10$
 5. $C_p = \frac{P}{\frac{1}{2} \rho A V^3}$

— NASA BLADE
 — CONSTANT CHORD
 WITH ZERO TWIST
 - - - CONSTANT CHORD
 WITH NASA TWIST

COLLECTIVE PITCH AT $\frac{r}{R} = 0.75$

COLLECTIVE PITCH AT $\frac{r}{R} = 0.75$

FIGURE F-2. POWER OUTPUT

FIGURE F3 TWO-BLADE ROTORS ARE 10% MORE EFFICIENT.
THAN ONE-BLADE ROTORS AS CONFIRMED BY 6 FT. MODEL TESTS

$$E_S = \frac{(KW \text{ hr})/YR}{Sq.Ft.}$$

P_S = RATED WATTS/Sq.Ft.

V_O = DESIGN WIND VEL., MPH

V_R = RATED WIND VEL., MPH

FIGURE F-4. GENERALIZED SPECIFIC ENERGY - POWER RELATIONSHIPS FOR MODEL SW-2 AT 60 METERS HUB HEIGHT

WINDMILL ANALYSIS

AMARILLO TEXAS, 60 METERS(196,8FT)

V	A	H	B	C	D	E	F	G	VH
1.	0,01	15.	0.	0,0	0.	0,0	0,0	0.	15,000
2.	0,04	25.	1.	0,0	0.	0,0	0,0	0.	50,000
3.	0,14	35.	5.	0,0	0.	0,0	0,0	0.	105,000
4.	0,33	55.	18.	0,0	0.	0,0	0,0	0.	220,000
5.	0,64	75.	48.	0,0	0.	0,0	0,0	0.	375,000
6.	1,10	105.	116.	0,0	0.	0,0	0,0	0.	630,000
7.	1,75	135.	236.	0,0	0.	0,0	0,0	0.	945,000
8.	2,61	180.	469.	0,0	0.	0,0	0,0	0.	1440,000
9.	3,71	225.	835.	0,0	0.	0,0	0,0	0.	2025,000
10.	5,09	270.	1375.	0,0	0.	0,0	0,0	0.	2700,000
11.	6,78	315.	2135.	0,126	270.	0,9	0,126	270.	3465,000
12.	8,80	355.	3124.	0,217	677.	1,9	0,217	677.	4260,000
13.	11,19	400.	4475.	0,275	1230.	3,1	0,275	1230.	5200,000
14.	13,97	445.	6219.	0,311	1936.	4,4	0,311	1936.	6230,000
15.	17,19	470.	8078.	0,333	2691.	5,7	0,333	2691.	7050,000
16.	20,86	470.	9804.	0,345	3378.	7,2	0,345	3378.	7520,000
17.	25,02	435.	10684.	0,349	3796.	8,7	0,349	3796.	7395,000
18.	29,70	405.	12029.	0,348	4186.	10,3	0,348	4186.	7290,000
19.	34,93	375.	13099.	0,344	4500.	12,0	0,344	4500.	7125,000
20.	40,74	350.	14260.	0,337	4800.	13,7	0,337	4800.	7000,000
21.	47,16	325.	15328.	0,328	5026.	15,5	0,328	5026.	6825,000
22.	54,23	310.	16810.	0,318	5346.	17,2	0,318	5346.	6820,000
23.	61,96	300.	18589.	0,307	5713.	19,0	0,282	5250.	6900,000
24.	70,40	285.	20064.	0,296	5941.	20,8	0,249	4987.	6840,000
25.	79,57	280.	22281.	0,285	6341.	22,6	0,220	4900.	7000,000
26.	89,51	270.	24168.	0,273	6598.	24,4	0,196	4725.	7020,000
27.	100,24	250.	26062.	0,261	6813.	26,2	0,175	4550.	7020,000
28.	111,80	245.	27390.	0,250	6844.	27,9	0,157	4287.	6860,000
29.	124,21	225.	27946.	0,239	6666.	29,6	0,141	3938.	6525,000
30.	137,50	190.	26126.	0,227	5940.	31,3	0,127	3325.	5700,000
31.	151,72	160.	24275.	0,216	5254.	32,8	0,115	2800.	4960,000
32.	166,88	130.	21694.	0,206	4464.	34,3	0,105	2275.	4160,000
33.	183,02	105.	19217.	0,195	3755.	35,8	0,096	1838.	3465,000
34.	200,16	95.	19016.	0,185	3523.	37,1	0,087	1663.	3230,000
35.	218,35	80.	17468.	0,175	3064.	38,3	0,080	1400.	2800,000
36.	237,61	65.	15444.	0,166	2562.	39,4	0,074	1138.	2340,000
37.	257,96	55.	14188.	0,157	2222.	40,4	0,068	962.	2035,000
38.	279,45	50.	13972.	0,148	2062.	41,2	0,063	875.	1900,000
39.	302,09	45.	13594.	0,139	1888.	42,0	0,058	788.	1755,000
40.	325,93	40.	13037.	0,130	1700.	42,5	0,054	700.	1600,000
41.	350,99	30.	10530.	0,122	1287.	42,9	0,050	525.	1230,000
42.	377,31	25.	9433.	0,114	1078.	43,1	0,046	438.	1050,000
43.	404,91	20.	8098.	0,107	863.	43,2	0,043	350.	860,000
44.	433,82	17.	7375.	0,099	731.	43,0	0,040	298.	748,000
45.	464,07	15.	6961.	0,092	639.	42,6	0,038	262.	675,000
46.	495,70	12.	5948.	0,085	505.	42,0	0,035	210.	552,000
47.	528,74	10.	5287.	0,078	412.	41,2	0,033	175.	470,000
48.	563,21	9.	5069.	0,071	362.	40,2	0,031	158.	432,000
49.	599,15	7.	4194.	0,065	272.	38,9	0,029	123.	343,000
50.	636,59	6.	3820.	0,059	224.	37,4	0,027	105.	300,000

SUM H=8806, SUM B= 550595, SUM D= 125560, SUM G= 90878,

PS LIMIT= 17,5

VELOCITY 0 = 17,3

CP MAX= 0,35

MEAN VELOC. = 19,697

TABLE F-a. DESIGN CONDITION FOR
MODEL SW-1-10 FOR 60
METERS WIND SPECTRA

FIGURE F 5 . GENERAL DESIGN CHART FOR MODELS SW-2-8 AND -10 FOR 60 METER HUB HEIGHT

FIGURE F 6. GENERALIZED DESIGN CHART FOR MODEL SW-2-13 FOR 45 METER HUB HEIGHT

FIGURE F 7. GENERALIZED DESIGN CHART FOR MODEL SW-1-13 FOR A 45 METER HUB HEIGHT

FIGURE F-8. PERFORMANCE OF WIND TURBINE MODEL SW-1
AT RATED POWER OF 1000 KW

APPENDIX G

STEEL SHELL TOWER DATA

STEEL SHELL TOWER DATA

Received from manufacturer: Bruce Lake Company, Coatesville, Pa.

Design Criteria

MATERIAL:

DESCRIPTION	AISA ASTM NO.	MIN. YIELD (KSI)
Tower Plate	A-572	65
Baseplate	A-537-B	60
Anchor Bolt	A-615, Gr. 75	75
Anchor Bolt Nut	A-307-2A	--
Arm Plate	A-572	65
Arm Box	A-572	65
Arm Bolt	A-325	110
Arm Bolt Nut	A-307-2A	--
Vangs	A-572	65
Miscellaneous	A-36	36
Square Structural Tubing	A-500, Gr. B	46

PARAMETERS:

$$W/t = 240 / \sqrt{F_y} \quad (\text{Max.})$$

Max. Allow. Anchor Bolt Load = 226.5k

Max. Allow. Bond Stress = 292 psi

Allowable Bending Stresses:

$$F_b = 0.6 F_y = 39 \text{ ksi}$$

For dynamic loading, increase load by 50% or divide F_b by 1.5

$$F_{b_d} = 26 \text{ ksi}$$

Factor of safety against ultimate load is 2.5.

Estimated Cost: (Tower Height = 165 Ft.)

Structure:	\$66,000
Foundation in place:	19,800
Total:	<u>\$85,800</u>

Estimated Weight:

Total pole, base plate and anchor weight: 127,250lb.

Miscellaneous:

Motorized car for access to top:	\$8,000
Support system:	\$7,000