Integration of Wind Power into Australian Electricity Grids Without Storage: A Computer Simulation.

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Abstract

A computer simulation is performed of the operation of two fuel-based Australian State electricity grids (WA and SA) with zero storage and added hypothetical wind power capacity. It is found that wind energy contributions of 20 percent (WA) and 30 percent (SA) of the annual grid energy output can be achieved before the losses of unutilized wind energy increase to 20 percent of wind energy generation. The results are sensitive to the extent to which the output of conventional units can be regulated or "cycled". Small modifications to the grid operating strategy can affect the extent to which wind energy substitutes for a mixture of peak, intermediate and base load fuel or mainly for base load fuel. The most economical operation strategy is not necessarily the one which places wind at the top of the merit order

1. Introduction

In this paper we study the integration of systems of large aerogenerators into each of two fossil-fuel based electricity grids with zero storage – the grids of Western Australia (WA) and South Australia (SA). A computer simulation is performed of the operation of each grid over a period of one year, using time steps of either half an hour or one hour. Actual data on electricity demand and wind speeds are utilized in the simulation. The following questions are examined:–

(i) the dependence of the losses of unutilized wind energy upon the penetration of wind power capacity into the grid;

(ii) the dependence of the number of start ups of conventional plant upon the wind power penetration;

(iii) the substitution of wind energy for base, intermediate and peak load fuel, as a function of wind power penetration, and the dependence of this substitution upon the choice of operation strategy for the grid;

(iv) the dependence of the losses of unutilized wind energy upon the ability to regulate or "cycle" the output of conventional units.

Questions (i) and (ii) have been discussed previously by Sørensen (1) within the framework of an electricity grid model having units of identical capacity and a single specified range of regulation, and having a fully predictable electricty demand. Questions (i) to (iii) have received a preliminary examination by Diesendorf and Martin (2) for the WA grid alone, based on limited demand data and wind speed data from SA rather than WA. The present paper incorporates more extensive and appropriate data, considers both the SA and WA grids and treats all four questions.

Consideration of the foregoing questions is necessary but not sufficient for the ultimate assessments of the economics of wind energy conversion systems in electricity grids. This paper does not consider the following topics: choice of alternator types (e.g. induction or synchronous) and details of local interfacing with the grid; frequency control and stability of the system; temporal variations on time-scales less than ½ hour; spatial variations in wind power; the rôles of storage and of demand modification; and optimal mix of base, intermediate and peak load conventional plant in the presence of wind power capacity.

Before introducing the computer model, we summarise existing knowledge of the resource potential for large scale wind energy conversion in Australia and outline the relevant basic features of electricity grids.

2. Potential for Large-Scale Wind Power in Australia

The basic geographic requirements for the deployment of arrays of large aerogenerators are: extensive sites at which the annual mean windspeed at a height of 50m above ground is greater than about 7m/s; accessibility, namely proximity to roads, transmission lines and load centres; and the absence of significant land use constraints. In Australia, there is only limited availability of data suitable for assessing wind energy potential. Hourly measurements of windspeed, spanning a minimum period of one year and taken at windy sites (rather than in towns and at airports), are required. The available data, together with general meteorological considerations, suggest that there exist three major regions which may be suitable for the initial development of large scale wind power (3):

a) The south-west coast of WA (omitting national park sections) between Cape Naturaliste and Albany might support an annual average wind power of about 280 MW, assuming two lines of megawatt rated aerogenerators (3). There is also likely to be much greater potential for later development on the more isolated southern WA coastline to the east of Albany.

b) About 2000 km of SA coastline might support an annual average wind power of about 2000 MW, again assuming two lines of megawatt-rated aerogenerators (3).

c) The northern part of Tasmania's west coast, which is particularly suitable in terms of land use (4), might support an average power of 200-400 MW. Because Tasmania's grid electricity is almost entirely provided from hydro-electricity with a very large energy storage capacity (currently equivalent to almost two years of average demand), it falls outside the framework of the present paper.

3. Basic Features of Electricity Grids

An electricity supply system or grid consists of a set of power stations – characterised by their rated power, fuel, start up times, range of regulation, etc. – linked together and to a set of users by a network of transmission lines. A fundamental operating requirement, which has become accepted by the electricity industry and the public, is that the probability that demand is not completely supplied is very small, e.g. less than one hour in one year. Unlike gas in a pipeline, electricity cannot be stored in a grid as electricity. At present, the only means of storing electricity on a large scale, in a state from which it can be recovered almost instantaneously, is in the form of the potential energy of water in a reservoir which feeds a hydroelectric power plant. Such a plant can respond to a change in demand on a timescale of seconds.

Neither WA nor SA has any significant hydro-electric storage and the potential for any future hydro development appears to be very limited (apart from a possibility of pumped storage of sea-water). Hence, the fundamental operating requirement implies that thermal generating plant of the appropriate capacity and type (i.e. response time) must be provided and that some of this must be kept in reserve to allow for unforeseen changes in demand and unscheduled outages in power plants.

At first sight, the incorporation of a stochastically varying source such as wind power might appear to complicate greatly the operation of an electricity grid and to pose entirely new operational problems. However, although the frequency of "outages" in wind power plant will be much greater than that of conventional plant, the mean duration of wind outages is much shorter. (Outages of wind generators result mainly from variations in the weather, while outages of thermal power plant result primarily from breakdowns). In addition, the existence of a random component in electricity demand, which is superposed on the predictable average daily and seasonal variations, has already ensured that fast-response reserve plant is available. Variability is an inherent feature of conventional electricity grids.

Figure 1 shows a typical diurnal variation in power demand in the WA grid in 1978. The bottom part of the demand is met from *base load* power stations. These have high capital costs but low running costs (they are fuelled with local coal in WA) and tend to require at least 6 hours to be started up from cold. Therefore, utilities try to operate these stations continuously, apart from scheduled maintenance.

The peak demands in Figure 1 are met with *peak load* plant which generally has low capital costs but high running costs and short start up times (e.g. minutes). For the purposes of our simplified computer model of the WA grid we have used the term "peak" for all oil burning plants. In 1978, oil provided about 20% of the annual energy input for electricity generation in WA. Since then, one unit, Kwinana 5, has been converted to dual coal/oil operation, and another unit is being converted.

Intermediate load plant, as defined here, consists of former base load plant (coal-fired in WA) which is older, smaller, less efficient and more expensive to run than present base load. Intermediate load plant can be started and regulated more

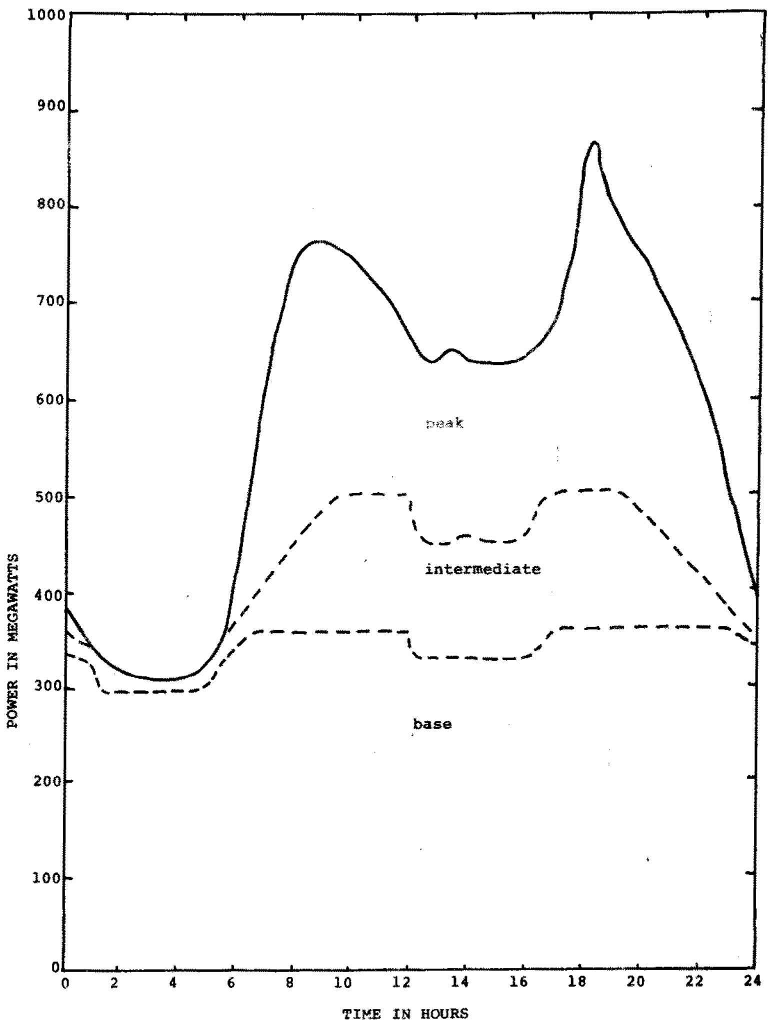

Figure 1 A typical diurnal variation in power demand in the WA grid in Winter 1978

quickly than can present base load plant. It should be noted that the distinction between base and intermediate load and between intermediate and peak load is not always a sharp one .

It is also useful to arrange the power plants of an electricity grid in a hierarchy, determined by their operating costs, known as the merit order. The plant which is cheapest to operate, in c/kWh, is top of the merit order, as shown in Tables I and II for WA and SA respectively.

In the 1978 SA grid, the diurnal load curves (Fig. 2) are typically less sharply peaked than in WA, the allocation of fuels between base, intermediate and peak load plant is more complex and, indeed, the categories of base, intermediate and peak become less useful. In 1978, SA obtained about 70 percent of its electrical energy from low-priced natural gas, which was burnt in boilers of some of the "base load" and "intermediate load" plant and in the gas turbines which comprise some of the peak load plant near the bottom of the merit order (see Table II). Despite the large proportion of gas fired plant in SA, the proven reserves of natural gas available to SA are very limited and so the next base load power station to be brought on line (at the top of the merit order) will burn coal.

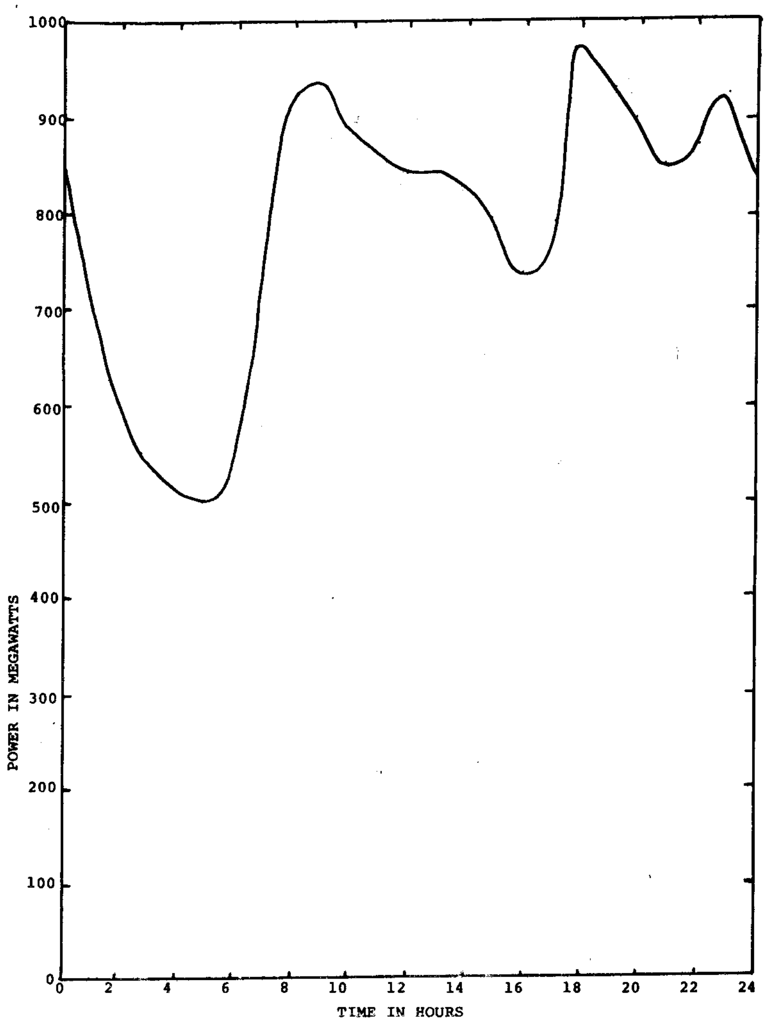

Figure 2 A typical diurnal variation in power demand in the SA grid in Winter 1978

4. Input Data

The computer model performs a half-hour by half-hour simulation of the 1978 WA electricity grid or an hour by hour simulation of the 1978 SA grid, incorporating variable wind power capacities. Input data for the model must be provided for wind speeds (hourly or less), aerogenerator characteristics, thermal power station characteristics, and electricity demand (hourly or less).

Hourly wind speed data from Fremantle WA for the year 1971, and from Waitpinga SA for the year 1955, have been utilized. The annual mean wind speeds at these sites are respectively about 4.5m/s and 6.0m/s at a height above ground of 9m. In each case, to allow for appropriate siting for large aerogenerators in each state, the observed annual mean wind speeds at a nominal hub height of 50m have been scaled to be 8m/s.

It has been assumed that the aerogenerators are characterised by a start up speed $v_s = 4$m/s, two alternative rated speeds $v_r = 12$ m/s or 16m/s (1.5 or 2 times the mean windspeed $\overline{v} = 8$m/s) and a furling speed $v_f = 40$m/s. For simplicity the idealised cubic relationship between wind generator power output P and windspeed v has been chosen, yielding the following relation

$$P = \begin{cases} 0 & v < v_s \\ (v/v_r)^3 P_r & v_s \leqslant v < v_r \\ P_r & v_r \leqslant v \leqslant v_f \\ 0 & v_f < v \end{cases} \qquad (4.1)$$

where P_r is the rated power of the wind generator. It has also been assumed that each region is spatially homogeneous, namely that windspeeds are identical within each state at any given time, so that P_r may be taken to be the rated power of the entire array of aerogenerators. This assumption will overestimate the variability of the total wind contribution.

Table I Characteristics of thermal power stations as used in the simulation model of the 1978 WA grid

Name	Fuel	No. of units	Rated power per unit (MW)	Minimum power output per unit (MW)	Type	Cold start up time (hours)	Forced outage rate
Muja	coal	4	60	45	base	6	0.08
Bunbury	"	4	30	15	"	6	"
South Fremantle	"	4	25	0	int.	1	"
East Perth	"	1	30	0	"	1	"
		1	25	0	"		
Kwinana	oil	4	120	0	peak	0	"
Kwinana	"	2	200	0	"	0	"

Note: Stations listed in merit order. Total rated power = 1395 MW, 1978 mean demand = 530 MW, 1978 peak demand = 991 MW.

Table II Characteristics of thermal power stations in the 1978 SA grid

Name	Fuel	No. of units	Rated power per unit (MW)	Minimum power output per unit (MW)	Type	Cold start up time (hours)	Forced outage rate
Torrens B	gas	2	200	80	base	8	0.05
Playford B	coal	4	60	30	base	2	0.07
Torrens A	gas	4	120	48	int.	8	0.05
Playford A	coal	3	30	30	"	2	0.07
Dry Creek	gas	3	52	0	peak	0	0.05
Osborne	oil	1	60	0	"	½	"
		6	30	0	"	½	"
Snuggery	distillate	3	25	0	"	0	"

Note: Stations listed in merit order used in SA. In our approximate simulation model, the positions of Playford B and Torrens A in the merit order are interchanged. Total rated power = 1681 MW, 1978 mean demand = 733 MW, peak demand = 1239 MW.

Characteristics of the thermal power stations used in the simulation model are listed in merit order in Tables I and II.

The model does not distinguish between cold and hot start up times. A zero start up time is used for peak load plant because the minimum time step used in the simulations is a half hour. The "peak" load plant in the 1978 WA grid actually consisted of oil-fired boiler units which were kept hot at appropriate times of the day so that they could be brought on line quickly Fuel used by hot reserve is not determined in this series of simulations. In the 1978 SA grid the peak load plant were two gas turbine plants, one fired by distillate and one by natural gas, plus an oil fired boiler plant.

Half hourly averaged demand data from the 1978 WA grid and hourly averaged demand data from the 1978 SA grid were made available by courtesy of the respective state electricity utilities.

It is difficult to estimate forced outage rates because much of the plant is relatively new, but we were informed by the utilities that 8% of the time is a reasonable figure for the WA units and 5% (natural gas) and 7% (coal) for base or intermediate units in SA. The down time is assumed to be exponentially distributed with a mean of 2 days, in each state.

5. Operating Strategies

Each time-step (½ hour in WA, 1 hour in SA), forecasts are made of wind power and power demand. The forecast of the mean wind power for the next time-step is set equal to the mean wind power for the previous time-step.

For the forecast of mean demand for the next time step we use the expression

$$D(\Delta t) = D(0) + [D(-24+\Delta t) - D(-24)] \quad (5.1)$$

where D(t) is the demand at hour t, t=0 is the present, and Δt=½ or 1 hour. In other words, the demand forecast is the immediately preceding demand plus the change in demand over the corresponding time step 24 hours earlier. These forecasts of windpower and power demand provide simple expressions for a computer model. They could be improved by incorporating meteorological forecasts of temperatures, known industrial demand power patterns (including the difference between weekdays and weekends) and possibly meteorological forecasts of changes in weather patterns and hence of wind speeds.

On the other hand, the assumption of zero start up time for peak load plant overestimates the operational flexibility of the power systems. Furthermore, most thermal power units have constraints on the rate at which power may be increased or efficiency reduced (e.g. 3 MW per minute for a 60 MW unit). In addition, grids normally try to keep a certain minimum amount of spinning reserve – such as half the power of the largest unit in operation – ready in case of sudden forced outages. These effects have not been incorporated in the present simulation. It is anticipated that restrictions on the incorporation of wind power into the grid resulting from these effects would be roughly offset by the superiority of the operation of the grid by experienced engineers familiar with plant characteristics, demand patterns and weather effects.

The purpose of any operating strategy for a given grid is to minimize the operation and maintenance costs (which are dominated by the fuel costs) while keeping the loss of load probability within the bound chosen by utility policy. In operating a grid containing wind power capacity one would therefore seek to optimize the fuel saving due to wind. In an idealised grid one would naturally place wind at the top of the merit order, so that it displaces the operation of conventional base load plant which in turn displaces the operation of conventional intermediate load plant which in its turn displaces peak load plant.

However, in practice there are differences in start-up times and in the range of regulation of power output between conventional base, intermediate and peak load plant, and other operational constraints, which imply that such a simple sequence of substitutions, starting with wind at the top of the merit order, may not be possible or at least may not always provide the economically optimum operation. To allow for these constraints, we include in the operating strategy two parameters. A parameter α can determine whether wind energy substitutes mainly for conventional base or mainly for the sum of conventional intermediate and peak. Our program also offers the option of loading an amount B_0 of conventional base load plant in addition to that needed for meeting minimum daily demand. B_0 can be regarded as a means of further ensuring reliability in a grid with low base load fuel costs; alternatively, B_0 could represent conventional plant of very high capital cost, whose output cannot be regulated (e.g. nuclear power), which is placed at the top of the merit order by utility policy.

Thus, at each time step the 'optimum' amount of conventional base load plant to be running is calculated as

$$B = B_0 - \alpha \overline{P} + \text{minimum}\ [D(0), D(-\Delta t), D(-2\Delta t), \ldots, D(-24+\Delta t)] \qquad (5.2)$$

where $\overline{P}$ is the annual mean wind power contribution to the grid, B_0 is a constant which is set according to the mean contribution of base load plant desired in the absence of wind power capacity and α is a constant which would usually be set to a value in the range $0 \leqslant \alpha \lesssim 1$. The case $\alpha = 1$, $B_0 = 0$ might be chosen for an idealised grid where wind energy is placed at the top of the merit order to displace base load fuel which displaces intermediate load fuel which in turn displaces peak load fuel.

As an example of equation (5.2), if the WA minimum demand over the previous hours is 400 MW, if utility policy requires B_0= 60 MW, if P = 200 MW and if α is chosen to be 0.5, then from equation (5.2) B = 360 MW: i.e. all the base plant in Table I is utilized.

The above calculation of B differs in one respect from the previous strategy of Diesendorf and Martin (2) in which the operator attempted to follow the variations in daily average wind power, so that B was given by

$$B = B_0 - \alpha P_d + \min\ [D(0), D(-\Delta t), \ldots, D(-24+\Delta t)]\ , \qquad (5.3)$$

where P_d is the forecast average wind power for the next 24 hours, which is set equal to the average wind power for the previous 24 hours. Instead of (5.3) the strategy (5.2) has been chosen for the present series of simulation in order to minimize the number of loss of load events caused by sudden drops in wind power in the absence of spinning reserve, and to investigate a "worst case" in predicting wind power in baseload operating strategies.

At each time step, the actual rated amount of base plant B_c that is operating or being fired up is compared to B. If B_c is more than a specified amount (e.g. 100

MW) larger than B, some base units are shut down. If B_c is less than B, base units are fired up. This algorithm thus causes base plant to be fired up when forced outages of base plant occur and sets the general level of base plant according to the daily minimum demand, which primarily varies seasonally.

In a similar manner, the intermediate plant I is adjusted according to the value

$$I = D(\Delta t) - B(\Delta t) - P(\Delta t) \tag{5.4}$$

where $D(\Delta t)$ is given by (5.1), $B(\Delta t)$ is the base plant expected to be available in the next time step and $P(\Delta t)$ is the forecast mean wind power for the next time step.

At the end of the time step for which adjustments have been made around B and I, the actual mean power demand is compared to mean power available from base, intermediate and wind plant. If the latter is smaller, available peak load plant is assumed to have been used. If this is insufficient, loss of load occurs. On the other hand, if mean demand is less than mean available power from base, intermediate and wind plant, then it is assumed that intermediate plant was run below rated power and if necessary that base plant was run below rated power (but only to the minimum power outputs – see Tables I and II). If these reductions are insufficient, energy is lost. Since virtually no energy is lost when the system operates without wind power, all lost energy is considered to be wind energy.

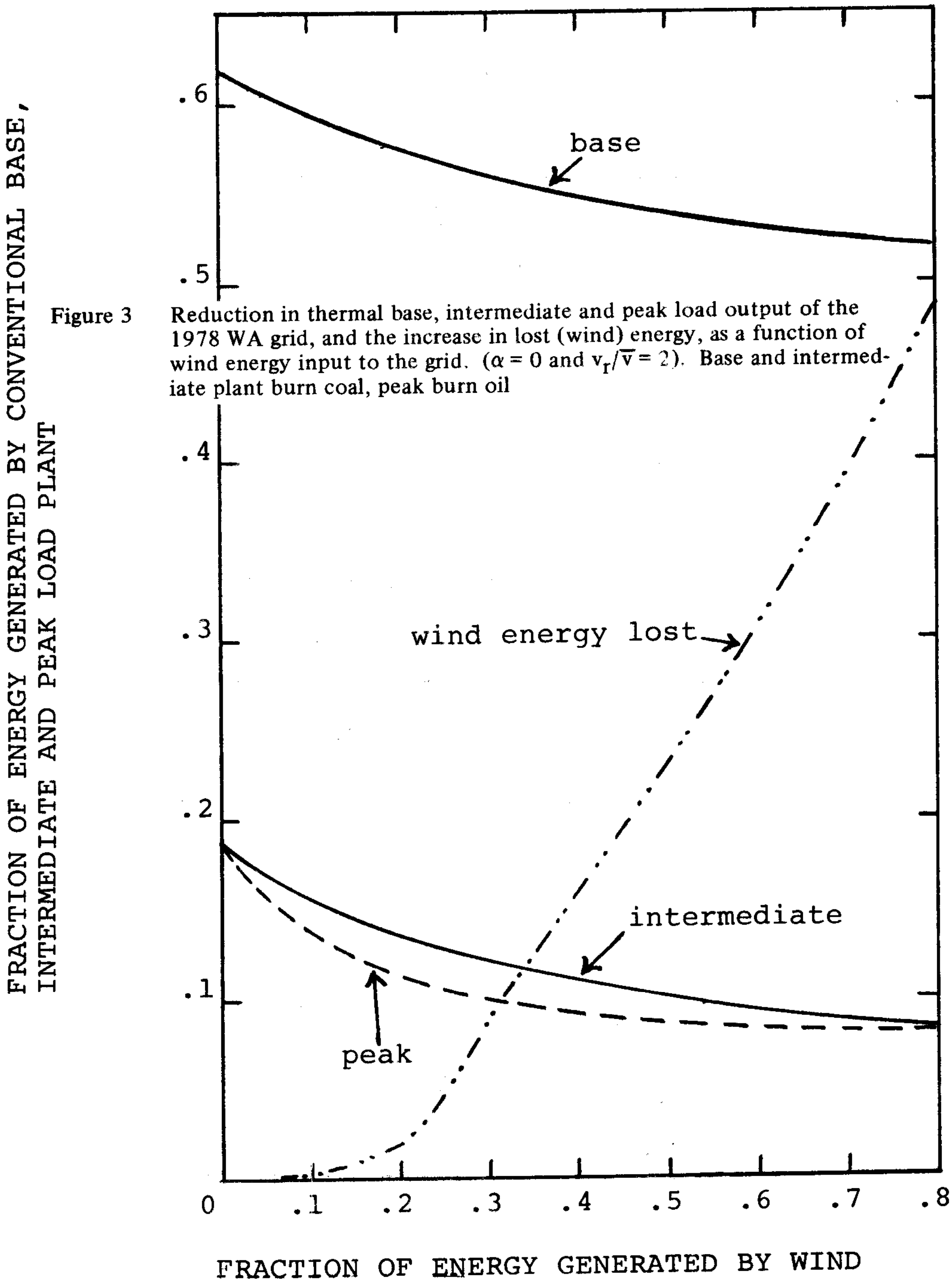

Figure 3 Reduction in thermal base, intermediate and peak load output of the 1978 WA grid, and the increase in lost (wind) energy, as a function of wind energy input to the grid. ($\alpha = 0$ and $v_r/\overline{v} = 2$). Base and intermediate plant burn coal, peak burn oil

Table III Penetration of wind power into 1978 WA grid

(a) $v_r / \overline{v} = 2$

Rated wind power capacity (GW)	$\alpha = 0$					$\alpha = 0.5$					$\alpha = 1.0$				
	Fraction of annual energy generated by					Fraction of annual energy generated by					Fraction of annual energy generated by				
	wind	base	int.	peak	wind energy lost	wind	base	int.	peak	wind energy lost	wind	base	int.	peak	wind energy lost
0	.00	.62	.19	.19	.000	.00	.62	.19	.19	.000	.00	.62	.19	.19	.000
.25	.10	.60	.16	.14	.006	.10	.59	.17	.15	.006	.10	.55	.18	.17	.005
.50	.20	.57	.14	.12	.04	.20	.53	.15	.14	.03	.20	.47	.18	.18	.03
.75	.30	.56	.12	.10	.09	.30	.48	.14	.15	.08	.30	.36	.18	.22	.06
1.00	.40	.55	.11	.10	.16	.40	.44	.14	.15	.14	.40	.25	.20	.26	.11
1.25	.50	.54	.10	.09	.23	.50	.40	.14	.16	.20	.50	.18	.19	.29	.16
1.50	.60	.53	.09	.08	.31	.60	.35	.14	.17	.26	.60	.10	.19	.31	.21
2.00	.80	.52	.08	.08	.48	.80	.25	.14	.20	.40	.80	0	.18	.34	.33

Table III (contd.)

(b) $v_r/\bar{v} = 1.5$

Rated wind power capacity (GW)	$\alpha = 0$					$\alpha = 0.5$					$\alpha = 1.0$				
	Fraction of annual energy generated by					Fraction of annual energy generated by					Fraction of annual energy generated by				
	wind	base	int.	peak	wind energy lost	wind	base	int.	peak	wind energy lost	wind	base	int.	peak	wind energy lost
0	.00	.62	.19	.19	.00	.00	.62	.19	.19	.000	.00	.62	.19	.19	.000
.14	.10	.60	.16	.14	.004	.10	.58	.17	.15	.003	.10	.55	.18	.17	.002
.28	.20	.58	.13	.11	.02	.20	.53	.15	.13	.02	.20	.46	.18	.17	.01
.42	.30	.55	.11	.10	.06	.30	.48	.13	.13	.05	.30	.36	.18	.20	.04
.56	.40	.54	.09	.09	.13	.40	.43	.13	.13	.10	.40	.25	.17	.23	.07
.70	.50	.53	.08	.08	.20	.50	.38	.12	.15	.16	.50	.16	.17	.27	.11
.84	.60	.52	.08	.07	.28	.60	.34	.12	.16	.23	.60	.09	.17	.29	.16
1.12	.80	.51	.07	.07	.46	.80	.25	.12	.18	.36	.80	.0	.16	.31	.28

6. Results for WA Grid

In Table III we present results showing the effects of progressively increasing the windpower capacity of the 1978 WA grid on the use of energy by base, intermediate and peak load conventional plant and on the amount of (wind) energy lost. Presented are results for three values of the parameter α in (5.2) and two values of the rated speed v_r of the wind generators. For all results quoted here, $B_0 = 0$. Non-zero values of B_0 tend to shift fuel savings towards intermediate and peak categories.

One general conclusion, also apparent from Figure 3 illustrating the results, is that 20 to 30% of annual energy generation by wind power is possible with relatively little lost energy. Beyond 30% penetration by wind, the losses increase rapidly. These results are in agreement with those of the simpler model of Sϕrensen (1).

Second, setting $\alpha = 0$ in (5.2) causes the wind energy to substitute mainly for intermediate and peak load thermal plant energy, while $\alpha = 1$ leads to wind energy substitution mainly for base load thermal plant energy. Energy losses are smaller in the latter case, which is to be expected since base load plant is less flexible in accommodating to rapid changes in load and available wind power. Generally, then, the operating strategy for the grid in the presence of wind power may be adjusted so as to lead to saving in energy primarily from either base or from intermediate and peak load thermal plant, with somewhat larger energy losses in the latter case. The results for $\alpha = 0.5$ show an intermediate strategy.

Third, the choice of the rated speed v_r has relatively little effect on the results, given the same annual energy generation by wind power. Energy losses are marginally smaller when $v_r/\overline{v} = 1.5$ rather than 2, which is to be expected since rated wind power capacity is smaller and hence variations in wind power contributions to the grid (specifically, the ratio $P_r/\overline{P}$) are reduced. This may also confer advantages in the local interfacing of aerogenerators into the grid system.

It could be mentioned in passing that the choice of the lower value of the rated speed will also have the advantage of reducing significantly the costs of the tower (5), at least for a horizontal-axis aerogenerator. However, this will be partially offset by the need to choose a larger turbine diameter in order to achieve the same annual energy generation per aerogenerator. For an aerogenerator with simple cubic response, as in equation (4.1), and $v_s/v_r = 0.4$, exposed to a Rayleigh distribution of wind speed, maximum annual energy is obtained by choosing $v_r/\overline{v} = 2.3$; for a displaced cubic response, the corresponding optimum $v_r/\overline{v}$ is 2.0 (6).

Another consequence of incorporating wind power into an electricity grid is a greater number of start-ups and regulations of the power output of conventional plant. For the present operating strategy, the number of base load unit start-ups is unchanged by increasing the wind penetration, since equation (5.2) does not depend on recent or expected wind speeds. The number of intermediate load start-ups has increased by 50% at a wind energy penetration of 20 percent, for both $v_r/\overline{v} = 2$ and 1.5. Also, the number of time-steps in which intermediate units are run below rated power is constant or slightly declining with increased wind penetration, while the number of time-steps in which base units are run below rated power increases significantly with increased wind penetration.

In the worst case ($\alpha = 0$ and $v_r/\overline{v} = 2$) treated here, the magnitude of the energy loss, when the penetration of wind energy into the grid is 20 percent of the total annual energy output of the grid, amounts to 20 percent of the wind energy contribution. This loss is slightly larger than that obtained in the same grid (15% of wind energy) when the operating strategy (5.3), which follows daily variations in wind power, is utilised (2). The losses in Sϕrensen's (1) model grid, about 13 percent of wind energy at the same penetration, are also consistent with our results.

Yet in the recent simulation by Whittle *et al* (7) of an approximate CEGB grid, the losses were much smaller: indeed they were negligible at 20 percent penetration, reaching only 3 percent of the wind energy contribution at 30 percent penetration. Contrary to the explanation of the different results proposed in (7) we have shown above that a substantial change in the grid operating strategy with regard to following wind power variations, only produces a minor reduction in energy losses. We suggest that the dramatic reduction in losses obtained by Whittle *et al* (7) results primarily from their assumption that the output of their fossil fuel conventional grid can be regulated over the full range from zero to the rated power. Our hypothesis is tested for the case of the WA grid in simulations summarized in Table IV It can be seen that the magnitude of the wind energy loss is very sensitive to the range of regulation chosen for the conventional plant.

7. An Approximate Model of the SA Grid: Method and Results

In the actual SA grid, natural gas is fed directly by pipeline from the gas fields in the Cooper Basin to the power stations in Adelaide. As a consequence, the daily gas demand by the electricity utility (which exceeds the combined gas demand of all other SA users) is constrained to lie within a range of variation of about 10 percent

Table IV Penetration of wind power into 1978 WA grid with different assumptions on the range of regulation of base load conventional power. $v_r/\overline{v} = 2$, $\alpha = 0.5$

No base load regulation.					Complete base load regulation.				
Fraction of annual energy generated by:					Fraction of annual energy generated by:				
wind	base	int.	peak	wind energy lost	wind	base	int.	peak	wind energy lost
.00	.63	.19	.19	.01	.00	.62	.19	.19	.000
.10	.61	.17	.15	.03	.10	.58	.17	.15	.000
.20	.57	.15	.14	.07	.20	.51	.15	.14	.005
.30	.52	.14	.15	.11	.30	.44	.14	.15	.03
.40	.48	.14	.15	.17	.40	.37	.14	.15	.07
.50	.44	.14	.16	.24	.50	.33	.14	.16	.13
.60	.38	.14	.17	.30	.60	.27	.14	.17	.19
.80	.28	.14	.20	.43	.80	.18	.14	.20	.33

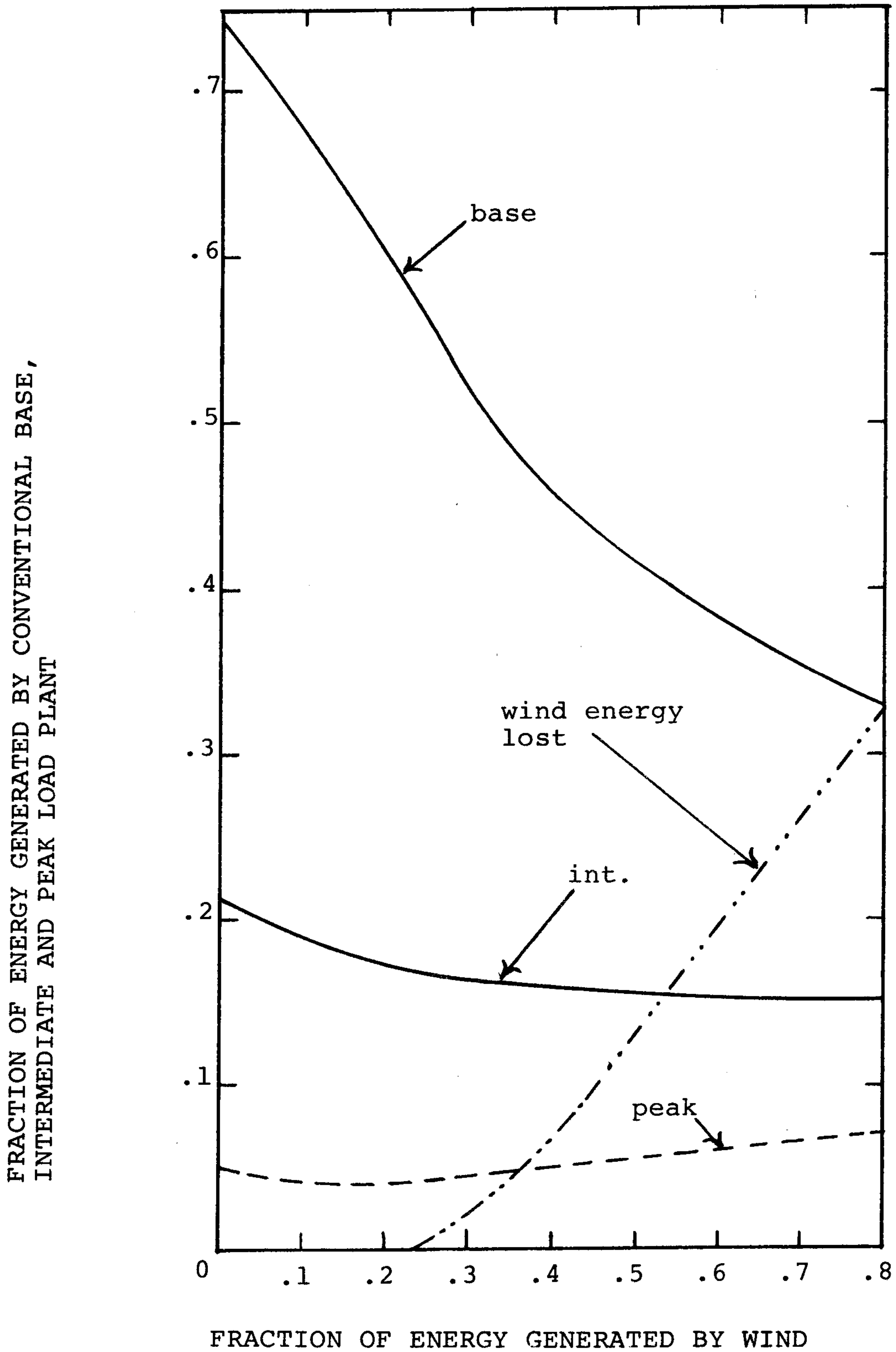

Figure 4 Reduction in the consumption of natural gas and coal, and the increase in lost (wind) energy, as a function of wind energy input to the 1978 SA grid, approximate model. ($\alpha = 1$ and $v_r/\overline{v} = 1.5$). Base plant burn gas, intermediate burn coal

around the average daily demand of the utility, which is in turn determined by the dimensions of the pipeline. This constraint has not been taken into account in the present simulation.

In addition, for convenience in the computer simulation, the positions of Torrens A and Playford B have been exchanged in the merit order, so that in our approximate model "base" load is all gas and "intermediate" load is all coal. Since the distinction between base and intermediate load is particularly arbitrary in the SA case, this interchange is not expected to be of importance. Since the utility's cost of burning natural gas (in c/kWh or c/GJ) in SA was much less in 1978 (and still is today, despite the rapid depletion of the proven reserves in the Cooper Basin), than the cost of burning coal, this approximate merit order would be the true merit order in the absence of the pipeline constraint.

Table V shows some of the results of simulations of the approximate SA grid. For conciseness, only the results for $\alpha = 0.5$ ($v_r/\overline{v} = 2$ and 1.5) are reproduced. The larger SA conventional units have a wider range of regulation than the larger WA conventional units, and this is one reason why the losses of wind energy, for a given penetration, are smaller in SA than in WA. Another reason, to be discussed in a following paper, is concerned with the shape of the diurnal demand curve and its relation to the range of regulation of conventional power plants.

The dependence of the results on the value of α is similar to that shown for WA. Figure 4 shows the substitution of wind energy for gas and coal in the case $\alpha = 1$, $v_r/\overline{v} = 1.5$.

These results, however, give only a rough indication of the changes in the SA grid operation characteristics to be expected when windpower is added, since the computer simulation reproduces actual operating strategies in at best a crude fashion.

8. Some Economic Aspects

The present work has been concerned with the flows of energy and power in electricity grids with wind power capacity. It does not in itself aim to present an economic analysis or an economic optimisation. However, the results can be utilised as one input to future economic treatments of the integration of wind power into electricity grids. For instance, in the present work, merit order of conventional power plants, type of fuel saved by wind energy, and the number of additional start-ups of conventional plant, which are all relevant to the economics of the system, are treated explicitly.

The economics of wind power depends strongly on the costs of new conventional sources of base load power which would otherwise be installed. Over the next 15 years, the only serious source of additional conventional base load power in WA or SA is coal. In an electricity grid with expanding demand, one might compare the cost of installing (say) 100 MW of annual average wind power $\overline{P}$ with the costs (capital plus operation and maintenance) of 100 MW of average power from new coal fired plant. To the cost of the wind plant would be added the capital cost of gas turbine plant of a capacity which makes up for the difference in capacity credits of wind power and coal power. In this case, an appropriate measure of capacity credit would be the "equivalent load carrying capability" (8,9).

On the other hand, in an electricity grid where demand is static or only increasing slowly, one might install wind plant instead of coal as older conventional plant is retired. In this case, one might simply compare the fuel saving value plus capacity credit (measured in terms of equivalent firm capacity or equivalent conventional capacity (8,9)) of wind power with the capital cost of wind power. In this case, referring to Table IIIa, we have $\overline{P} = 100$ MW and, if $v_r/\overline{v} = 2$, rated wind power $P_r = 500$ MW. If $\alpha = 1$, so that wind substitutes almost entirely for base load fuel, the total fuel saving is 20 percent of coal usage in the absence of wind power or, in absolute terms, about 743 GWh(e). If coal is priced at 1c/kWh(e) the saving amounts to $7.4 million per annum. There is also a modest oil saving of 46 GWh(e) which amounts to $1.85 million when oil is priced at its mid 1980 WA price of 4c/kWh (about $160 per tonne). Since coal is relatively cheap in WA, we next consider the operating strategy for which $\alpha = 0$. Then wind substitutes for 37 percent of peak load fuel (oil) used and for 12% of coal. In absolute terms the annual oil saving is 326 GWh(e) or $13.0 millions; coal saving is 464 GWh(e) or $4.64 million. Costs are measured in terms of mid-1980 Australian dollars.

Clearly the strategy with $\alpha = 0$ leads to a significantly greater total fuel saving in dollars than that with $\alpha = 1$, for this particular grid with this particular choice of relative fuel prices. This result actually holds quite generally for all wind energy penetrations into real (i.e. constrained, as discussed in Section 5) fuel-based electricity grids for which the cost of peak load fuel is greater than the cost of base load fuel. Under these conditions it may, in many cases, be more economical to operate the grid so that wind, despite its zero fuel cost, is not at the top of the merit order but rather displaces some peak load fuel. However, as wind energy

Table V Penetration of wind power into an approximate model of the 1978 SA grid for two values of $v_r/\bar{v}$ and $\alpha = 0.5$.

$v_r/\bar{v} = 2$						$v_r/\bar{v} = 1.5$					
Rated wind power capacity (GW)	Fraction of annual energy generated by: wind	base	int.	peak	wind energy lost	Rated wind power capacity (GW)	Fraction of annual energy generated by: wind	base	int.	peak	wind energy lost
0	0	.74	.21	.05	.00	0	0	.74	.21	.05	.00
.34	.10	.67	.19	.04	.00	.19	.10	.67	.19	.04	.00
.68	.20	.59	.18	.05	.02	.38	.20	.60	.17	.04	.00
1.02	.30	.54	.17	.05	.06	.57	.30	.52	.16	.05	.02
1.36	.40	.48	.18	.06	.11	.76	.40	.45	.16	.05	.07
1.70	.50	.44	.18	.06	.17	.95	.50	.42	.16	.05	.13
2.04	.60	.42	.17	.06	.24	1.14	.60	.39	.15	.06	.20
2.72	.80	.35	.17	.07	.39	1.52	.80	.33	.15	.07	.34

penetration is increased, the fuel-saving cost advantage of $\alpha = 0$ operating strategy is offset to an increasing degree by the higher losses of wind energy it entails. In general, the choice of optimum operating strategy depends on the relative fuel prices, the wind energy penetration and the range of regulation of the conventional plant (of which the latter two factors are the primary ones determining wind energy cost).

At 20 percent penetration into the WA grid, the capacity credit of 100 MW average wind power from a single site is equivalent to that of a single idealised unit with zero forced outage rate having a rated power of about 40 MW (9). (In a real grid into which wind power is fed from a number of dispersed sites, between which there is less than perfect correlation in wind speed, the capacity credit of wind power will be significantly larger than this). This is in turn equivalent to a coal-fired base-load unit with a forced rate of 9 percent, rated at a bout 45 MW (8,9). At a capital cost for coal-fired power plant of about $500/rated kW this capacity credit amounts to $22.5 million; at an interest rate of 12.5 percent per annum (the current rate on semigovernment bonds in Australia), the annual value is $2.8 million. The total annual value of wind power (fuel saving + capacity credit) is about $20.4 million when $\alpha = 0$.

If the capital cost of wind power is taken to be $400/rated kW, with a capacity factor of 20 percent (i.e. $2000/average kW), which corresponds to the current quoted price and capacity factor for the ALCOA 500 kW rated Darrieus aerogenerator installed at a high wind site ($\overline{v} = 7.6$ m/s at reference height 9.14m), then the total capital cost is $200 million or $25 million per annum. Assuming the ratio of oil to coal prices (in c/kWh(e)) remains approximately constant in WA, then an escalation of only 30 percent in fuel prices would make wind power economically viable in the model WA grid.

For the real WA grid, the recent policy of the State Energy Commission has been to convert some of the peak load oil burning units to intermediate load coal burning units with reduced capacity. One of the effects of these conversions is to reduce the economic value of wind energy as a fuel saver. Nevertheless, continued escalation of both oil and coal prices seems likely.

The above brief economic calculations have not taken into account environmental and health costs nor the scarcity value of non-renewable fuels. In the case of SA natural gas, the imposition of a substantial resource rent or depletion quota (10) might be advisable, in order to conserve a scarce resource. A fuller accounting of the costs of different means for generating electricity for the WA and SA grids is likely to be more favourable to wind power than a narrow economic comparison.

However, in isolated towns situated on the very windy south coast of WA – e.g. Esperance, Hopetoun and Bremer Bay – wind power is likely to be already economically competitive as a fuel saver for the diesel sets of those towns.

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