Report to

The Independent Market Operator

Supplementary Analysis of Capacity Valuation Metrics

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VERSION

Version	Date	Comment	Approved
Draft 0.1	24 February 2010	Initial draft	Ross Gawler
Draft 0.2	3 March 2010	Amended comments about impact of changes to plant reliability arising from additional decommitments	Ross Gawler
Draft 0.3	17 March 2010	Amended title for Table 2-3	Ross Gawler
Draft 0.4	25 March 2010	Added further commentary in response to comments received	Ross Gawler
Draft 0.5	26 March 2010	Analysed the impact of additional wind generation on the level of reliability (in progress)	Ross Gawler
Draft 0.6	30 March 2010	Added analysis of loss of load probability capacity value versus penetration	Ross Gawler
Draft 0.7	12 April 2010	Further explanation in sections 2.5 and 2.9.	Ross Gawler

1 INTRODUCTION

This supplementary report contains additional information on the capacity valuation of intermittent generation following consultation with the Office of Energy, Verve Energy, the Oates Committee and System Management. Issues arising from this preliminary consultation were:

- It was noted that the uncertainty in the reliability equalisation analysis took account of the sampling error but not the inherent uncertainty in the incidence of the wind output that was applied in the modelling of the wind output.
- It was confirmed that the capacity valuation did not take account of the effect that increasing wind penetration would increase the stopping and starting of thermal units and may thereby cause a deterioration in their reliability. Such an effect would reduce the capacity value of intermittent generation because more scheduled capacity would be needed to compensate for the loss of performance on the cycling plant.
- The analysis should show the effect of doubling the existing wind resources based on new turbines closely located with existing wind farms. More work is needed on the penetration effects once the preferred approach for valuing intermittent generation capacity has been confirmed.
- More analysis was requested on considering less trading intervals for the purposes of calculating average output. Specifically 60 and 160 trading intervals were proposed as alternatives. This report presents the new data for these periods.
- It was also requested to review the capacity that would be assessed using the 12 trading intervals that are included in the analysis of reserve capacity performance, being the three highest loads on the four days with the highest daily energy. This report presents the new data for these periods.
- If trading interval methods are to be applied, then it would be more accurate to select the relevant periods based on maximum load for scheduled generation, having regard to penetration of intermittent generation, rather than the system load profile. The effect of using such a method is discussed in this report.
- The draft report presented charts of the correlation of wind farm output at 4 pm on the hottest of days with the maximum daily temperature. A question was raised as to whether any of these observations of wind farm output were based on simulated outputs from winds speeds rather than measured outputs. There was a concern that there may be some temperature derating of wind farm generating plant. The analysis of wind output at 4 pm under high temperatures should be shown with actual and simulated outputs shown separately. Wind farm outputs were simulated for 2003 and 2004 calendar years based on a power curve and wind speed observations. These should be considered separately from actual output values.
- The basis of the simulated values of wind farm outputs was questioned.

In response to presentations made by Ross Gawler of MMA and feedback received, questions were raised as to whether the level of expected unserved energy would increase as more intermittent generation is added to the system, such that the expected unserved energy with the current 8.2% reserve margin factor could be exceeded. This matter refers to the question of the sensitivity of the analysis to intermittent generation penetration level and whether a particular policy is viable irrespective of the level of penetration. It is concluded that the proposed mechanisms whether based on suitably chosen peak demand periods, or loss of load probability modelling can be adapted to ensure that capacity credits would be properly assessed consistent with the system reliability criteria as they may evolve over time. This outcome depends on how the reliability standard is adapted to the changing plant mix and power system economics. Even given the current formulation of the reliability standard, the proposed capacity valuation methods would ensure that expected unserved energy does not exceed 0.002% on average over time.

A further question concerned whether the performance could be aligned with the rationale behind the 8.2% reserve margin factor directly, with regard to more extreme events of system load shedding or other measures of reliability such as mean time between failures or loss of load hours, or the incidence of major events well above 0.002% in a single event. There is no objection definition in the Market Rules of the basis of the 8.2% reserve margin factor in reliability terms so it was not possible to make such an assessment. However the MMA modelling did show that basing the analysis of capacity value on a more reliable system delivering some 0.0004% unserved energy did not change the assessed equivalent capacity materially.

It was also queried how the proposed methods would influence the loss of load probability at the 10% POE peak demand and how the assessment of capacity value would vary as the penetration of wind power increased. This was assessed by using the existing wind profiles for Albany, Emu Downs and Walkaway and scaling up the wind penetration whilst adding base load demand to keep the system reliability constant. It was thereby assessed that between 1200 and 1500 MW of wind could be added whilst keeping the maximum loss of load probability in any trading interval below 50% with the reserve margin factor of 8.2% in the period to 2016/17.

The Office of Energy has proposed that a risk adjusted capacity value be defined that would have a 90% probability of being exceeded with respect to the uncertainty in the performance of intermittent generation within each technology class (wind, solar thermal, solar photovoltaic etc). The Office has also proposed a moving three year averaging process whereby a new assessment is made each year based on the previous years fleet performance and the new value is averaging with the assessed values from the two prior years. This approach would provide a conservative and less volatile outcome than basing the capacity measure on the actual or projected performance over the last 10% POE and 30% POE years which would be more accurate on average but much more volatile as new data become available. The method would create additional conservatism as more technology groups are added because each group would be assessed at the 90% level, rather than the combined fleet as a whole.

MMA accepts that the Office of Energy approach would be a viable option, although there are some practical difficulties in developing a standard method for assessing the inherent volatility of the metric that could apply to each technology fleet. MMA's work could provide the basis for acceptance of a standard approach to volatility measurement but the focus on the details and the lack of neutrality with respect to technology may be used by proponents to dispute the capacity credit value.

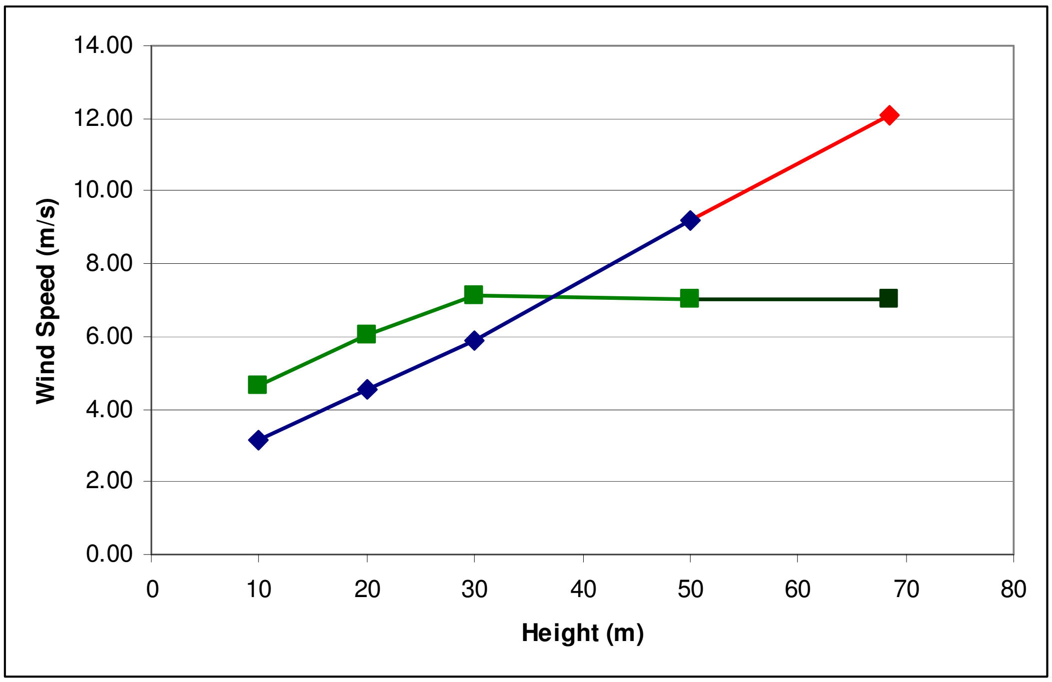
It is considered that the averaging method is fit for the intended purpose, it is consistent with the way the reliability of scheduled generation is assessed in aggregate for reliability assessment, it is simple to apply in an objective way across technologies, and it maintains the support for renewable energy which has longer term risk mitigation value with respect to climate change. The volatility can be mitigated by using the three year averaging method proposed by the Office of Energy and by choosing additional trading intervals for the assessment. There appears to be no undue bias in using 750 trading intervals versus 250 trading intervals for the wind and solar thermal technologies. Thus there is an opportunity to reduce the volatility without loss of accuracy.

2 ANALYSIS

2.1 Basis of simulated values

The output of WF3 for 2003 and 2004 calendar years was based on wind speed measurements at 20, 30 and 50 m heights with extrapolation to 68.5 n hub height by assessment of wind shear versus height. An example of two periods for this calculation are shown in Figure 2-1. The extrapolated wind speed versus height is shown in another colour. Where there was an apparent levelling or decline the wind speed below the 50 m level, the wind speed at 68.5 m was kept at the 50 m level.

Figure 2-1 Example of wind speed estimation at hub height



The power curve was applied up to 21 m/s wind speed. Above that level the output was deemed to be zero.

2.2 Trading interval analysis

The analysis of wind and solar thermal outputs based on trading intervals was extended to include:

- The 12 trading intervals used to assess reserve capacity performance based on the three highest loading periods on the four days with highest daily energy demand;
- 60 and 160 trading intervals based on the highest system demand or highest load for scheduled generation;

- Weighting based on the incidence of peak demand or weighting based on the relative contribution to expected unserved energy. The latter method would be expected to better represent the impact on reliability of supply.

The relative weightings applied by these two methods are shown in the two right hand columns of Table 2-1. The weighting according to unserved energy gives a much greater impact for the 2003/04 capacity year. It also results in a much more volatile measure.

Table 2-1 Selection of Capacity Years

Capacity Year from October	Extremity of the Summer	Extremity of the Peak Demand	Nominated for Percentile of Exceedance	Weighting for USE	Proportion of USE (2012/13)
2003	60%	10%	10%	37.48%	90.2%
2004	75%	45%	30%	6.78%	6.1%
2002	15%	75%	50%	5.00%	0.9%
2006	70%	75%	70%	23.31%	1.9%
2008	50%	90%	90%	27.42%	0.9%

Source: NIEIR data and MMA analysis

Using less trading intervals increases the volatility of the measure because fewer periods of power output are used. However, it may increase the accuracy of the estimated value because it focuses better on the critical periods. The LOLP method showed that about 1% of periods (175 trading intervals) represents 98% of the risk of unserved energy.

2.2.1 Based on system peak demand

Table 2-2 shows the capacity valuation defined by the intermittent generation output at times of high system demand weighted over the five capacity year profiles according to the incidence of peak demand over the five reference years, or according to the relative contribution to expected unserved energy. The value shown as "12" refers to the twelve intervals selected for individual reserve capacity assessment under the reserve capacity mechanism as detailed in Appendix 5 of the Rules.

The values are compared to the results from the LOLP analysis. It would be expected that the weighting based on expected unserved energy would be a more accurate assessment of the impact on system reliability and such a weighting was applied for the LOLP based method. Generally the shorter trading interval analysis gives a result closer to that of the LOLP method. Based on the results of the LOLP method, and using the weighting based on unserved energy, the 160 trading intervals gives a closer match, as would be expected because 175 trading intervals represents 98% of the risk of unserved energy.

Table 2-2 Capacity valuation weighted according to incidence of peak demand

Trading Intervals	12	60	160	250	500	750	LOLP	Best Fit
Peak								
WF1	0.474	0.475	0.442	0.440	0.408	0.405	0.578	60
WF2	0.374	0.371	0.397	0.401	0.399	0.408	0.274	60
WF3	0.427	0.404	0.420	0.411	0.406	0.403	0.522	12
GPV	0.646	0.677	0.647	0.653	0.623	0.594	0.605	750
GST	0.880	0.809	0.749	0.757	0.693	0.656	0.708	500
IST	0.681	0.685	0.662	0.638	0.610	0.592	0.507	750
USE								
WF1	0.565	0.553	0.465	0.461	0.421	0.421	0.578	12
WF2	0.289	0.346	0.373	0.382	0.392	0.395	0.274	12
WF3	0.509	0.564	0.525	0.505	0.481	0.465	0.522	160
GPV	0.496	0.638	0.615	0.653	0.616	0.592	0.605	160
GST	0.753	0.771	0.722	0.767	0.678	0.641	0.708	160
IST	0.434	0.598	0.558	0.523	0.550	0.563	0.507	250

The use of the 12 IRCR trading intervals gives a similar result as for the 60 peak trading intervals in most cases. The Geraldton solar thermal plant is an exception because the 12 intervals include periods when full output at 100% was expected.

2.2.2 Based on load for scheduled generation

Basing the trading interval analysis on load for scheduled generation should give a more accurate assessment of the reliability impact as well as provide for the valuation related to penetration levels of intermittent generation that changes the timing of critical system reliability conditions. Table 2-3 shows the capacity valuation defined by the intermittent generation output at times of high load for scheduled generation weighted over the five capacity year profiles according to the incidence of peak demand over the five reference years, or according to the relative contribution to expected unserved energy. The 12 trading intervals are not included because they are defined according to system demand, not load for scheduled generation.

The values are again compared to the results from the LOLP analysis. Generally the shorter trading interval analysis gives a result closer to that of the LOLP method. Based on the results of the LOLP method, the 160 trading intervals gives the closest match, as would be expected because 175 trading intervals represents 98% of the risk of unserved energy.

On average the use of load for scheduled generation gives capacity values about 6% lower than according to system peak demand. MMA considers that the reference to load for scheduled generation would be an improvement to the trading interval method relative to referencing system peak demand.

Table 2-3 Capacity valuation weighted according to incidence of load for scheduled generation

Trading Intervals	60	160	250	500	750	LOLP	Best Fit
Peak							
WF1	0.451	0.442	0.435	0.406	0.400	0.578	60
WF2	0.337	0.372	0.379	0.376	0.386	0.274	60
WF3	0.359	0.400	0.394	0.383	0.383	0.522	160
GPV	0.624	0.620	0.620	0.593	0.561	0.605	500
GST	0.730	0.692	0.702	0.646	0.602	0.708	250
IST	0.624	0.625	0.595	0.572	0.551	0.507	750
USE							
WF1	0.495	0.462	0.454	0.422	0.417	0.578	60
WF2	0.313	0.351	0.362	0.369	0.384	0.274	60
WF3	0.502	0.510	0.486	0.455	0.453	0.522	160
GPV	0.563	0.597	0.626	0.597	0.572	0.605	160
GST	0.672	0.686	0.722	0.646	0.612	0.708	250
IST	0.522	0.524	0.487	0.522	0.539	0.507	60

2.3 Impact of uncertainty

The main disadvantage of using a lesser number of trading intervals is the greater volatility of the measure. The 80% confidence range in the capacity assessments versus trading interval duration is shown in Figure 2-2 for the wind farms based on system peak demand. Below 250 trading intervals the uncertainty band increases significantly as the trading interval duration reduces for the wind farms. This presents a significant barrier to adopting a shorter averaging period. Lesser trading intervals per year could be applied as there are more years of weather conditions to apply. This would enable improved accuracy for a given level of volatility of the capacity measure.

The equivalent data for the solar resources is shown in Figure 2-3. There is considerable volatility associated with the solar resources which makes selecting only 12 intervals quite volatile. MMA could not recommend such a principle for the purposes of determining a capacity value of solar or wind farm resources due to this high volatility in the measure.

When applying the trading intervals according to load for scheduled generation, the band of uncertainty for wind farms is as shown in Figure 2-4 and Figure 2-5 shows the results for the solar resources. The 12 interval case is not shown as this has not been defined on the basis of load for scheduled generation, although it could be.

For the solar resources, the uncertainty is less than for wind as seen by comparing Figure 2-4 and Figure 2-5. There would be less uncertainty in adopting a shorter period. However, for the solar resources, the assessed capacity for 750 trading intervals is similar

Figure 2-2 Confidence range of capacity value based on unserved energy distribution and trading intervals selected by peak load for the wind farms

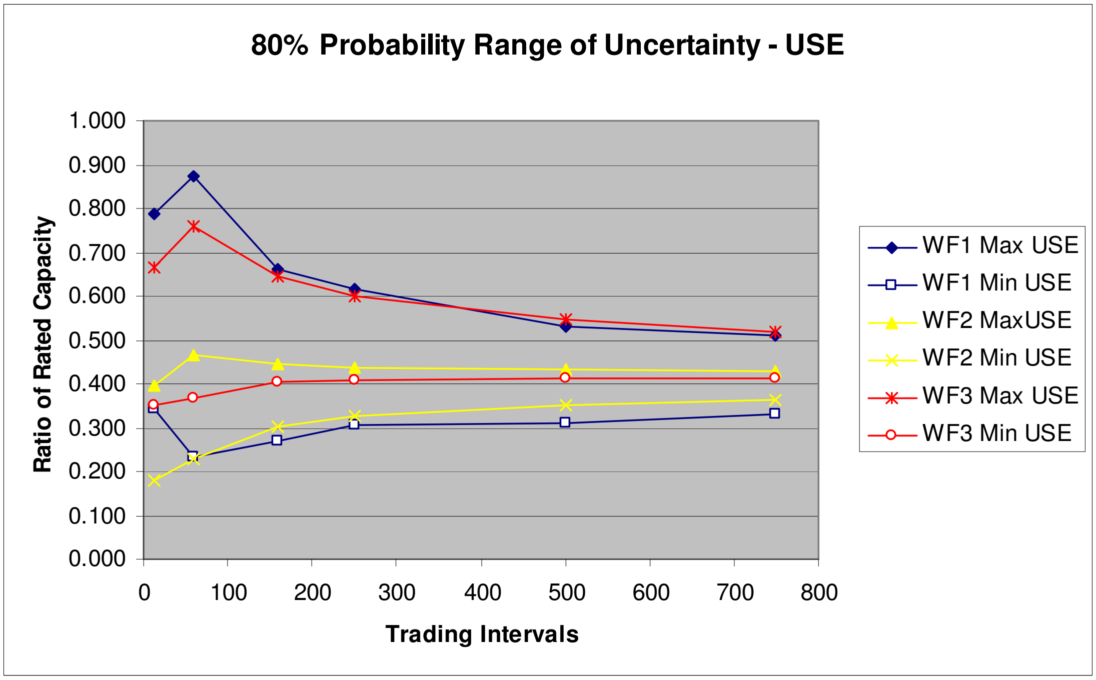


Figure 2-3 Confidence range of capacity value based on unserved energy distribution and peak load for the solar resources

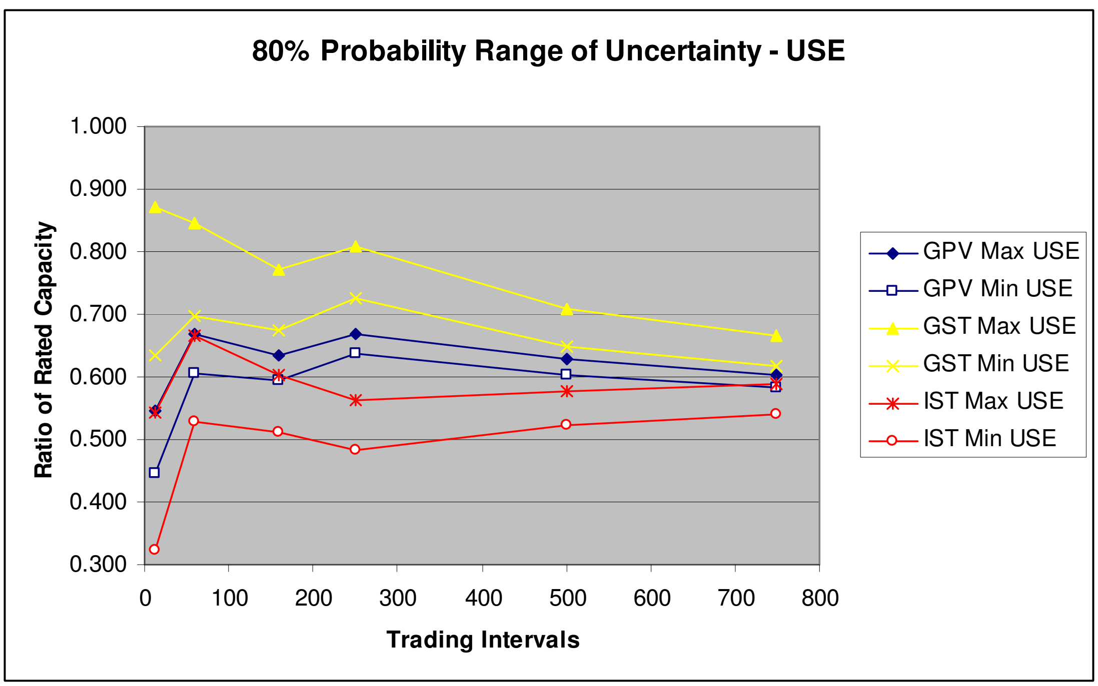


Figure 2-4 Confidence range of capacity value based on unserved energy distribution and load for scheduled generation for wind farms

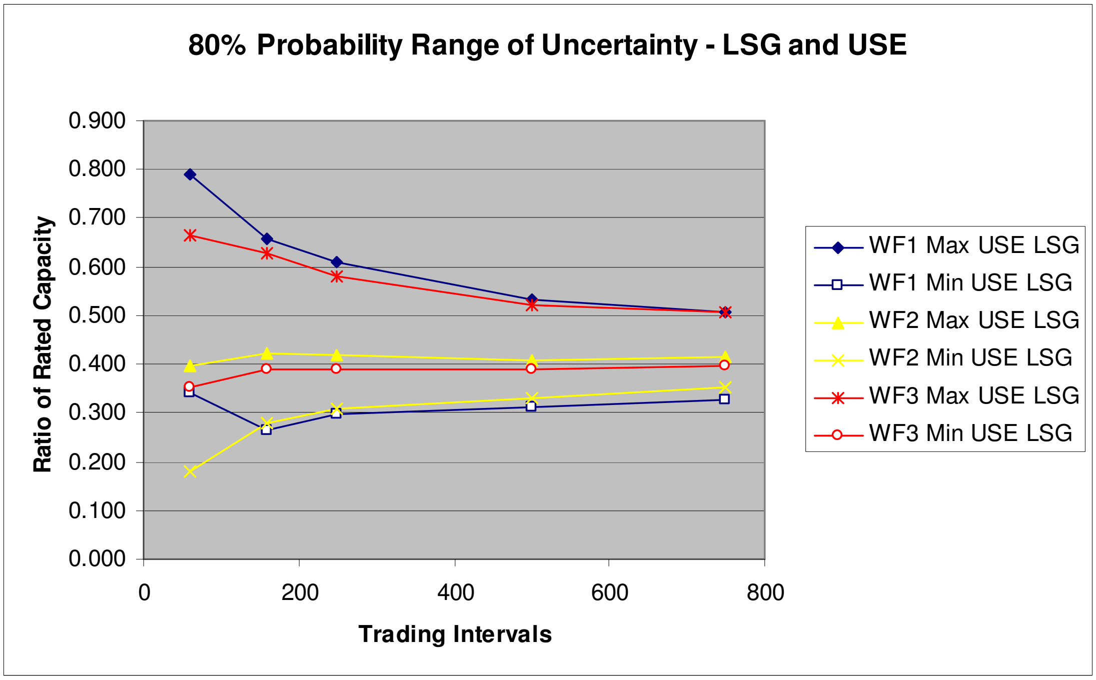
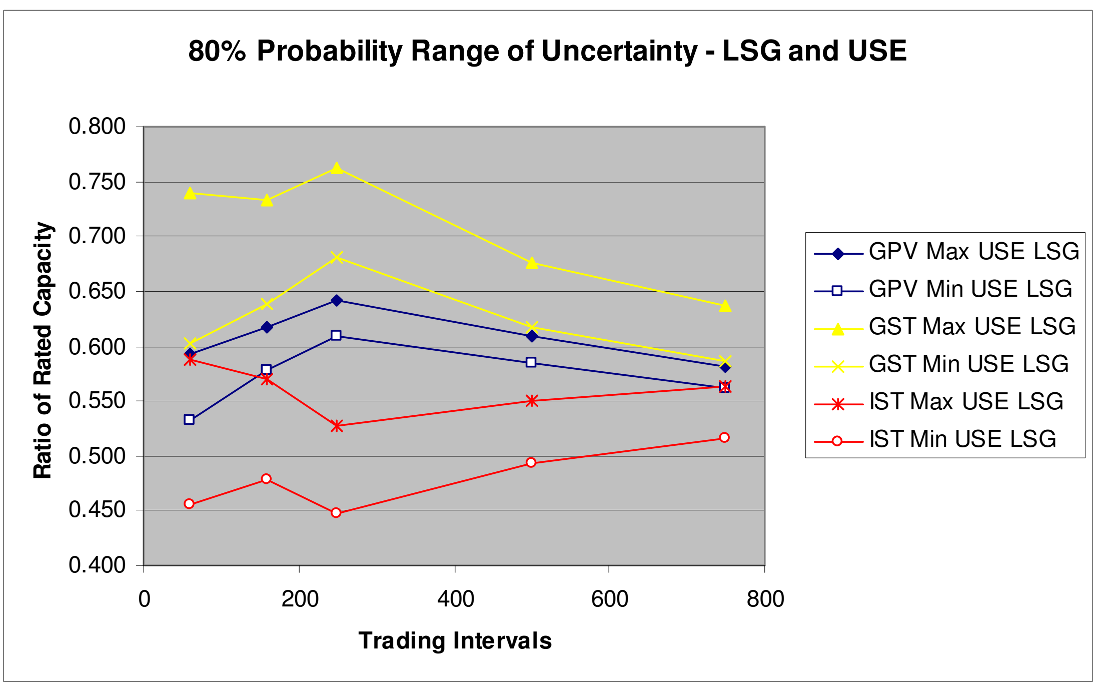


Figure 2-5 Confidence range of capacity value based on unserved energy distribution and load for scheduled generation for the solar resources

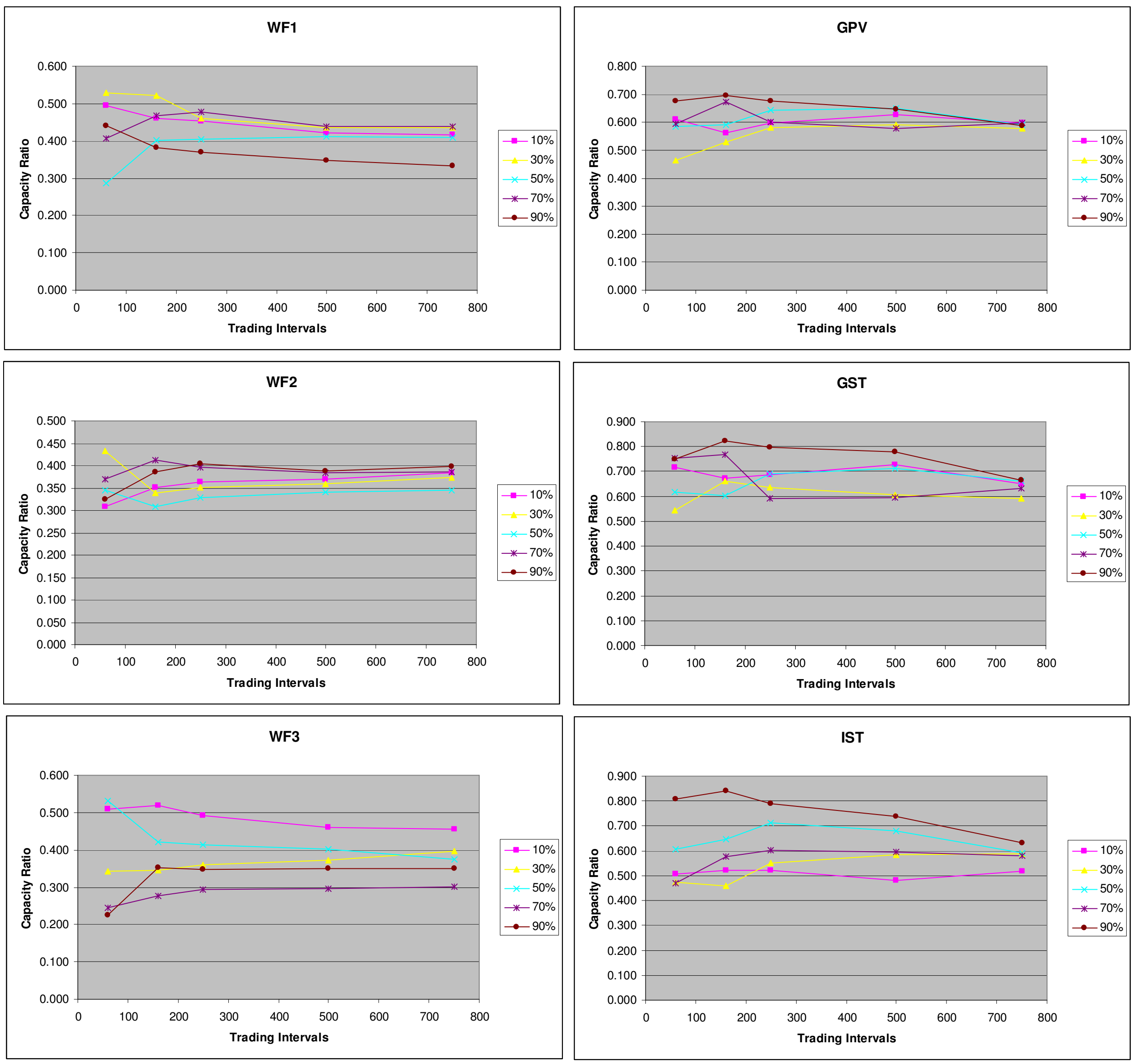


to that for the shortest period of 60 trading intervals. Given that the wind assessment does not seem to be too dependent on the length of the assessment period, at this stage it would seem more appropriate to use the longer period until the volatility of the assessment for shorter trading interval periods can be reduced.

2.4 Impact of year chosen

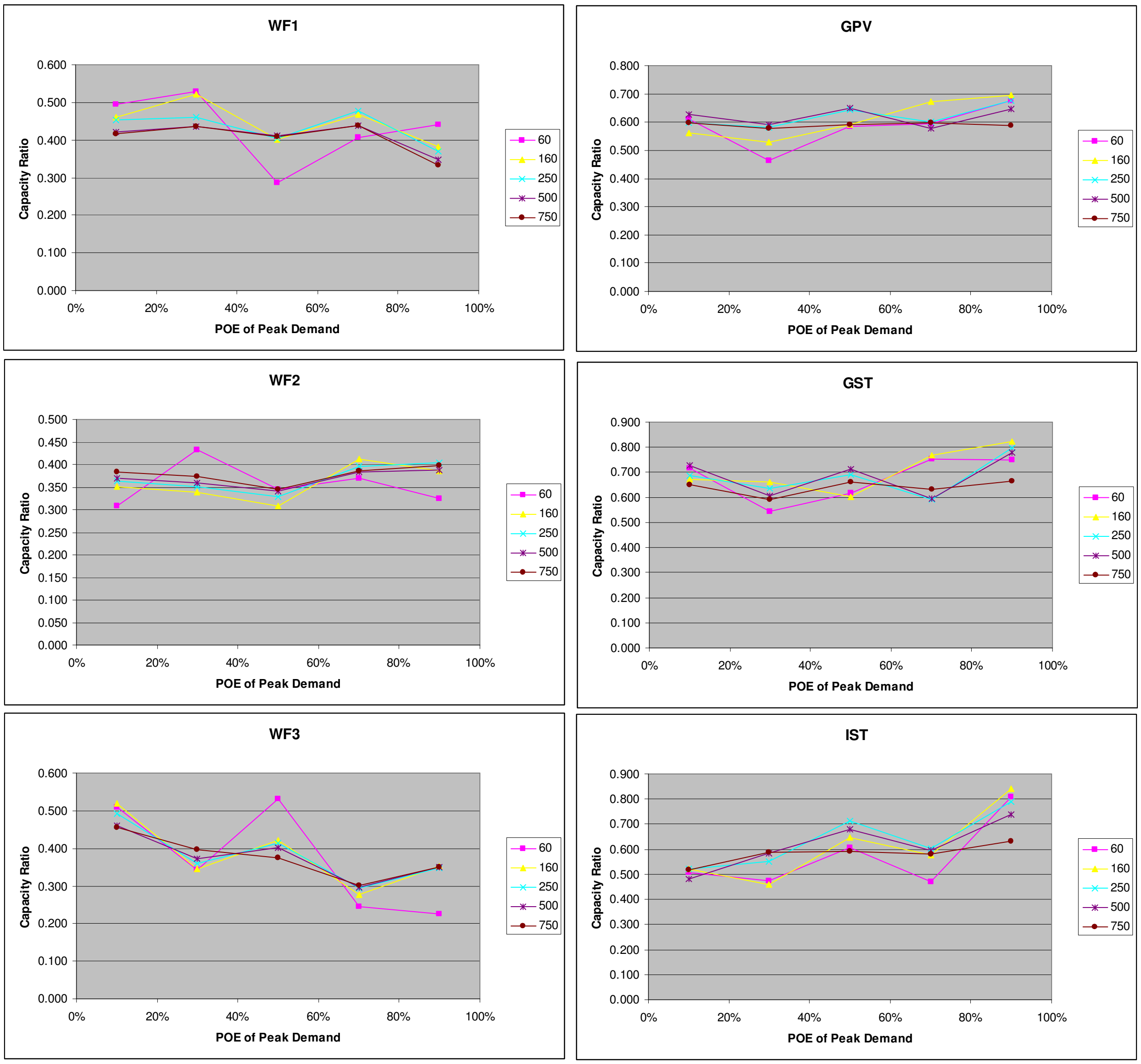
The question has also been raised about the extent to which capacity profiles assessed for particular years vary between the 10% POE year and the 90% POE year. These data are presented in Figure 2-6 for the calculation based on load for scheduled generation for each of the five capacity years that were analysed. The capacity values are shown versus the number of trading intervals for each of the profiles separately. There is more consistency among the profiles for the solar resources than for the wind resources. This reflects the greater volatility of wind output in relation to high levels of demand.

Figure 2-6 Variation of capacity value by capacity year profile



The same data are plotted versus POE of the peak demand in Figure 2-7. The solar resources have a slight bias to higher value for lower peak demand and the wind farms are the opposite, fairly independently of the trading interval assessment period.

Figure 2-7 Variation of capacity value by POE of peak demand



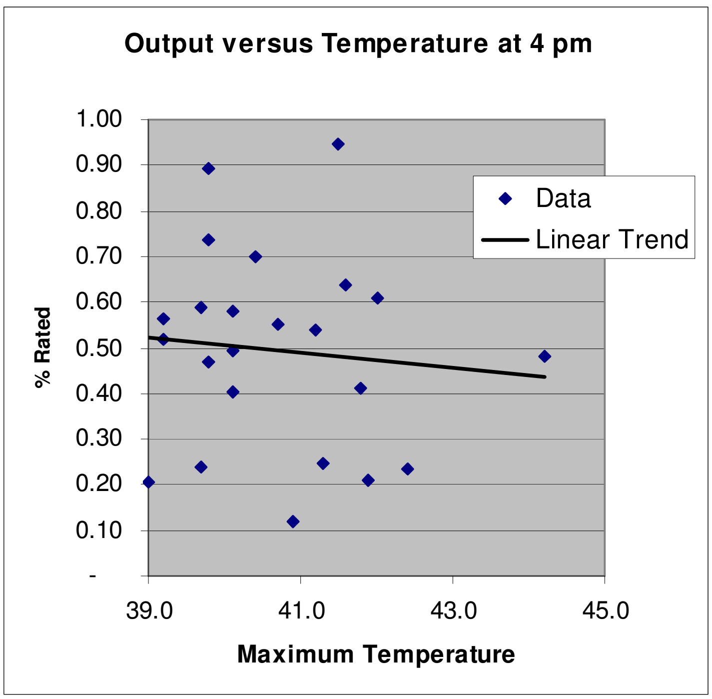
Theoretically, higher temperatures lead to higher peak demand and put more energy into the atmosphere which may cause higher wind speeds. Higher temperatures lead to more evaporation and ultimately more cloud cover which may reduce solar output. These trends may need to be considered in the light of further analysis of meteorological data on wind, temperature and insolation.

With respect to the immediate objective of developing a non-discriminatory and consistent way of assessing capacity, the focus should be on the 10% and 30% POE conditions as these cause system reliability to be put at risk. As compared to treating all profiles equally, giving greater weight to the more extreme conditions would result in a higher assessed capacity for wind and a lower assessed capacity for solar resources for the projects that have been analysed.

2.5 Output versus temperature

The draft report presented two charts of the correlation of wind farm output at 4 pm on the hottest of days with the maximum daily temperature. A question was raised as to whether any of these observations of wind farm output were based on simulated outputs from winds speeds rather than measured outputs. There was a concern that there may be some temperature derating of wind farm generating plant. In Figure 2-8, the data for WF2 related only to measured outputs. There were no simulated values used. Thus the assessment is robust for the sensitivity to temperature.

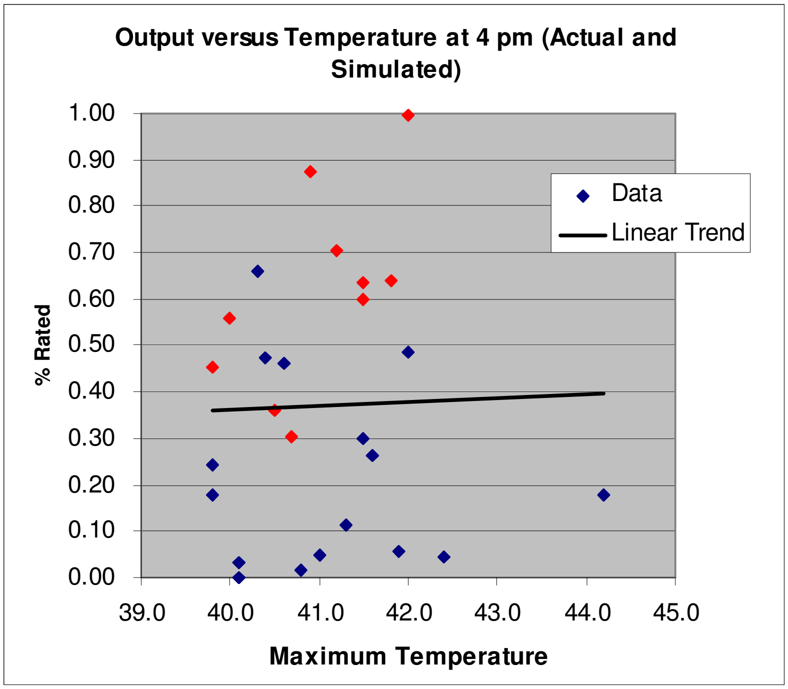
Figure 2-8 Wind output versus maximum daily temperature (WF2)



However, for WF3, some simulated values were used based on wind speed observations, extrapolation of wind shear to 68.5 m hub height based on wind observations at 20, 30 and 50 m height and a power curve with the wind data assessed on a 10minute basis and the power values averaged. The data presented previously included 10 simulated outputs as shown in red in Figure 2-9. It is apparent that these simulated values are generally much higher than the corresponding actual values for WF3.

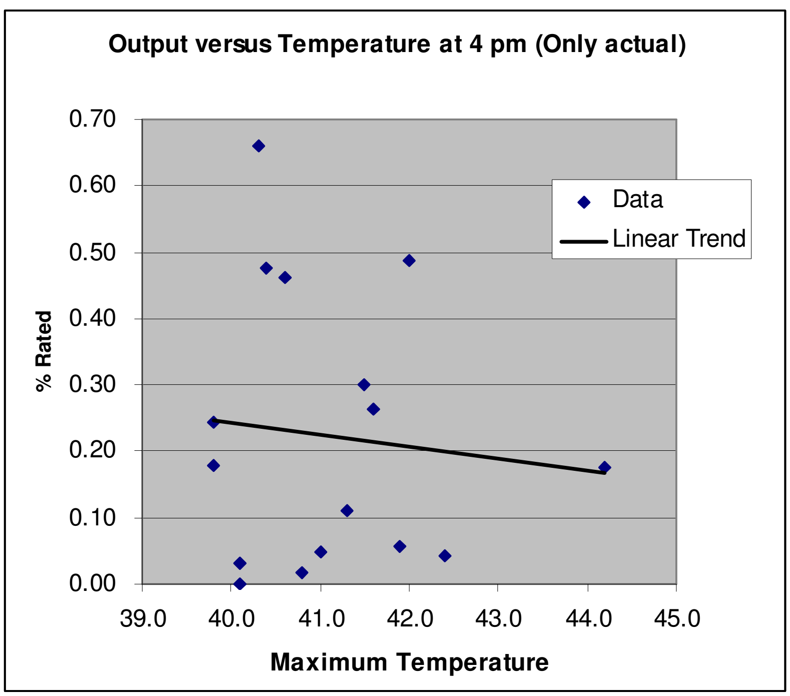
When the simulated values are removed, the trend line is much less favourable as shown in Figure 2-10. This result is much less favourable than for WF2. It shows that some further investigation is needed on the performance of WF3 and why the simulated values were much higher than the actual for equivalent conditions. There may be some temperature related performance limitations for this wind farm which are not adequately

Figure 2-9 Wind output versus maximum daily temperature (WF3)



Note that the red diamonds represent output estimated from wind speed data, whereas the other values are measured output.

Figure 2-10 Wind output versus maximum daily temperature (WF3) for actual observations



represented by applying only the turbine power curve. At least the simulated data shows that measured wind speeds tend to increase with maximum ambient temperature, even if the dispatched values may be higher than is realistic given other potential limitations of the wind farm.

2.6 Impact of decommitment on base load plant reliability

It was confirmed that the capacity valuation did not take account of the effect that increasing wind penetration would increase the stopping and starting of thermal units and may thereby cause a deterioration in their operating reliability. Such an effect would reduce the capacity value of intermittent generation because more scheduled capacity would be needed to compensate for the loss of performance on the cycling plant.

No evidence has been offered or assessed to show that additional decommitment of units has occurred due to the current and future levels of intermittent generation and then caused a deterioration in performance. Additional decommitment could also be caused in the future through the addition of the Bluewaters units and the Kwinana CCGT. Therefore identifying the cause of any reliability problems and allocating any discount in capacity to the base load units and the intermittent generation would be a complex and potentially controversial process.

It would be arguable that if any resource whether schedulable or not causes a reduction in the performance of other plant, then its capacity rating could be discounted if the objective is to measure its contribution to total system reliability. Similarly, a storage device which reduces unit cycling could potentially gain an extra capacity credit.

MMA has not seen such a methodology which values the consequential effects on system reliability applied elsewhere and would not recommend this course of action based on the current state of knowledge about the Western Australian market. It may become beneficial if it were necessary to discourage very high levels of penetration of intermittent generation that could not be accommodated by economic means through market mechanisms. Such a market state is not currently anticipated and the proposed methods for valuing intermittent generation capacity are suited to the next five years at least.

2.7 Impact on unserved energy level

Greg Thorpe of Oakley Greenwood for the Oates Committee raised the question as to whether the expected unserved energy would rise as the penetration of intermittent generation is increased in the SWIS, and assuming that the reserve margin factor is not increased above 8.2% as currently formulated in the Market Rules.

This matter has not been explicitly studied and it is difficult to be definitive about the issue without detailed and specific analysis. The magnitude of the impact would depend on which option for capacity valuation is adopted. For the current 8.2% reserve margin factor, the expected unserved energy is about 0.0004%. For a given reserve margin factor and load profile, the expected unserved energy would increase with respect to forced outage rate and the amount of scheduled maintenance. If wind plant replaces reliable controllable plant at a capacity level that maintains 0.002% expected unserved energy, irrespective of any other constraint on reserve margin, then it would be expected that the expected unserved energy would increase toward 0.002% with increasing penetration. The expected unserved energy could never exceed 0.002% if such a method were applied consistently with that objective. However, the assessed reserve margin factor may well exceed 8.2% for very high levels of wind penetration, even if calculated based on the discounted capacity for wind generation.

All of the methods proposed for consideration:

- reliability equalisation to meet 0.002% expected unserved energy
- LOLP weighting with adjustment of system conditions back to 0.002% expected unserved energy
- averaging output across trading periods when load for scheduled generation is at its highest value

inherently take account of the penetration effects. However the averaging method may not exactly match to the volume of unserved energy as precisely as do the reliability based methods (ignoring issues related to data quality).

MMA would expect that any method adopted would be considered during the five yearly review of the reliability standard and that the reserve margin would be increased as necessary to maintain reliability within the unserved energy standard. As long as the equivalence between intermittent generation value and controllable capacity is maintained with respect to system reliability, then there would be no discrimination among technologies. If the averaging method is adopted now as an interim stage of development then its reliability equivalence should again be reviewed when the reliability settings are next reviewed.

It is concluded that the proposed mechanisms whether based on average output at times of peak load for scheduled generation, or loss of load probability modelling, can be adapted to ensure that capacity credits would be properly assessed consistent with the system reliability criteria as they may evolve over time.

2.8 Relevance to the 8.2% reserve margin factor

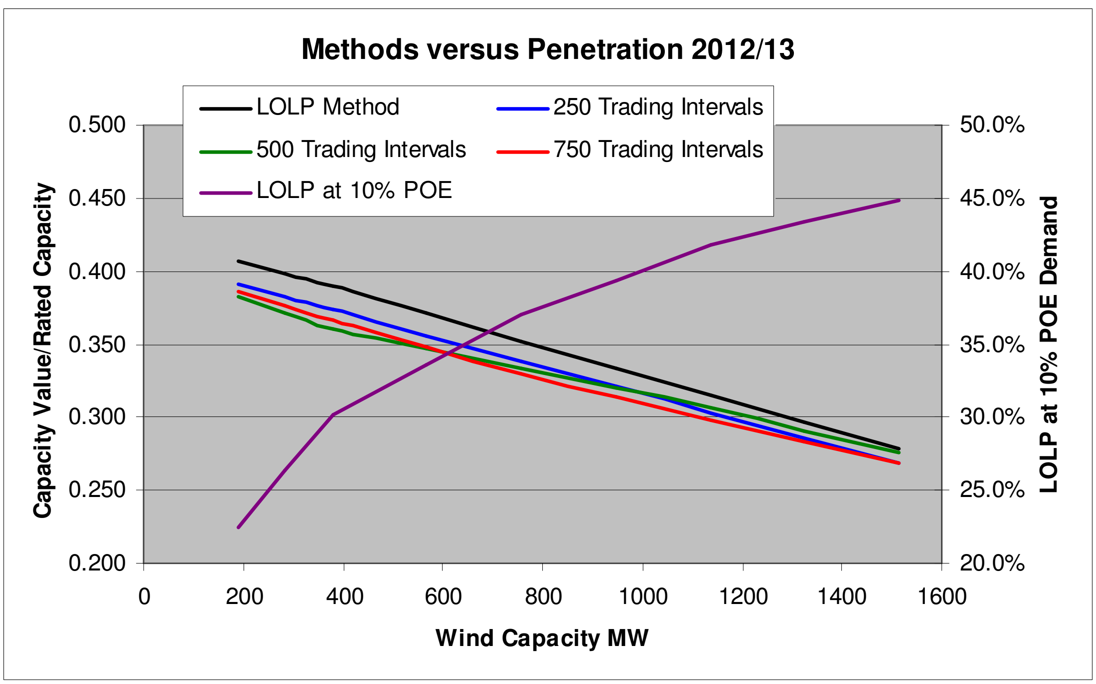
A further question concerned whether the assessment of equivalent capacity could be aligned with the rationale behind the 8.2% reserve margin factor directly, with regard to more extreme events of system load shedding or other measures of reliability such as mean time between failures, loss of load hours, or the incidence of major load shedding events well above 0.002% in a single event. There is no objective definition in the Market Rules of the basis of the 8.2% reserve margin factor in reliability terms so it was not possible to make such an assessment. However the MMA modelling did show that basing the analysis of capacity value on a more reliable system delivering some 0.0004% unserved energy did not change the assessed equivalent capacity materially in the next five years.

2.9 Capacity valuation versus wind penetration

It was queried how the proposed methods would influence the loss of load probability at the 10% POE peak demand and how the assessment of capacity value would vary as the penetration of wind power increased. This was assessed by using the existing wind profiles for Albany, Emu Downs and Walkaway and scaling up the wind penetration whilst adding base load demand to keep the system reliability constant. The system reliability was measured as the sum of the trading interval loss of load probabilities as discussed in the original draft report section 6.6.1.

Figure 2-11 shows the results of the valuation of capacity using both LOLP and trading intervals methods based on the load for scheduled generation assuming no diversity for additional wind farm outputs. Also shown is the maximum loss of load probability in the system profile with 10% POE peak demand. It ranges from 22% to 45% from 189 to 1514 MW of wind farm capacity. The capacity value progressively declines in an almost linear pattern as wind farm capacity in creased. This case has a reserve margin factor of 7.3% so it represents a condition that does not quite meet the reliability requirement. The aggregate wind farm capacity ratio declines from 39% to 27% over the range studied.

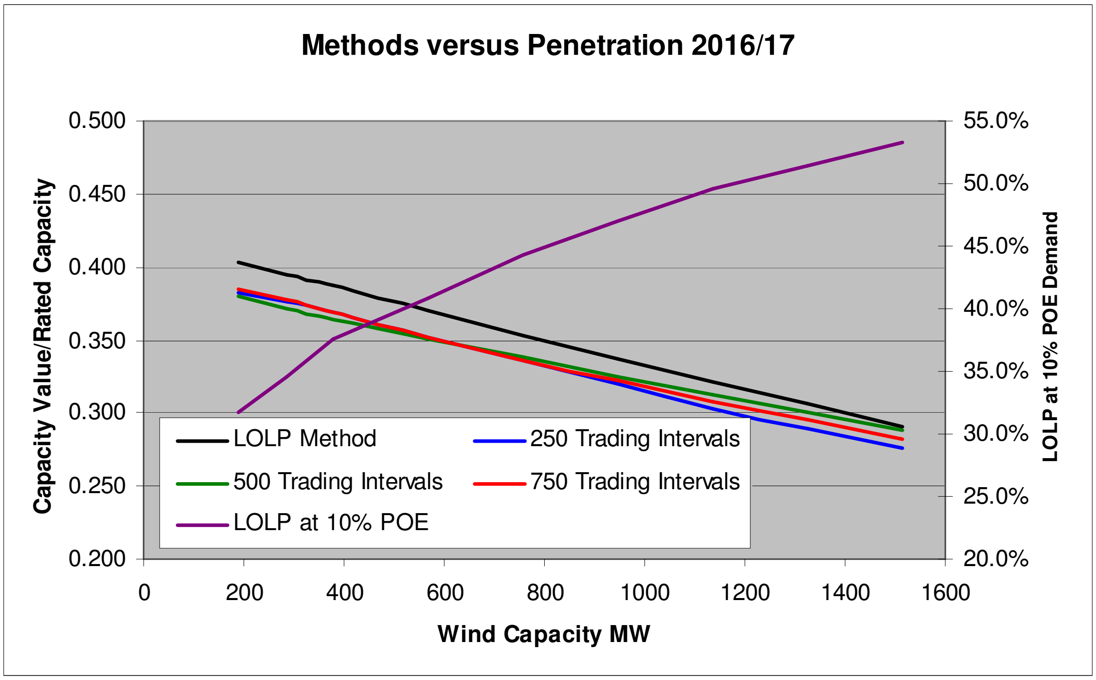
Figure 2-11 Capacity valuation versus penetration for 2012/13



This result affirms the expectation that as more intermittent generation is added the reliability benefits would decrease unless there is diversity in the additional resources. Assuming that 50% probability of load shedding is accepted as the maximum tolerable, it is considered that up to 1,500 MW of wind could be added in 2012/13 even if other resources were withdrawn from the market without jeopardising reliability of the system.

The equivalent results for 2016/17 are shown in Figure 2-12. This case has a reserve margin of 6.66% and so is a little less reliable than the 2012/13 result. Accordingly the maximum loss of load probability is 50% at 1200 wind penetration. The linear tend versus wind capacity is the same although it declines more slowly with wind capacity as the system is larger by that year.

Figure 2-12 Capacity valuation versus penetration for 2016/17



The use of 750 trading intervals provides some conservatism relative to the LOLP methodology. The general trend versus installed wind capacity is that this conservatism is sustained over the range of wind capacity that was studied.

It id therefore assessed that between 1200 and 1500 MW of wind could be added whilst keeping the maximum loss of load probability in any trading interval below 50% with the reserve margin factor of 8.2% in the period to 2016/17.

2.9.1 Impact on individual wind farms

The impact of the wind farm penetration was assessed for each wind farm as shown in Figure 2-13 for 2012/13. The equivalent data for 2016/17 is shown in Figure 2-14. Note that the capacity falls more slowly for WF1 which is not correlated with the outputs of WF2 and WF3. Moreover, the output of WF2 and Wf3 is correlated at about 49%. So it is reasonable that their capacity value should decrease more rapidly with wind penetration since their output is highly correlated with the aggregate wind output.

Thus the proposed method does represent the impacts of high penetration of intermittent generation and would create risk for new entrants that choose sites near existing facilities that have a high correlation of generation on a trading interval basis.

Figure 2-13 Sensitivity of wind farm capacity ratios to penetration 2012/13

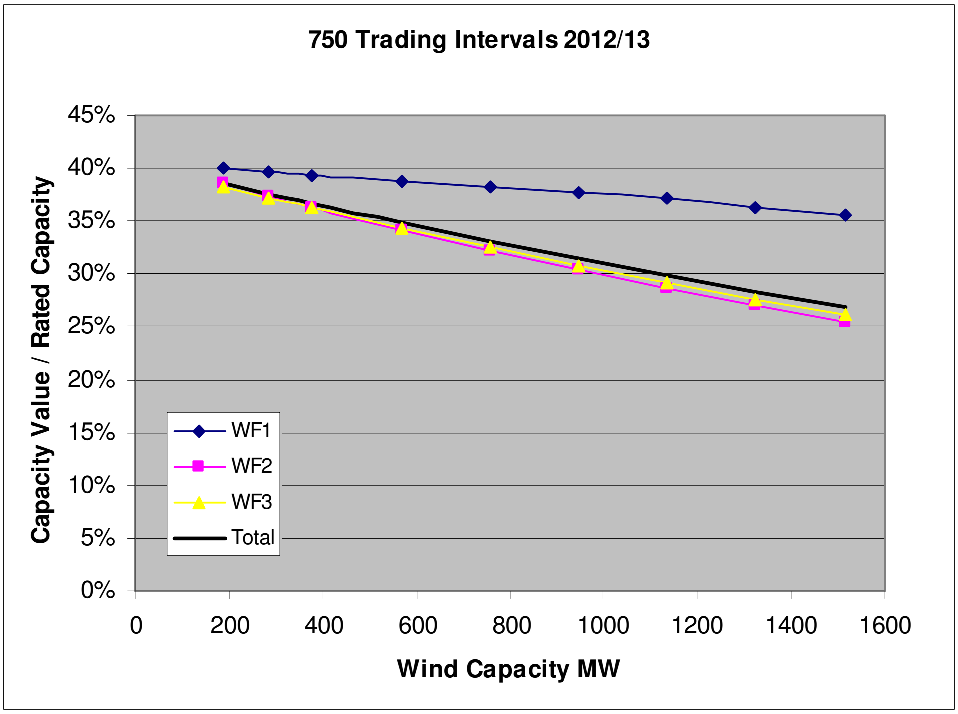
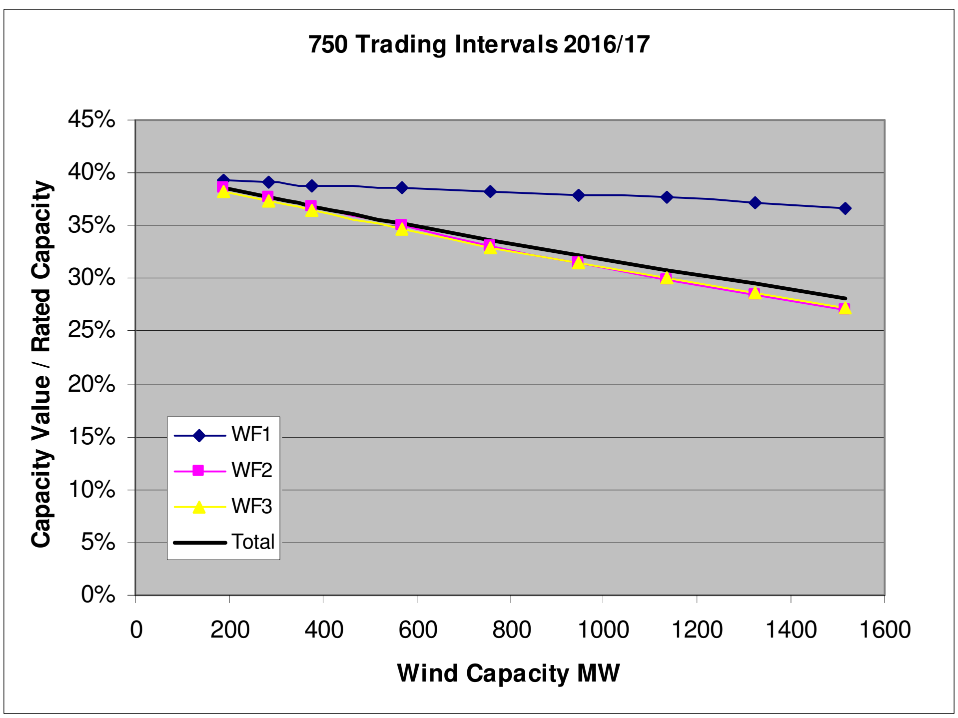


Figure 2-14 Sensitivity of wind farm capacity ratios to penetration 2016/17



2.10 Office of Energy and volatility of measure

The Office of Energy (OOE) response highlighted concern about the volatility of the capacity measures and recognised that this was inevitable due to the limitations on the available performance data for the existing and prospective intermittent generators. The OOE submission highlights the difficulty of obtaining a robust quantification of the relationship between weather, system demand and the output from specific intermittent generation resources as these are mostly one in ten years events. Using 10% POE and 30% typical years of data is not sufficient to obtain a robust result due to the high importance of the 10% POE system conditions and the resulting impact on volatility of the capacity metric.

The OOE's submission proposes the following method of assessing capacity value for consideration:

2.10.1 Proposed Method

Rather than applying the data from selected years that represent the 10% and 30% POE peak demand conditions, the OOE's method assumes that every year of data is used with equal weighting.

1. Identify for the relevant year(s) the top 250 periods which experienced the highest load for scheduled plant.
2. Estimate in percentage for each technology fleet, the 80% confidence range for the annual average output over the selected periods, considering as many years as have data available.
3. For the particular intermittent generation plant, determine the average output over the selected periods for the previous year of actual data (existing plant) or modelled data (new plant).
4. Discount the value determined under step 3 by half of the 80% confidence range for the technology fleet (determined in step 2) to approximate the value with 90% probability of exceedance, while acknowledging the value of fleet diversity.
5. Assign capacity to the plant for the next year at the average of the amount calculated in step 4 and the amounts assigned in the previous two years. This provides a moving average of the three latest annual assessments.
6. For new plant where previous assignments have not been made, perform steps 3 and 4 for the years where there has not been an assignment, and then average the three years.

This method is practical in principle, with some refinements and clarifications:

(a) The data in Figure 2-6 and Figure 2-7 above do not show any obvious trend of average values over the various candidate years according to the extent of peak demand or according to the averaging period over the range from 160 to 750 trading intervals. This evidence supports the approach that a longer averaging period can be used to reduce volatility without any gross inaccuracy given the data we have to date. Thus the proposal by the OOE would be practical even though it doesn't give the theoretically appropriate weight to the more extreme years in terms of peak demand. The use of a three year averaging process would reduce the volatility of year to year changes if based on the values set in the previous two years and a 90% confidence value for the latest completed year.

(b) A standard method would need to be approved for assessing the correlation of the outputs of the various technology fleets along the lines of the methods developed in the draft MMA report. This is necessary to estimate the volatility of the averaging metric. Note that wind and solar resources needed quite different representations of inter-trading period correlation. The disadvantage of using confidence levels rather than averages is that they are even more difficult to define objectively than are the average values. This would be expected to create the opportunity for criticism concerning the neutrality of measures for various technologies. This is why MMA has not recommended using more conservative measures than the averages which do align in magnitude with the values obtained using the loss of load probability method.

(c) One important objective of the process would be to provide a tool that would allow proponents to make their own capacity assessments. The standard method of volatility assessment would need to take into account this requirement. IMO would need to develop an approved method for each technology class based on historical energy data or project modelled data. This would be a problem for new and emerging technologies. The question of call definition may become contentious.

(d) Once there is more than one fleet type (say solar thermal as well as the incumbent wind), there would be more conservatism in the measure as each fleet would have a 90% value rather than the intermittent portfolio as a whole. It would be more accurate to measure the volatility over the whole portfolio if a suitable and credible method could be developed.

(e) It should also be recognised that a workable methodology must address the impact of penetration levels and the time shift in critical system loading as penetration increases. To that end the selection of the critical 750 trading intervals should be conducted by scaling the historical load shape to represent the forecast demand in the future capacity year and then the critical periods would be selected based on the future penetration of intermittent generation rather than the immediately prior year. The only data that would be applied without alteration would be the intermittent generation profile adjusted for any losses due to abnormal system conditions.

The main unresolved issue would be to confirm a consistent methodology for estimating the uncertainty of the averaging measure given observations of wind power and solar thermal output power over a suitable class of high load periods.

2.11 Recommendation

In view of these potential difficulties with the development of standard measures of volatility, MMA recommends that averaging be regarded as the preferred method with volatility reduced through moving averaging as proposed by the Office of Energy and using more trading intervals to assess the value. The conservatism would be initially achieved by averaging over additional trading intervals than are strictly appropriate for obtaining an accurate assessment assuming that sufficient years of data are available. At this stage 750 trading intervals does not seem to be too many, and is therefore recommended by MMA. Periodically, the IMO would review the available data on intermittent generation in relation to system conditions and confirm whether the prevailing measures adequately match the capacity values that would equalise reliability performance in accordance with the prevailing standard.

On the basis of the analysis versus penetration in section 2.9, and the analysis presented in the main report, it would be convenient and less contentious to adopt 750 trading intervals as the averaging period and not rely on assessing the volatility of the capacity metric for each project. This method is conservative for wind and solar technologies based on the project data provided for analysis in this project. It is conceded that this is not necessarily the most accurate method on an expected value basis, but it does provide for some discount to reflect the uncertainty in the loss of load probability analysis of capacity value.

3 CONCLUSIONS

This supplementary work has confirmed that trading interval averages could be better based on high levels of load for scheduled generation rather than system peak demand. This would reduce assessed capacity by about 6%, would be conservative and would provide for the inclusion of penetration effects.

The poorer performance of WF3 under high temperature conditions needs to be investigated before confirming a basis for assessed capacity based on simulated half-hourly dispatch for 2003/04 capacity year based on wind speed measurements.

Assessments based on 10% and 30% POE peak demands would be more accurate than basing the calculation on an equal treatment of possible peak demand profiles or weighting them according to the incidence of peak demand but would have higher volatility. This more realistic approach would give a slightly higher capacity value to wind farms and a lower capacity value for solar resources. However the additional volatility tends to undermine the value of the accuracy, so it may be acceptable to base the capacity measure on annual observations irrespective of extreme peak demand conditions until more data of performance under extreme conditions becomes available.

Basing a capacity value on outputs over the 12 trading intervals applied for the IRCR would not produce a useful measure due to very high volatility.

It is concluded that adjusting measures according to assessed volatility would produce a more conservative result which would be appropriate if intermittent generation is not subject to capacity refunds. However, there is likely to be some difficulty in assessing a volatility measure on a technology neutral basis that would not provide scope for gaming, contention and inequity. MMA recommends that an averaging method based on 750 trading intervals and a three year moving average assessment as proposed by the Office of Energy be proposed as the next step. If a measure of volatility can be agreed by stakeholders, well and good, but it is likely to be too conservative and too contentious if applied separately according to technology based fleets.

It should also be recognised that a workable methodology must address the impact of penetration levels and the shift in critical loading as penetration increases. To that end the selection of the critical 750 trading intervals should be conducted by scaling the historical load shape to represent the forecast demand in the future capacity year and then the critical periods would be selected based on the future penetration of intermittent generation rather than the immediately prior year.

The analysis of the impact of wind farm penetration on the capacity value and the maximum loss of load probability indicates that the proposed method with trading interval or loss of load probability metrics should be satisfactory in maintaining system reliability at an acceptable level for up to 1,200 to 1,500 MW of wind farm capacity up to 2016/17 based on medium growth. It is therefore recommended that the methodology be reviewed when 1,200 MW of wind farm capacity is approached or 1,500 MW is foreseeable.