The Treatment of Intermittent Generation in the SWIS Capacity Market

Review of Certified Reserve Capacity Calculation Methodologies for Intermittent Generators

Senergy Econnect Project No: 2413

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Executive Summary

Senergy Econnect Australia (SEA) has been contracted by the Office of Energy in Western Australia (WA) as an independent expert to undertake a review of the treatment of intermittent generation in the Reserve Capacity Market (RCM) through undertaking a comparison of existing and potential Reserve Capacity Credit allocation rules for intermittent generators.

This study undertakes statistical analysis which quantifies the interaction between intermittent generation and system load based on available intermittent energy resource and generation data. A variety of calculation methodologies are applied to historical and simulated data to assess the impact the different calculation methodologies have on the allocation of Capacity credits in the Reserve Capacity Market.

Intermittent generation may also have implications for other aspects of the Reserve Capacity Mechanism. For example, a substantial increase in the reserve margin may be required to allow for ancillary services needed to manage variability in wind generation. While this could have significant commercial ramifications for intermittent generators in the future, it is addressed in other work streams of the Market Advisory Committee. In line with market operation, network constraints or support are also not considered here.

The analysis is not a review of the Reserve Capacity Mechanism framework, nor does it quantify the contribution intermittent generators may make to the reliability of the electricity system. It is the intention of the Office of Energy that this work will provide information to the Renewable Energy Generation (REG) Working Group on the potential impact of rule changes with regards to the efficient allocation of Capacity Credits to intermittent generators.

Key study conclusions

In making an assessment of potential Reserve Capacity allocation methodologies three key characteristics of each methodology have been considered in the presentation of results: time frames, interval selection techniques and calculation methodologies have all been investigated. In total, 24 individual calculation methodologies were tested and examined across 15 locations around the SWIS. The generation technologies considered include wind, solar thermal and landfill gas. Correspondingly, a substantial amount of secondary analysis was conducted in order to validate, and test the sensitivity of, the results. The following conclusions have been made.

- The Reserve Capacity allocated to generators which are characterised by significant variability in generation due to a variable primary resource can be subject to highly variable allocations where interval selection data sets are limited in size. This is particularly evident in the case of allocations based on the 12 Peak and Top 250 load intervals.
- Calculation methodologies based on larger data sets can provide relatively stable results that do not vary significantly when derived from longer time frames. This is particularly true where these data sets are expanded as additional years are considered, as in the case of All intervals and the Peak Period intervals. Calculations based on single year time frames derive results similar (typically within ±~15%) to those based on longer time frames for the majority of the calculation methodologies (with the exception of the 10th percentile calculations) (Section 4).
- Reserve Capacity allocations based on 10^{th} percentiles have the potential to allocate little or no Reserve Capacity to some generation technologies in the absence of a fleet component. Furthermore, 10^{th} percentiles of All intervals appear to misrepresent the contribution to peak load where generation profiles are positively correlated with peak load as with solar thermal generators (Section 4).
- The correlation between intermittent generation and times when load is highest is an important determinant of the likely contribution variable generators make to system reliability as intervals

when the load is highest give an indication of when the system is likely to be most at risk. Although wind resource variability (and hence reliability) varies between wind sites (Section 4.2) there is a general trend in all wind generators considered here, and particularly for those located in coastal areas, for above average generation during peak load times. In the case of wind generation, calculation methodologies that consider peak load intervals only typically result in Reserve Capacity allocations which are higher than that calculated with All intervals by a factor of ~1.2-1.4 for recorded wind generation and ~1.1-2 for modelled wind generation where calculations are based on averages (Section 4).

- Solar thermal generation has a strong correlation with peak load intervals that is under-recognised by the current allocation approach. It is highly reliable during summer peak load intervals when the sun is available, with incidences of cloud obstruction being comparatively low (Section 5.2). Despite a substantial portion of peak load intervals occurring towards the end of the day or in the early evening, when insolation is low, the Current allocation method allocates approximately 60-70% less Reserve Capacity to those methods which consider peak load intervals only. Furthermore, Reserve Capacity allocations based on purely reliability focused calculation methodologies, such as 10th percentiles have the potential to lead to very low allocations for solar thermal generators (Section 4).
- Longitude influences alignment of solar insolation with SWIS peak loads, with a substantially better match in Geraldton compared to Kalgoorlie. During peak load periods system loads during peak load intervals when solar radiation is available for capture are typically similar to loads during peak load intervals with little insolation. However, during peak load periods solar thermal generation has a high reliability when considering its ability to meet typical daily peak loads (Section 5.2). Thermal energy storage capacity can moderate the effect of cloud cover and would allow a solar thermal facility to generate during high early evening loads, providing a more reliable generation resource (Section 5.5.5).
- As stochastically independent sources of wind generation are added to the wind generation fleet, the likelihood of relatively low levels of generation is reduced. The 90 per cent reliable level of generation for the existing fleet is approximately double the 90 per cent level of reliable generation from each individual wind farm (Section 4.4). While this outcome could be affected by weather-based correlations between wind sites, no material correlations were evident in generation from existing wind farms over contemporaneous trading intervals, or between various Bureau of Meteorology wind mast locations distributed around the SWIS (Section 4.4). Note that this outcome may not hold in the future if new wind farms are located in close proximity to existing wind farms.
- Reserve Capacity allocations based on fleet calculation methodologies are influenced by three aspects which can be made evident by, and depend on, the calculation methodology applied. The fleet average of All intervals will vary with the scale of the resource captured by the fleet and corresponding generator capacities and capacity factors. The fleet 10th percentile of the Top 250 intervals can be influenced by the availability of generation during these intervals whereby a single generator can contribute in the form of a security impact. Furthermore, a comparison can be made between peak load focussed calculations with and without the fleet whereby variations in the fleet 10th percentile of the Top 250 loads can represent a resource security impact (Section 4.4). Overall, the Original calculation method tends to allocate around 50% of that from the Current method (Section 4).
- The allocation of Reserve Capacity to intermittent generators with stable generation profiles (e.g., landfill gas and other biogas generators) is relatively independent of the calculation methodology used as these generators exhibit no correlation with load. Thus, the effect of rule allocations analysed here has a relatively small impact (Section 4).

Additional analysis conclusions

Further to the above conclusions the study was extended to investigate and conclude on the following quantitative and qualitative aspects.

Generation and load correlations

A strong positive correlation between load and temperature has been identified. However, the results here show that, while there is a relationship between the temperature and wind generation, it is highly complex. Conversely, while remaining complex to an extent, a clear relationship between average daily solar thermal generation and Perth temperatures has been shown to exist (Section 5.1).

Generation interval histograms

Generation distribution histograms have been shown to provide an insight into the performance of the generation captured by each calculation methodology along with the probability of generators meeting their Reserve Capacity allocations. They show that under the All, Top 250 or Peak Period interval selection techniques, allocations based on averages tend to have a 40-50% probability of being met. Where only the 12 Peak intervals are considered this range increases to around 40-60% while calculation methodologies based on medians and 10th percentiles will always have 50% and 90% probabilities of being met respectively (Section 5.2).

Wind is a highly variable energy resource and this volatility is evident over relatively small interval selections, including at times when system load is highest. Generation during a small number of hot weather episodes that have occurred over the last few years demonstrate this potential for large variations in output between trading intervals at peak times (Section 5.3). However, further work would be necessary to establish a systematic correlation with high loads at a 1 in 10 year timescale.

Fleet diversity impacts

Reserve Capacity allocations based on fleet calculation methodologies can potentially provide measurable impacts to the RCM in the form of the scale, security and reliability of generation from wind resources. The implications of these characteristics are that the Reserve Capacity allocated under a fleet method such as the Original method would be highly dependent on the characteristics of the fleet. Therefore, this method may present issues for generation technologies that do not have an existing and established geographically diverse fleet (Section 5.4).

Despite an inverse correlation between the wind resources across different regions not being found it is evident that different regions across the SWIS have the potential to contribute to a diverse intermittent generation fleet in different ways. In general, the wind resources along the southern regions of the SWIS including Fitzgerald, Albany and Margaret River have the capacity to benefit a fleet based north of Perth as the wind resource along the southern coast presents different characteristics to that north of Perth. An assessment is made of the influence of regional weather patterns on the SWIS regions which shows that wind farms in the SWIS can effectively be considered as independent variables (Section 5.4).

Sensitivity analyses

A comparison between the modelled and recorded generation was made at three locations around the SWIS which validated the wind farm modelling assumptions made for this study. The fact that modelled wind farm generators applied here are based on resource data which is not the optimum for wind farm development introduces some error in the outcomes. However, given the desired outcomes of this study these errors are not considered to be significant (Section 5.5.2). Reserve Capacity allocations based on calendar years are shown to be relatively unchanged (<1%) from allocations based on Reserve Capacity Years (Section 5.5.3) and the allocations are found to be relatively insensitive to the timing of the weekly business cycle (Section 5.5.4). Thus, the results presented in this report do not appear to be highly sensitive to the time periods selected.

Financial impacts

Capacity Credits provide an additional revenue stream to new generation that rewards capacity availability. Based on recent energy market and Renewable Energy Certificate prices, capacity credits contribute around ten per cent of the potential revenue stream of intermittent generation projects (Section 7).

Adapted generation technologies such as solar thermal generation which includes thermal energy storage can achieve a significant increase in the allocated Reserve Capacity as reliability is increased. However, under the consideration of the financial benefits available by such adaptations, it has been shown that the RCM does not allocate any greater contribution to them as increased capacity factors increase both energy revenue and Capacity Credit revenue accordingly in most cases (Section 7).

The analysis in this report suggests that a greater focus on peak load periods could marginally increase payments to wind generation and double capacity credits revenue for solar thermal generation in comparison with current arrangements. On the other hand, the use of highly conservative approaches to allocating credits for intermittent generation could substantially reduce revenue gains from the RCM (Section 7).

Further work identified

A number of items for further work and analysis have been identified, including (Section 8):

- The determination of a specific correlation, if any, between intermittent generation and very high temperatures and the level of risk imposed by a calculation method which focuses on specific high risk load intervals such as loss of load probability analysis .
- The appropriate level of geographic and technological diversity across the SWIS and the interaction of the RCM and such distribution.
- The development of wind generation forecasting tools for the SWIS along with generator control and market strategies which consider such forecasting tools.

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1 Introduction

Western Australia (WA) is widely recognised to hold one of the worlds best resource potentials for the two most widely utilised renewable energy sources: wind and solar.

The Reserve Capacity Mechanism currently ties capacity incentives for generators (reflected in their allocations) with a system-wide assessment of capacity needs and expectations. One of the pressing issues associated with the rapid expansion of renewable generation technologies is the ability of existing regulatory frameworks to adapt to the requirements of intermittent generators which are no longer fully dispatchable.

The Wholesale Electricity Market in the SWIS is divided into the Energy and Capacity Markets. Energy is traded bilaterally and through the Short Term Electricity Market (STEM), while the Capacity Market provides an additional revenue stream promoting investment into new capacity in the SWIS to meet future electricity consumption projections. In order to facilitate this investment, the Capacity Market encompasses the Reserve Capacity Mechanism (RCM) which intends to ensure that the SWIS has adequate installed capacity available from generators and demand-side management options at all times. More specifically, the purpose of the Reserve Capacity Mechanism is to

1. Operate in conjunction with capacity requirements to cover expected system peak demand while (i) providing adequate additional capacity to ensure demand can be met in the event of the failure of the largest generator, and (ii) maintaining some capability to respond to frequency variations.
2. Remove the need for high and volatile energy prices, which are required in markets like the NEM, to both provide adequate revenue for peaking facilities and to trigger new investment. Instead, energy prices are capped based on the cost of generation from peaking plant, with the Reserve Capacity Mechanism contributing to generator capital cost. The Reserve Capacity Mechanism may fully fund the capital costs for peaking facilities, and it will contribute towards a base load unit's capital costs.

At present the Reserve Capacity Mechanism allocates Reserve Capacity Credits to generators with the intention of reflecting a generator's contribution to the SWIS peak demand. Credits are allocated to potentially provide a significant revenue stream to conventional generators based on their rated capacity. Conventional generators are required to refund them should they fail to deliver energy on demand [1]. Intermittent generators are allocated credits on the basis of actual generation such that they are not subject to penalties for not delivering power on demand.

The Independent Market Operator (IMO) administers the Reserve Capacity Mechanism. The annual Reserve Capacity Requirements are specified by the IMO based on a Statement of Opportunities Report that considers the Capacity requirements of the SWIS for the next 10 years. Each Market Customer will be allocated a share of the Reserve Capacity Requirement, called an Individual Reserve Capacity Requirement, and will be required to secure Capacity Credits to cover that requirement. A Capacity Credit is effectively installed Capacity or Demand Side Management registered with the IMO [1].

SEA has been commissioned by the Office of Energy to undertake a review the treatment of intermittent generation in the Capacity Market through undertaking a comparison of existing and potential Capacity Credit allocation rules for intermittent generators. The study includes statistical analysis of historical and simulated intermittent generation and load data in order to detail the potential impact of rule changes, with regards to the efficient allocation of Capacity Credits to intermittent generators, to the Renewable Energy Generation (REG) Working Group.

2 Project Scope

This project considers a number of Reserve Capacity allocation methodologies as derived for a number of intermittent generators located around the entire SWIS. Although the study focuses on wind and solar thermal generation, landfill gas generators are also considered to a limited extent. In all cases Reserve Capacity allocations are based on statistical analysis of load and generation data where the latter is composed of recorded generation data and modelled generation data based on resource data records. Following the initial Reserve Capacity calculations, a significant amount of analysis considers the impact of each methodology in terms of the security of the allocations for each methodology and the quality of some of the outcomes found. The full study Scope is outlined below.

2.1 Reserve Capacity Calculation Methodologies

A statistical analysis of the acquired load, generation, and meteorological data, including both measured and simulated generation data, was performed to assess the potential impact of rule changes on the allocation of Reserve Capacity Credits to intermittent generators. The alternative allocation methods and parameters have been drawn from proposed alternative and potential precedent calculation criteria drawn from the operation of the WEM and other electricity markets and that reflect system reliability considerations. Reserve Capacity allocations were calculated for each data set, based on the following calculation criteria:

1. **Current Method of Rule 4.11.3A (Current)**: Average generation over all trading intervals for the preceding three years [1].
2. **Fleet Method (Original)**: The 10th percentile for the top 250 load intervals of the preceding hot or intermediate season. Wind generation is grouped together as a fleet which is geographically distributed with a generator in each region as shown in Figure 1 and apportioned according to the basis of their individual contributions to the total generation (based on the Original Clause 4.11.3, prior to 2005) [2].
3. **Proposed Method of Rule 4.11.3B (Proposed)**: The 10^{th} percentile of generation during the top 250 load intervals of the preceding year [3].
4. **PJM Method (PJM)**: Average generation during the summer daily peak load periods. The Peak Period time interval has been determined by SEA to represent the three peak load months, as a reflection of the PJM method applied in North America.
5. **Individual Reserve Capacity Requirements (IRCR)**: The median value of the 12 peak trading intervals selected as the three highest demand intervals on the four highest demand days of the preceding peak demand season [1].
6. **Reserve Capacity Refund Mechanism (RCRM)**: Weighted average over All intervals, with weighting based on business versus non-business hours and between the December-January versus February-March periods. The weightings are based on the Refund Table of Rule 4.26.1 of the Market Rules [1] and are normalised to maintain the correct amount of Reserve Capacity Credits across the market as shown in Section 12 (Appendix B).

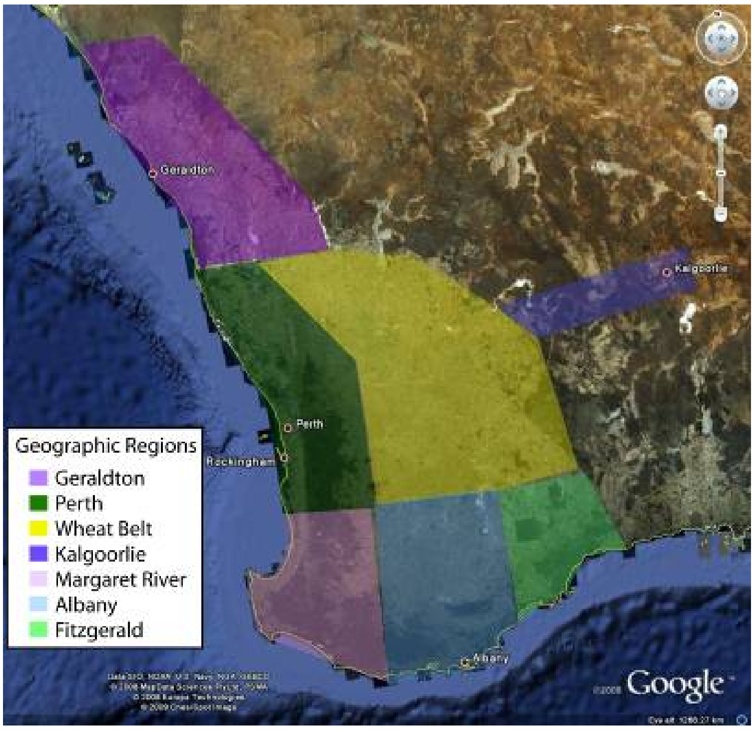


Figure 1: Map identifying the approximate boundaries to be used for the fleet calculations. Seven regions are considered where each is represented by a single generator.

In order to compare the different calculation methodologies, calculations were performed by comparing each statistical technique against each interval selection technique. Table 1 indicates each combination of calculation methodology considered along with the position of the six criteria listed above. The data driven analysis of allocation methods presented in this study allows an assessment of the ramifications of rule changes that could reflect a closer alignment with intermittent generator's contribution to system reliability. This study does not undertake an assessment of how well any particular method aligns with an intermittent generator's actual contribution to system reliability. Such an analysis requires consideration of the interaction between the generator and the market as a whole and is an area for future work.

A large majority of the calculations and results presented here are based on fundamental statistical principals. In order to ensure that the analysis is complete and the reader is directed to Section 11 (Appendix A) for a summary of these principals and how they relate to the results presented here.

Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5pm (Jan-Mar)
Average	Current	X	X	PJM
Tenth Percentile	X	Proposed	X	X
Median	X	X	IRCR	X
RCRM Weighted Average	RCRM	X	X	X
Fleet (Average)	X	X	X	X
Fleet (Tenth Percentile)	X	Original	X	X

Table 1: Calculation methodologies and intervals analysed. Each of the six criteria listed above is indicated as text. Each of the X's indicates a calculation that is not one of the six criteria, but will be calculated in order to compare methodologies and interval selections. The determination of the Peak Period times of 2-5pm is contained in Section 3.2.

The analysis considers three time frames for each calculation methodology: (i) individual years, (ii) three consecutive years (or less where data is unavailable), (iii) all available years of data for each site (noting that all available years will be used to compare outcomes rather than for in depth analysis). These year selection groups are based on the 2001 to 2008 calendar years. For example, the 'Proposed' calculation methodology (using the 10^{th} percentile of the Top 250 load intervals) was calculated on a yearly basis, over a three year time frame, and from 2001 to 2008 where the highest 250 load intervals were found over each time frame.

As shown in Table 1 there are four load interval selection techniques on which statistical calculations are based in order to derive all 24 Reserve Capacity allocation methodologies. Each load interval selection technique is unique in its quantification of the peak load. For example, the Top 250 technique will select the highest 250 half hourly load intervals over the given time frame. Where time frames are over single years this represents the highest 1.4% of all load intervals, as there are 17520 half hourly load intervals in a non-leap year. Alternatively, only 0.48% is represented over three year time frames.

The selection of peak load intervals or times reduces the analysis to only represent the times of the year when the SWIS is operating under its most strenuous conditions. When considering the load over 2007 the total SWIS consumption was 17.6GWh, however, the selection of the Top 250 load intervals represents only 2.2% of this total, while the 12 Peak intervals represents only 0.1% in this year. For three year time frames the number of intervals selected remain the same for these two interval selection techniques which implies that the Top 250 and 12 Peak intervals represent approximately 0.7% and 0.04% respectively for three year time frames. Alternatively, the Peak Period intervals consider ~4% of the total energy over any time frame selected, as the number of intervals considered increases with respect to the number of years.

As would be expected through different assessments of the peak load, some of the load intervals are included in each interval selection technique. More precisely, it is almost always certain that the 12 Peak intervals are expected to also fall into the Top 250 intervals while the Top 250, and Peak Period intervals also fall into All intervals as would be expected. However, while there are 540 Peak Period intervals in a non-leap year, it is not certain that the entire Top 250 load intervals are encompassed in them as the former is determined from the average daily load profile, not the magnitude of the load in comparison to other intervals. Correspondingly, as time frames increase the number of Peak Period intervals increase (at 540 per year) while the 12 Peak and Top 250 intervals are assessed over the specified time frame accordingly.

Given that there has been significant load growth in the SWIS over the period considered in this study, the load data was adjusted accordingly such that the peak load intervals could occur at any interval between 2001 and 2008. Adjustments were also made where necessary to accommodate the occurrence of daylight savings in WA (see Section 4.3). Generation levels are represented in a normalised manner or as a percentage of the nominal Capacity of both recorded and modelled generation. Planned and forced outage rates are unknown in many cases and are not considered here.

2.2 Secondary Considerations

Further to the analysis of the individual Reserve Capacity allocation calculation methodologies outlined above, the study also considers the following.

Data Management and Modelling

The scope of the analysis was dictated (to a large extent) by the availability of data. The data used included measurements from the Bureau of Meteorology (BOM) and existing generators participating in the SWIS. The quality and availability of the data was assessed in accordance with maintaining the quality of the outcomes (see Section 4). As there is a limited amount of generation data available for intermittent generators in the SWIS, models were developed to represent wind and solar thermal generators. Assumptions made in the development of these models are documented along with the validation details of simulated generation profiles.

Correlation Coefficients

Correlation coefficients were calculated in order to determine and quantify the relationship between weather, generation and load. Load was first correlated with temperature, in order to establish the weather dependency of the SWIS load, and then generation types were correlated with temperature and load.

Histograms and Distributions

Statistical distributions and histograms were developed for a selection of sites based on the generation occurring during the intervals captured by each interval selection technique. They illustrate the probability of generation during the given intervals and assist in ascertaining any relevant patterns in resource availability throughout the SWIS while also representing the site specific nature of generation.

Confidence and Risk

A probabilistic analysis of the data provides information on the confidence of the conclusions, from which an evaluation of the level of risk of alternative rule changes can be based. Correspondingly, an assessment of the performance of the existing wind farm fleet during six assumed 1 in 10 year events was made in order to capture the behaviour of wind generation during these times.

Fleet Diversity Impacts

A detailed analysis of the performance of each fleet region in terms of the individual contribution of an intermittent generator fleet to the RCM was undertaken. This analysis was performed in order to better understand the individual contribution each SWIS region can make to the scale and security of generation capacity offered to the RCM under certain Reserve Capacity calculation methodologies.

Sensitivity Analysis

The study has also considered sensitivity analysis of aspects such as:

- The impact of geographic diversity was examined through the fleet calculation methodologies by pooling the fleet generation together and calculating the Reserve Capacity. The generation for an individual region was then removed from the fleet, and the resulting pooled Reserve Capacity recalculated. This process was repeated for each region as shown previously in Figure 1 in order to quantify the impact of the individual SWIS regions. The impact of geographic diversity on solar thermal generation gave consideration to the variation of generator output with longitude in comparison with load.

  Corresponding to the hypothetical fleet scenarios the impact of geographic diversity on the existing wind farm fleet was also assessed under the consideration of the time varied development of the three existing, one proposed and one hypothetical wind farms.

- A significant portion of the results presented in this study are dependant on modelled hypothetical wind farms based on wind data recorded at non-ideal wind farm sites. As such a comparison is made between wind farm generation data and modelled generation data from adjacent wind farm sites in order to validate the likeness in study outcomes where outcomes are based on these differing sources.

- Results here are based on the calendar year (January - December), which differs from the Capacity Year (October - September) on which the Reserve Capacity Cycle is based [1]. The impact of the selected 'year' is analysed.
- To attempt to quantify the susceptibility of the results to the exact conditions of the years considered, a sensitivity study was conducted by scaling up loads on non-business days. This considered the possible situation of a year happening to have all of its hottest days on business days.
- The inclusion of four hours of thermal storage for a solar thermal generator at Geraldton was also considered. It is expected that the inclusion of a small amount of thermal storage for solar thermal generation will have a significant impact on the generation profiles and resulting capacity factors of such plant. Thus, results in terms of Reserve Capacity allocations are expected to differ greatly from those found without storage.

Qualitative Aspects

Further qualitative aspects of this work also consider:

- **Forecasting of Reserve Capacity**: The IMO Planning Criterion has been used to inform on Reserve Capacity forecasting and its impact on meeting the nine in ten years Planning Criterion target. A discussion is based around the Reserve Capacity calculation methodology parameters and their application in terms of forecasting.
- **Network Augmentation:** The impacts of increased generation capacities in particular regions of the SWIS transmission network are discussed based on the results found in the geographic diversity investigation Section (5.5.1) and the fleet impacts analysis Section (5.4).
- **Allocation of Incentives:** The impact of the results on the Reserve Capacity allocations for different generation technologies was examined in terms of the financial impacts of Reserve Capacity requirements. The financial implications for generator developers includes quantification of the impact which various Reserve Capacity calculation methodologies have on the income stream to the generator considered in terms of the Reserve Capacity Mechanism's contribution to each technologies total income over a year.
- **Areas of Further Research:** Section 8 identifies a number of areas where further research may be required to extend certain aspects of this study which have become evident during the undertaking of this work.

3 Data Management and Modelling Details

This study bases its outcomes on a significant amount of data which has been provided in a variety of forms from a number of sources. Correspondingly, the data is managed and manipulated with appropriate software packages and methods. This section presents the methods and processes behind this management and manipulation in order to ensure confidence in the study outcomes.

The availability of generation data from intermittent generators is very limited due to the lack of long standing generators in the SWIS. Furthermore, recorded resource data is also sometimes limited. This is particularly evident in terms of solar irradiation data recorded over the half hour intervals. Accurate data detailing the diurnal variation in irradiation is limited to two sites at Geraldton and Kalgoorlie and half hourly irradiation records are only available for direct irradiation on the horizontal plane. Furthermore, both of these meteorological stations ceased recording solar irradiation in mid 2006.

In terms of wind and generation data, there are a number of sources used in this study. The data ranges in its type and available time frames, as shown in Table 2. A single source provided generation data for landfill gas generators in the Perth metropolitan area and, as the generation profile from landfill gas is relatively constant compared to other intermittent generators, an aggregated generation profile was composed utilising the three sites. Figure 2 shows the geographic location of each site data site around the SWIS by generation and data type.

Data Provider	Location	Marker	Abbreviation	BOM Weather Station #	Data Type	Data Avilability
Western Power	Perth	-	-	-	Load	From 2001
					Temperature	From July 2001
Verve Energy	Albany	A	ALB	-	WF Generation	From 2002
					Test Mast Wind	From 2002
Infigen	Walkaway	C	WLK	-	WF Generation	From July 2007
					Test Mast Wind	From July 2007
Griffin Energy	Emu Downs	D	EMU	-	WF Generation	From Oct 2007
					Test Mast Wind	From Oct 2007
Pacific Hydro	Nilgen	E	NIL	-	Test Mast Wind	2005 - 2008
Landfill Gas & Power	Tamala Park	G	LGP	-	Landfill Generation	From 2007
	Canning Vale	H		-	Landfill Generation	From 2007
	Red Hill	I		-	Landfill Generation	From 2007
Bureau of Meterology (Note: ST => Solar Thermal Generator, W => Wind Generator)	Geraldton ST	K	GER	8051	Solar Radiation	2002 - 2006
	Kalgoorlie ST	L	KLG	12038	Solar Radiation	2001 - 2006
	Hopetoun	M	HPT	9961	Half-Hour Wind	From 2001
	Badgingarra	N	BRS	9037	Half-Hour Wind	From 2001
	Cape Naturaliste	O	CPN	9519	Half-Hour Wind	From 2001
	Walpole	P	NWP	9998	Half-Hour Wind	From 2004
	Geraldton W	Q	GRD	8051	Half-Hour Wind	From 2001
	Gingin Airport	R	GIN	9178	Half-Hour Wind	From 2001
	Cunderdin	S	CDD	10286	Half-Hour Wind	From 2001
	Kalgoorlie W	T	KBD	12038	Half-Hour Wind	From 2001

Table 2: Summary of the data made available to SEA, including the data sources along with the site abbreviations, and the respective BOM weather station where the data was provided by the BOM database. Marker letters correspond to markers on Figure 2.

Figure 2: Map of the SWIS region with the location of recorded data identified by markers corresponding to their source (see Table 2). Red labels denote Wind Farms (WF), Green denotes Landfill Gas Plants (LF), Yellow denotes Solar Resource Locations (Solar) while blue denotes a BOM recorded wind data site. Image produced courtesy of Google Earth.

3.1 Data Validation

While the available data is comprehensive, it is subject to some inconsistencies where data is simply not present over varying time scales. The worst case is the KLG records which are missing a large portion of data (~70%) over the summer of 2002/2003. Thus results derived from the 2003 summer peak period for KLG should be considered with caution. In some cases the available data did not extend to the full range of the study period (2001 – 2008) as is evident from GER and KLG where data starts in 2002 and ceases in mid June 2006. Thus the 2006 data for the solar thermal generators was not adjusted and GER and KLG results for 2006 should also be considered with caution where load intervals selected extend beyond the January – June window.

In some cases there are a number of missing single data entries in the original resource data due to unknown reasons. Where single data records are missing they were replaced with values that were interpolated from the previous and subsequent data records. Note that this method was heavily utilised in the case of some BOM wind sites as some half hourly wind speed data contains data recorded at hourly intervals. Where sequential entries were not present these data points were considered to be null values and were removed from the final data sets analysed. In all cases, final results are presented with any null data removed if the outcomes were calculated with the modified data set.

Table 3 illustrates the quality of the adjusted generation data used in the calculation of Reserve Capacity allocations for all sites.

Site Abbreviaton	Utilisable Data Year Start	Utilisable Data Year End	Data Recovery Rate
ALB	2002	2008	100.0%
BRS	2001	2008	87.7%
CDD	2001	2008	99.1%
CPN	2001	2008	98.1%
EMU	2007	2008	100.0%
GIN	2001	2008	97.6%
GRD	2001	2008	99.6%
HPT	2001	2008	99.5%
KBD	2001	2008	99.6%
LGP	2007	2008	100.0%
NIL	2005	2007	100.0%
NWP	2004	2008	96.6%
WLK	2007	2008	99.9%
GER	2002	2006	92.1%
KLG	2001	2006	85.9%

Table 3: Summary of data quality utilised for Reserve Capacity allocation calculations.

Summer Load Correlation Coefficients		
Year	Peak Load : Max Temperature	Peak Load : Min. Temperature
2001	0.677	0.595
2002	0.601	0.549
2003	0.717	0.468
2004	0.689	0.708
2005	0.648	0.467
2006	0.746	0.623
2007	0.756	0.715
2008	0.818	0.678

Table 4: Correlation coefficients as calculated yearly between SWIS summer load data and maximum and minimum daily temperatures. Note that the generally high values indicate that the load data is accurately recorded. Furthermore, the correlation coefficients are generally increasing over the study years corresponding to increasing air conditioner loads.

Further to the simple data validation procedures outlined above, correlations were made between the load data and temperature over the study period in order to identify any outlying data as shown in Table 4.

3.2 Determination of Peak Period Load Intervals

In order to determine the peak load period on which the PJM calculation methodology is based, the load data was initially analysed to find the three month period which consistently handles the largest energy consumption in all of the study years considered. These were identified as January, February and March. The average of each half hour interval was taken over these three months for the full study period. The resulting normalised load profile (Figure 3) shows the average peak period to be between 2 and 5 pm (WST).

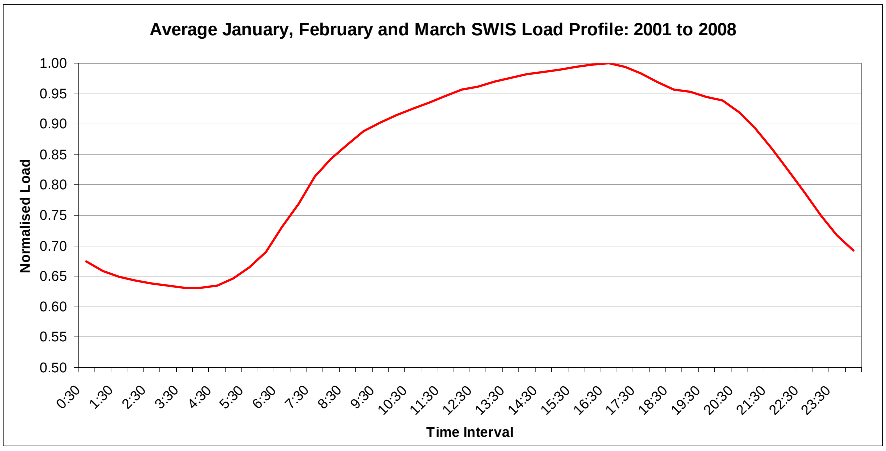


Figure 3: Average SWIS load profile derived from the average of each half hourly interval over the months of January, February and March from 2001 to 2008 where WST is shown.

3.3 Load Data Adjustment

In order to correlate peak load intervals with generation for data sets exceeding one year, it was necessary to remove load growth from the load profile over the period to focus on shorter term periodic trends (i.e., seasonal and daily). An exponential was fitted to the load data, of the form: $A_0 + A_1 e^{(t-t_0)/\tau}$, where A_0 is a DC offset, A_1 is a scaling factor, τ is a time constant, and t_0 is the starting minute which is set to $t_0 = 0$. The resulting exponential fit was calculated as:

$$\exp(-57.4362 + 8.867 \times 10^{-5} t)$$

which was subtracted from the load profile as shown in Figure 4 for load data sets exceeding one year.

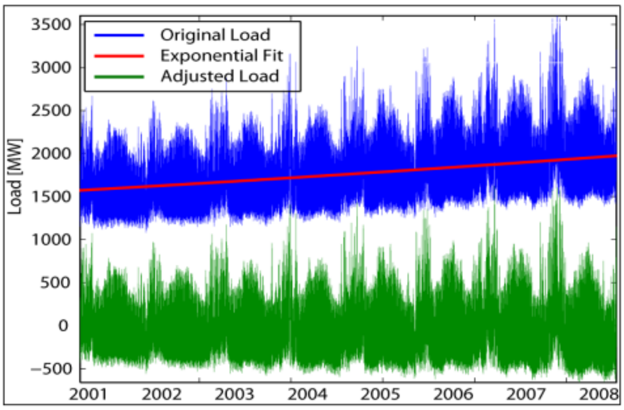


Figure 4: Load data comparison with and without exponential growth. Note that the negative load occurring once the exponential was removed has no impact on the study outcomes as they are dependent on the time of local maxima not the magnitude of these maxima.

3.4 Adjustment for Time Differences Across the SWIS and Daylight Savings

The SWIS covers a significant geographic area, which is all contained within the single, Western Standard Time (WST) time zone. As such this is the standard measure of time on which generation, wind and load data is provided for this study.

The availability of the solar resource at any given location is dependent on the Solar Time at that location. Hence, the standard unit of time for solar radiation data is Solar Time which is similar to WST in that there are 24 hours in a day. However, it is defined by having a noon time that corresponds to the sun passing across the local meridian at the site at 'Solar Noon' which does not necessarily correspond to noon in WST. WST is defined by the Solar Time seen at a longitude of 120° which lies approximately 140km west of Kalgoorlie. The impact of the time difference on the available solar resource is considered to be significant and generation profiles have been adjusted accordingly.

The western and eastern extremities of the SWIS can be defined by Geraldton to the west and Kalgoorlie to the east. These two cities are longitudinally separated by approximately 7° which translates to a Solar Time difference of 28 minutes. The relationship between WST and Solar Time in WA is given by Equation 1 where L is a site's longitude and E is the Equation of Time, defined by Equation 2 where n is the day of the year starting with 1 on January 1 [8].

$$t_{WST} = t_{ST} - 4(L - 120) - E \quad \text{(Eq. 1)}$$

$$E = 0.01719 + 0.4282\cos\left(2\pi\frac{n-1}{365}\right) - 7.352\sin\left(2\pi\frac{n-1}{365}\right) - 3.358\cos\left(4\pi\frac{n-1}{365}\right) - 9.372\sin\left(4\pi\frac{n-1}{365}\right) \quad \text{(Eq. 2)}$$

Figure 5 shows the variation in time difference between the Solar Time and WST throughout a year at Geraldton. Note that in order to model the impact of this time difference in terms of the calculation of Reserve Capacity, the difference is rounded to the nearest half hour and added to the Solar Time which the data was recorded on effectively shifting the data by half an hour where necessary as shown in Figure 6 for March 1 2002 in Geraldton.

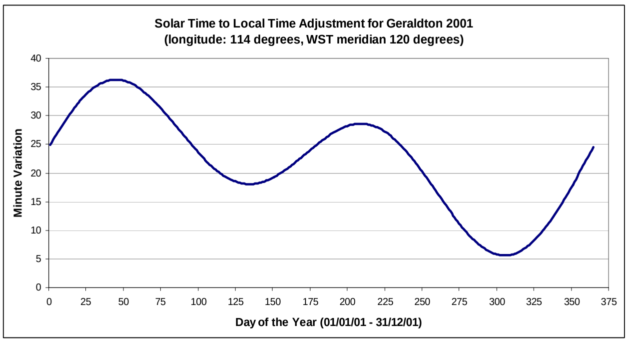


Figure 5: Minute difference between Solar Time and WST for Geraldton throughout the year. Note the sinusoidal nature of the Equation of Time is due to factors such as the eccentricity of the earth's orbit around the sun over a year. Adjustments to the solar radiation data are made in order to accommodate this difference for each day of each year. Half hour intervals are shifted according to the time adjustment above rounded to the nearest half hour.

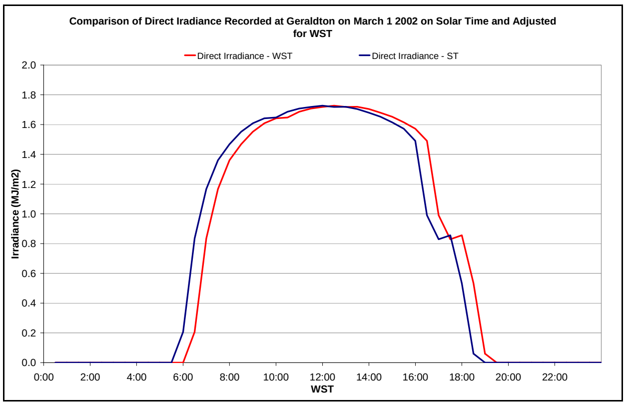


Figure 6: Comparative illustration of the impact of adjustments made to the daily solar irradiance profiles to compensate for time differences across the SWIS where ST and WST are Solar Time and Western Standard Time, respectively, for March 1 2002 (day number 60).

Time adjustments were also made to compensate for the recent adoption of daylight savings in WA. Daylight savings began on December 3 2006, and then occurred on the final Sundays of March and October of the following years. In order to compensate for this, the times that correspond to the load data have been adjusted accordingly.

3.5 Generator Models

While the use of recorded generation data is preferred to modelled generation data, the lack of available recorded generation data necessitated the use of modelled generation data. Models were developed to convert recorded BOM wind velocity and solar irradiation records to modelled generation data. This section details the assumptions, applications, outcomes and validation procedures for both wind farm and solar thermal generator models.

3.5.1 Wind Farm Generators

Wind Farm Power Curve Development

The power available in wind is a function of both wind velocity (v) and air density (ρ) as can be seen in Equation 3 where A is the area which the air is passing through or the area swept by the wind turbine blades in this case.

$$P = \frac{1}{2}\rho A v^3 \qquad \text{(Eq. 3)}$$

Due to the complex relationship between wind velocity and air density the wind farm model applied here calculates generation as a function of wind velocity alone. This assumption is considered to be acceptable as the cubic exponent of wind velocity dominates in Equation 3. Furthermore, the objective here is to capture the variability of a hypothetical generation profile, rather than to accurately model the wind power availability at a particular site. Fine time scale variability of wind power availability is more closely related to wind speed that air pressure (density).

The resulting wind farm model power curve was based on a generic wind turbine power curve which has typical characteristic cut-in, rated and cut-out wind speeds along with a region between the cut-in and rated wind speeds where power is related to wind velocity by a fourth order polynomial as in Equation 4 and Figure 7.

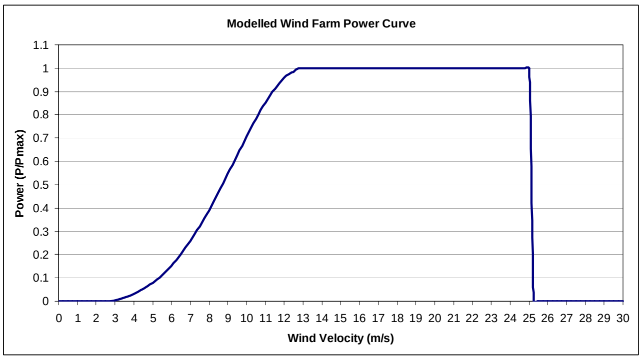


Figure 7: Wind farm power curve as derived from characteristic wind speed values and Equation 4. The power curve is applied to convert half hourly average BOM wind speed records to generation records in the development of modelled generation profiles.

$$P = \begin{cases} v \le 3 \text{ m/s} = 0 \\ 3 < v \le 12.5 \text{ m/s} = 0.0022175 + 0.025889v + 0.00066973v^2 \\ \qquad + 0.003224v^3 - 0.00025642v^4 \\ 12.5 < v \le 25 \text{ m/s} = 1 \\ v > 25 \text{ m/s} = 0 \end{cases} \qquad \text{(Eq. 4)}$$

In order to validate the assumptions made in the development of this model a comparison was made between the modelled and metered wind farm generation over a full year. The data applied was made available from one of the wind farms where half hourly wind speed data, recorded at 50m, was applied to the model resulting in a modelled wind farm generation profile extending over a full year. Correspondingly, the metered generation records from the site were extracted for the same year and comparisons made between the two data sets.

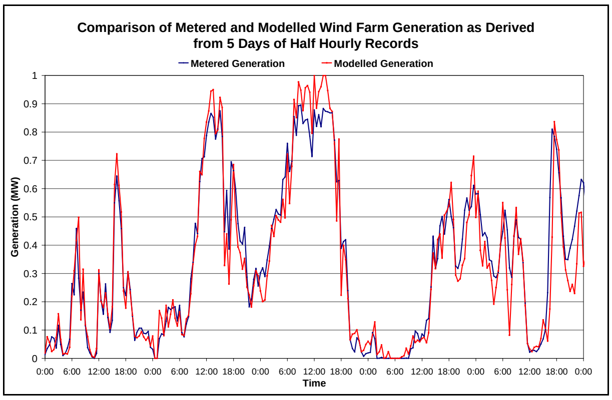


Figure 8: Comparison of modelled wind farm generation based on wind speeds recorded at the wind turbine hub height and metered generation profiles over five days. The correlation coefficient between the two generation profiles over the year has been found to be 0.927.

A correlation coefficient of 0.927 was calculated over the full year which indicates that the omission of air density from the generation model is acceptable. A comparative illustration of the modelled versus metered generation profiles over five days is shown in Figure 8 where all generation data is normalised.

Application of the Wind Farm Model

The standard height for measuring wind speed is 10m and this is the height that all of the BOM wind speed data has been provided at. Thus, a conversion methodology is assumed to extrapolate 10m wind speeds to an assumed wind turbine hub height of 50m. Equation 5 is a form of the power law equation whereby the assumed wind sheer exponent is $\alpha = 0.14$, and the extrapolated and recorded heights and wind velocities are denoted by subscripts 1 and 2 respectively [9].

$$v_1 = v_2 \left(\frac{h_1}{h_2} \right)^{\alpha} \qquad \text{(Eq. 5)}$$

Table 5 summarises the performance of the resulting wind speeds at the test site used previously. Some variation is event, however this is expected as, while the wind sheer coefficient α has been assumed to be 0.14 across all of the wind data analysed, the specific characteristics of a site can significantly alter this value. However, it is unrealistic to assume the terrain characteristics for each modelled wind farm considered here and this conversion is necessary as there is a significant difference between wind speeds at 10m and those which occur at typical wind turbine hub heights.

Wind Farm Wind Metrics Over the Test Year		
Metric	**Modelled Wind (from 10m)**	**Measured Wind (50m)**
Average (m/s)	6.04	6.69
Standard Deviation (m/s)	2.83	2.65
Correlation Coefficient	**0.89**	
Wind Farm Generation Metrics Over the Test Year		
Metric	**Modelled Gen. (from 10m)**	**Modelled Gen. (50m)**
Capacity Factor (%)	0.23	0.29
Average (P/Pmax)	0.13	0.29
Standard Deviation (P/Pmax)	0.28	0.27
Correlation Coefficient	**0.87**	

Table 5: Comparison of wind and generation data metrics as calculated for the test wind farm and modelled generation based on the recorded wind speed at the site.

Wind Farm Model Limitations

As shown by the discrepancies in Figure 8 the relationship between recorded wind speed at a single point and wind farm generation data is heavily reliant on the terrain at a wind farm site and the terrain in the prevailing wind direction close to the site. Furthermore, this terrain characteristic directly influences the site's wind characteristic which in turn determines the characteristics of the wind turbine installed at the site and the optimal site layout of the turbines around the site. Hence, there are many possible outcomes across the variety of potential sites across the SWIS such that the standardisation into a single model for all sites, based on extrapolated wind velocity alone, is a necessary simplification.

Another factor faced by the modelling process applied here is that, while wind data is recoded at a multitude of sites across the SWIS by the BOM, these sites are often small rural airports, towns or research stations. They are not of the same wind availability or quality class as typical wind farm sites. However, one of the key aspects of this study is the application of readily available data from both present Market Participants and the BOM and this factor is considered to be a limitation to the study as a whole.

3.5.2 Solar Thermal Generators

Models have been developed to represent generation profiles for solar thermal plant based on half hourly direct irradiance recorded at both Geraldton and Kalgoorlie over 2001 to 2006. In the development of appropriately simplified, yet reasonably accurate models for solar thermal plant a number of assumptions have been made about the thermal characteristics of the plant.

In all cases the generation technology being considered is Direct Steam Generation (DSG) Linear Fresnel solar thermal generation plant with electrical generation capacities in excess of 50MW such that storage options are expected to be financially viable. This design assumption is considered to be arbitrary in terms of the study outcomes. Thermal storage options considered include 4 hours of operation without sufficient irradiation which is achieved by over-sizing the generator's collector. Further, the models developed consider shading effects from adjacent collectors and thermal time constants to a limited extent and collectors are assumed to track on a single axis [11].

All relevant assumptions are detailed in the following sections.

Solar Thermal Plant Excluding Thermal Storage

For generation excluding thermal storage a Solar Multiple* of 2 (SM2) is assumed for collector size as this will permit the plant to operate with an increased capacity factor. Given this it is assumed that a SM1 collector will generate its rated capacity at a direct irradiance 900W/m^2, as is typical of a good solar resource site such as in the northern and eastern areas of the SWIS. Thus, a SM2 field is expected to operate at capacity under direct irradiance of 450W/m^2 – 500W/m^2 is assumed to compensate for losses. Thus 250Wh/m^2 (0.90MJ/m^2) must have been recorded in a *half hourly* interval for the generator to have operated at capacity for that half hour.

The ability of solar thermal plant to generate during sunrise and sunset hours is limited by the solar altitude angle of the sun throughout the day. Here it is assumed that a solar altitude angle of 20° is required in order for the collector to be subject to effective direct irradiation for operation.

Inside the correct operating hours, the minimum irradiation for a SM2 collector field to generate effective steam is assumed to be 0.38MJ/m^2 or 106Wh/m^2 in a half hourly record which is assumed to correspond to steam turbine generator operation at a minimum capacity of 25% [10].

The DSG collector has an assumed thermal time constant of approximately 15 minutes which is accounted for as part of the previous half hourly record. Thus, where the radiation is reducing there is a slower decrease in generation which is not evident in increasing irradiation as there is an inherent delay in the model due to the half hourly record providing information for the previous half hour. The case where a half hourly direct irradiation falls from a value above the maximum in the previous record to below the minimum, in the current record, is accounted for by calculating the generation based on one third of the value of the previous half hourly direct irradiation. Note that the divisor of three has been arbitrarily selected to estimate some generation resulting from the time constant in the half hour interval, the accuracy of this estimation has not been validated.

Where the solar altitude angle is within an acceptable range and the half hourly irradiation ($\bar{I}$) is subject to the parameters above, the following generation characteristics result:

$$P = \begin{cases} \bar{I} < 0.38\text{MJ/m}^2 = 0 \\ 0.38 \le \bar{I} < 0.9\text{MJ/m}^2 = 0.25 + \dfrac{\bar{I} - 0.38}{0.9 - 0.38} \times 0.75 \\ \bar{I} \ge 0.9\text{MJ/m}^2 = 1 \end{cases}$$

Solar Thermal Plant Including Thermal Storage

In the case where the plant is designed with four hours of thermal storage a Solar Multiple of 3 (SM3) is used for the collector size as this will permit the plant to operate while storing excess energy [10]. Repeating the assumptions made above an SM3 collector is expected to operate at capacity under direct irradiance of one third of 450W/m^2 for the previous half hour – 175Wh/m^2 is assumed to compensate for losses. Thus, 175Wh/m^2 (0.63MJ/m^2) must have been recorded in a half hourly data record for the generator to have operated at Capacity for that half hour.

Repeating the previous assumption on the solar altitude angle and plant thermal time constants, the minimum irradiation for a SM3 collector field to generate effective steam will be 0.26MJ/m^2 or 73Wh/m^2 (based on an assumed minimum irradiance of 437W/m^2) which again corresponds to steam turbine generation capacity of 25% [10].

The storage in the system is accounted for by absorbing any direct irradiation above 0.63MJ/m^2, or below 0.26MJ/m^2. While not being consumed by the generator this accumulates such that generation for four hours will require 13MJ/m^2 to be stored (4 x 3.25MJ/m^2 based on 900W/m^2 as

* The 'solar multiple' is the ratio of the actual collector size to the minimum required to run the generator at capacity at solar noon in mid-summer and a SM2 value is expected to financially optimise DSG plant without storage [10].

previously explained). This stored irradiation will be used for generation when there is a deficit in the present half hourly direct irradiation record regardless of the time of day implying that the irradiation available to the generator is the sum of that available from the sun and that from the accumulated store – once the stored irradiation is expired the generator can no longer operate.

Where the solar altitude angle is within an acceptable range and the half hourly irradiation ($\bar{I}$) is subject to the parameters above, the following generation characteristics result:

$$P = \begin{cases} \bar{I} < 0.26\text{MJ/m}^2 = 0 \\ 0.26 \le \bar{I} < 0.63\text{MJ/m}^2 = 0.25 + \dfrac{\bar{I} - 0.26}{0.63 - 0.26} \times 0.75 \\ \bar{I} \ge 0.63\text{MJ/m}^2 = 1 \end{cases}$$

Solar Thermal Generation Characteristics

Figure 9 shows example generation profiles from the generator models over a four day period in 2002. Of much importance to this modelling process is that while the models are developed with the best available information, the ability to directly validate the outcomes against recorded generation data is not present, such that no other validation process has been undertaken.

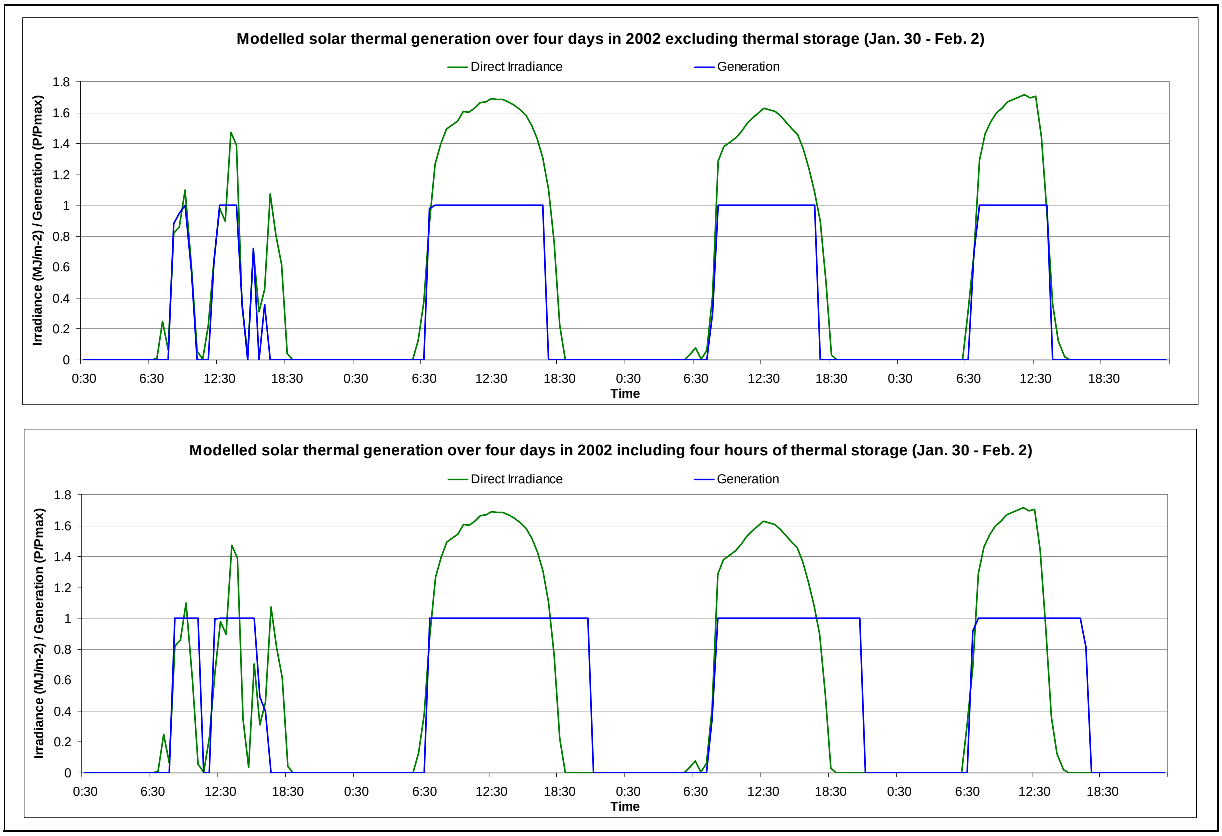


Figure 9: Example generation profiles as modelled over four days in 2002. The models behave as expected with the storage option maintaining generation over the expected time period under the condition of an excess of irradiation above that required for nominal generation.

3.6 Fleet Generators

As shown in Figure 1, and in accordance with the Original calculation criteria, the fleet generators intend to represent seven regions around the SWIS. Hence, the wind fleets are limited to seven wind generators with each representing a region and the corresponding resource characteristics of its region. Table 6 presents the different fleets applied with the methodology. Note that Reserve Capacity allocations from 2002 to 2006 are mainly based on modelled generation profiles in Wind Fleet 1, with the exception of ALB. In order to accommodate the availability of generation data in 2007 and 2008 the Geraldton and Perth regions are replaced with generation data from WLK and EMU in Wind Fleet 2. Reserve Capacity allocations are then calculated with Wind Fleet 2 for 2007 and 2008. Note that the solar thermal generators are considered as a stand-alone fleet.

Wind Fleet 1: 2002-2006			
Region	**Site**	**Years**	**Data Type**
Geraldton	GRD	2002 - 2006	BOM Wind
Perth	GIN		BOM Wind
Wheat Belt	CDD		BOM Wind
Kalgoorlie	KBD		BOM Wind
Margaret River	CPN		BOM Wind
Albany	ALB		Generation
Fitzgerald	HPT		BOM Wind

Wind Fleet 2: 2007-2008			
Region	**Site**	**Years**	**Data Type**
Geraldton	WLK	2007 - 2008	Generation
Perth	EMU		Generation
Wheat Belt	CDD		BOM Wind
Kalgoorlie	KBD		BOM Wind
Margaret River	CPN		BOM Wind
Albany	ALB		Generation
Fitzgerald	HPT		BOM Wind

Solar Thermal Fleet: 2002-2006			
Region	**Site**	**Years**	**Data Type**
Solar	GER	2002 - 2006	BOM Solar
Solar	KLG		BOM Solar

Table 6: Summary of sites used to calculate Reserve Capacity allocations based on the Original calculation criterion. There are two wind fleets covering different years. The two solar thermal generators are a stand-alone fleet.

4 Results

As outlined in the project scope, the aims of this study are to represent the outcomes of the potential Reserve Capacity allocation calculation methodologies outlined in Table 1. Thus, the selection of an optimum methodology for intermittent generation is not one of the goals of this work. Noting that, while there are six calculation methodology criteria which led to all methodologies considered here, these criteria are only considered to be potential outcomes. Thus, the results are presented here considering all possible outcomes rather than focussing on these six criteria alone. There are a number of characteristics of the outcomes which have been singled out and presented as being of high importance.

A ramification of methods that increase variation in Reserve Capacity allocations over calculation years is that they are much more likely to deviate at any point in time from expectations of generation required to determine system Capacity requirements. A calculation methodology that led to a high variability in year to year allocations would need to be disconnected from the Reserve Capacity requirement setting process. Accordingly, the ranges in allocation magnitudes over calculation years for individual sites are assessed for each methodology being considered.

As stated in the Revised Analysis Proposal [12] for this study the outcomes emphasise wind and solar thermal generation over landfill gas generation. As such, the results below are presented in terms of wind and solar thermal generators (excluding thermal storage). The outcomes from LGP are displayed in Section 13.2 (Appendix C2). Although limited to only two years of data, the results are typically representative of a generation technology which, while dependant on a renewable resource, is not as ‘intermittent’ as wind and solar thermal generators.

In all cases considerations have been made of calculations over single and three year time frames and over time frames utilising all of the available data for each site (noting that where the latter is less than three years this is presented in the place of three year calculations). However, the results presented here focus on single and three year time frames as the outcomes from calculations considering extended time frames tend to show characteristics similar to those found with three year time frames.

There is a significant amount of data analysed in this study. As such results are initially presented by comparing the time frames over which results are calculated and the different interval selection techniques. Focus is then turned to consideration of each calculation methodology and a summary is offered of the six different calculation criteria listed in Section 2.1.

All detailed results are available in Section 13 (Appendix C) for further reference and the key findings of these results include the following

- Should a rule change be implemented whereby a new Reserve Capacity allocation calculation method results in highly varied outcomes from year to year there is a suggestion that Reserve Capacity incentives should be de-coupled from the SWIS’ system Capacity Requirements.
- The Reserve Capacity allocated to generators which are characterised by significant variability in generation due to a variable primary resource can be subject to highly variable allocations where interval selection data sets are limited in size. This is particularly evident in the case of allocations based on the 12 Peak and Top 250 load intervals.
- Calculation methodologies based on larger data sets can provide relatively stable results that do not vary significantly when derived from longer time frames. Particularly where these data sets are expanded as additional years are considered, as in the case of All intervals and the Peak Period intervals.
- Reserve Capacity allocations based on 10^{th} percentiles have the potential to allocate little or no Reserve Capacity to some generation technologies in the absence of a fleet component,

particularly in the case of the solar thermal generation considered here. Furthermore, 10^{th} percentiles of All intervals appear to misrepresent the contribution to peak load where generation profiles are positively correlated with peak load.

- While there is significant variation in the correlation between generation and SWIS demand between sites there is a general trend in all generators considered here, and particularly in coastal areas for existing and prospective generators, for above average generation during peak load times. In the case of wind generation, calculation methodologies that consider the average of peak load intervals, such as in the PJM criteria or the average of the Top 250 load intervals in some cases, result in Reserve Capacity allocations which are higher than that calculated with All intervals by a factor of ~1.2-1.4 for recorded generation and ~1.1-2 for modelled generation where calculations are based on averages. Similarly, the Current method reduces the magnitude of the allocations given to the solar thermal generators considered here by ~60-70% when compared to calculation methodologies that consider peak or daytime load intervals only.
- Calculations based on single year time frames derive results similar (typically within ±~15%) to those based on longer time frames for the majority of the calculation methodologies (with the exception of the 10th percentile calculations). However, Reserve Capacity allocations for a given generator can change substantially from year to year for certain calculation methodologies, particularly when allocation calculations are based on small data sets.
- Reserve Capacity allocations based on fleet calculation methodologies are influenced by three aspects which can be made evident by, and depend on, the calculation methodology applied. The fleet average of All intervals will vary with the scale of the resource captured by the fleet and corresponding generator capacities and capacity factors. The fleet 10^{th} percentile of the Top 250 intervals can be influenced by the availability of generation during these intervals whereby a single generator can contribute in the form of a security impact. Furthermore, a comparison can be made between peak load focussed calculations with and without the fleet whereby variations in the fleet 10^{th} percentile of the Top 250 loads can represent a resource security impact. Overall, the Original calculation method tends to allocate around 50% of that from the Current method and peak load focussed allocation methods can significantly under allocate Reserve Capacity if the fleet aspect is excluded.
- The allocation of Reserve Capacity to intermittent generators with relatively stable generation profiles (e.g., landfill gas and other biogas generators) is relatively independent of the calculation methodology used. The potential impact of changes to the calculation methodology on these generation technologies is therefore minimal.

4.1 Results by Time Frame

The results from this study indicate that, in general, the use of single year time frames for selecting the appropriate load and generation intervals derives Reserve Capacity allocations which are variable from year to year. Should the present condition, whereby Capacity Credit allocations and system security are tied, remain in place, system security may be negatively impacted upon where calculations are based on single year time frames.

This variability can be markedly reduced given the appropriate interval selection method for certain calculation methodologies such as All and the Peak Period intervals as shown by the example in Figure 10. However, calculations based on the Top 250 and 12 Peak intervals appear to show no or very little change in this aspect regardless of the length of the time frame selected as would be expected from the discussion in Section 2.1.

Thus, it is expected that, should Capacity Credit allocations be tied to the SWIS' Reserve Capacity requirements, the selection of intervals based on single year time frames is expected to be undesirable unless the calculation relied on a significant number of intervals.

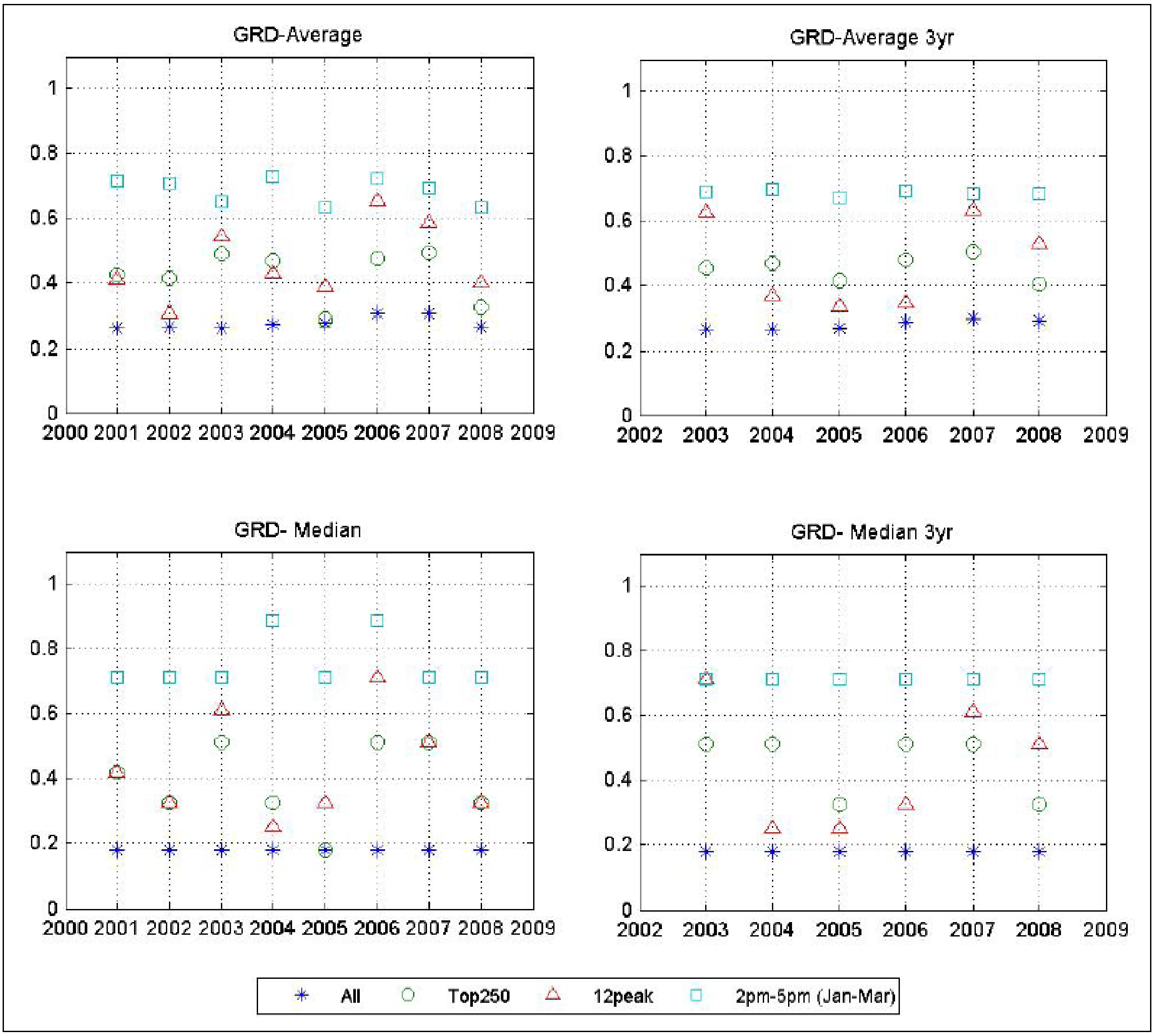


Figure 10: Comparison of average and median calculation methodologies for GER where the differences between the use of single and three year time frames is evident.

4.2 Results by Interval Selection

The literature on system reliability suggests that the need for reliability support is most pronounced at times of highest load, when generator failure puts the system at greatest risk of load shedding.

Daily and seasonal variations are observable in load patterns and some intermittent generation technologies. This suggests the possibility of systemic correlations between output from intermittent generators and system load that could influence the contribution of intermittent generation to system reliability. Positive correlations will enhance an intermittent generator's contribution to system reliability and negative correlations will tend to undermine it.

The current rule, which assesses generation expectations over all intervals, is blind to correlations between expected generation and system risk.

An alternative is to base availability expectations on generation observed during intervals with the highest load periods as in the Top 250 interval approach. Output expectations will tend to be more volatile the smaller the number of periods used. However, to the extent daily, seasonal or weather-related correlations with high system risk intervals are present, these will be better reflected in Capacity Credit allocations.

Another option is to base generation expectations on a period of hours deemed high risk on a seasonal and daily basis as in the PJM approach. Correlations between generation and load driven by the specifics of the weather pattern prevailing on any particular day will not be captured by this approach but general resource trends over specified daily time periods will be.

Intervals can be weighted to better reflect relative system risk. The capacity refund multipliers are used as the basis for a potential weighting system in this study. In this instance the weights are applied over the comparatively large interval ranges used in the application of the Capacity Credit Refund Mechanism. As such, they are unlikely to reflect large gradations in system risk associated with the extremes.

<u>All intervals</u>

The use of All intervals for each calculation methodology provides results that are relatively consistent across all wind farm sites and from year to year for each site and again when considering single or multiple year time frames. However, considering solar thermal generation it is apparent that calculations based on All intervals will not reflect the generator's contribution to peak demand. This is made evident in Figure 11 where the median calculation method represents the 50^{th} percentile of each year's generation interval data set which implies that only the intervals where the plant is not generating are captured by this calculation methodology. Solar thermal generation which does not include any thermal storage capacity is not being represented accordingly when All intervals are considered (particularly when compared to interval selection techniques which concentrate on peak load times).

Further consideration will show that, while wind generation may be represented appropriately under most calculation methodologies based on All intervals, solar thermal generators' contribution to peak load intervals could only be represented by a calculation methodology which focussed on such intervals.

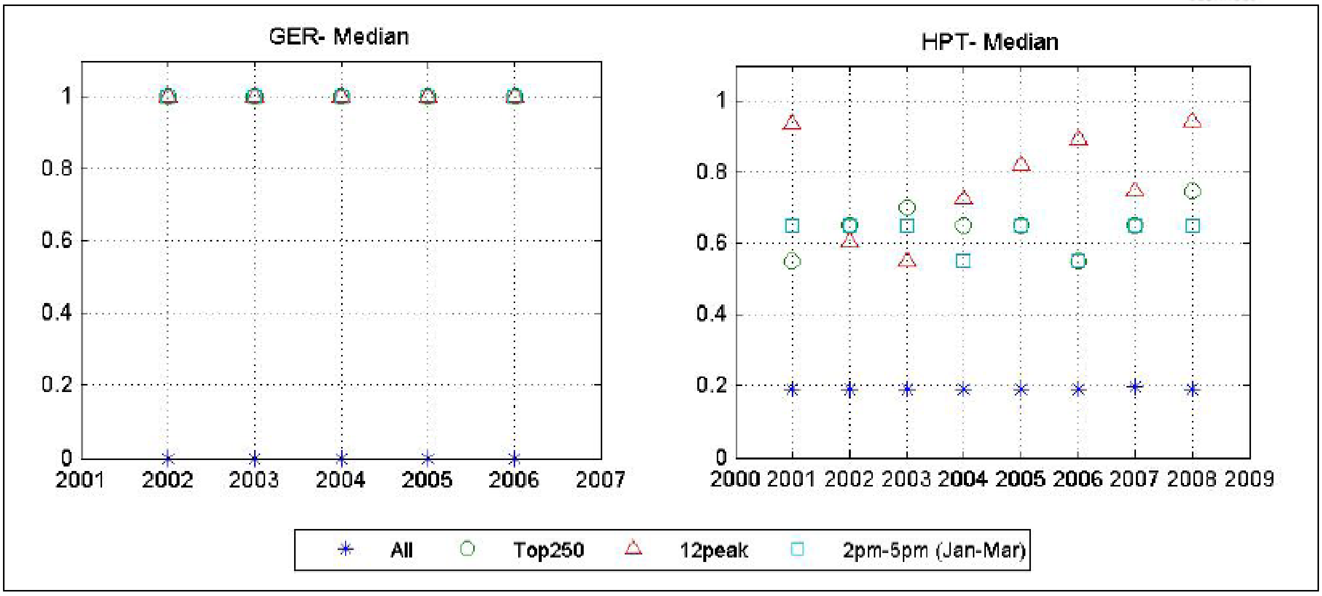


Figure 11: Comparison the median calculation methodology which highlights the impact of night time intervals being included in All intervals for GER. Note the contribution to peak load intervals evident from GER solar thermal generation where the selection of the median (50th percentile) of All intervals is always zero for solar thermal generation while the result for wind generation is comparatively reasonable.

Top 250 intervals

The Top 250 intervals represent ~1.5% of all the load intervals for a given year or ~0.5% of all of the intervals over three year time frames. The selection of the Top 250 load intervals gives differing results for each generation technology considered here. In terms of wind generation the outcomes can vary significantly from year to year. Figure 12 shows the comparison between the Top 250 intervals selection for the average calculation methodology for HPT over single and three year time frames.

In terms of solar thermal generation results vary greatly between calculation years when single year time frames are considered, but stabilise significantly when calculations are based on three year time frames. The reason for this is assumed to be that a higher incidence of clear sky days is captured by the Top 250 intervals over three year time frames. Correspondingly, the 250 highest load intervals over the three years are also occurring on these days.

The use of the Top 250 intervals for certain calculation methodologies can exaggerate the Reserve Capacity allocation and the contribution to the peak load as was shown in Figure 11 where the medians are calculated of the Top 250 intervals are shown.

For both wind and solar thermal technologies Reserve Capacity allocations are typically higher when the Top 250 intervals are considered, compared to when All intervals are used, suggesting that many of the generators considered here generate positively correlated with the SWIS load. As expected this affect is more pronounced with solar thermal generation.

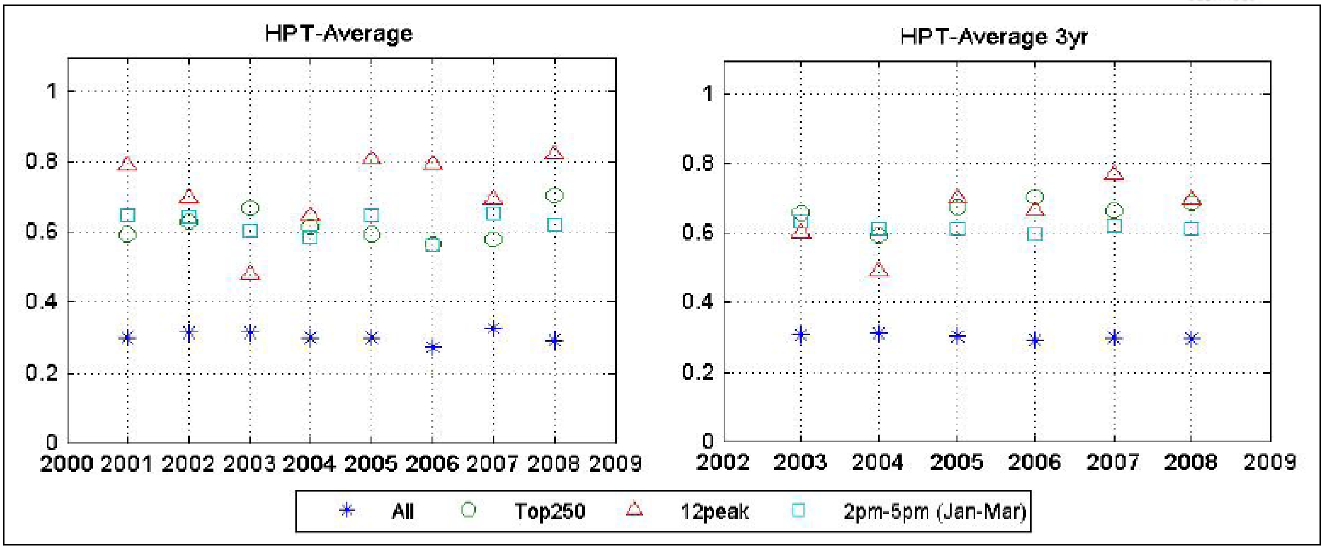


Figure 12: Comparison of the average calculation methodology which highlights the small variation between the selection of the Top 250 intervals over single or three year time frames.

12 Peak intervals

Where calculations are based on the 12 Peak intervals it is apparent that Reserve Capacity allocations for both wind generators can become subject to significant variability from year to year irrespective of the time frames considered.

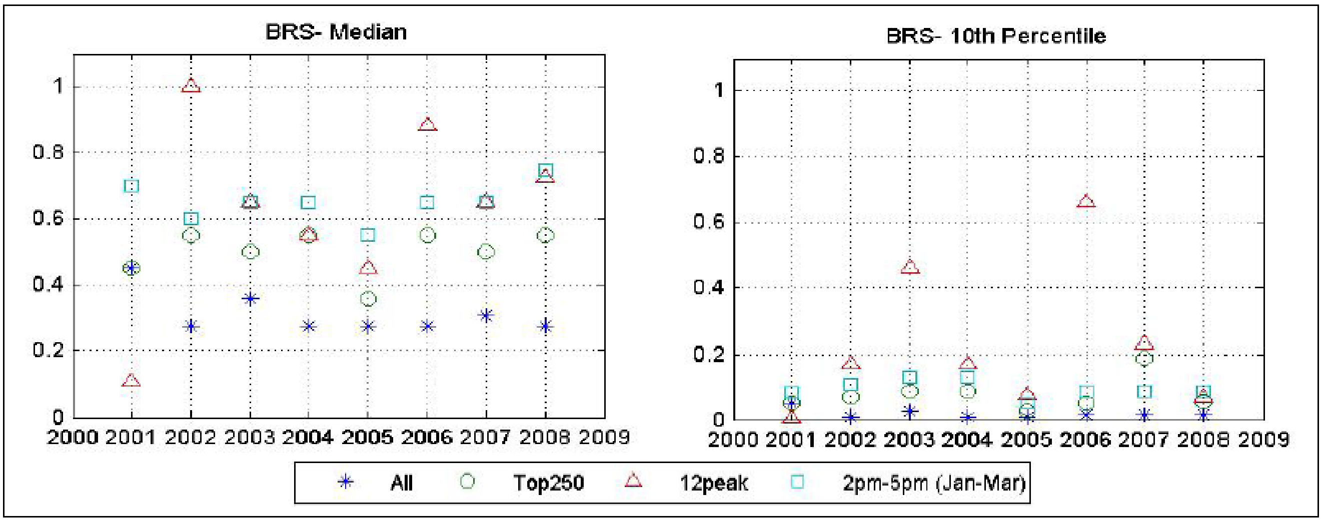


Figure 13: Comparison of the outcomes of the median and tenth percentile calculation methodologies over single years from BRS modelled wind generation. Note the variation found in the use of 12 Peak load intervals.

In general, basing calculations on a selection of only 12 intervals results in an apparently significant potential to over or under allocate Reserve Capacity irrespective of the time fames considered as shown by Figure 13 and throughout Appendix C. This level of variability is not expected to be desirable should Reserve Capacity allocations remain tied to system Capacity requirements.

Peak Period intervals

The selection of the Peak Period intervals provides a result for wind generation that is consistent with that of All intervals described above as would be expected due to both data sets being relatively large and which increase with the time frame selected. However, Peak Period results for solar thermal generators generally allocate higher Reserve Capacity as the Peak Period represents high generation times for solar thermal generators.

Of significance to calculations based on Peak Period intervals is the ability of this interval selection technique to capture the availability of the wind and solar resources at the generation sites considered in this study. More specifically, the selection of the 2-5pm time window captures a time when the load is consistently high but not necessarily peaking (as discussed in Sections 2.1 and 3.2) while the solar resource is also typically good. Furthermore, as is made evident in Figure 14 the nature of diurnal summer wind patterns along the west coast is also captured by the modelled wind generation at GRD and CPN. Further investigation finds that the average of the Peak Period intervals typically result in higher levels of Reserve Capacity to wind generators (by a factor of ~1.2-1.4 for recorded generation and ~1.1-2 for modelled generation) and much higher allocations to solar thermal generators (by a factor of ~2-3) when compared to the average of All intervals.

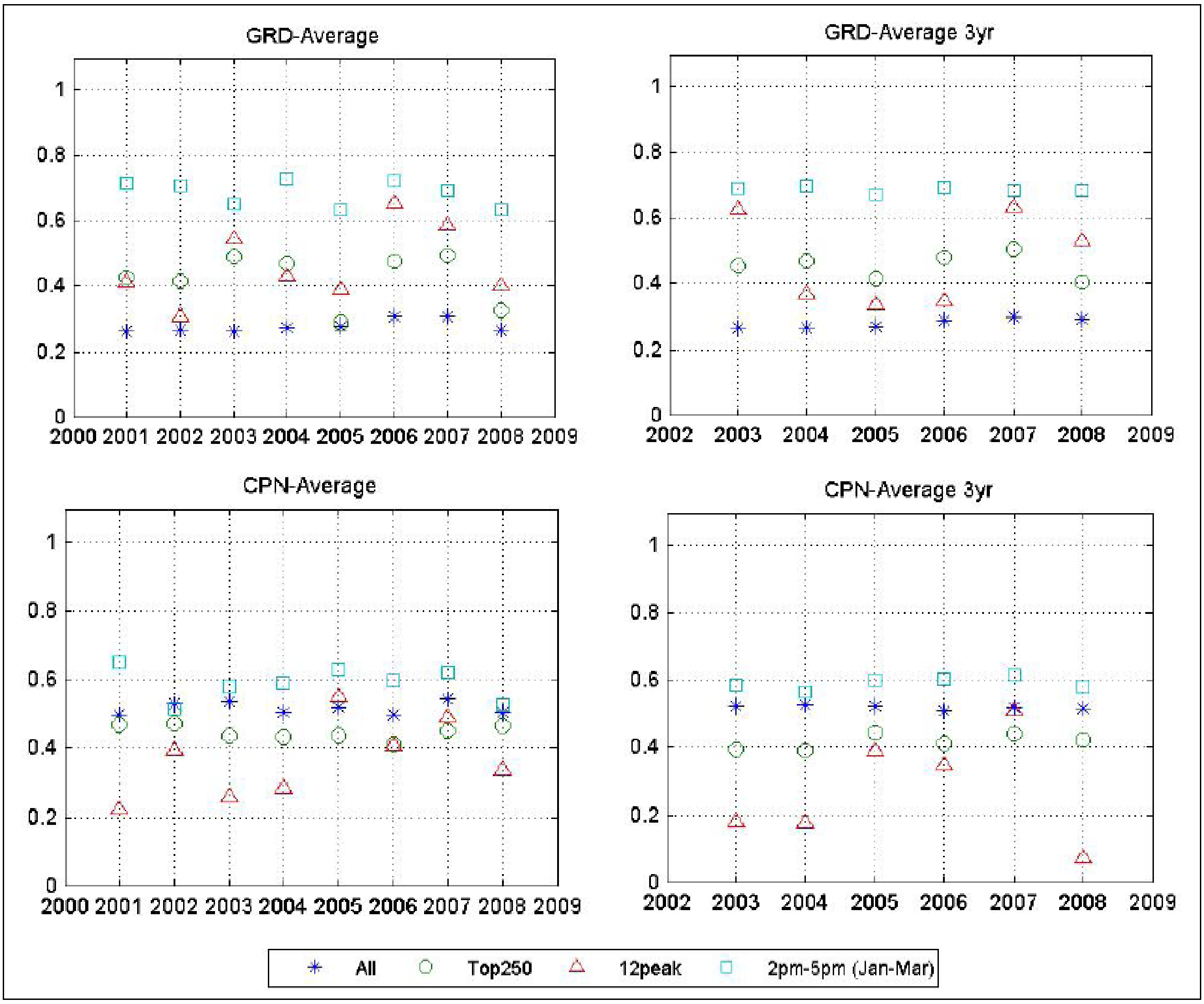


Figure 14: Comparison of the outcomes of the average calculation methodologies over single and three year time frames from modelled wind generation at GRD and CPN. Note the tendency for Reserve Capacity allocation to be increased with the Peak Period interval selection due to coastal diurnal summer wind patterns.

4.3 Results by Calculation Methodology

The calculation methodology applied to the respective interval selection is the most important aspect in the calculation of Reserve Capacity allocations. One of the key reasons for this is that the calculation methodology can provide significantly different outcomes depending on the generation technology under consideration.

Studies of the contribution intermittent generation makes to reliability in other electricity systems suggest average generation (during high load intervals) may be a reasonable basis for estimating the contribution to system reliability when penetration of intermittent generation is low. However, the benefit of additional intermittent generation declines as penetration increases with this method.

Average generation is sensitive to the relative scale of generation as well as the frequency. Percentile-based allocation methods are a coarser representation of a distribution of generation outcomes and focus on a threshold level of reliability. For example, the 50th percentile is the level of output observed to be achieved at least half of the time.

Capacity Credit allocation rules could focus on reliability thresholds, eg the implications of basing allocations on the 10th percentile is examined in this study and reflects a notional reliability of 90 percent. The level of reliability may be benchmarked to conventional generation. Such an approach is conservative in the sense that no contribution to system reliability is acknowledged for levels of output above the level determined by the reliability threshold. Consequently, the overall contribution to system reliability is likely to be underestimated with such methods.

The comparative variability of total generation reduces as stochastically independent generation sources are added to the fleet. This is because high output by some generators in any particular interval will, to some degree, be offset by low generation from others. This effect could be undermined by positive correlations between individual generators.

Weights can be used to prioritise generation in intervals when the system is more likely to be at risk similarly to the RCRM method.

For calculation methodology comparisons the results are presented graphically in terms of the maximum and minimum allocations over all sites, along with the maximum and minimum range of the allocations for any single site over all study years for each interval selection technique.

<u>Averages</u>

As shown in Figure 10, Figure 12 and Figure 14 averages can derive relatively consistent outcomes from year to year given an appropriately sized interval selection. The average of the intervals selected effectively represents the availability of the primary resource, for the generator in question, during the intervals selected. The maximum ranges shown in Figure 15 show that, when considering interval selection techniques which result in small data sets, Reserve Capacity allocations based on averages are susceptible to varied results from year to year.

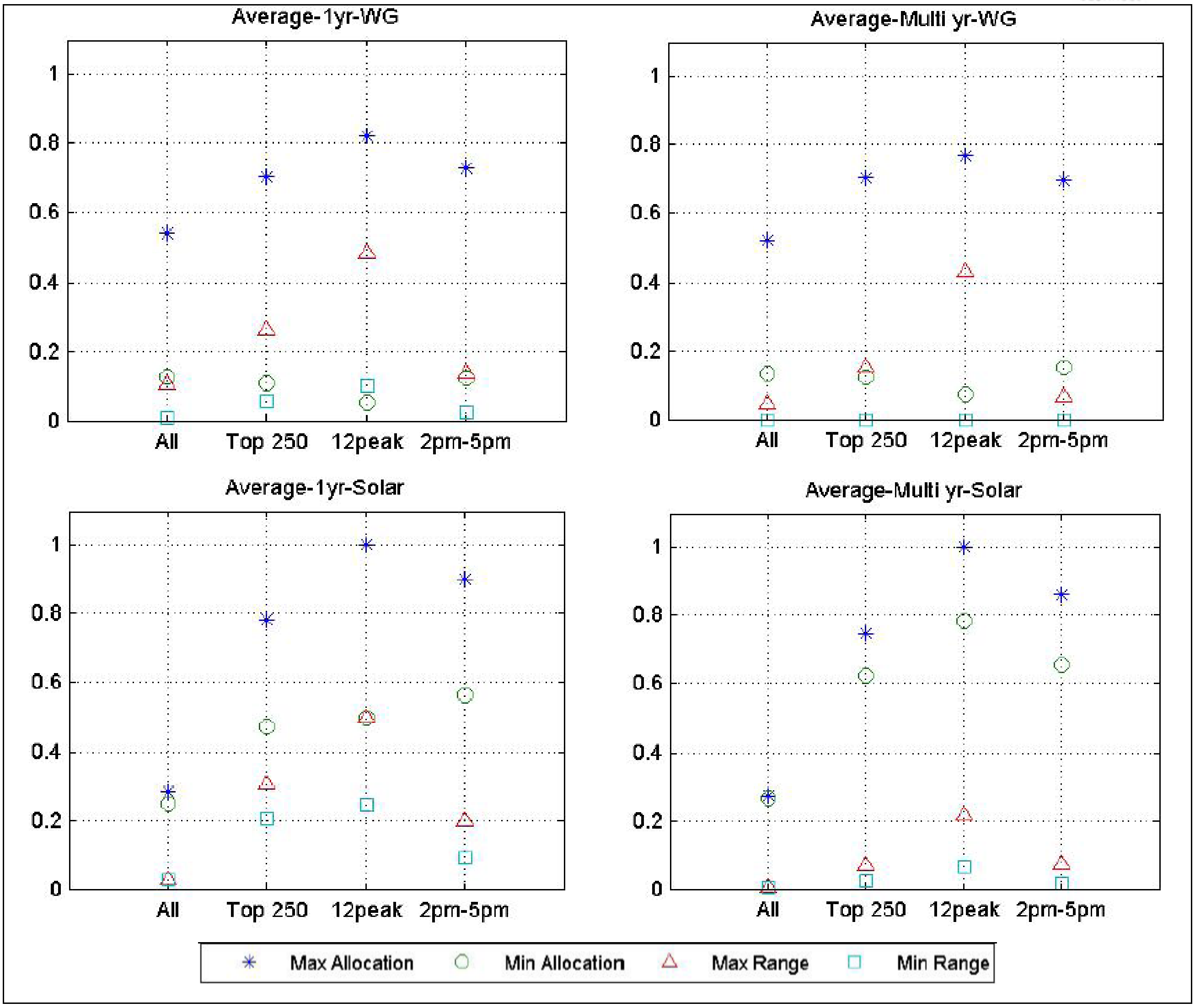


Figure 15: Summary of results derived from the consideration of Averages over single and multiple year time frames. The maximum and minimum Reserve Capacity allocated over all sites for wind and solar thermal generation is presented. The maximum and minimum ranges over the time frames selected for any single site are also shown. This highlights the volatility of the methodology to variations in respective resources.

10th Percentiles

When using the 10th percentile for assessing the Reserve Capacity allocations for solar thermal generation, results tend toward zero in many cases and can be highly varied when considering the 12 Peak intervals. As is exemplified by BRS in Figure 13, wind sites are not as heavily impacted upon but Reserve Capacity allocations tend to be very low in all cases. For generators which are well correlated with load, using the 10th percentile of All intervals may result in Reserve Capacity allocations that are significantly less than when only peak load intervals are considered. The range of Reserve Capacity allocations assigned increases when smaller data sets are used. For example, for wind generators Reserve Capacity allocations vary from 0 to 60% when only the 12 Peak intervals are considered.

While the selection of a three year or longer time frame does remove some variability in results for each site, the typically low Reserve Capacity allocations remain regardless and it is expected that they will not be sufficient in terms of the intention of the RCM.

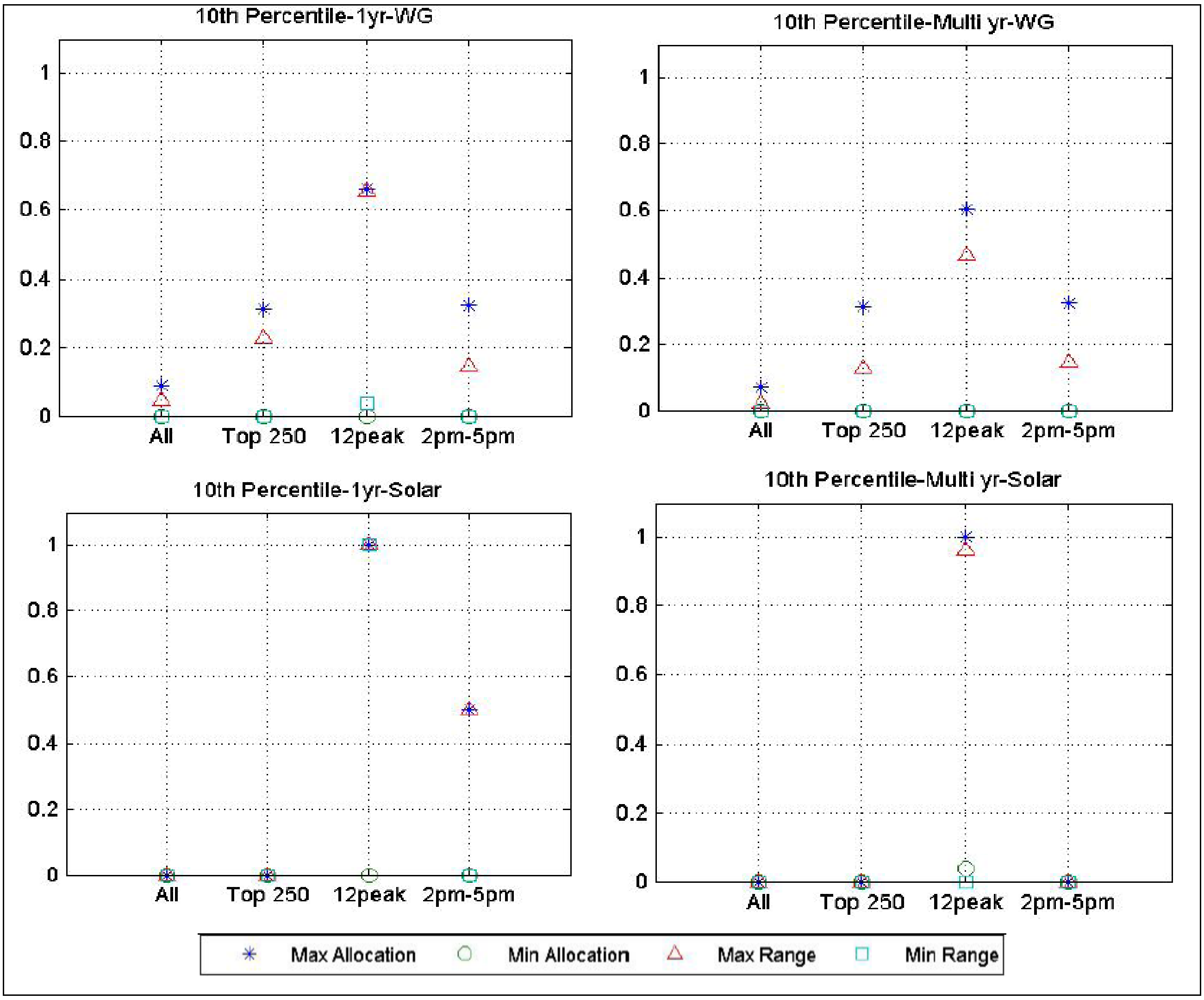


Figure 16: Summary of results derived from the consideration of 10th percentiles over single and multiple year time frames. The maximum and minimum Reserve Capacity allocated over all sites for wind and solar thermal generation is presented. The maximum and minimum ranges over the time frames selected for any single site are also shown which highlights the volatility of the methodology to variations in respective resources.

Medians

Figure 17 shows that medians tend to have low variance in the allocations from year to year and from site to site when derived from larger data sets in a similar light to averages. Particularly when calculations are made over multiple year time frames. However, in the case of wind generation, the outcomes are generally more varied than averages. When considering solar thermal generation Reserve Capacity allocations based on intervals which consider peak load times tend toward 100%. This implies that generation is very high for more than 50% of the intervals captured by each selection technique. Comparing this to the results for averages however, results based on medians may be exaggerating the contribution of solar thermal generation to the RCM. Like most of the other statistical metrics, the median generally increases when only the peak load intervals are considered for Reserve Capacity allocation calculations, suggesting a positive correlation with load for most of the generators considered.

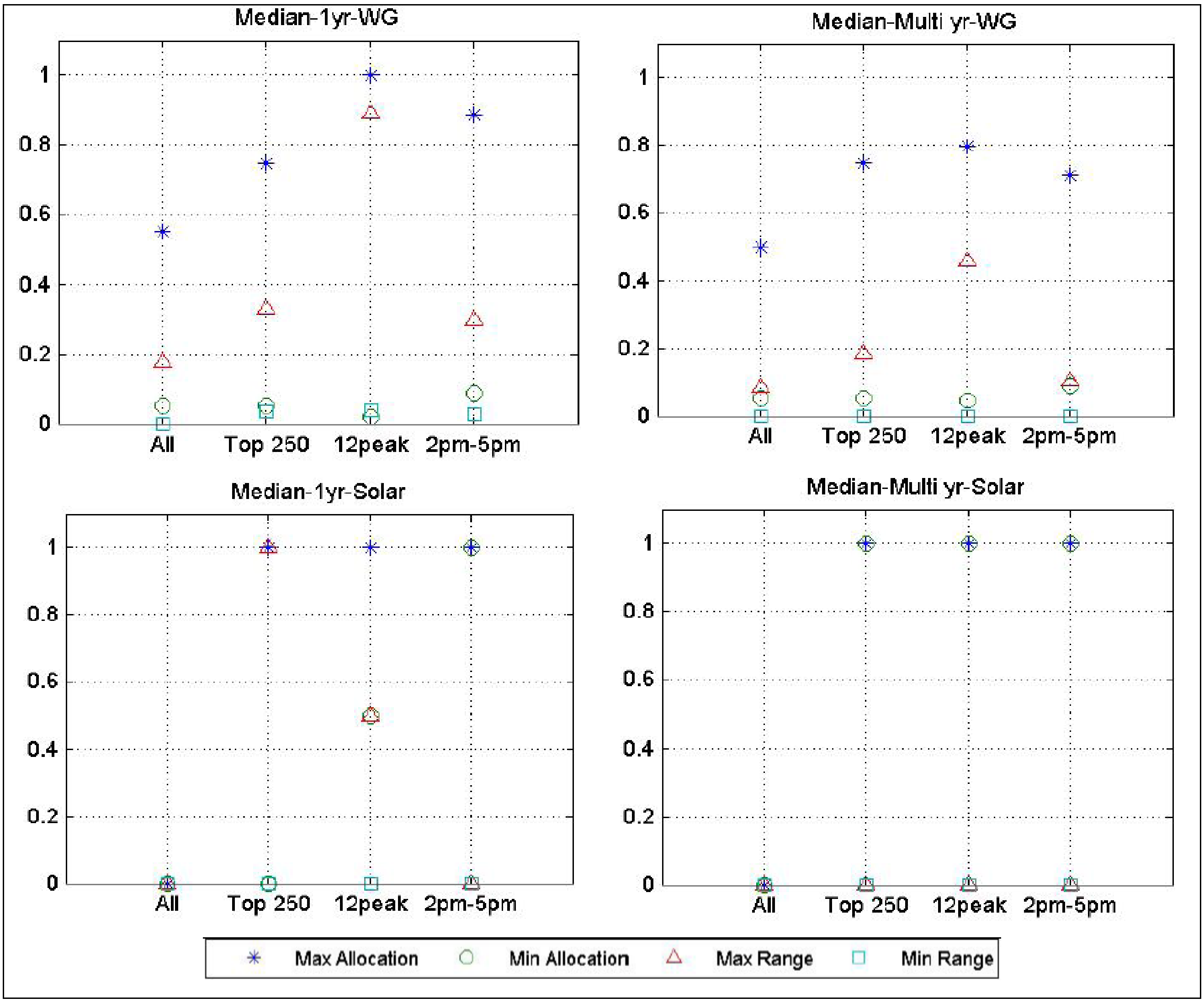


Figure 17: Summary of results derived from the consideration of Medians over single and multiple year time frames. The maximum and minimum Reserve Capacity allocated over all sites for wind and solar thermal generation is presented. The maximum and minimum ranges over the time frames selected for any single site are also shown which highlights the volatility of the methodology to variations in respective resources.

RCRM Weighted Averages

The weightings used for the RCRM method are drawn from an application applied to all non-intermittent generation in the SWIS. The use of the normalised RCRM weighting system as defined in Appendix B of this report is not appropriate for Reserve Capacity allocations considering only peak load intervals. As is made clear by Figure 18 where the maximum (and minimum in the case of solar thermal) allocations far exceed 100%.

It is apparent that the only reasonable outcomes are derived from All intervals as the weightings are normalised across this data set. This outcome shows that this methodology has the potential to evolve into an effective means of Reserve Capacity allocation. However, more scrutiny of the weightings applied is required such that the method can be applied to all generation technologies participating in the SWIS. The weightings do provide a means to reward generators with a positive correlation with load while including All intervals. The weighted average for All intervals is typically higher (by ~3-8% at wind generation sites and up to ~40% at modelled wind farm sites) than the unweighted average, again suggesting that most of the generators examined here exhibit a positive correlation with the SWIS load.

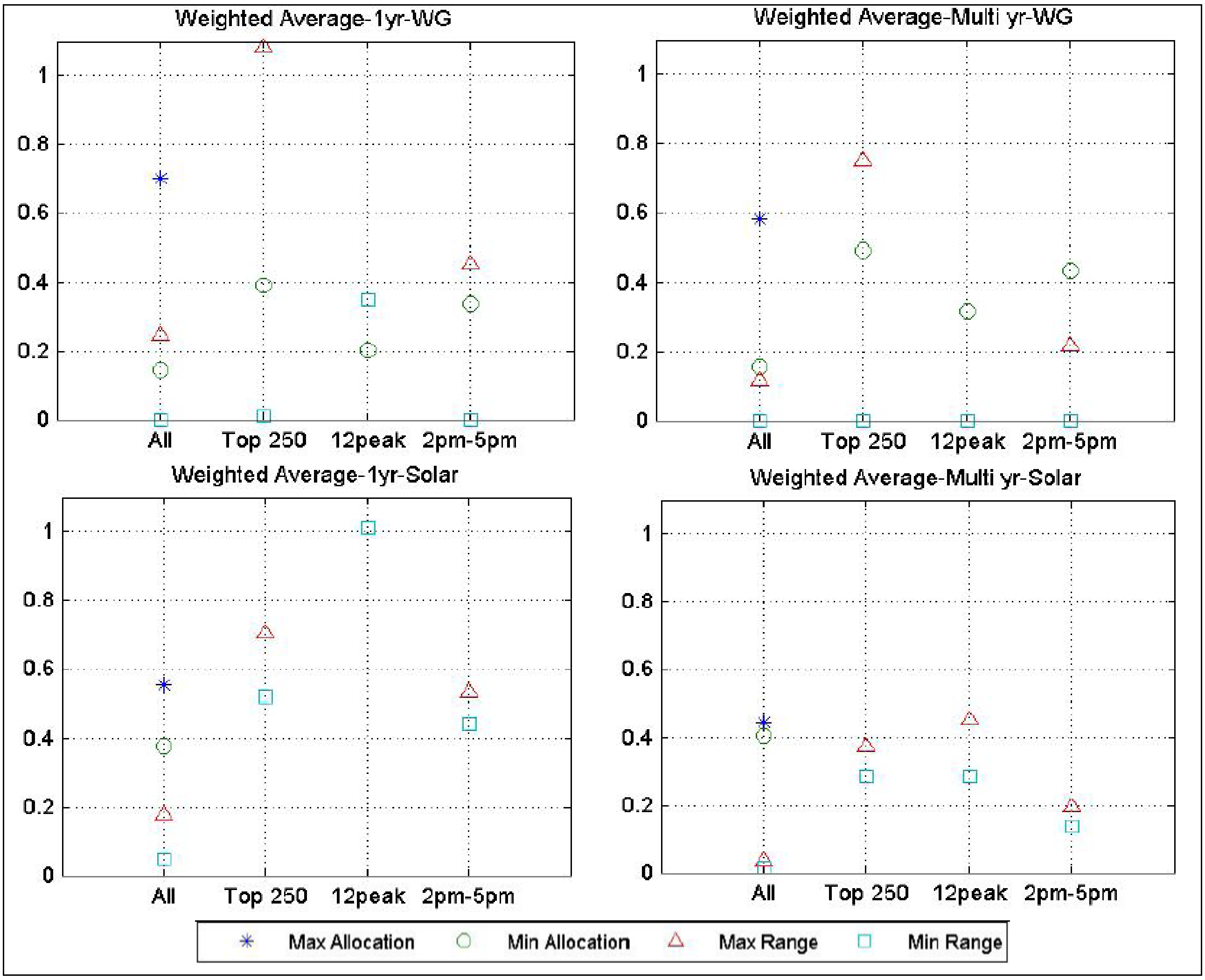


Figure 18: Summary of results derived from the consideration of RCRM weighted averages over single and multiple year time frames. The maximum and minimum Reserve Capacity allocated over all sites for wind and solar thermal generation is presented. The maximum and minimum ranges over the time frames selected for any single site are also shown which highlights the volatility of the methodology to variations in respective resources.

4.4 Results: Fleet Allocations

The Original calculation criteria stated that an intermittent generator's Reserve Capacity allocation was to be calculated by considering all intermittent generation as a fleet and then apportioning the allocations in proportion to the individual contributions to the fleet (see Appendix A for an explanation of the reasoning behind fleet calculations). Here we make this assessment based on the fleets defined in Section 3.6 and based on generator capacity factors (CF) with Equation 6. In this derivation, the Fleet Capacity Factor (FCF) is derived from a generation profile which represents the average of generator capacity factors for each generator in the fleet during each half hour interval. Single site Reserve Capacity (RC) allocations are derived exclusively of the fleet. Appendix C5 contains the full set of results for the fleet calculations.

$$\text{Fleet Allocation (CF)} = \frac{\text{Single Site RC Allocation (CF)}}{\text{Average of Single Site RC Allocations (CF)}} \times \text{FCF} \qquad \text{(Eq. 6)}$$

In all cases the results indicate that the use of the average calculation methodology will derive results which fall into ±1% of those previously calculated exclusively of the fleet. In contrast, Reserve Capacity allocations based on the 10th percentile methodology are consistently increased from those derived without the fleet as shown in Figure 19 for GRD modelled wind farm contributing to Wind Fleet 1.

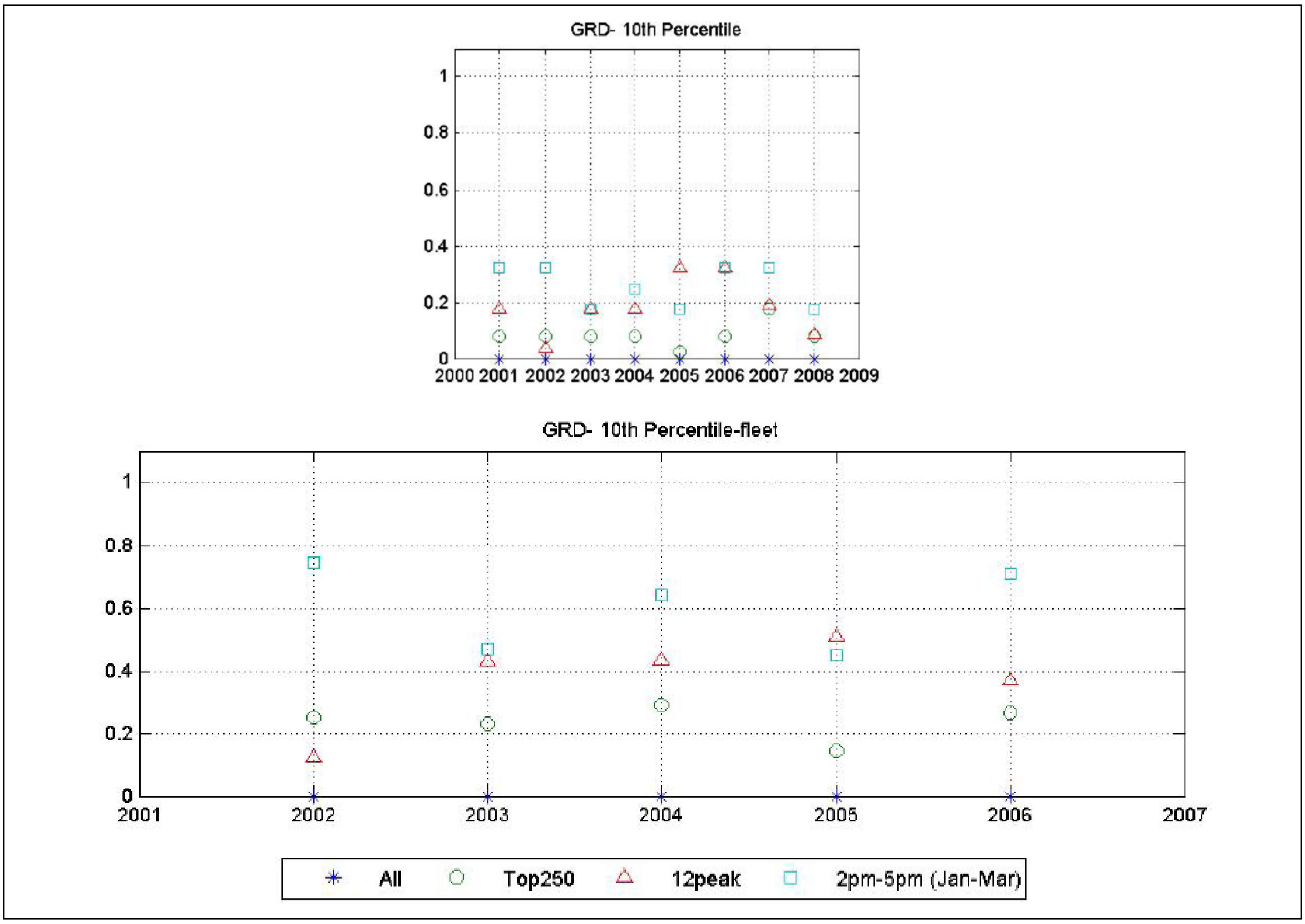


Figure 19: Comparison of the results for the 10th percentile calculation methodology as calculated with (top) and without (bottom) Wind Fleet 1 for GRD where results are based on generator capacity factors only. Note that GRD is considered in Wind Fleet 1 here such that 2001, 2007 and 2008 are not reflected in the fleet plot.

As fleet calculation methodologies focus on aggregated wind farm generation, it is important to understand the performance of the existing fleet of wind generators (i.e., ALB, EMU and WLK). One of the influential attributes of the Original calculation criteria is that it incorporates aggregated plant capacities. Hence, the Fleet Reserve Capacity (FRC) allocation calculations are repeated with Equation 7 for each generator in the existing fleet where generation is considered in MW.

$$\text{Fleet Allocation (MW)} = \frac{\text{Single Site RC Allocation}}{\text{Sum of Single Site RC Allocations}} \times \text{FRC} \qquad \text{(Eq. 7)}$$

In order to represent the time related variations in the combined fleet capacity, and geographic diversity, allocations are calculated here for the changing fleet. This is represented with 2007 generation data by starting from ALB as a single generator then adding WLK, then EMU and then the proposed future development of NIL as shown in Table 7. In order to fully investigate the impact of a diversified fleet the analysis also includes the addition of a hypothetical 100MW wind farm at HPT.

Fleet	FRC		ALB (22MW)		WLK (90MW)		EMU (79MW)		NIL (132MW)		HPT (100MW)	
	Average - All	10% - Top 250	Average - All	10% - Top 250	Average - All	10% - Top 250	Average - All	10% - Top 250	Average - All	10% - Top 250	Average - All	10% - Top 250
ALB	7.57	1.54	7.57	1.54	-	-	-	-	-	-	-	-
ALB WLK	47.89	23.73	7.57	2.45	40.32	21.28	-	-	-	-	-	-
ALB WLK EMU	77.23	37.55	7.57	3.07	40.31	26.70	29.35	7.78	-	-	-	-
ALB WLK EMU NIL	124.26	67.38	7.57	3.07	40.30	26.65	29.34	7.77	47.05	29.89	-	-
ALB WLK EMU NIL HPT	156.49	126.90	7.56	4.16	40.29	36.10	29.34	10.52	47.04	40.49	32.26	35.63

Table 7: Results of the Fleet Reserve Capacity allocations based on the existing and proposed SWIS wind generator fleet showing the variations of the allocations over time as the wind fleet is expanded in 2007. A 100MW HPT wind farm is included as a hypothetical future scenario.

As discussed in Appendix A, there is very little difference found in each generator's fleet average as the fleet is expanded. Conversely, the 10th percentile of the Top 250 load intervals increases as the fleet is expanded.

Using ALB as an example generator from Table 7 we can see that the expansion of the fleet will gradually increase the 10th percentile allocations. However, the fact that the addition of NIL to the fleet does not increase the allocation to ALB does not necessarily mean NIL does not impact on the fleet. More precisely, NIL will provide an additional impact of resource scale to the fleet, but not diversity as it is subject to similar wind patterns as are WLK and EMU. With the addition of NIL a 79% increase in the sum of the individual 10th percentile allocations is matched by a 79% increase in the FRC 10th percentile allocation such that Equation 7 allocates the same to ALB with or without NIL in the fleet for the 10th percentile. Conversely, the addition of the hypothetical HPT vastly increases the allocation to ALB as this site contributes considerably to the FRC, but only presents a small contribution from the individual 10th percentile. This implies that generation at HPT differs substantially from that at WLK, EMU and NIL during peak load times during 2007.

From the discussion above, it is apparent that there are two measurable influences on performance of the wind generator fleet. Through the use of the average and 10th percentile FRC calculations these can be broken down in terms of *resource scale* and *resource security* impacts. The first of these influences can be seen in increases in the power magnitude of average generation, which is represented by both installed generator capacities and their corresponding capacity factors. The second influence is evident in the 10th percentile FRC allocations which represent the lowest 10 percent of available generation during the 250 load intervals in which system security is assumed to be most at risk.

Figure 20 shows how the average and 10th percentile FRC allocations change with the changes to the fleet shown in Table 7. The results for the same analysis in 2008 are also shown for completeness noting that data from GIN was used in the place of NIL due to unavailability of 2008 data from the latter. The two allocation methodologies vary independently of each other by the influences described above. The scale impact seen in the average is evident by an almost linear increase in FRC. This increase can be approximated in terms of FRC per MW installed in the fleet at around 0.37MW of FRC per MW in 2007, and around 0.31MW of FRC per MW in 2008. This linear behaviour is to be expected in both cases as the aggregated installed capacity increases with an expanding fleet while the resource scale across the fleet sites is relatively even resulting in a stable average capacity factor. More interestingly, the security impact varies relative to the availability of generation during peak load times at the site in question. For example, the proposed addition of NIL to the fleet results in an FRC of around 0.20MW of FRC per MW installed in 2007. Correspondingly, the addition of GIN in 2008 results in an FRC of around 0.16MW of FRC per MW installed. However, in both cases the expansion of the fleet to HPT significantly increases the security parameter to around 0.31MW of FRC per MW installed in 2007 and around 0.28MW of FRC per MW installed in 2008.

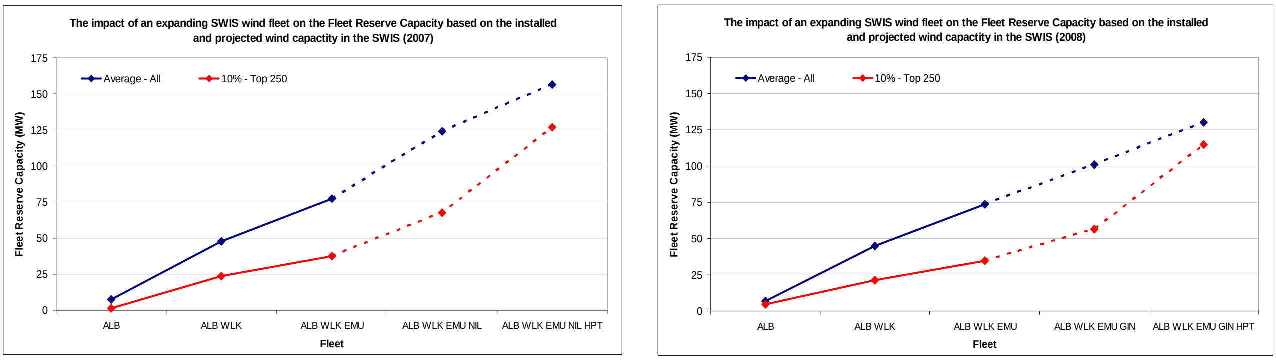


Figure 20: Plot of the variation of the average and 10th percentile Fleet Reserve Capacity (FRC) allocations as the existing wind fleet is expanded to include additional existing, planned and hypothetical wind generators. Both 2007 and 2008 are shown where the GIN replaces NIL with an equivalent installed capacity in 2008.

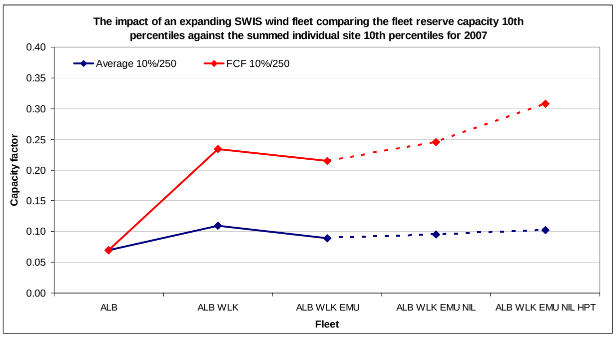
One would expect that the almost linear increase in the 10th percentile as the fleet expands to include ALB, WLK, EMU and NIL/GIN could be related to similar weather patterns at these sites such that they each contribute similarly during peak load times. The addition of HPT increases the 10th percentile because the weather patterns at this site are conducive to generation which correlates better with peak load times and thus provides greater security to the fleet.

As discussed above the FRC average is almost identical to the sum of the individual averages or the Current method allocations. Thus, Figure 20 shows that, considering the existing fleet of ALB, WLK and EMU, the Reserve Capacity allocated with the Current method is typically around twice that allocated with the Original method.

Further to the fleet impacts discussed above, the implications of the inclusion of a fleet calculation methodology can be compared to calculations based on a methodology which excludes the fleet by comparing 10th percentile allocations of the Top 250 loads. This is best done by initially normalising generation at each site as in Equation 6. The FCF 10th percentile is then compared to the average of the individual site 10th percentile allocations. Furthermore, this analysis provides a measurable parameter in terms of the reliability of the resource at a given site which reflects the relative impact of the addition of each fleet generator on the FCF as compared to the fleet without the specific generator.

This *resource reliability* impact can be clearly seen in Figure 21 where the FCF and average of the individual site capacity factors are compared in 2007 and 2008. Given that individual 10th percentiles are relatively stable across the fleet sites there is little deviation in the average of the individual site 10th percentile allocations and the average will tend to level off to a definite value as the fleet expands. However, the FCF allocations clearly vary substantially as the fleet changes.

Measuring the resource impact as the net change in the FCF from that calculated prior to the addition of each generator we can see that the addition of EMU to the fleet reduces the FCF by 2% (capacity factor magnitude) in 2007 and increases it by only 1% in 2008. While the substitution of GIN for NIL in 2008 provides differing outcomes here the addition of HPT provides a positive resource impact of 6% in both cases and the end result is similar in both 2007 and 2008.



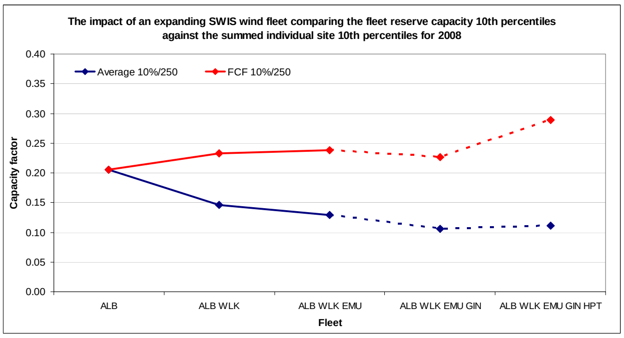


Figure 21: Comparison of 10th percentile FCF allocations and the average of the individual site 10th percentile allocations with an expanding wind farm fleet. All calculations are normalised such that generator capacities are neglected.

A further important outcome of Figure 21 is that a comparison can be made between a peak focussed reliability calculation method with and without the use of the fleet parameter. It is clear in both 2007 and 2008 that the individual 10th percentiles tend to level off at an average capacity factor of around 10% as the fleet is expanded. However, the inclusion of the fleet component tends to allocate around 30% in the final case here where the two different fleets represent almost identical geographic diversity characteristics. Hence, a Reserve Capacity allocation method which focuses on peak load intervals without a fleet component appears to under allocate reserve capacity by around 50-66% in these cases.

In summary, while Reserve Capacity allocations based on averages remain almost exactly the same, those based on 10th percentile allocations present contrasting outcomes when compared to those calculated exclusively to the fleet. Correspondingly, in terms of the behaviour of a geographically distributed wind fleet, three types of potential influences have been identified and can be separately quantified in terms of resource security, scale and reliability. The combined assessment of each can provide an indication of the performance of an expanding SWIS wind farm fleet.

4.5 Assessment of the Reserve Capacity Calculation Criteria

The six Reserve Capacity allocation calculation criteria on which this study has been based (Section 2.1) have been selected from proposed alternatives and potential precedent methodologies. As such they are considered above others in their effectiveness. The following makes a brief assessment of each based on the results found and in regard to the wind and solar thermal generating technologies considered here. Note that the comments regarding landfill gas generators made at the beginning of Section 4 remain relevant to this summary.

Current Method

The Current method can provide reasonable Reserve Capacity allocations to the wind generators and over the study years considered here. The amount of Reserve Capacity allocated under the

Current method is not influenced by any correlation between resource availability and load, with the exception of that available to specific generators, as it is an unweighted average of All intervals. Reserve Capacity allocated under the Current method does not change significantly from year to year for a given site, as shown in Table 22 where the maximum standard deviation for any site between years is 1.52%.

The level of Reserve Capacity allocated to the different generators considered here is lower under the Current method that that calculated with an allocation method which concentrates on peak load intervals. This suggests that some generators have a positive correlation with load, and that this characteristic is not being captured by the Current method which is particularly true for solar thermal generation. Given the diurnal variation in solar resource, and its positive correlation with the daily load profile, the use of the Current method results in a significantly reduction (~60-70% lower) of Reserve Capacity allocations to solar thermal generators than when a calculation methodology that concentrates on peak load intervals is applied.

In summary, the use of the Current method is independent of any correlation between the generation and load. In comparison to methodologies which concentrate on peak load intervals, the Current method reduces the range of Capacity Credit allocation given to wind generators across years, and reduces the magnitude of the allocations given to the solar thermal generators considered here by ~60-70%.

Original Method

The results found with the application of the Original calculation method indicate that the use of the 10th percentile of the Top 250 intervals for the fleet of wind generators results in Reserve Capacity allocations typically lower than that assigned via the Current method. Figure 21 shows that peak load focussed Reserve Capacity allocations which do not include a fleet component typically reduce Reserve Capacity allocations by around 50-66% than those which consider the fleet. Correspondingly, the Original method will tend to allocate around 50% of the Reserve Capacity allocated by the Current method.

The consideration of the resource scale, security and reliability impacts that a geographically diverse fleet can present imply that the Reserve Capacity allocated under the Original method would be highly dependent on the characteristics of the fleet. Therefore, this method may present issues for generation technologies that do not have an existing and established fleet.

Proposed Method

The use of the 10th percentile of the Top 250 intervals without a fleet component typically results in lower Reserve Capacity allocations to all intermittent generators than all other methods considered here. The Proposed method may result in the allocation of zero (or near zero) Reserve Capacity to generation technologies that have bipolar generation distributions such as solar thermal. As shown in Table 20 the range of Reserve Capacity levels allocated to different generators and from year to year under the Proposed methodology is not as wide as that calculated with other calculation methods. However, the Proposed method risks allocating very low levels to many of the generators considered here.

PJM Method

Using the PJM method typically results in higher levels of Reserve Capacity to wind generators (by a factor of ~1.2-1.4 for recorded generation and ~1.1-2 for modelled generation) and much higher allocations to solar thermal generators (by a factor of ~2-3) when compared to the Current method. In the case of wind and solar thermal generators there is a clear indication that diurnal weather patterns have an impact on allocations made with the PJM method. The selection of a time period which considers high load intervals (rather than All intervals) provides a means to recognise the contribution of generation technologies which are positively correlated with load. Results indicate that the standard deviation between calculation years for the PJM method is roughly twice that for Current method. Further work would be needed to assess the relationship between the time window selected here and its impact on system security.

IRCR Method

The use of a data set of only 12 intervals has a significant impact on the level of Reserve Capacity allocated to a given generator. The use of the IRCR method results in Reserve Capacity allocations that very greatly (from 0 to 100%) from site to site and year to year. Compared to some of the other methods, there is not a strong statistical relationship between the IRCR method and the purposes of the RCM. It is expected that the use of the IRCR method would result in sending signals to market generators that may not correspond to enhancing system security.

RCRM Method

The use of the RCRM method has the potential to reward generators with a positive correlation with load while including All intervals. For the solar thermal generators examined, this method results in ~10% higher allocations than the Current method, but ~10-40% less than that calculated with the PJM method. Like the Current method, this method, as currently configured, requires the use of All intervals, which may not be necessary in terms of the purposes of the RCM. The weightings derived in this report are drawn from an application applied to all non-intermittent generation in the SWIS, and may not provide an accurate statistical representation of the resulting security risks to the market. There may be potential for a weighted average method which can be applied across all technologies participating in the SWIS should an adaptation of the weightings applied be designed accordingly.

4.6 Summary of Reserve Capacity Allocation Results

In making an assessment of the Reserve Capacity allocation methodologies the three key characteristics of each methodology have been considered in the presentation of results: the time frames considered, the interval selection techniques and the calculation methodologies applied. The key findings of these results include

- The Reserve Capacity allocated to generators which are characterised by significant variability in generation due to a variable primary resource can be subject to highly variable allocations where interval selection data sets are limited in size. This is particularly evident in the case of allocations based on the 12 Peak and Top 250 load intervals.
- Calculation methodologies based on larger data sets can provide relatively stable results that do not vary significantly when derived from longer time frames. This is particularly true where these data sets are expanded as additional years are considered, as in the case of All intervals and the Peak Period intervals. Calculations based on single year time frames derive results similar (typically within ±~15%) to those based on longer time frames for the majority of the calculation methodologies (with the exception of the 10th percentile calculations) (Section 4).
- Reserve Capacity allocations based on 10th percentiles have the potential to allocate little or no Reserve Capacity to some generation technologies in the absence of a fleet component. Furthermore, 10th percentiles of All intervals appear to misrepresent the contribution to peak

load where generation profiles are positively correlated with peak load as with solar thermal generators (Section 4).

- o The correlation between intermittent generation and times when load is highest is an important determinant of the likely contribution variable generators make to system reliability as intervals when the load is highest give an indication of when the system is likely to be most at risk. Although wind resource variability (and hence reliability) varies between wind sites (Section 4.2) there is a general trend in all wind generators considered here, and particularly for those located in coastal areas, for above average generation during peak load times. In the case of wind generation, calculation methodologies that consider peak load intervals only typically result in Reserve Capacity allocations which are higher than that calculated with All intervals by a factor of ~1.2-1.4 for recorded wind generation and ~1.1-2 for modelled wind generation where calculations are based on averages (Section 4).
- o Solar thermal generation has a strong correlation with peak load intervals that is under-recognised by the current allocation approach. It is highly reliable during summer peak load intervals when the sun is available, with incidences of cloud obstruction being comparatively low (Section 5.2). Despite a substantial portion of peak load intervals occurring towards the end of the day or in the early evening, when insolation is low, the Current allocation method allocates approximately 60-70% less Reserve Capacity to those methods which consider peak load intervals only. Furthermore, Reserve Capacity allocations based on purely reliability focused calculation methodologies, such as 10th percentiles have the potential to lead to very low allocations for solar thermal generators (Section 4).
- o Longitude influences alignment of solar insolation with SWIS peak loads, with a substantially better match in Geraldton compared to Kalgoorlie. During peak load periods system loads during peak load intervals when solar radiation is available for capture are typically marginally higher than loads during peak load intervals with little insolation (Section 5.2), however this is not recognised in any of the allocation methods analysed here. Thermal energy storage capacity can moderate the effect of cloud cover and would allow a solar thermal facility to generate during high early evening loads, providing a more reliable generation resource (Section 5.5.5).
- o As stochastically independent sources of wind generation are added to the wind generation fleet, the likelihood of relatively low levels of generation is reduced. The 90 per cent reliable level of generation for the existing fleet is approximately double the 90 per cent level of reliable generation from each individual wind farm (Section 4.4). While this outcome could be affected by weather-based correlations between wind sites, no material correlations were evident in generation from existing wind farms over contemporaneous trading intervals, or between various Bureau of Meteorology wind mast locations distributed around the SWIS (Section 4.4). Note that this outcome may not hold in the future if new wind farms are located in close proximity to existing wind farms.
- o Reserve Capacity allocations based on fleet calculation methodologies are influenced by three aspects which can be made evident by, and depend on, the calculation methodology applied. The fleet average of All intervals will vary with the scale of the resource captured by the fleet and corresponding generator capacities and capacity factors. The fleet 10th percentile of the Top 250 intervals can be influenced by the availability of generation during these intervals whereby a single generator can contribute in the form of a security impact. Furthermore, a comparison can be made between peak load focussed calculations with and without the fleet whereby variations in the fleet 10th percentile of the Top 250 loads can represent a resource security impact (Section 4.4). Overall, the Original calculation method tends to allocate around 50% of that from the Current method (Section 4).
- o The allocation of Reserve Capacity to intermittent generators with stable generation profiles (e.g., landfill gas and other biogas generators) is relatively independent of the calculation

methodology used as these generators exhibit no correlation with load. Thus, the effect of rule allocations analysed here has a relatively small impact (Section 4).

5 Secondary Analysis

As discussed in Section 2.2 this study considers a significant amount of secondary analysis. These analyses are included in order to compare the benefits and issues surrounding each Reserve Capacity calculation methodology when combined with the results previously reported in Section 4.

Secondary Analysis	Data Type Considered		
	Load	Wind	Solar
Correlation Coefficients	X	X	X
Generation Interval Selection Distribution Histograms		X	X
Confidence and Risk Assessment		X	
Fleet Diversity Impacts		X	X
Sensitivity Analysis			
- Geographic Diversity		X	X
- Comparison of Modelled and Metered Generation Data		X	
- Year Selection: Capacity Year vs. Calendar Year		X	X
- Load Timing	X	X	
- Adapted Generaton Technologies			X

Table 8: Secondary analysis considered here. Each X denotes an area of analysis for each relevant data set.

Table 8 outlines the secondary analysis considered here in Section 5. Noting that, in line with previous results, the focus is on solar thermal and wind generation. The following summarises the outcomes of these analyses.

- Correlation coefficients are used to show that, while there is a relationship between the temperature at East Perth and wind generation it is highly complex. As such, the use of correlation coefficients for Reserve Capacity calculations would not represent the contribution of wind generation to the RCM. Conversely, a strong positive correlation of 0.85 is found between East Perth temperatures and the SWIS load.
- Distribution histograms are used to show the diversity of generation captured by each interval selection technique. Results of this analysis show that wind is a highly variable resource and that there is no precise correlation between wind generation and any particular SWIS load interval. However, a clear trend for generation to be above average during peak load times is shown along with a tenancy for allocations calculated with averages to present approximately a 40-50% probability of being met. The longitudinal influences on solar thermal generation is also made evident in the capacity for the peak load focussed interval selection techniques to capture more intervals in which GER can operate than KLG.
- A high level probabilistic analysis formed under a defined set of assumptions shows that the use of the 10th percentile for individual generator allocations is likely to overestimate the risks to the market posed by intermittent generators. The use of an average may, on the other hand, underestimate the risk to the market, depending on the degree of correlation between intermittent generation and the SWIS load. An analysis of the performance of the existing wind fleet is undertaken whereby high temperature days are selected and the operating points of the existing SWIS wind farms is compared to the selected Reserve Capacity allocations. This analysis shows that, while there may be a small correlation between generation and temperature, it is highly complex and may be site specific. Further work is required to investigate the performance of wind generation during specific high risk load intervals before specific conclusions can be drawn on the performance of wind during these intervals.

- An assessment of key influences on a geographically diverse wind fleet is made which shows that specific regions around the SWIS have the potential to contribute to a diverse intermittent generation fleet in different ways. The wind resources along the southern regions of the SWIS have the capacity to benefit a fleet mainly based north of Perth. Furthermore, it is shown that generation from geographically separated wind farms can be effectively treated as independent variables.

Sensitivity analyses investigate a number of aspects and make the following conclusions.

- Specific regions around the SWIS have the capacity to impact on a geographically diverse fleet from the scale of the resource in each region and the capability of different sites to generate above average during high load periods. Furthermore, solar thermal generation is shown to match SWIS loads better where these generators are located on a similar longitude to Perth.
- A comparison between the calculated Reserve Capacity allocations for modelled generation from BOM data and those for the recorded generation shows that similar results have been found in most cases despite BOM resource data not be being the optimum for wind farm development.
- In most cases the choice of year (calendar year or Capacity Year) selected for the calculation of Reserve Capacity show a difference between allocations of less than 1% while the lack of sensitivity to the start and end dates for the year chosen validates the robustness of the results found in this study.
- The results found here for Reserve Capacity allocations are not highly sensitive to the timing of the business cycle in relation to the weather.
- While wind generation is more sensitive to the availability or scale of the wind resource accessed by the generator in question, solar thermal generators have the ability to increase their contribution to the RCM through the inclusion of thermal storage as a design option.

5.1 Correlation Coefficients

Correlation coefficients have been calculated between load and temperature, generation and temperature, and generation and load. In order to assess the correlation of different generation technologies with load, the load is first correlated with temperature with the aim of establishing the weather dependency of the SWIS load. Temperature data applied here is that provided by Western Power and recorded by the SCADA system at the East Perth control centre. Generation profiles from the different generation technologies were then correlated with temperature and directly with load. The results of this analysis are tabulated in Appendix D (Section 14).

<u>Load – Temperature correlation</u>

The daily load profile in the SWIS during the summer months typically peaks in the afternoon, and is assumed to be strongly influenced by air conditioning usage. As such, it is expected that peak loads during the summer months will be strongly correlated with temperature. Daily peak loads were correlated with the maximum summer daily temperature in order to remove the dependence on the daily load profile (e.g., variations during the night). Only the summer months are considered as the correlation between temperature and load becomes negative during the winter and the peak load occurs during the summer.

There is a strong correlation between the maximum daily temperature and the peak daily load for each year, with a correlation coefficient of ~0.85 each year. Considering an extended data set where the summer months are appended for the whole study period finds a similar result of 0.81. The high positive correlation indicates that the peak SWIS load is highly temperature dependent, and that if a given generation technology is positively correlated with temperature it is likely to also be positively correlated with load.

Generation – Load and Generation – Temperature correlation

In order to investigate generation dependency on load and temperature, the generation data for different sites are correlated with the adjusted load data (with the exponential load growth removed), and with the daily maximum and minimum temperature data. The correlation coefficient values for peak daily generation data shows that the generation profile from either technology (i.e. wind , solar) does not correlate well either with the *peak* daily load or the *peak* daily temperature. Appendix D shows generation correlation coefficient values for a wind farm site.

Both wind and solar thermal generation was correlated with both the daily temperature and with load. First, the peak daily generation was correlated with the maximum and minimum daily temperature and the peak daily load for each summer day. The correlation was not significant between peak generation and peak load, although it was generally positive for either wind or solar thermal generation. It is important to note that the peak generation for solar thermal generators would almost always be a 100% Capacity factor, and hence would not vary with daily peak loads or maximum temperatures according to our model. Thus, the resulting low correlation coefficient is not considered to be representative of the actual contribution of solar thermal generators to the peak daily load.

Given the typical operation at Capacity during the peak intervals for solar thermal generation a sensitivity case was included where the average daily solar thermal generation from GER was correlated with the maximum daily temperature. The result was much improved over all summer month intervals where the correlation coefficient increased from 0.112 to 0.456. When considering wind generation, the same analysis showed that the ALB does not correlate as well. In fact the minimum daily temperature in East Perth has a closer relationship to the average daily wind generation from ALB under the same conditions. The individual year results from this sensitivity case are shown in Table 35 and Table 36 in Appendix D.

As the peak daily generation does not necessarily occur at the same time as the peak daily load, wind generation at ALB and load were correlated for the Top 250 and Peak Period interval selection techniques. This allowed a comparison of half hourly variations in generation with load. The outcomes indicate that there is no apparent relationship between wind generation at ALB and the peak load intervals as the correlation coefficients swing from positive to negative from year to year. However, in a similar way to the generation characteristic of solar thermal generation this result fails to identify that wind generation is typically higher than average during these load intervals, as will be highlighted in the following section.

The strong positive correlation of load with temperature reported in Section 3.1 indicates that forecasting of load based on temperature may be a realistic approach. However, the results here show that, while there is a relationship between the temperature at East Perth and wind generation, it is highly complex and may have more in common with minimum temperatures rather than those which promote peak SWIS loads. As such a simplistic approach to the allocation of Reserve Capacity to wind generation which considers correlation coefficients would highly likely not represent the contribution of wind generation to the RCM. Conversely, while remaining complex to an extent, a clear relationship between average daily solar thermal generation and Perth temperatures has been shown to exist. Further work would be required in this area before any conclusive results could be drawn.

5.2 Generation Interval Selection Distribution Histograms

In order to investigate the effective generation captured by the different interval selection techniques, and the performance of the Reserve Capacity allocations, generation distribution histograms were developed for specified generators. The Wind Fleet 2 generators are initially considered from 2008 and further analysis considers KLG solar thermal generation from 2005. Correspondingly, the intermittency effect of cloud cover and interruptive effect of solar altitude angle is also considered for solar thermal generation from both KLG and GER.

While Section 15 (Appendix E) contains all of the histogram results for each site considered, Figure 22 shows the results for HPT for each interval selection technique. Each figure shows the frequency and cumulative probability of the occurrence of generation within a 10% bin range during the intervals selected by each calculation methodology. The percentage cumulative probability curve is included to show the probability for generation to be less than or equal to some specific value during the chosen intervals. It helps to show how any particular generator is performing during the intervals captured by each technique.

Along with the cumulative probability curve, each figure also includes the calculated Reserve Capacity allocations for the respective site whereby the cumulative probability curve can also be used to determine the probability of each allocation being met. For example, looking at the Top 250 intervals in Figure 22, we can say that the generation will be above average for ~55% of these intervals (alternatively: generation will be below average for ~45% of these intervals). Plus and minus one standard deviation is also shown by the blue shaded area in each figure in order to indicate the variability of generation around the mean during each set of intervals selected.

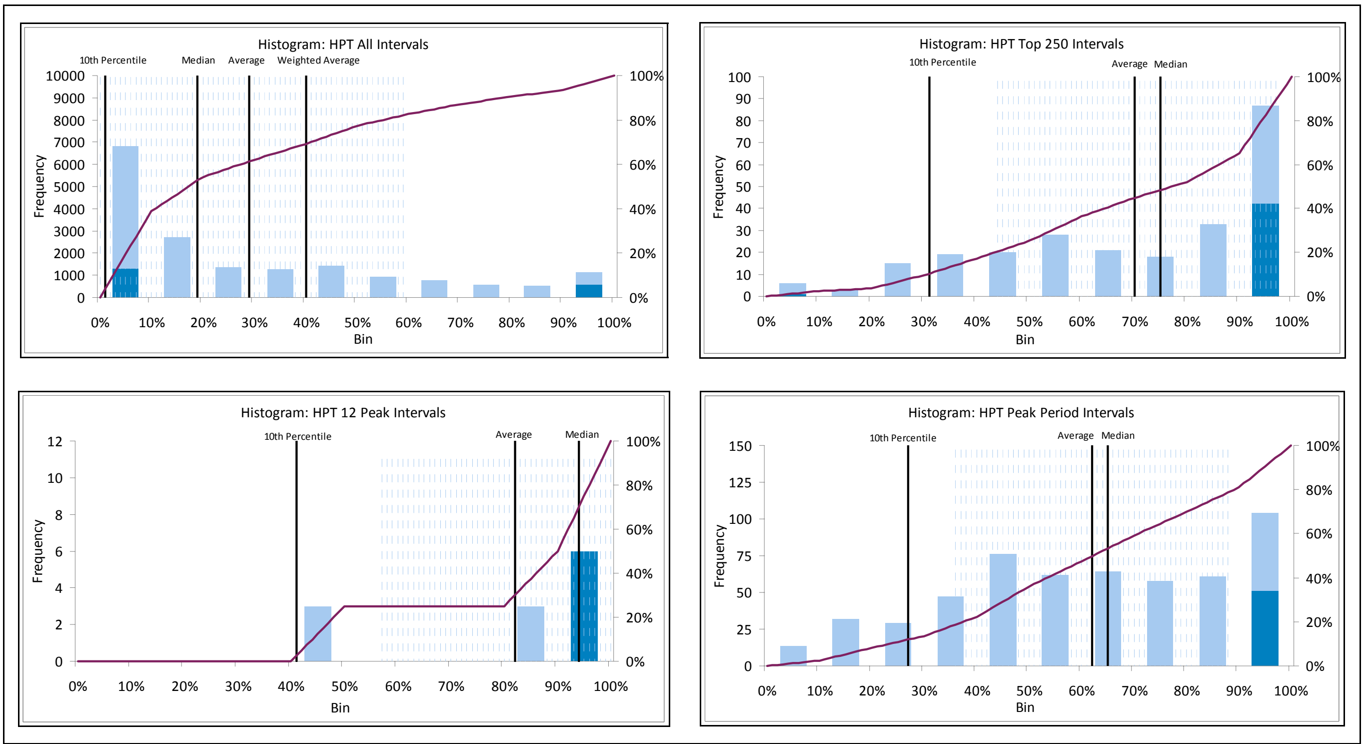


Figure 22: Comparison of generation distribution histograms for HPT based on the generation occurring during the intervals selected by each interval selection technique for 2008. Each figure shows the 2008 single year Reserve Capacity allocations for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing generation bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at the limits of 0 and 100 percent respectively.

The distribution histograms show the frequency of occurrence of generation across each respective interval selection technique. This provides a good graphical representation of the spectrum of generation captured by each interval selection technique for any particular site considered. Furthermore, quick visual comparisons can also be made of the performance of generation during each interval selection technique across the different sites considered.

In general these results show that, as would be expected, wind is a highly variable resource and that there is no precise correlation between wind generation and any particular SWIS load interval. In order to provide further insight into the performance of the recorded and modelled generation the dark blue regions shown on the histogram bars represent the frequency of occurrence of generation at its limits (0 and 100 percent). One outcome of this inclusion observable in Figure 22 is that approximately 500 out of all 17568 trading intervals in 2008 are modelling generation at its maximum for HPT. Analysing the same characteristic during the other interval selection techniques indicates that it is not unusual for many of these maximum generation intervals to occur during peak load times. For example, ~50 of the 546 Peak Period intervals correspond to maximum generation intervals. This in turn corresponds to 10% of all of the maximum generation intervals recorded for 2008 falling into just 3% of the year for HPT. Appendix E shows that this outcome is not uncommon for all of the Fleet 2 sites. As discussed in Section 3.5.1 the wind generator model may be exaggerating generation at 100% in some cases, however, this result shows that there is a clear trend for generation to be above average during peak load times.

Considering the individual probabilities of each calculation methodology for different sites shown in Appendix E enables some conclusions to be made on the performance of each methodology. In order to represent generation from existing wind farms only EMU, ALB and WLK are considered in this discussion. By definition medians and 10th percentiles will always have 50% and 90% probabilities of being met respectively. However, Appendix E shows that under the All, Top 250 or Peak Period interval selection techniques, allocations based on averages tend to have a 40-50% probability of being met. Where only the 12 Peak intervals are considered this range increases to around 40-60% which reflects the high variability in allocations based on small data sets as found and discussed in Section 4.

Appendix E shows that a special case exists for solar thermal generation as the histograms are effectively bipolar in nature. This is due to such technology tending to generate at its limits of 0 and 100 percent. One of the key influences on solar thermal generators is the incidence of peak load intervals during times when they are unable to generate. This is particularly evident in Figure 122 which shows generation during the Top 250 intervals for KLG.

	KLG 2005				KLG 2003 - 2005			
Interval Selection	**All intervals**	**Peak Period**	**Top 250**	**Peak 12**	**All intervals**	**Peak Period**	**Top 250**	**Peak 12**
Operable percentage of time	37%	89%	54%	50%	37%	89%	70%	58%
Cloud cover affected percentage	25%	23%	12%	0%	25%	18%	11%	0%
	GER 2005				**GER 2003 - 2005**			
Interval Selection	**All intervals**	**Peak Period**	**Top 250**	**Peak 12**	**All intervals**	**Peak Period**	**Top 250**	**Peak 12**
Operable percentage of time	37%	98%	59%	83%	37%	98%	76%	83%
Cloud cover affected percentage	23%	16%	7%	0%	23%	14%	5%	0%

Table 9: The impact of the limitations of modelled solar thermal generation (excluding storage) on generation characteristics captured by the interval selection techniques for 2005 and 2003-2005. The percentage of intervals selected that each generator is capable of operating is shown along with the percentage of these intervals which are impacted upon by cloud cover (defined as generation falling below 50% of the plant capacity).

Table 9 summarises the generating capabilities of KLG and GER (excluding storage) during each interval selection technique for 2005 and 2003-2005 and gives an approximation of the stochastic influence of cloud cover for each. The table shows that there is a clear difference in each site in terms of solar resource as GER is less affected by cloud cover than KLG. The longitudinal difference between the sites is also evident in the capacity for the peak load focussed interval selection techniques to capture more intervals in which GER can operate than KLG.

During high load days in the SWIS there is a tendency for the load to peak in the afternoon which results in the Top 250 intervals often occurring in the late afternoon. In many of these cases the sun's altitude angle has fallen below that which the KLG solar thermal generator collector model has the capacity to collect effective irradiation. As shown in Figure 122, approximately 50% of the generation intervals captured during the Top 250 load intervals occur when KLG cannot generate. Considering the impact of cloud cover finds that of these 250 intervals 135 occur when the solar altitude angle is high enough for effective operation while 16 (12%) of these 135 are affected by cloud cover. Similarly, GER shows that this generator can operate during 147 intervals of the Top 250 while 10, or 7%, of these are impacted by could cover during 2005.

Further analysis of the relationship between peak load times and the solar altitude angle at Geraldton finds that during the months of January – March the sun's position is such that the daily peak load occurs during times when GER can operate for 75% of the time. However, in the case of KLG the same analysis finds a 70% occurrence.

In order to better understand the nature of the relationship between the peak SWIS load and the operating characteristics of solar thermal plant a simple comparison of the average load is made. This finds that during the peak load months of January – March each year the average load captured when both GER and KLG can operate is 23.7% and 22.4% higher respectively than that when the solar altitude angle prevents them from operating. Furthermore, analysing the Top 250 intervals in this manner finds that on average the load occurring when both GER and KLG can operate is effectively equivalent to that occurring when the solar altitude angle prevents them from operating (noting that in both cases and for both sites the average load is 85% of the peak load).

Overall these outcomes indicate that a Reserve Capacity allocation based on a purely reliability focused calculation methodology, such as the 10th percentile has the potential to lead to very low allocations. The use a peak load focussed interval selection technique, such as the Top 250, for solar thermal generation would not provide an effective representation of the contribution these generators make to the RCM. However, the inherent ability of these generators to generate matched to a high load times implies that a calculation method which applies a weighting principal to high risk load intervals may provide a reasonable representation of their contribution to the RCM.

5.3 Confidence and Risk Assessment

Section 5.3 initially attempts to illustrate and quantify the risk posed to the market of calculation methods based on 10th percentiles and averages through a simplified probabilistic approach under various assumptions. The section then investigates the performance of the existing wind fleet during a set of assumed high risk load intervals captured over 2007 and 2008. The outcomes initially show that the Current and Proposed methods would theoretically present a risk to the market of 40% and 5.1% respectively. The performance based assessment then presents a similar result where the Current method poses a risk of 35% to the market over the two year sample.

Probabilistically Based Risk Assessment

Ultimately, the objective of the RCM is to ensure that there is adequate capacity to meet peak SWIS loads through the allocation of Reserve Capacity. In providing confidence in this insurance it is necessary to assess the risk imposed to system security by the Reserve Capacity allocation process. Although the determination of the exact risk to system security is outside of the scope of this report it can be assessed through hypothetical scenarios, based on assumed conditions and through an assessment of the performance of the existing intermittent generators operating in the SWIS during times when the system is assumed to be most at risk.

In order to asses the risk to system security that potential rule changes may have with regards to intermittent generation, a simple probabilistic analysis of the use of a 10th percentile calculation methodology versus the use of an average calculation methodology is considered. This analysis will be notionally related to the system security requirement of providing adequate generation no less than 1 in 10 years. Several significant assumptions are made, so the probabilities of risk presented here are meant to serve only for comparative purposes.

In terms of system security, the use of the 10th percentile is the most conservative approach considered here. However, without the benefit of a fleet component this approach is likely to be overly conservative, especially for generators which are positively correlated with load. Section 5.1 showed that there is not a clear correlation between load and generation and if this was the case the use of a different interval selection technique could account for this correlation directly. Detailed below are some simple assumptions made here to give an indication of the likelihood of a failure of system security under various calculation methodologies.

The following initial assumptions have been made to give an indication of the probability that the allocated reserve capacity would not be reached by the intermittent generation fleet. First, that a single intermittent generator is assigned ~1% of the total Capacity Credits in the SWIS Reserve Capacity Market, a reasonable assumption given that there is over 5GW of Capacity Credits currently assigned to the market. The second assumption is that the fleet is large enough such that no single intermittent generator is assigned more than 10% of the total capacity credits assigned to intermittent generators as a whole. This assumption may be broken if the amount of total intermittent generation in the market is very low (i.e., less than a few percent), but in such a case the risk posed by intermittent generation is also very low. The third assumption is that the highest peak load for a given year is greater than the second highest peak load of that year by an amount at least as great as by the amount a given intermittent generator is producing below it's 10th percentile mark at that time. The fourth assumption is that the distribution curve for an intermittent generator is relatively smooth near its 10th percentile. The third and fourth assumptions may not be true for some technologies that have unusual distribution curves (e.g., solar thermal), and it should be kept in mind that this indicative analysis may not be applicable for all technology types.

Firstly, an examination of the risk to the market if all intermittent generators were assigned their Reserve Capacity according to their individual 10th percentile will be considered. Based on the assumptions above, all of the intermittent generators in the fleet would need to be operating near to their respective 10th percentile point as, if a site was operating well above this point, it would provide excess generation that makes up for the other sites' deficiency. This analysis initially assumes that all intermittent generators are completely independent of each other, with no correlation between sites. With our assumption of a smooth distribution, there is a 10% chance a given generator will be operating at or below its 10th percentile, but also a 10% chance that it will producing at the 10th percentile and an equivalent amount higher. Therefore, there is a 20% chance for each site that its generation will be "centred" on the 10th percentile. If we assume we have ten intermittent generators in the fleet, all contributing ~10% of the total intermittent fleet generation, then the probability that all 10 sites are operating in this range is approximately 0.2^{10} or 10^{-7}%. This result obviously suggests a very low risk to system security, but makes the unreasonable assumption that all intermittent generators are uncorrelated which has been shown to not be the case.

Secondly, assuming that all intermittent generators are perfectly correlated, as in if one site is operating at its 10th percentile point, then all other sites will be operating at their 10th percentile points as well. The probability of one site operating at or below its 10th percentile point is 10%, but with perfect correlation between the sites there is a 100% chance that all other sites will also be operating at this point. Therefore, there is a 10% chance of a risk to system security. Given our assumptions above, this notionally indicates a 1 in 10 year risk to the market but again makes the unrealistic assumption that all generators are perfectly correlated.

Thirdly, considering the more realistic scenario where all the intermittent generation is highly positively (but not perfectly) correlated with each other. The degree of this correlation will depend on the technology types and the geographic distribution of the fleet. For our purposes we assume that if one generator is operating near its 10^{th} percentile point, there is an 80% chance that other sites will also be operating near their own 10^{th} percentile point. So the probability of a risk to the market would therefore be approximately 0.1×0.8^9 or 1.3%. Given our assumptions, this would notionally result in a failure to the market approximately once in every 75 years. In order to more closely represent the existing market status we can adjust our assumptions for this case to represent a fleet of four similar wind farms with equivalent capacities. In this case the probability of a risk to the market becomes approximately 0.1×0.8^3 or 5.1% notionally implying failure to the market approximately once in every twenty years.

So even with a high positive correlation between sites, it is probable that the use of individual 10^{th} percentiles to assess capacity credits would significantly overestimate the risks to the market posed by intermittent generators. Using the 10^{th} percentile of the fleet generation takes some of the correlation between sites into account, and gives a better indication of the risks to the market. However, the difficulty in establishing a large enough fleet across different technology types indicates that the sample size may be too small in some cases to accurately assess the risk via this method.

Finally, considering allocations based on averages, under the same assumptions as above. For the case of uncorrelated and independent sites, there is a ~50% chance that any single generator will be operating at or below its average point. Given a smooth distribution curve, there is a ~50% chance that the rest of the generation will not be operating at a fleet level above its average equal to the amount the single generator is operating below its average. This gives a probability of risk of 0.5^2 or 25%, or notionally once in every four years based on our assumptions.

With a 100% positive correlation, the probability of risk would be 50% with our assumptions while the more realistic 80% correlation assumption will result in a probability of risk of 40%. Regardless, if the generation and load were not correlated in any manner, the use of the average generation may underestimate the risk to the market. However, if the load and generation are positively correlated, as is indicated to a small extent by previous results, the risk to the market would be less than that presented here.

In summarising this high level probabilistic analysis it is evident that the use of the 10^{th} percentile for individual generator allocations is likely to overestimate the risks to the market posed by intermittent generators. The use of an average may, on the other hand, underestimate the risk to the market, depending on the degree of correlation between intermittent generation and the SWIS load.

Performance Based Risk Assessment

Section 5.1 showed that, while solar thermal generation is strongly correlated with the peak load, wind generation is only weakly correlated such that assumptions about the availability of generation during these times cannot be made for the wind generators considered here. Section 5.1 also shows a very strong positive correlation between the SWIS load and Perth temperatures. As such the most significant pressures placed on system security in the SWIS occur during the hottest days of the year. Further, given the periodic nature of weather patterns the worst case for system security is considered to be a sequence of three or four days with sustained high mean temperatures with maximum temperatures of around 41°C and overnight temperatures of around 28°C. Such an event is considered to represent a 1 in 10 year occurrence [15].

Given the limitations of data available to this study a performance based risk assessment can be made by assessing the performance of the existing wind fleet in 2007 and 2008 through investigating the behaviour of these wind farms during assumed 1 in 10 year events. Ideally such an event would capture three or more business days with the temperatures described previously. However, temperature records do not present such an event occurring within 2007 or 2008 and an adaptation is required. Here, a selection criterion of three or more consecutive days with maximum temperatures exceeding 35° is assumed instead and the generation from the three existing wind farms is compared to respective Reserve Capacity allocations.

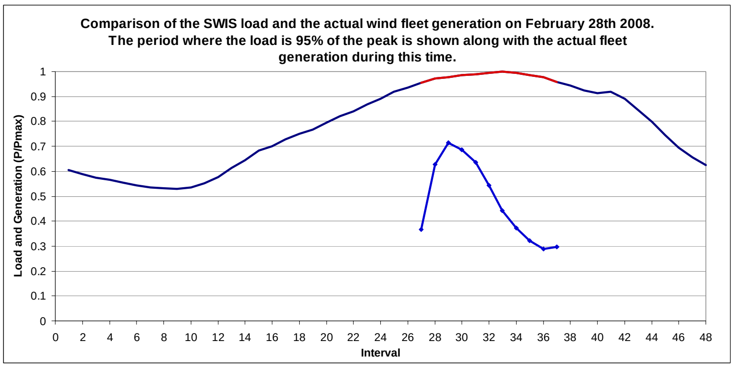


Figure 23: Illustration of the methodology applied to assess the performance of the actual wind fleet during an assumed 1 in 10 year event on a business day.

In order to assess the peak load only, the load intervals which present the highest risk to system security are considered. These are those business days in which the load is above 95% of the daily peak as illustrated in Table 10. The analysis finds that four assumed 1 in 10 year events are captured in 2007 and 2008 when only business days are considered. Analysis of these days shows that the >95% time frame is typically captured between the intervals ending at 2:30pm and 6:30pm. Non-business days are treated by considering these intervals independently of the load profile and six events are thus considered.

Day Number	Date	Day	Peak Load (MW)	Maximum Temp.	Minimum Temp.	Intervals > 95% of peak
1	25-Jan-07	Thu	3122	38.6	21.1	11
2	26-Jan-07	Fri	2965	41.2	21.6	9
3	27-Jan-07	Sat	2998	40.6	23.2	9
4	28-Jan-07	Sun	3010	41.5	25.5	9
5	05-Mar-07	Mon	3010	39.8	22.6	9
6	06-Mar-07	Tue	3521	41.6	21.9	10
7	07-Mar-07	Wed	3561	42.1	18.7	9
8	08-Mar-07	Thu	3346	37.6	19.9	10
9	24-Dec-07	Mon	2845	35.8	19.1	8
10	25-Dec-07	Tue	2563	40.4	18.9	9
11	26-Dec-07	Wed	2952	43.2	20.2	9
12	02-Feb-08	Sat	3092	37	21.5	9
13	03-Feb-08	Sun	3004	36.7	24	9
14	04-Feb-08	Mon	3454	35.3	22.2	9
15	05-Feb-08	Tue	3435	35.7	25.1	9
16	10-Feb-08	Sun	2937	35.1	20.8	9
17	11-Feb-08	Mon	3603	36.9	22.5	9
18	12-Feb-08	Tue	3477	36.3	20.7	8
19	13-Feb-08	Wed	3413	36.3	22.6	10
20	25-Feb-08	Mon	3187	35.4	17.2	7
21	26-Feb-08	Tue	3331	36.7	17.3	9
22	27-Feb-08	Wed	3482	37.5	20.6	8
23	28-Feb-08	Thu	3571	41.3	20.9	11

Table 10: Days considered in the 1 in 10 year assessment along with the peak SWIS load for that day, the number of load intervals where the load was above 95% of the daily peak load and the maximum and minimum daily 'drybulb' temperatures as recoded at the Western Power North Perth control centre [16]. Note: day number colours cross reference to the points plotted in Figure 24.

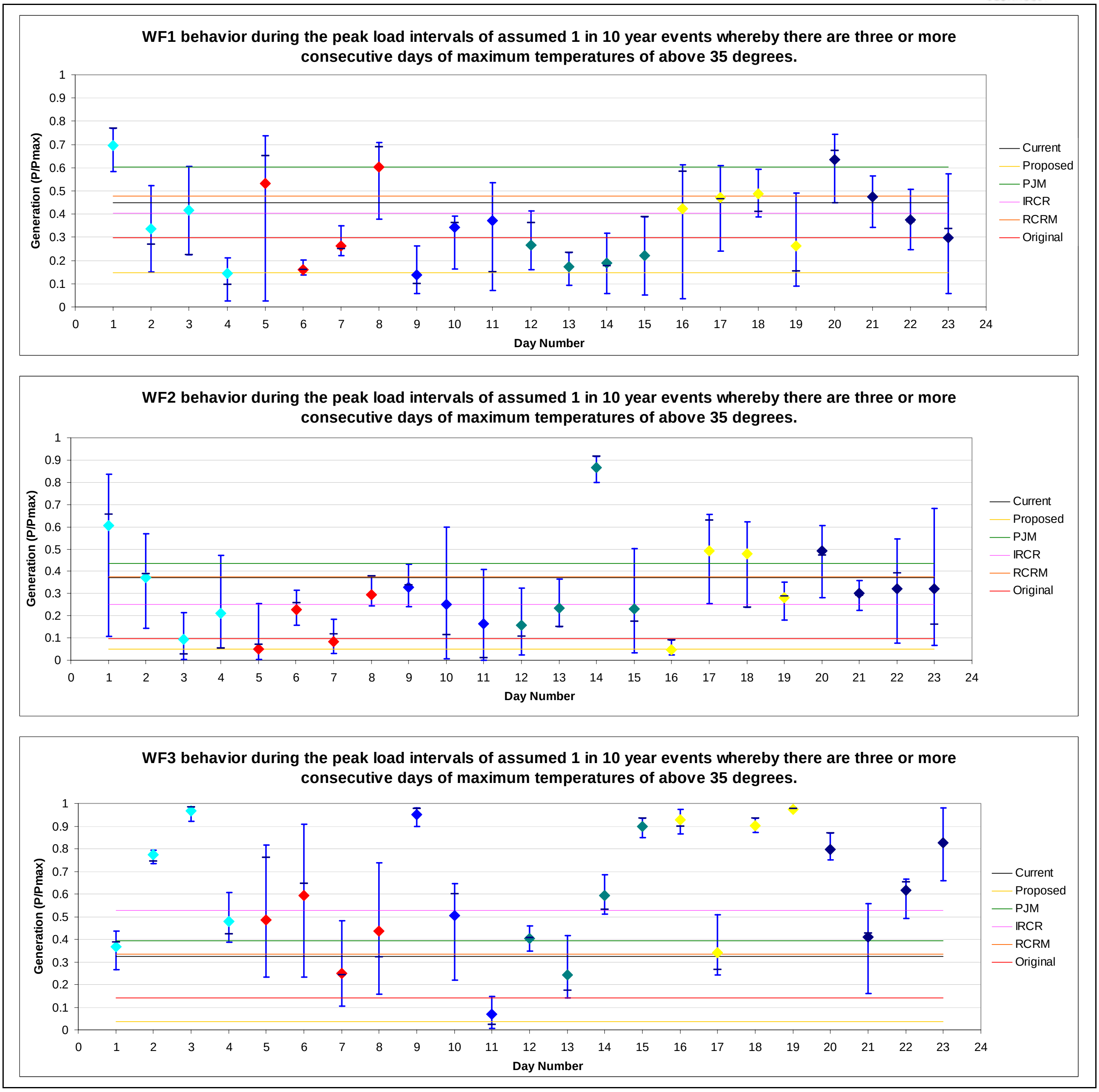


Figure 24: The performance of the existing wind generators during the assumed 1 in 10 year events. Each set of days, or event, is represented by a different colour set as defined in Table 10. The average generation across the intervals considered is shown, along with the range, by the diamond and the vertical bars respectively. Generation during the single peak load interval is also shown by the small blue horizontal bars. The horizontal lines represent the allocated Reserve Capacity for the six calculation criteria based on 2007 single year time frames or three year time frame ending in 2007 where available. Fleet calculations for the Original criterion are based on 2007 calculations using the existing wind fleet only (ALB, WLK and EMU) and based on MW. Generation data is presented anonymously.

Figure 24 shows how the three generators were performing on the days in question, compared to their respective allocations based on the six calculation criteria. When comparing other methodologies to the Current methodology it is apparent that, in most cases and with the exception of the PJM and RCRM allocation criteria, the alternatives are not necessarily negatively impacting on present levels of system security. As discussed elsewhere, allocations based on a 10th percentile provide the most conservative approach to system security margins. This is clearly evident in Figure 24 where the Proposed and Original calculation methods offer a reduction in risk as compared to the Current methodology.

As already indicated in Section 5.1, this limited analysis again shows a significant level of variability in generation such that that there is no defined correlation shown between generation from the three existing wind farms and the temperature in Perth on these high temperature days. Figure 24 shows that there is a high degree of variability in generation from the wind farms and it appears that, while one wind farm generates above average for 20 of the 24 cases, this is not always the case for the other two. Similarly, ALB wind farm was analysed over the full available time series (2002-2008) which presented a further 6 high risk events. These results presented no evident change to those found above in Figure 24. While this characteristic may be due to weather patterns on particularly hot days in Perth, this limited data set and the assumptions behind the analysis make it difficult to draw definite conclusions on the performance of the wind farms during those times when system security is most at risk.

Thus, it is important to analyse more closely the actual risk to system security during these high risk intervals. Assuming that each generator's contribution to system security is measured by the generation capacity made available through Reserve Capacity allocations, this assessment can be conducted by considering the actual recorded generation and fleet capacity factor (taken as the average capacity factor across the three wind farms) during these high risk intervals. These parameters are then compared against that allocated by each of the six calculation criterion to the three generators as a fleet in Figure 25.

Figure 25 shows the combined contribution from the existing wind fleet where parameters are derived from the average values across the high risk intervals defined in Table 10. Results are presented in terms of the deviation above that allocated to system security by the RCM during the high risk intervals. The fleet capacity factors are shown (top) along with the available MW from the three generators combined (bottom).

In this case the results indicate that the Current, IRCR and RCRM methodologies are effectively offering equivalent outcomes in terms of available generation. This outcome could be expected as these methodologies rely on averages and medians which, as discussed previously, offer approximately a 50% probability of the allocation being met. Looking at the normalised fleet case in Figure 25 we can see that the Current method presents a risk to the market of 35% which implies that the previous assumption of an 80% correlation of the existing wind farm fleet has overstated the risk only slightly. Similarly, from Figure 25 the Original method presents a probability of a risk to the market of 13%.

Comparing the Current, IRCR and RCRM criteria in Figure 24 and Figure 25 it appears evident that, despite the fleet capacity factor being met in many cases, the combined MW from the three generators is not met. Hence, it is clearly apparent that the outcomes in terms of system security are very susceptible to the scale of individual generator capacities.

The PJM calculation criterion is tending to fall short of the system security allocation by around 36MW on average. Conversely, the Proposed criterion creates a significant surplus of available generation at around 51MW, or 27% of the total installed wind capacity. The Original criterion also creates a scenario here whereby system security is only barely put at risk in one case. On average the Original criterion provides a generation surplus of 33MW or 17% of the installed capacity in these high risk cases.

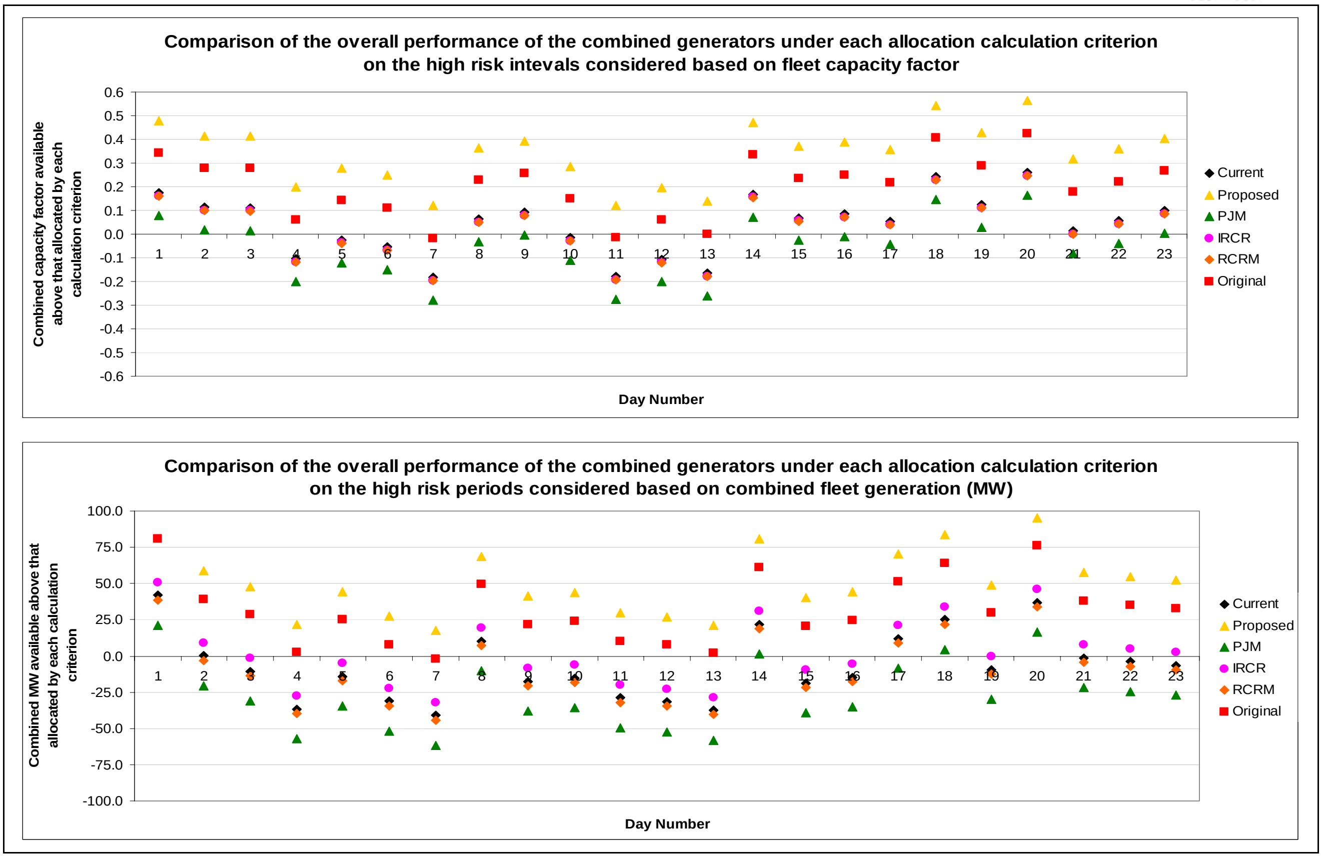


Figure 25: The combined fleet performance during the assumed 1 in 10 year events as defined in Table 10 along with corresponding day numbers. The points outline the available MW or fleet capacity factor above that allocated to system security from the existing wind fleet only. Reserve Capacity allocations are as defined in Figure 24.

In summary, it is apparent from the average wind generation during high risk load intervals that, while there may be a small correlation between generation and temperature, it is highly complex and may be site specific to the extent that this analysis can only give a brief insight into its implications. This limited insight would suggest that further work is required to investigate the performance of wind generation during specific high risk load intervals before specific conclusions can be drawn on the performance of wind during these intervals. From this assumed assessment of the 1 in 10 year planning criterion and the high level probabilistic analysis, it is apparent that, should the Reserve Capacity allocation process remain tied to system security, a careful selection of calculation methodology can reduce the risk posed to system security from intermittent generation.

5.4 Fleet Diversity Impacts

As highlighted in Section 4.4 a fleet of wind farms can potentially be influenced by three resource impacts: scale, security and reliability. Section 4.4 showed that resource scale is reflected in the average generation of the combined wind fleet, resource security is related to the performance of the combined wind fleet during peak load times while resource reliability is reflected in variations of the normalised fleet 10th percentile of the Top 250 loads. In order to better understand the behaviour of a combined SWIS intermittent generator fleet an investigation considering the average and 10th percentiles of All intervals and the Top 250 intervals has been conducted where the impact on the FCF is analysed (FCF was introduced and discussed in Section 4.4).

The premise for this fleet diversity impact investigation is to try to better understand the changing nature of intermittent generation in the SWIS by initially comparing the area which is currently best placed for both existing generation and proposed future development against the impacts of further diversification. From Figure 1, a base region is assumed to be the Geraldton and Perth regions combined (represented by GRD and GIN in the base fleet), as these represent the majority of the present development of intermittent generation in the SWIS. From this base, additional single generators are added, where each single generator represents a different SWIS region as shown in Figure 1. The diversity impacts on the FCF are then broken down into 'Combined', 'Resource', 'Diversity' and 'Regional' impacts as below.

Combined: The Combined impact is the simple difference between the FCF allocations of the base fleet and the combined fleet (with the additional site added). The Combined impact shows how the inclusion of the additional site impacts on the combined fleet. A positive outcome implies that the resource scale at the additional site benefits the combined fleet allocation while this benefit increases with the magnitude of the Combined impact while it remains positive.

Resource: The Resource impact is represented by the difference between the average of the base fleet FCF allocation and the Reserve Capacity allocated to the additional site (exclusively of the combined fleet), and the base fleet FCF allocation. Thus, where the Resource impact is negative, the additional generator has had a negative impact on the fleet as a whole, suggesting a poorer resource at the additional site relative to the base fleet. Alternatively, a positive outcome implies an improved resource at the additional site, thus impacting on the combined fleet through resource scale.

Diversity: The Diversity impact is derived from the difference between the FCF calculated for a random selection of combined fleet generation intervals (10,000 intervals are used here), and the sum of the base fleet allocation and the Resource impact. Thus, the Diversity impact is calculated under the assumption that the resources available to the base fleet and the additional generator are independent. As such the 10^{th} percentile calculations should always result in a positive Diversity impact as independence increases reliability and the security of the combined fleet. Correspondingly, with averages the Diversity impact approximates to the difference between the combined fleet allocation and the average of the base fleet FCF and the additional site's Reserve Capacity allocation.

Regional: The Regional impact represents the remainder of the fleet Diversity impacts by the Combined impact, minus the Resource impact, minus the Diversity impact. Hence, the Regional and Diversity impacts are interrelated in that, while the Diversity impact assumes independence between resources, the Regional impact tests the accuracy of this assumption. This factor can be either positive or negative and the further it is from zero the less likely it is that the sites are independent.

Following the initial analysis with the Geraldton / Perth region the focus is turned to the interaction of the existing wind fleet for the years 2007 and 2008. Here the interaction of two wind farm combined fleets are considered initially followed by two wind farm base fleets where the remaining wind farm is then added to the fleet. While Appendix F (Section 16) contains all of the results from this investigation, Figure 26 and Figure 27 show the fleet diversity parameters for 10^{th} percentiles for different base fleets and additional sites. Thus far the study has focussed on fleets where solar thermal and wind generation have been considered separately. Appendix F also shows results where KLG has been added to the GRD/GIN base fleet in order to better understand the behaviour of the combination of both wind and solar thermal generation technologies.

As discussed in Section 4.4 and above, calculations based on averages have the ability to identify a scale impact to the combined fleet. Appendix F again reiterates this characteristic where Figure 125 and Figure 127 show the resource performance of CPN, ALB and HPT as the base fleet is expanded to include these coastal regions. Correspondingly, the opposite effect is seen in both All intervals and the Top 250 intervals when the fleet is expanded inland to CDD and KBD. In effect changes in the averages are reflected in either a positive or negative Resource impact which represents the impact on the average FCF. For example, in the Top 250 intervals case the inland sites reduce the FCF when they are added to the GRD/GIN fleet as the wind resource at CDD and KBD is typically reduced by ~5% and ~13% respectively when compared to the base fleet. Conversely, the expansion of the base fleet into the southern regions of the SWIS can have a positive impact on the scale of the wind resource available to the RCM. As is typical of all results for the solar thermal generators considered in this study, the outcomes when the fleet is expanded to include KLG only look promising when looking at the average of the Top 250 intervals. This is due to invariable zero 10th percentile allocations along with a low average over All intervals.

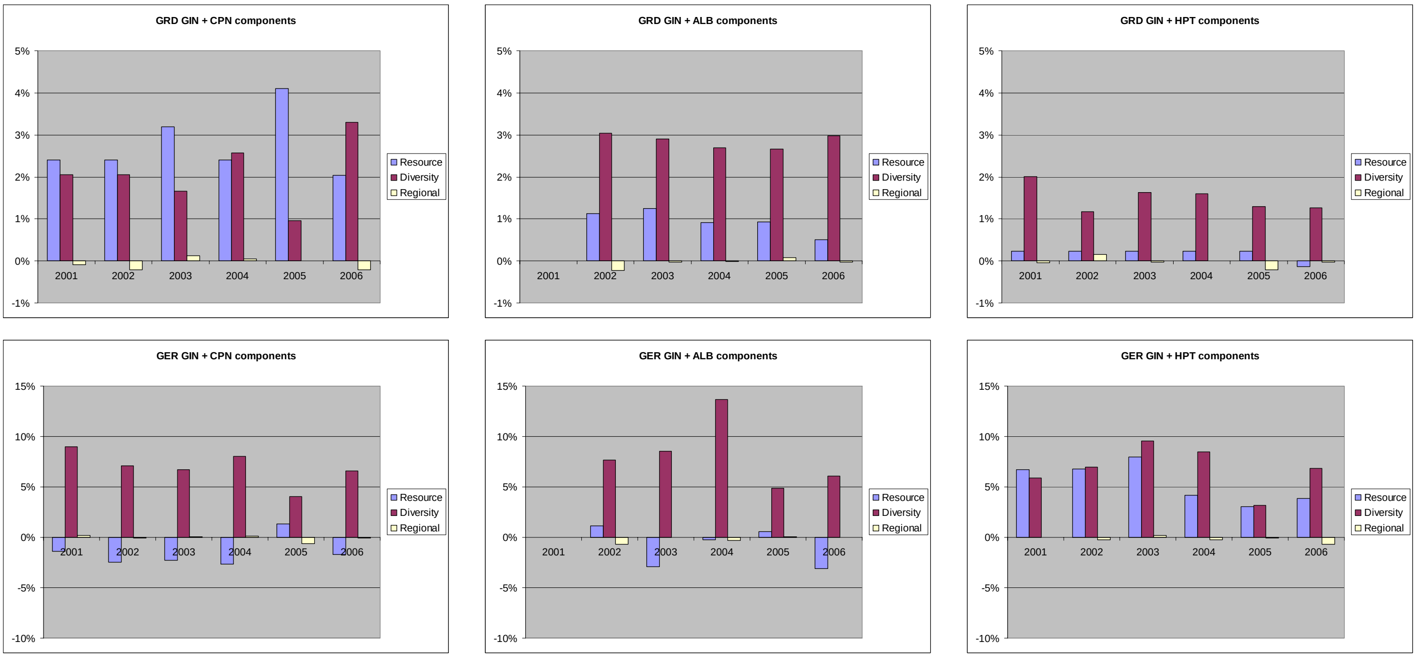


Figure 26: Comparison of the 10th percentiles for All intervals (top) and the Top 250 intervals (bottom) where the fleet diversity parameters are compared when the fleet is expanded from the GRD/GIN base fleet to include CPN, ALB and then HPT.

When considering 10th percentiles shown in Figure 26 results vary to some extent as the fleet is expanded from the base fleet. Considering the southern coastal sites the Combined impact is always positive and all cases show that this is due to a significant Diversity impact. This is to be expected as base fleet 10th percentiles are invariably larger than single site 10th percentiles, as discussed in Appendix A. The 10th percentile will tend to only show a strong representation of a Resource impact where the resource is exceptional, as in for HPT during the Top 250 intervals or CPN during All intervals (note that this is also represented in the histograms in Figure 109 and Figure 118). A further aspect shown in Figure 26 is the characteristic of CPN with a strong wind resource overall but no evident correlation with peak load periods while the opposite can be seen for HPT which has a tendency to receive higher wind resources during the Top 250 intervals.

Appendix F shows that for any two site fleet the averages change little because the two sites are typically exposed to similar average wind resources. Most of the resulting deviation is represented as a Resource impact which is to be expected as the average of the fleet is identical to the average of the two sites. Similarly, a two site fleet will always present a significantly increased 10th percentile than a single site, thus resulting in a positive Combined impact being represented as a Diversity parameter. Of importance to the results from the two site fleet analysis is a significant degree in the variability of the Resource impact for 10th percentiles which implies that the existing wind farms operate independently of each other.

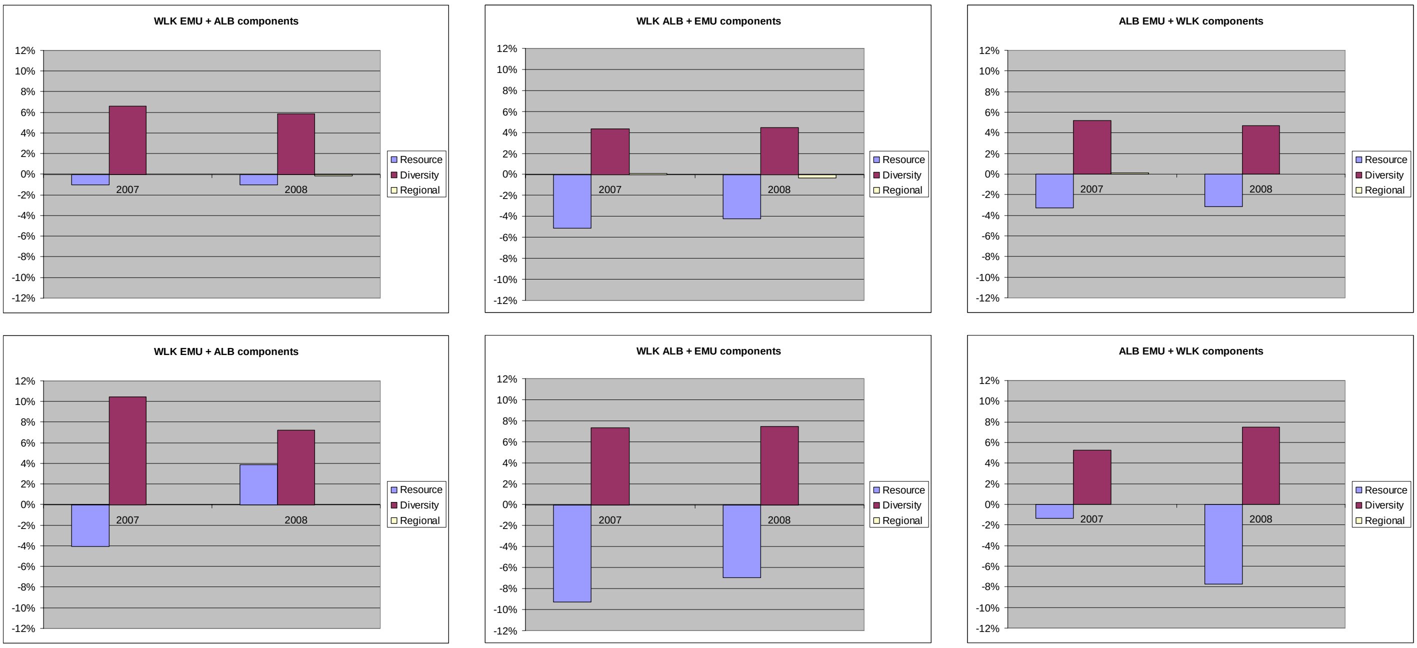


Figure 27: Comparison of the 10th percentiles for All intervals (top) and the Top 250 intervals (bottom) where the fleet diversity parameters are compared when the fleet is expanded from various base fleets to incorporate the remaining wind farm.

Figure 27 shows the outcomes of this analysis for 10th percentiles as the various existing wind farms are included in a base fleet and the outstanding wind farm is added. As was found previously the Combined impact tends to be positive in all cases and this can be considered to be a Diversity impact as the fleet 10th percentile is increased. Site Resource impact differences are evident from site to site as would be expected and, for 10th percentiles, they are typically negative due to the base fleet 10th percentiles being greater than the average of the site and base fleet 10th percentiles. As discussed above individual site 10th percentiles tend to only present positive Resource impacts for sites exposed to an exceptional wind resource. In all cases the Regional parameter is close to zero which again implies that sites are independent of each other.

In summarising this investigation there is a clear indication that specific regions around the SWIS have the potential to contribute to a diverse intermittent generation fleet in different ways. In general, the wind resources along the southern regions of the SWIS including Fitzgerald, Albany and Margaret River have the capacity to benefit a fleet based north of Perth as the wind resource along the southern coast presents different characteristics as that north of Perth. This is particularly evident in the Diversity parameter for 10th percentile calculations as the fleet 10th percentile increases significantly as the fleet expands. Implicit in Regional impacts tending to be very close to zero is that generation from geographically separated wind farms can be effectively treated as independent variables.

5.5 Sensitivity analysis

Given that the data sets were limited in some cases (i.e., some generators had only been in operation for the last 2 or 3 years), it was important to perform sensitivity analyses to ensure that the results were not biased by the time period selected or the modelling and calculation methodology considered. The inclusion of several different sites, including both measured and modelled generation, that all obtained relatively similar results, indicates that the results are relatively robust. More importantly, the consistency of the results from year to year, and between single year and multiple year time frames indicates the results are unlikely to be sensitive to variations in environment, weather, or other external factors over the time scales of this study. As discussed earlier however, the exception lies in calculations which focus on small load interval selections such as the 12 Peak intervals which have been shown to be highly sensitive to the time period selected.

The following sections present the sensitivity analyses as outlined in Section 2.2.

5.5.1 Geographic Diversity

A quantitative analysis is performed as part of the examination of the fleet component of the Reserve Capacity calculation. By considering Wind Fleet 2 in 2007 and 2008 where each generator in the fleet represents a region, as defined in Figure 1 (repeated below in Figure 28). The implications of geographic diversity presented by each region are assessed in terms of both wind and solar thermal generation.

To assess the impacts of a geographically diverse fleet of wind generators this analysis calculates the FCF for each fleet based on the Current and Original calculation methodologies as these have been shown to be related to potential fleet diversity impacts (FCF was introduced and discussed in Section 4.4). Sequential calculations are then completed with single sites removed. The associated change in the FCF allocated to the varied fleet is then assessed and conclusions can be drawn from the magnitude and direction of this change.

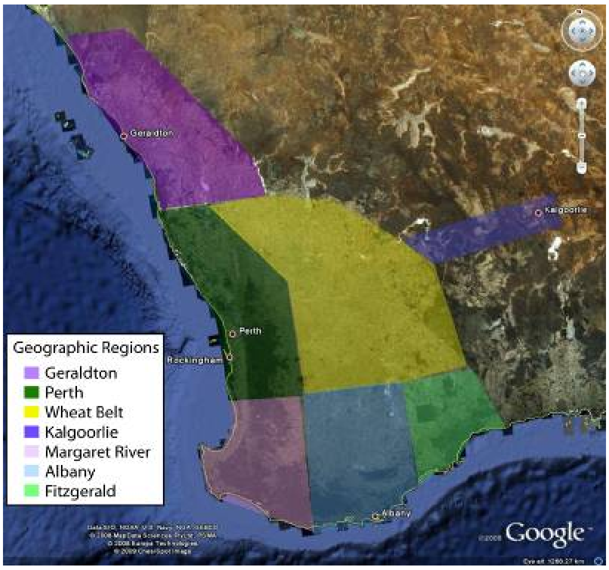


Figure 28: Map showing the approximate boundaries to be used for the fleet calculations. In all there are seven regions considered where each is represented by a single generator from Wind Fleet 2.

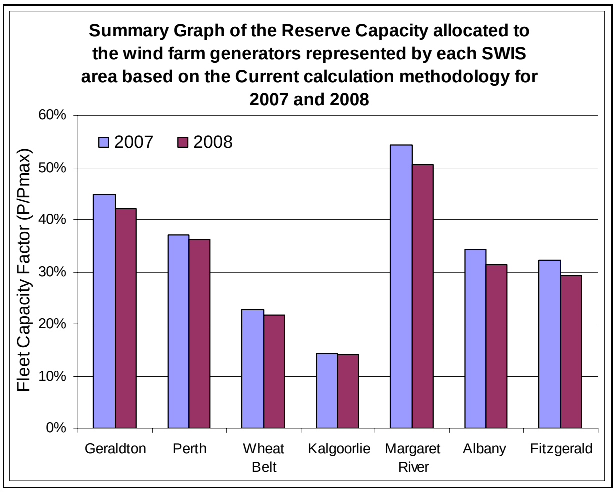


Figure 29: Comparison of the Reserve Capacity allocated to each SWIS region where the regions are represented by the Wind Fleet 2 generators for 2007 and 2008. Only the Current calculation method is considered here in order to show the relative scale of the resource available to each region.

Table 11 shows that the change in FCF with different regions removed can be observed to a varying degree for both calculation methods. As discussed in Section 4.4 and shown in Figure 21, it is expected that there could be a significant impact on the FCF due to the scale of the resource available to each region which is reflected in variations in the average. For example, in both years the omission of the Kalgoorlie region increases the average which implies that Kalgoorlie lowered the average due to a poorer wind resource. Conversely, the removal of Margaret River decreases the average as this region is represented by a strong wind resource.

Alongside the averages, the 10th percentile introduces a measure of the impact that each region has on the reliability of the fleet's generation as shown in Section 4.4 and 5.4. Hence, the 10th percentile FCF notionally represents the reliability of the resource in the combined SWIS regions by representing the lowest 10% of generation available to the combined fleet during the Top 250 load intervals.

It is evident from Table 11 that a single site may not necessarily present a correlated change in the average and 10th percentile either, as shown by Albany and Fitzgerald. These regions present very little change in the average, which indicates that average generation here is similar to full fleet average. However, a considerable change in the 10th percentile implies that generation in these regions is well correlated with peak load times which results in improved reliability. As already highlighted, this behaviour is most evident in the Albany and Fitzgerald regions as diurnal wind patterns are conducive to above average generation during peak load times here as shown by previous results.

Geographic Dependence - 2007				
Region Removed	**Fleet Capacity Factor (Average - All)**	**Change in Fleet Capacity Factor**	**Fleet Capacity Factor (10% percetile - Top 250)**	**Change in Fleet Capacity Factor**
Full Fleet	34.26%	0.00%	24.89%	0.00%
Geraldton	32.47%	-1.79%	23.37%	-1.52%
Perth	33.80%	-0.46%	26.16%	1.27%
Wheat Belt	36.26%	2.00%	26.02%	1.13%
Kalgoorlie	37.59%	3.33%	27.88%	2.99%
Margaret River	30.87%	-3.39%	22.54%	-2.35%
Albany	34.21%	-0.05%	22.02%	-2.88%
Fitzgerald	34.63%	0.37%	18.64%	-6.25%

Geographic Dependence - 2008				
Region Removed	**Fleet Capacity Factor (Average - All)**	**Change in Fleet Capacity Factor**	**Fleet Capacity Factor (10% percetile - Top 250)**	**Change in Fleet Capacity Factor**
Full Fleet	32.24%	0.00%	26.14%	0.00%
Geraldton	30.58%	-1.67%	24.80%	-1.34%
Perth	31.57%	-0.67%	24.55%	-1.59%
Wheat Belt	33.98%	1.73%	26.24%	0.09%
Kalgoorlie	35.20%	2.96%	29.51%	3.37%
Margaret River	29.19%	-3.05%	23.33%	-2.82%
Albany	32.39%	0.14%	22.97%	-3.18%
Fitzgerald	32.72%	0.47%	20.67%	-5.47%

Table 11: The impact of geographic diversity assessed by considering Wind Fleet 2 by sequentially removing the sites noted in each row and considering the deviation of the resulting FCF from that calculated with the full Wind Fleet 2.

Geographic Dependence - Solar Thermal Fleet				
Year	**2005**		**2006**	
Region Removed	**Fleet Capacity Factor (Average - All)**	**Change in Fleet Capacity Factor**	**Fleet Capacity Factor (10% percetile - Top 250)**	**Change in Fleet Capacity Factor**
Full Fleet	26.89%	0.00%	25.23%	0.00%
Geraldton	26.98%	0.09%	25.08%	-0.15%
Kalgoorlie	27.69%	0.80%	26.13%	0.90%

Table 12: The impact of geographic diversity assessed by considering the Solar Thermal Fleet by sequentially removing the sites noted in each row and considering the impact on the resulting FCF.

When considering the Solar Thermal Fleet the lack of available sites makes any firm conclusions on the impact of having a geographically distributed fleet difficult to quantify. It is evident from the results shown in Table 12 that there is little impact on the fleet in both cases which suggests that, in terms of resource scale and reliability, there is little difference between the sites, as was found in Section 5.2.

While it is clear that all deviations are small for the Solar Thermal Fleet, one conclusion can be made from an increased reliability offered from Geraldton relative to Kalgoorlie. This is effectively due to the longitudinal differences between the sites as previously found in Section 5.2. Figure 30 shows the generation profiles from the two sites considered on January 19th 2006 where both sites experience maximised generation from clear skies. The time axes are shown in Western Standard Time which allows the comparison to the normalised average summer business day SWIS load profile. The impact of the longitudinal difference between sites is clear by the fact that GER provides a better match to the peak load period by operating for half an hour longer into the afternoon thus providing a small reliability impact on the fleet. Correspondingly, having KLG unavailable for the same half hour interval has a negative impact on the reliability of the fleet.

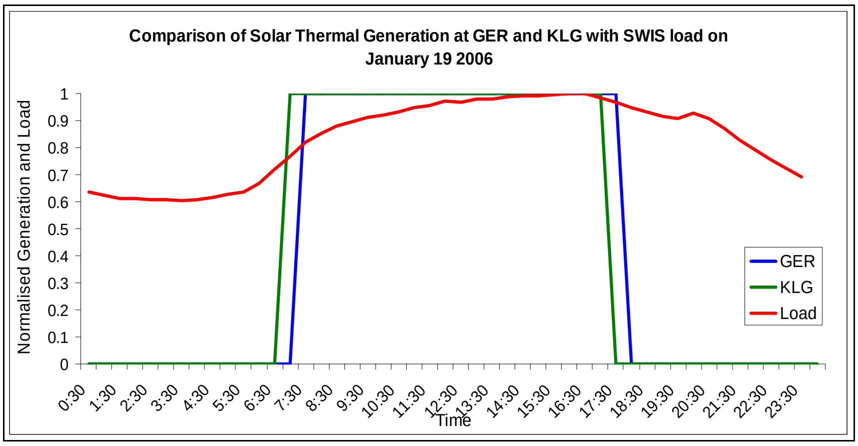


Figure 30: Comparison if generation and load profiles showing the longitudinal differences between solar thermal generation at GER and KLG which are permanently separated by a 28 minute Solar Time difference due to the 7° longitudinal separation.

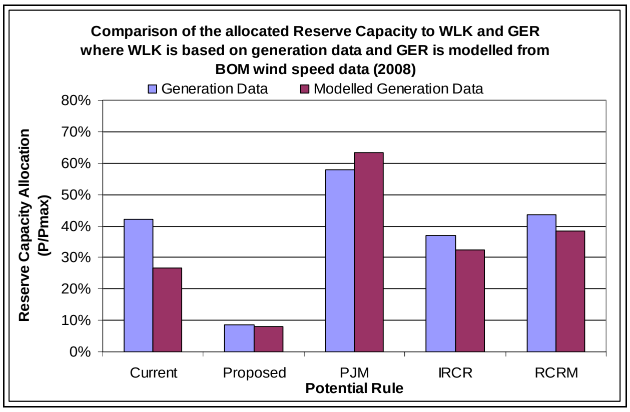
5.5.2 Comparison of Modelled and Metered Generation Data

As highlighted earlier in Section 3.5.1 the use of BOM recorded wind speed data for modelling hypothetical wind farms imposes some limitations. Furthermore, the topography of the area around a wind farm site or that surrounding a BOM weather station can have a significant impact on the wind speeds at the site. It is due to the complex nature of wind that this study relies on a simplified wind farm model which is considered as generic across all modelled wind farm sites.

This section seeks to highlight and explain some of the differences found between the modelled and metered wind farm generators by comparing three pairs of each located within close geographical proximity to each other.

The analysis is restricted to 2008 and graphically compares the Reserve Capacity allocations calculated for five of the six allocation criteria, for metered and modelled generation by comparing WLK against GER, EMU against BRS and ALB against a new hypothetical wind farm modelled from Albany Airport recorded wind speed data (ALBA). These sites are considered to be the closest proximity to each other available to this study as approximately 20km lies between WLK and GER, and EMU and BRS while ALB and ALBA are approximately 13km apart.

Figure 31 compares WLK with GER and EMU with BRS. It is apparent that, while these sites are located in relatively close proximity to each other, despite relative scale there is no clear relationship between the Reserve Capacity allocations to either. While the modelled generation may be reflecting the wind availability at the modelled wind farm sites in the allocation magnitudes, the characteristics of the resource at the modelled sites are clearly different to those at the existing wind farms. The exact reasons for these differences are difficult to capture from a visual comparison but some can be partially explained by comparing site topographies.



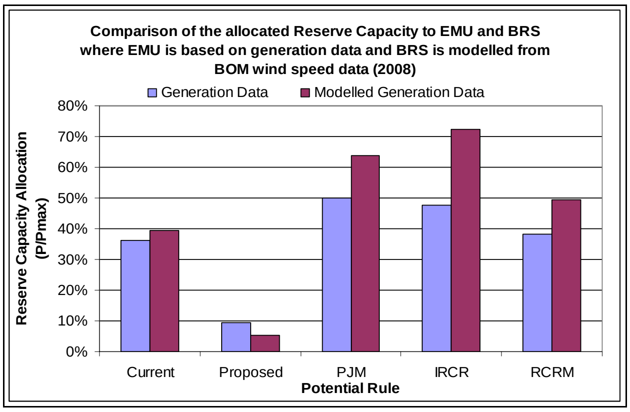


Figure 31: Comparison of Reserve Capacity allocations based on recorded generation data and modelled generation data based on BOM wind speed data. In both cases the modelled and recorded generation sites are approximately 20km apart. Five of the six calculation criteria are considered for comparison.

Firstly, WLK is located approximately 16km from the coast in the prevailing wind direction. However, it is apparent that the landscape in the prevailing wind direction is relatively smooth which is conducive to good average wind speeds* at the wind turbine hub height. Conversely, GER is derived from an anemometer assumed to be mounted at 10m above ground level at Geraldton Airport which not only experiences a lower average wind speed than the WLK turbine hub height, but is probably also subject to higher turbulence effects from surrounding terrain and buildings. Despite these differences, it is apparent that the GER closely reflects WLK, with the exception of the overall average used in the Current method, which implies that the modelling approach used was well suited to the wind characteristic at GER.

Secondly, EMU is located approximately 25km from the coast in the prevailing wind direction with relatively smooth terrain between the coast and the site. In this case BRS is located 15km down wind from the prevailing wind direction at the EMU site such that the two sites should experience similar wind characteristics. Thus, in this case the difference between the two sites can be assumed to be in the generic nature of the model as it is possible that generation based on the wind speeds occurring at BRS during peak load periods is being slightly overstated by the model.

A special case can be found in the comparison of ALB and ALBA. As shown in Figure 32 ALB is situated only 500m from the shoreline in the prevailing wind direction however the site is approximately 100m above ground level where a very steep incline rises from the shoreline. This would be expected to create significant turbulence with the higher wind speeds that occur during peak load periods. The nearby ALBA site is situated 15km inland from the coast, however the terrain is relatively smooth from the airport in the prevailing wind direction. This suggests that the turbulence effect may actually be more prevalent at ALB than it is at ALBA during the peak load periods as the wind speeds are higher. Thus, while it is possible that generation at ALBA is being overstated during peak load intervals from Figure 32, there is also a negative impact on generation

* For reference, turbulent airflows slow the movement of the air and make it difficult to extract energy from the airflow. Many good wind farm sites are characterised by smooth terrain which is conducive to laminar airflow resulting in higher energy extraction from the wind. Also, airflows are typically less affected by turbulence effects as the height above ground level increases [8].

at ALB during these intervals which may be understating the resource available during these times aiding the mismatch between the sites.

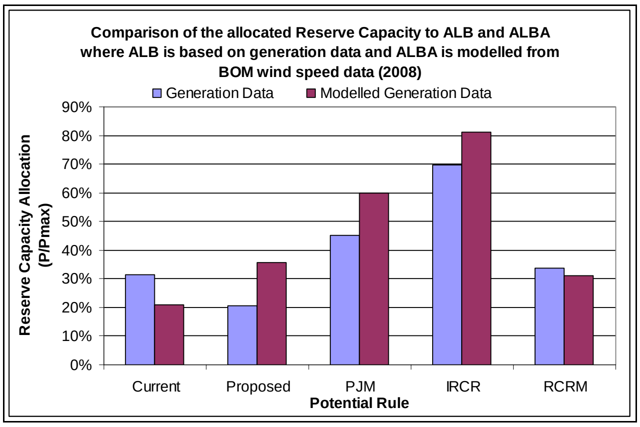


Figure 32: Comparison of Reserve Capacity allocations based on recorded generation data and modelled generation data based on BOM wind speed data for ALB and ALBA. Five of the six allocation criteria are considered for comparison along with a photograph of the terrain at ALB.
(Picture: www.panoramio.com//photo/948688, 27/5/09)

In general, a comparison between the calculated Reserve Capacity allocations for the BOM sites and those for the recorded generation as shown in Appendix C shows that similar results have been found in most cases. The fact that modelled wind farm generators applied here are based on resource data which is not the optimum for wind farm development introduces some error in the outcomes. The importance of more detailed resource assessment in priority wind farm development areas has a reliance on the application of the data being analysed. Here the results focus on the characteristics of the different Reserve Capacity Credit allocation methodologies and not the scale of the individual allocations such that the results are not considered to be significantly impacted upon by errors introduced by the modelling process.

5.5.3 Year Selection: Capacity Year vs. Calendar Year

Thus far all of the calculations presented in this report have been based on the calendar year such that the year 2007 thereby signifies 1 January through 31 December 2007. In the Reserve Capacity Market the *Capacity Year* begins on 1 October such that the 2007 Capacity Year runs from 1 October 2006 through 30 September 2007. Thus, in order to validate the results here in terms of the Capacity Year, and to assess the impact of the year selection, the Reserve Capacity allocations were recalculated for a wind generator for the 2005 – 2007 Capacity Years. These results were then compared to the results based on the 2005 – 2007 calendar years as shown in Table 13. The full results are tabulated in Table 37 and Table 38 contained in Section 17 (Appendix G).

Magnitude of the Difference Between the Results Found with the Reserve Capacity and Calendar Year				
2005				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	0.63%	5.43%	0.00%	0.00%
10th Percentile	0.03%	1.89%	0.00%	0.00%
Median	0.86%	15.66%	0.00%	0.00%
Weighted Average	0.48%	8.09%	0.00%	0.00%
2006				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	0.43%	0.81%	0.00%	0.00%
10th Percentile	0.07%	0.74%	0.00%	0.00%
Median	0.61%	0.27%	0.00%	0.00%
Weighted Average	1.81%	1.09%	0.00%	0.00%
2007				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	0.15%	1.15%	0.00%	0.00%
10th Percentile	0.40%	0.00%	0.00%	0.00%
Median	0.34%	0.68%	0.00%	0.00%
Weighted Average	0.31%	9.51%	0.00%	0.00%

Table 13: Comparison of the magnitude of the error between results for Reserve Capacity allocations based on the calendar year or the Capacity Year for 2005 – 2007. Note that in the case of the 12 Peak and Peak Period intervals all fall into the calendar year and corresponding Capacity Year such that the error is 0.

Comparing the results in Table 13 show there is a minimal (<1%) difference between the calendar and Capacity Year calculations in most cases. This is true for all calculation methodologies and for all years with the exception of the RCRM weighted average methodology in 2005 and 2007 where the results are already unrealistic due to the impact of the weightings applied to peak load intervals. Furthermore, all trading intervals are ultimately used in applying the calculation methods, regardless of whether they are grouped by calendar or Capacity Year. Stated another way, the Capacity Year is simply an average of the encompassing calendar years, and vice versa as shown in Figure 33. Also, the use of calendar years allowed for the maximisation of the data set by using the most recent data available at the time (i.e., through December 2008).

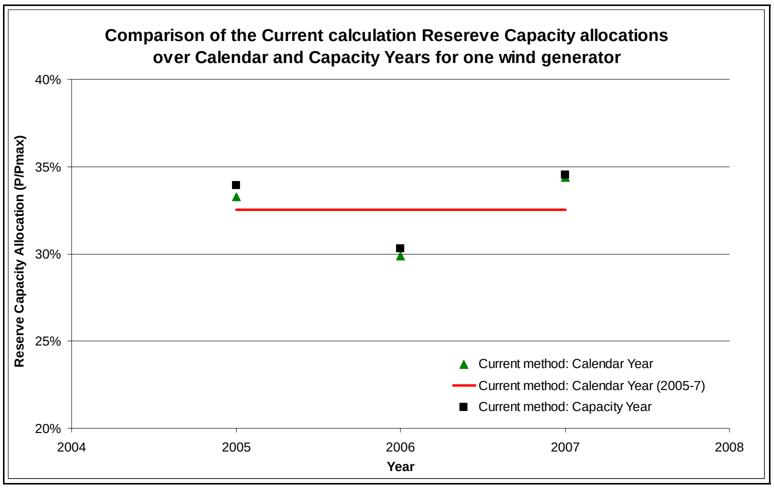


Figure 33: Comparison of the results of the Current calculation methodology found across the calendar and Capacity years for one wind generator as calculated for 2005-7. The average generation found during the 2005-7 three year (calendar year) time frame is also included for comparison.

The lack of sensitivity to the start and end dates for the year chosen validates the robustness of the results found in this study. This was to be expected given that the majority of the peak load intervals occur between January and March and hence would be included in both the calendar year and corresponding Capacity Year. Furthermore, where larger data sets are used, the results do not change significantly from year to year.

5.5.4 Load Timing

The SWIS load has a clear dependency on the weekly business cycle. In order to examine the susceptibility of the results to the exact conditions of the year studied. A sensitivity study was conducted by scaling up loads on non-business days.

The data was also adjusted to accommodate for differences in load between business and non-business days. This was taken into consideration in conjunction with the weighted averaging of the Reserve Capacity Refund Mechanism [1] in order to expand the data set and also to understand what would occur if a particular hot non-business day happened to occur instead on a business day.

In order to make this adjustment a scaling factor was derived by taking a ratio of the average daily peak of all business and non-business days. This ratio was found to be 1.127 which implies that if, for example, a peak demand of 100MW occurred on a particularly hot non-business day, this would be scaled up to 112.7MW, which is the peak demand that is assumed would have occurred if this particularly hot day had fallen on a business day instead. Figure 34 shows the impact of making this adjustment: the distribution of peak loads of adjusted non-business days has a similar shape to the recorded business day loads.

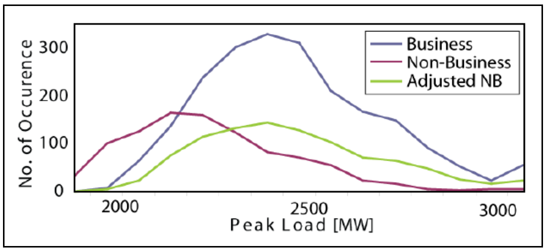


Figure 34: Histogram showing the conversion of non-business days to reflect approximated business days as applied to a sensitivity study considering the timing of the weekly business cycle.

This attempts to capture the instance of conditions where, for example, a given year happened to have all of its hottest days of the year on business days. Thus, this sensitivity test would show how sensitive the calculation methodologies were to the timing of the weekly business cycle in relation to the weather.

In all cases calculation methodologies which are not dependant on peak load times (i.e., All and Peak Period intervals) are not effected by this variation. As is evident in Table 14, which shows a comparison of the outcomes of this sensitivity study for GRD in 2001 and 2002, a difference is found between the original results and those with the non-business days scaled up.

Reserve Capacity - adjusted load vs. non-adjusted load GRD Simulated Wind Farm: 2001				
Calculation Methodology	Intervals and Year Selected			
	2001: Non-adjusted		2001: Adjusted	
	Top 250 Loads	12 Peak Intervals	Top 250 Loads	12 Peak Intervals
Average	42.36%	40.93%	42.57%	58.22%
10th Percentile	7.90%	17.68%	7.90%	32.31%
Median	41.60%	41.60%	50.89%	70.99%
Weighted Average	143.22%	153.49%	126.10%	128.40%

Reserve Capacity - adjusted load vs. non-adjusted load GRD Simulated Wind Farm: 2002				
Calculation Methodology	Intervals and Year Selected			
	2001: Non-adjusted		2001: Adjusted	
	Top 250 Loads	12 Peak Intervals	Top 250 Loads	12 Peak Intervals
Average	41.25%	30.74%	39.48%	30.74%
10th Percentile	7.90%	3.89%	2.36%	3.89%
Median	32.31%	32.31%	32.31%	32.31%
Weighted Average	140.85%	87.37%	128.68%	87.37%

Table 14: Comparison of the Reserve Capacity allocations based on the Top 250 and 12 Peak intervals for GRD in 2001 and 2002 where the load intervals selected are based on load data with and without the adjustments for business and non-business days.

Due to the reliance of the 12 Peak intervals on the four peak load days of the year the impact of the weekly cycle is varied as there is always a chance that the hottest days of the year (peak load days by default) may or may not fall on a weekday. Similarly the use of the Top 250 intervals will typically vary slightly from year to year due to the increased probability that a larger selection of peak loads will fall on a weekend. Typically, this study indicates that the results are not highly sensitive to the timing of the business cycle in relation to the weather as the weather and the weekly business cycle is not correlated in any way.

5.5.5 Adapted Generation Technologies

It is expected that the generation technologies considered in a study such as this could have a significant impact on the study outcomes. As already noted in the case of the landfill gas generators where they have generation profiles that are relatively constant despite being considered as ‘intermittent’. Similarly, the use of technologies such as solar thermal gives generator developers a design option to include a thermal storage component which allows the generator to remain in operation for a period of time without effective solar irradiance (i.e., to ‘ride through’ cloud cover or operate into the evening). Thus resulting in increased generator capacity factors and impacting on Reserve Capacity allocations.

As discussed in Section 5.2, the distributions for solar thermal generation are typically bipolar where generation is either at a 0% or 100% capacity factor. While the inclusion of storage may not necessarily change the bipolar nature of the distribution, the frequencies of 90-100% generation bins will tend to increase suggesting that the Reserve Capacity allocations for solar thermal generators are highly sensitive to this technology adaptation. This is evident by the summary plots in Section 13.4 (Appendix C4) and in Figure 35 where the single year time frame average and 10th percentile calculation methodologies are compared with and without four hours of thermal storage.

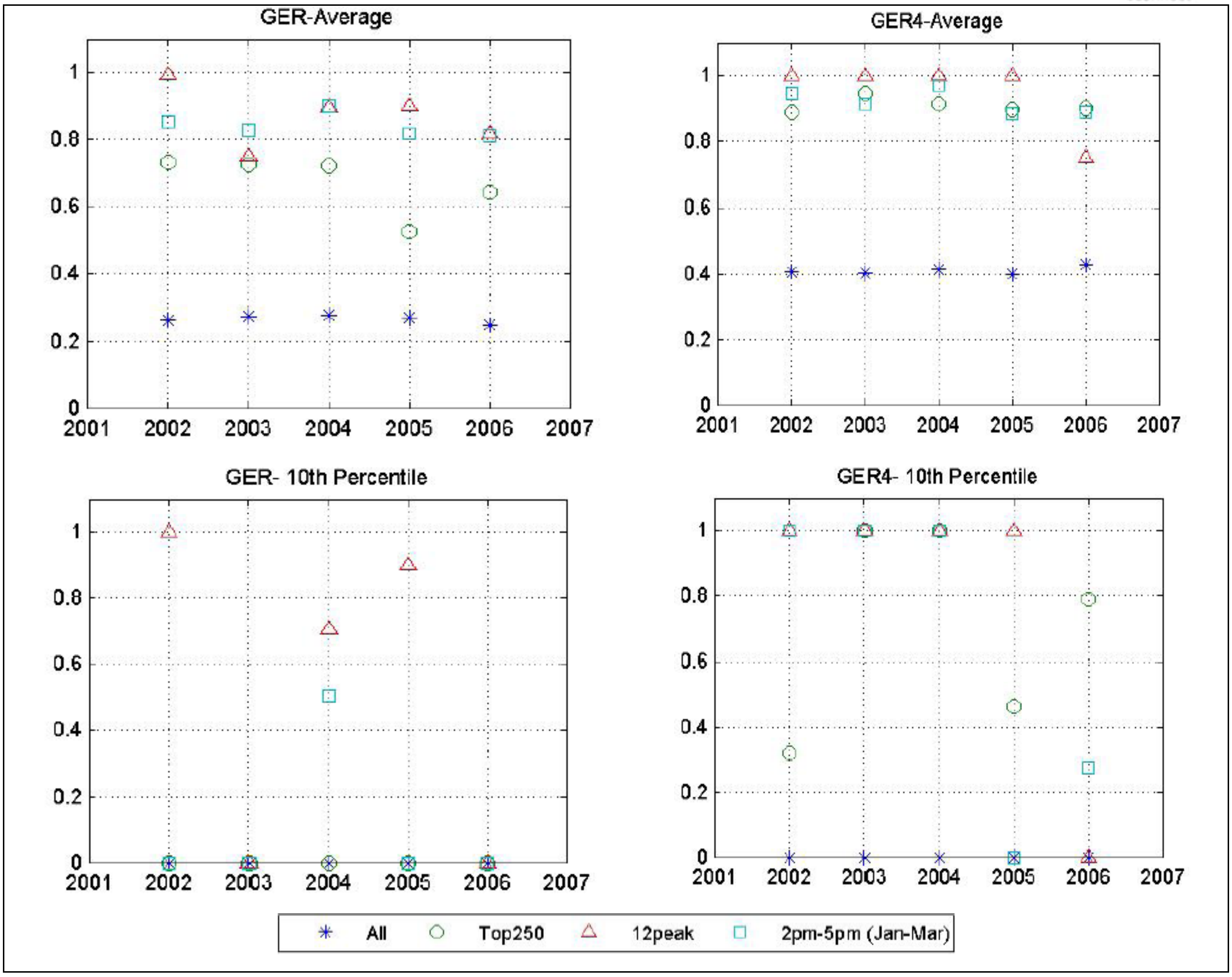


Figure 35: Comparison of results found with (left) and without (right) the inclusion of four hours of thermal storage for GER based on single year time frame average and 10th percentile calculation methodologies. Note the significant change found in both cases.

From Figure 35 it is evident that a significant increase in the allocated Reserve Capacity can be achieved with the inclusion of only four hours of thermal storage for GER: the average of All intervals has increased by a factor of ~1.7 while allocations based on peak load times have also increased substantially. Thus, while wind generation is more sensitive to the availability or scale of the wind resource accessed by the generator in question, solar thermal generators have the ability to increase their contribution to the RCM through this design adaptation.

This outcome is significant as it presents a scenario whereby the RCM could potentially allocate increased Reserve Capacity to solar thermal generators which include this design option. It is outside of the scope of this study to determine whether this is a desirable outcome to the RCM, however Section 7 of this study makes an assessment of the financial implications of this design option.

6 Network Augmentation

The dramatic difference between the Reserve Capacity allocated under different calculation methodologies and for different sites around the SWIS indicates the importance of choosing a methodology which both ensures system security and incentives diversification through necessary network augmentation. The generation technologies considered here all have the potential to contribute significantly to the RCM, thus it is important that the RCM properly rewards this contribution in order to properly ensure that necessary network augmentation can occur.

In particular, the strong dependence of the Reserve Capacity allocated by the Original methodology to a geographically and technologically diverse fleet, as shown in Sections 4.4, 5.4 and 5.5.1, indicates that a geographically and technologically diverse fleet has the potential to improve the security of the fleet as a whole. Hence, it may be necessary to ensure proper incentives in the allocation process to achieve a geographically and technologically diverse fleet. Given that to achieve this diversity would likely require significant network augmentation, a Reserve Capacity scheme that appropriately rewards the Reserve Capacity benefits of diversity may be necessary. It is likely that this issue will become more important at higher (assumed >20%) penetration of the intermittent generation technologies considered here, as the fleet will consist of a larger part of the full generation portfolio. The results presented in Sections 4.4, 5.4 and 5.5.1 suggest that a calculation methodology which considers the fleet impacts which a new generator can offer to the RCM may give an excellent indication of the additional benefits proper diversity may provide to the RCM, such as improved intermittent generation security.

For example, a generator A that is installed in a remote location from the rest of the fleet may require substantial network augmentation to connect to the SWIS. However, it may significantly improve the security of intermittent generation as a whole as it provides a diversity impact to the fleet (as introduced in Section 5.4). Depending on the extent of such an impact it may be necessary to properly reward this generator for its contribution to aggregated fleet generation by offsetting some of the network augmentation costs. Furthermore, this could reward the first generator harnessing the resource in a given area as it is often required to bear significant network augmentation costs, while later generators do not see the extremity of this cost. Once the network is augmented, any new generators developed in the same area would not receive the same benefit as the initial one, as they are not providing an equivalent impact to the aggregated fleet generation to the initial development. Hence, providing proper incentives promoting the geographic and technological diversity of intermittent generation could help promote and offset the costs of network augmentation for generators in remote locations while improving system security.

As indicated above, it is not expected that the issue of security of the intermittent generator fleet will become a major issue until the penetration of these generation technologies reaches a high level. It is however, worth noting that the analysis presented in this report has shown that there are benefits to the RCM to be found in operating both a geographically and technologically diverse fleet of intermittent generators. Thus, it would be expected that aspects such as this could be reflected in the RCM under future scenarios.

7 Allocation of Incentives

The results presented in this report indicate that the calculation methodology selected will have a significant impact on the Reserve Capacity allocated to intermittent generators. Therefore, the selection of the calculation methodology will have significant financial implications for project developers. As such, a calculation of the financial implications of various rule options was considered whereby the Reserve Capacity Credit contribution to total annual revenue of four different generators was estimated.

In order to asses the financial impact of the six calculation criterion, an assumed value of $127,500 (AUD) per MW per year was assigned to each Capacity Credit [14]. The STEM price was provided as a half hourly time series for 2007 and 2008. The time-weighted average STEM price calculated was 43.7 and 83.9 $/MWh/year for 2007 and 2008 respectively while the average STEM price during solar generators' standard operation timeframe (noting that the operating capabilities of solar thermal generators is limited by the height of the sun above the horizon or the solar altitude angle) was calculated as 52.7 and 92.8 $/MWh/year for 2007 and 2008 respectively. In addition to these values an assumed average REC price of $35/MWh was used which permitted calculations of the annual revenue from generation exclusively of the RCM. Further sensitivity analysis investigates the impact of an increased Rec price on the initial results. Note that other financial incentives, such has the Commonwealth Government's Solar Flagships program, are not considered.

The analysis included a single year of recorded generation from a wind farm and landfill gas generator and modelled solar thermal generation with and without the inclusion of thermal storage. Results are presented in terms of the percentage contribution to total revenue from the RCM such that results are independent of plant capacities. The change in revenue allocated by alternative calculation criteria is also shown in order to represent the driving influence for the change in revenue from the RCM.

Due to the unavailability of solar thermal generation data from 2008 these generators apply 2006 data while all other data is referenced from 2007 and 2008 as described above. All wind farm calculations are based on the average allocations calculated for the three major wind farms operating in the RCM, while the wind fleet considered is also based on these three wind farms only. The calculated Reserve Capacity allocations were applied based on the availability of data for each generator: the three year time frame ending in 2006 for solar thermal and either the two year time frame ending in 2008 or the single year 2007 allocations for the wind farm and the landfill gas generator.

The RCM contribution was then estimated by multiplying each allocation by the assumed value of each Capacity Credit for a $/MW/year value*. Each generator's total annual revenue was then derived on the same basis and the percentage contribution from the RCM was calculated as shown in Table 15.

While landfill gas generators are clearly the least affected by the calculation methodology, it is clear from these estimates that the Proposed calculation methodology, would present the lowest revenue stream for intermittent generators unless some form of energy storage is included to increase plant capacity factors. The use of the PJM, IRCR, or RCRM calculation methodology would likely increase the financial incentive for all intermittent generators as there is a positive correlation between load and generation during the summer peak load times. However, the RCM

* While the financial benefit to generators from Capacity Credits may be calculated differently in practice, this method gives a good indication of the financial implications of each methodology to an acceptable accuracy for this comparative analysis.

will not provide any additional incentive for the inclusion of storage for solar thermal generation under these methodologies as the generation revenue increases correspondingly.

2007 Approximate Financial Benefit from Capacity Market								
	Wind Farm		Solar Thermal (No Storage)		Solar Thermal (4 hrs. Storage)		Landfill Gas	
Rule Change Criteria	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule
Current (Average - All)	14.2%	0%	14.4%	0%	14.5%	0%	14.6%	0%
PJM (Average - Peak Period)	17.4%	+27.9%	33.0%	+193.7%	27.4%	+122.2%	15.6%	+7.9%
Proposed (10% - Top 250)	3.7%	-77%	0.0%	-100%	29.1%	+142.1%	12.8%	-14%
IRCR (Median - 12 Peak)	12.0%	-17.6%	37.0%	+249.7%	29.1%	+142.1%	15.4%	+6.6%
RCRM (Weighted - All)	14.7%	+4.4%	21.1%	+59.4%	21.4%	+60.8%	15.5%	+7.8%
Original (Fleet 10% - Top 250)	7.0%	-54.7%	0.0%	-100%	-	-	-	-

2008 Approximate Financial Benefit from Capacity Market								
	Wind Farm		Solar Thermal (No Storage)		Solar Thermal (4 hrs. Storage)		Landfill Gas	
Rule Change Criteria	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule
Current (Average - All)	9.5%	0%	10.6%	0%	10.5%	0%	10.2%	0%
PJM (Average - Peak Period)	12.7%	+39.4%	25.8%	+193.7%	20.6%	+122.2%	10.9%	+7.9%
Proposed (10% - Top 250)	3.6%	-64.8%	0.0%	-100%	22.1%	+142.1%	8.9%	-14%
IRCR (Median - 12 Peak)	12.8%	+40.7%	29.2%	+249.7%	22.1%	+142.1%	10.8%	+6.6%
RCRM (Weighted - All)	9.9%	+5.4%	15.9%	+59.4%	15.8%	+60.8%	10.9%	+7.8%
Original (Fleet 10% - Top 250)	4.8%	-52%	0.0%	-100%	-	-	-	-

Table 15: Approximate contribution to total annual revenue from the RCM based on the six Reserve Capacity allocation calculation criteria. Recorded wind farm and landfill gas generation and modelled solar thermal generation was applied under assumed 2007 and 2008 revenue streams.

A further factor to consider in assessing the financial influences on generators is fluctuations in REC prices. Over the life of the REC scheme the value of RECs have varied significantly and, under the recent implementation of the Mandatory Renewable Energy Target, REC prices are expected to change significantly. In order to examine the effect of REC price variations on these results, calculations were performed as described above only with the average price of the REC assumed to be $60/MWh rather than $35/MWh. The results are presented in Table 16.

2007 Approximate Financial Benefit from Capacity Market								
	Wind Farm		Solar Thermal (No Storage)		Solar Thermal (4 hrs. Storage)		Landfill Gas	
Rule Change Criteria	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule
Current (Average - All)	11.1%	0%	11.6%	0%	11.7%	0%	11.5%	0%
PJM (Average - Peak Period)	13.7%	+27.9%	27.8%	+193.7%	22.7%	+122.2%	12.3%	+7.9%
Proposed (10% - Top 250)	2.8%	-77%	0.0%	-100%	24.3%	+142.1%	10.0%	-14%
IRCR (Median - 12 Peak)	9.3%	-17.6%	31.4%	+249.7%	24.3%	+142.1%	12.1%	+6.6%
RCRM (Weighted - All)	11.5%	+4.4%	17.3%	+59.4%	17.6%	+60.8%	12.3%	+7.8%
Original (Fleet 10% - Top 250)	5.3%	-54.7%	0.0%	-100%	-	-	-	-

2008 Approximate Financial Benefit from Capacity Market								
	Wind Farm		Solar Thermal (No Storage)		Solar Thermal (4 hrs. Storage)		Landfill Gas	
Rule Change Criteria	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule	RCM contribution to total revenue	% change in RCM revenue from Current rule
Current (Average - All)	7.9%	0%	9.0%	0%	8.9%	0%	8.5%	0%
PJM (Average - Peak Period)	10.7%	+39.4%	22.4%	+193.7%	17.9%	+122.2%	9.2%	+7.9%
Proposed (10% - Top 250)	2.9%	-64.8%	0.0%	-100%	19.2%	+142.1%	7.4%	-14%
IRCR (Median - 12 Peak)	10.8%	+40.7%	25.6%	+249.7%	19.2%	+142.1%	9.1%	+6.6%
RCRM (Weighted - All)	8.3%	+5.4%	13.6%	+59.4%	13.6%	+60.8%	9.2%	+7.8%
Original (Fleet 10% - Top 250)	4.0%	-52%	0.0%	-100%	-	-	-	-

Table 16: Approximate contribution to total annual revenue from the RCM based on the six Reserve Capacity allocation calculation criteria with RECs valued at 60$/MWh. Recorded wind farm and landfill gas generation and modelled solar thermal generation was applied under assumed 2007 and 2008 revenue streams.

In summary, the Proposed or Original calculation methods would likely decrease the financial incentives provided from the RCM for many intermittent generation technologies as compared to the Current method. Other methods would likely result in increased financial incentives, especially where generation is well correlated with load. Furthermore, under the scenario of high REC prices the impact of a rule change is only reduced slightly as the financial contribution from the RCM is reduced overall.

It is beyond the scope of this work to price the benefits of system security. However, Section 5.3 discussed the risk and probability that various calculation methodologies would result in a loss of system security. This information, coupled with a pricing of system security risk, can be compared to the financial benefits provided to project developers under various calculation methodologies.

8 Potential Issues and Areas for Further Research

The study presented herein analyses a selection of potential calculation methodologies for the allocation of Reserve Capacity to intermittent generators participating in the SWIS' RCM. In doing so potential benefits and shortcomings of these calculation methodologies are exposed along with some significant channels for further work to proceed with the rapid expansion of intermittent generation in the SWIS.

The following further work has been identified.

- In all calculations involving the weighted average calculation methodology as derived here the weightings have been based on the Reserve Capacity Refund Mechanism as outlined by Rule 4.26.1 of the Rules [1]. As the weightings are normalised they provide a reasonable outcome across All intervals, as would be expected.

  There is some apparent potential in the use of a weighted average due to the fact that the use of an average of all data available will derive a consistent outcome from year to year. Furthermore, the application of weightings could potentially provide a good representation of a generator's contribution to peak load and a more sophisticated approach to these weightings could be used to reflect variations in system security with load levels and reward generator output accordingly.

- The study outcomes determined that there was a complex relationship between temperature and wind generation while recognising a simplified relationship between temperature and solar thermal generation. Although the statistical analysis applied here did not present an obvious relationship in any case those that do exist could potentially be expanded or studied in detail in order to ascertain their applicability in the development of intermittent generation forecasting tools for the SWIS.
- As stated earlier, Reserve Capacity allocations based on the average of peak load intervals typically consider above average generation due to the fact that generation is typically higher than average during these intervals. These interval selections provide a good basis to reflect a generator's actual contribution to the peak load. However, further work would be required before a correlation between very high load temperatures and the intermittent wind generation could be established.
- Given the proposed rapid expansion of renewable generation in the near future [4] it is expected to be of great benefit to develop a long term and short term forecasting system for intermittent generators. As the dominating force in renewable generation is currently wind it is expected that such a system would focus on this resource and may be formed from a system such as the National Electricity Market's Anemos forecasting system. The benefits of a system such as this can be the efficient dispatch of conventional generation to compensate for the variability of renewable generation and the ability to develop long term records to apply to forecasting of future Reserve Capacity.
- Further studies may be required to undertake Loss of Load Probability analysis to get a better handle on when the system is at risk on the basis of the planning criterion, the generation mix and network constraints. Also in this vein, undertake analysis of the Effective Load Carrying Capability provided by intermittent generators and determine its potential to be used as the basis for Reserve Capacity allocation to intermittent generators in the SWIS.
- This study does not undertake an assessment of how well any particular Reserve Capacity allocation methodology aligns with an intermittent generator's actual contribution to system security. Such an analysis is highly complex and requires consideration of the interaction between the generator and the market as a whole and is an area for future work.

9 Conclusions

The study presented herein has analysed a selection of potential calculation methodologies for the allocation of Reserve Capacity to intermittent generators participating in the SWIS' Reserve Capacity Market. In making this assessment, data provided by intermittent Market Generators presently operating in the SWIS has been applied along with modelled generation for wind farms and solar thermal generators based on BOM long term recorded resource data. Collectively, this combination of modelled and recorded generation data enabled the study to consider the geographic and potential technological diversity of the SWIS. Intermittent generation technologies considered include wind, solar thermal and landfill gas generation, while the study outcomes focus on wind and solar thermal generators as these are characterised by generation profiles which are inherently variable.

Key study conclusions

In making an assessment of potential Reserve Capacity allocation methodologies three key characteristics of each methodology have been considered in the presentation of results: time frames, interval selection techniques and calculation methodologies have all been investigated. In total, 24 individual calculation methodologies were tested and examined across 15 locations around the SWIS. The generation technologies considered include wind, solar thermal and landfill gas. Correspondingly, a substantial amount of secondary analysis was conducted in order to validate, and test the sensitivity of, the results. The following conclusions have been made.

- The Reserve Capacity allocated to generators which are characterised by significant variability in generation due to a variable primary resource can be subject to highly variable allocations where interval selection data sets are limited in size. This is particularly evident in the case of allocations based on the 12 Peak and Top 250 load intervals.
- Calculation methodologies based on larger data sets can provide relatively stable results that do not vary significantly when derived from longer time frames. This is particularly true where these data sets are expanded as additional years are considered, as in the case of All intervals and the Peak Period intervals. Calculations based on single year time frames derive results similar (typically within ±~15%) to those based on longer time frames for the majority of the calculation methodologies (with the exception of the 10th percentile calculations) (Section 4).
- Reserve Capacity allocations based on 10th percentiles have the potential to allocate little or no Reserve Capacity to some generation technologies in the absence of a fleet component. Furthermore, 10th percentiles of All intervals appear to misrepresent the contribution to peak load where generation profiles are positively correlated with peak load as with solar thermal generators (Section 4).
- The correlation between intermittent generation and times when load is highest is an important determinant of the likely contribution variable generators make to system reliability as intervals when the load is highest give an indication of when the system is likely to be most at risk. Although wind resource variability (and hence reliability) varies between wind sites (Section 4.2) there is a general trend in all wind generators considered here, and particularly for those located in coastal areas, for above average generation during peak load times. In the case of wind generation, calculation methodologies that consider peak load intervals only typically result in Reserve Capacity allocations which are higher than that calculated with All intervals by a factor of ~1.2-1.4 for recorded wind generation and ~1.1-2 for modelled wind generation where calculations are based on averages (Section 4).
- Solar thermal generation has a strong correlation with peak load intervals that is under-recognised by the current allocation approach. It is highly reliable during summer peak load intervals when the sun is available, with incidences of cloud obstruction being comparatively

low (Section 5.2). Despite a substantial portion of peak load intervals occurring towards the end of the day or in the early evening, when insolation is low, the Current allocation method allocates approximately 60-70% less Reserve Capacity to those methods which consider peak load intervals only. Furthermore, Reserve Capacity allocations based on purely reliability focused calculation methodologies, such as 10th percentiles have the potential to lead to very low allocations for solar thermal generators (Section 4).

- Longitude influences alignment of solar insolation with SWIS peak loads, with a substantially better match in Geraldton compared to Kalgoorlie. During peak load periods system loads during peak load intervals when solar radiation is available for capture are typically similar to loads during peak load intervals with little insolation. However, during peak load periods solar thermal generation has a high reliability when considering its ability to meet typical daily peak loads (Section 5.2). Thermal energy storage capacity can moderate the effect of cloud cover and would allow a solar thermal facility to generate during high early evening loads, providing a more reliable generation resource (Section 5.5.5).
- As stochastically independent sources of wind generation are added to the wind generation fleet, the likelihood of relatively low levels of generation is reduced. The 90 per cent reliable level of generation for the existing fleet is approximately double the 90 per cent level of reliable generation from each individual wind farm (Section 4.4). While this outcome could be affected by weather-based correlations between wind sites, no material correlations were evident in generation from existing wind farms over contemporaneous trading intervals, or between various Bureau of Meteorology wind mast locations distributed around the SWIS (Section 4.4). Note that this outcome may not hold in the future if new wind farms are located in close proximity to existing wind farms.
- Reserve Capacity allocations based on fleet calculation methodologies are influenced by three aspects which can be made evident by, and depend on, the calculation methodology applied. The fleet average of All intervals will vary with the scale of the resource captured by the fleet and corresponding generator capacities and capacity factors. The fleet 10th percentile of the Top 250 intervals can be influenced by the availability of generation during these intervals whereby a single generator can contribute in the form of a security impact. Furthermore, a comparison can be made between peak load focussed calculations with and without the fleet whereby variations in the fleet 10th percentile of the Top 250 loads can represent a resource security impact (Section 4.4). Overall, the Original calculation method tends to allocate around 50% of that from the Current method (Section 4).
- The allocation of Reserve Capacity to intermittent generators with stable generation profiles (e.g., landfill gas and other biogas generators) is relatively independent of the calculation methodology used as these generators exhibit no correlation with load. Thus, the effect of rule allocations analysed here has a relatively small impact (Section 4).

Additional analysis conclusions

Further to the above conclusions the study was extended to investigate and conclude on the following quantitative and qualitative aspects.

Generation and load correlations

A strong positive correlation between load and temperature has been identified. However, the results here show that, while there is a relationship between the temperature and wind generation, it is highly complex. Conversely, while remaining complex to an extent, a clear relationship between average daily solar thermal generation and Perth temperatures has been shown to exist (Section 5.1).

Generation interval histograms

Generation distribution histograms have been shown to provide an insight into the performance of the generation captured by each calculation methodology along with the probability of generators meeting their Reserve Capacity allocations. They show that under the All, Top 250 or Peak Period interval selection techniques, allocations based on averages tend to have a 40-50% probability of being met. Where only the 12 Peak intervals are considered this range increases to around 40-60% while calculation methodologies based on medians and 10th percentiles will always have 50% and 90% probabilities of being met respectively (Section 5.2).

Wind is a highly variable energy resource and this volatility is evident over relatively small interval selections, including at times when system load is highest. Generation during a small number of hot weather episodes that have occurred over the last few years demonstrate this potential for large variations in output between trading intervals at peak times (Section 5.3). However, further work would be necessary to establish a systematic correlation with high loads at a 1 in 10 year timescale.

Fleet diversity impacts

Reserve Capacity allocations based on fleet calculation methodologies can potentially provide measurable impacts to the RCM in the form of the scale, security and reliability of generation from wind resources. The implications of these characteristics are that the Reserve Capacity allocated under a fleet method such as the Original method would be highly dependent on the characteristics of the fleet. Therefore, this method may present issues for generation technologies that do not have an existing and established geographically diverse fleet (Section 5.4).

Despite an inverse correlation between the wind resources across different regions not being found it is evident that different regions across the SWIS have the potential to contribute to a diverse intermittent generation fleet in different ways. In general, the wind resources along the southern regions of the SWIS including Fitzgerald, Albany and Margaret River have the capacity to benefit a fleet based north of Perth as the wind resource along the southern coast presents different characteristics to that north of Perth. An assessment is made of the influence of regional weather patterns on the SWIS regions which shows that wind farms in the SWIS can effectively be considered as independent variables (Section 5.4).

Sensitivity analyses

A comparison between the modelled and recorded generation was made at three locations around the SWIS which validated the wind farm modelling assumptions made for this study. The fact that modelled wind farm generators applied here are based on resource data which is not the optimum for wind farm development introduces some error in the outcomes. However, given the desired outcomes of this study these errors are not considered to be significant (Section 5.5.2). Reserve Capacity allocations based on calendar years are shown to be relatively unchanged (<1%) from allocations based on Reserve Capacity Years (Section 5.5.3) and the allocations are found to be relatively insensitive to the timing of the weekly business cycle (Section 5.5.4). Thus, the results presented in this report do not appear to be highly sensitive to the time periods selected.

Financial impacts

Capacity Credits provide an additional revenue stream to new generation that rewards capacity availability. Based on recent energy market and Renewable Energy Certificate prices, capacity credits contribute around ten per cent of the potential revenue stream of intermittent generation projects (Section 7).

Adapted generation technologies such as solar thermal generation which includes thermal energy storage can achieve a significant increase in the allocated Reserve Capacity as reliability is increased. However, under the consideration of the financial benefits available by such adaptations, it has been shown that the RCM does not allocate any greater contribution to them as increased capacity factors increase both energy revenue and Capacity Credit revenue accordingly in most cases (Section 7).

The analysis in this report suggests that a greater focus on peak load periods could marginally increase payments to wind generation and double capacity credits revenue for solar thermal generation in comparison with current arrangements. On the other hand, the use of highly conservative approaches to allocating credits for intermittent generation could substantially reduce revenue gains from the RCM (Section 7).

<u>Further work identified</u>

A number of items for further work and analysis have been identified, including (Section 8):

- The determination of a specific correlation, if any, between intermittent generation and very high temperatures and the level of risk imposed by a calculation method which focuses on specific high risk load intervals such as loss of load probability analysis .
- The appropriate level of geographic and technological diversity across the SWIS and the interaction of the RCM and such distribution.
- The development of wind generation forecasting tools for the SWIS along with generator control and market strategies which consider such forecasting tools.

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alternative energy
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10 References

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[15] "*Providing New Capacity in the South West Interconnected System: A guide for Investors and Developers, November 2008*", IMO, 2008, available: www.imowa.com.au, accessed: 25/1/2009.

[16] Western Power Temperature data provided January 2009 for the purposes herein.

11 Appendix A: Statistical Concepts

As indicated by the Reserve Capacity allocation calculation methodologies presented in Table 1, a large majority of the calculations and results presented are based on fundamental statistical principals. In order to ensure the results presented in this study are complete to the extent that the reader can appreciate them, a summary of these principals in their application here is included below.

Generation Data and Averages

The average, or sample mean of a generation interval data set is dependant on all of the data included in the data set such that any outliers are also included. In terms of the calculations performed here, the average can provide a good representation of generation data sample as the influence of outliers is constricted in the data considered.

Generation Data and Medians

The median is the generation interval which lies at the middle of the ordered generation interval data set. Also termed the 50th percentile, or the 0.5 quartile, the median is either the centre of the data for odd data sets or the average of the two middle data points for even data sets. The median has the potential to provide a good descriptive measure of the location of the data as outliers are not considered in its derivation.

Generation Data and 10th Percentiles

The 10th percentile is the single generation value which lies at the top of the bottom 10% of the ordered generation interval data set. Here the focus is on the 10th percentile of the Top 250 load intervals where this interval selection is thought to represent the times when system security is most at risk. Hence, this assessment at high risk times is expected to give an indication of a generators contribution to system reliability. As the lowest 10% of the data is captured by the 10th percentile the 10th percentile is typically a low value and given a small interval data set such as the Top 250 or Peak 12 the outcome can be highly varied.

Generation Data and Modes

The mode of any data set is the most frequently occurring value in the data set. Given that the generation data considered here is normalised, and can vary across the full 0-1 range, outliers are not present. However, one of the influences of the calculation of both averages and medians is the incidence of modes that are skewed toward the maximum or minimum of the available range of data. For example, the average of a Top 250 set of generation interval data will be high if the mode is toward 100% and low if the mode is closer to 0%. Similarly, a median of a data set may vary greatly from the average given a data set that is heavily skewed. However, the results found here typically present medians that are relatively close to averages which indicates that the data is typically well distributed and not heavily impacted upon by any outlying data points or modes.

Generation Data and Interval Selections

There are four main interval selection techniques applied here and each has a different impact on the Reserve Capacity calculations based on them. One general conclusion which is made about these impacts is that the use of larger data sets as the basis for calculations derives more reliable results. Here, this conclusion relies on the retest reliability or results from year to year as each year is assessing an entirely different generation data set.

Generation Data, Normality and Standard Deviation

The standard deviation of a data set is used to describe the spread or diversity of the data set in that the more dispersed the data is in the sample the larger the standard deviation will be. Given a normally distributed data set with a small standard deviation the data will cluster around the sample mean. In general, the wind generation data considered here is not normally distributed such that the standard deviation can only give an indication of the variability of the data being considered.

Load data and Maxima

The maxima of a given data set represent the peaks or maximum values of the data over a given time frame. A data set can have any number of maxima depending on the desired application of this data. For example, load interval selection techniques which consider the peak load only, such as the Top 250 intervals, are effectively selecting the largest maxima by magnitude, across the specified time frame. Alternatively, the 12 Peak load intervals are selecting the three highest half hourly load maxima for the four highest load days found in the time frame considered (noting that these four days are also the four highest maxima of the daily loads in the time frame considered).

Fleet calculations and Geographic Diversity

The key attribute of fleet calculations is that they attempt to capture the characteristics of aggregated generation presented by a geographically diverse fleet of wind generators. When comparing wind characteristics a single wind turbine will present a generation profile (power output vs. time characteristic) which is erratic and highly susceptible to short term wind fluctuations. Introducing geographic diversity to this example by considering the generation profile of a large wind farm of say 100 wind turbines will smooth out the short term variations and more closely represent the average wind speed across a site. Further expansions, and corresponding increases in geographic diversity, by say adding another two or three 100 turbine wind farms, which are some distance apart and subject to different wind patterns, will further smooth short term variations and result in a generation profile which represents the average wind speed across the aggregated sites. In effect the addition of any new wind farms to the fleet will result in aggregated generation which tends around the average across the sites resulting in generation at the extremes of zero and the maximum becoming less probable. Hence, aggregated generation data presents a smaller standard deviation around a relatively constant average explains why the fleet calculations present a constant average and an increased 10th percentile with an expanding fleet.

12 Appendix B: RCRM Weighted Average Weightings

As discussed in Section 2.1 the RCRM Reserve Capacity calculation methodology is based on an adaptation of the Refund Table of Market Rule 4.26.1 of the Market Rules [1]. These weightings are normalised as shown below and applied in all RCRM calculations.

RCRM Weighting Methodology for Business / Non-business and Peak / Non-peak Intervals				
Days x Weighting	**1 April - 1 October**	**1 October - 1 December**	**1 December - 1 February**	**1 February - 1 April**
Business Off-Peak	1270 x 0.25 = 317.5	440 x 0.25 = 110	390 x 0.5 = 195	400 x 0.75 = 300
Business Peak	1778 x 1.5 = 2667	616 x 1.5 = 924	546 x 4 = 2184	560 x 6 = 3360
Non-business Off-Peak	560 x 0.25 = 140	170 x 0.25 = 42.5	230 x 0.5 = 115	190 x 0.75 = 142.5
Non-business Peak	784 x 0.75 = 588	238 x 0.75 = 178.5	322 x 1.5 = 483	266 x 2 = 532
Sum of Weighted Hours = 12279 **Tot. Hours in 2002 = 8760**			**Normalising Factor = 0.713413**	
Normalised Weightings Applied				
Business Off-Peak	**0.178353**	**0.178353**	**0.356707**	**0.535060**
Business Peak	**1.070120**	**1.070120**	**2.853653**	**4.280479**
Non-business Off-Peak	**0.178353**	**0.178353**	**0.356707**	**0.535060**
Non-business Peak	**0.535060**	**0.535060**	**1.070120**	**1.426826**

Table 17: Adaptation of the Refund Table of Rule 4.26.1 of the Market Rules [1] and the normalised weighting factors used here to calculate the Reserve Capacity under the weighted average calculation method.

13 Appendix C: Reserve Capacity Allocation Results

The complete sets of results of the study are displayed below. For simplicity and space saving, the outcomes for each site and calculation methodology are represented graphically for both single and three year time frames as shown in Table 18. In order to summarise the results from the study Table 20 and Table 21 provide the minimum, average, maximum and standard deviation of each calculation methodology as calculated for the six calculation criteria, as outlined in Section 2.1 for each site for single year time frames. Table 22 and Table 23 then present the three year equivalent.

Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2PM-5PM (Jan-Mar)
Average	Current	X	X	PJM
Tenth Percentile	X	Proposed	X	X
Median	X	X	IRCR	X
RCRM Weighted Average	RCRM	X	X	X
Fleet (Average)	X	X	X	X
Fleet (Tenth Percentile)	X	Original	X	X

Table 18: Analysis conducted for each site and year group.

All calculation methodology results are initially presented in terms of individual sites and separated in terms of generating technology and are ordered according to Table 19.

Summary of Results for Reserve Capacity Calculation Methodologies							
Data Provider	**Site**	**Technology**	**Abbreviation**	**BOM Weather Station #**	**Data Type**	**Years Utilised**	**Year Groups**
Bureau of Meterology	Badgingarra	Wind (Modelled)	BRS	9037	Half-Hour Wind*	2001 - 2008	All years, 5 x 3 years, Fleet
	Cunderdin	Wind (Modelled)	CDD	10286	Half-Hour Wind*	2001 - 2008	All years, 5 x 3 years, Fleet
	Cape Naturaliste	Wind (Modelled)	CPN	9519	Half-Hour Wind*	2001 - 2008	All years, 5 x 3 years, Fleet
	Gingin Airport	Wind (Modelled)	GIN	9178	Half-Hour Wind*	2001 - 2008	All years, 5 x 3 years, Fleet
	Geraldton	Wind (Modelled)	GRD	8051	Half-Hour Wind	2001 - 2008	All years, 5 x 3 years, Fleet
	Hopetoun	Wind (Modelled)	HPT	9961	Half-Hour Wind*	2001 - 2008	All years, 5 x 3 years, Fleet
	Kalgoorlie	Wind (Modelled)	KBD	12038	Half-Hour Wind	2001 - 2008	All years, 5 x 3 years, Fleet
	Walpole	Wind (Modelled)	NWP	9998	Half-Hour Wind*	2004 - 2008	All years, 3 x 3 years, Fleet
Verve Energy	Albany	Wind (Metered)	ALB	-	Generation	2002 - 2008	All years, 5 x 3 years, Fleet
Griffin Energy	Emu Downs	Wind (Metered)	EMU	-	Generation	2007 - 2008	All years, 1 x 2 years, Fleet
Alinta (B&B)	Walkaway	Wind (Metered)	WLK	-	Generation	2007 - 2008	All years, 1 x 2 years, Fleet
Pacific Hydro	Nilgen	Wind (Modelled)	NIL	-	Ten minute wind	2005 - 2007	All years, 1 x 3 years, Fleet
Landfill Gas & Power	Tamala Park, Canning Vale and Red Hill	Landfill Gas	LGP	-	Generation	2007 - 2008	All years, 1 x 2 years, Fleet
Bureau of Meterology	Kalgoorlie	Solar Thermal	KLG	12038	Half Hour Direct (Hor.) Irradiation	2002 - 2006	All years, 4 x 3 years, Fleet
	Geraldton	Solar Thermal	GER	8051	Half Hour Direct (Hor.) Irradiation	2001 - 2006	All years, 3 x 3 years, Fleet
* Note that the data available from the BOM for these sites is reported as half hourly wind speed. It is in fact hourly and half hourly data is either recorded on the hour or interpolated for intermediate records.							

Table 19: Analysis conducted for each site and year group along with data availability, abbreviations and site locations.

Summay Table for Reserve Capacity allocations based on single year time frames													
Site	Avail. data points	Current				Original				Proposed			
		Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.
BRS	8	36.69%	40.02%	47.41%	3.57%	-	-	-	-	2.77%	7.73%	18.93%	4.93%
CDD	8	20.25%	22.08%	24.28%	1.46%	0.00%	3.19%	10.20%	3.75%	0.00%	1.12%	2.77%	1.06%
CPN	8	49.51%	51.58%	54.32%	1.85%	16.89%	21.09%	32.34%	5.39%	2.77%	5.61%	8.67%	1.63%
GIN	8	18.32%	19.38%	20.61%	0.86%	5.52%	12.80%	32.72%	9.38%	0.90%	3.51%	8.67%	2.48%
GRD	8	26.38%	27.86%	30.79%	1.82%	14.48%	29.06%	66.76%	17.38%	2.36%	8.43%	17.68%	4.21%
HPT	8	27.54%	30.16%	32.27%	1.46%	49.79%	64.84%	78.02%	11.69%	8.67%	19.75%	31.47%	7.36%
KBD	8	12.88%	13.90%	14.54%	0.58%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
NWP	5	13.76%	15.72%	17.19%	1.34%	-	-	-	-	0.00%	1.23%	3.92%	1.67%
ALB	7	29.87%	33.06%	35.43%	2.02%	8.38%	27.93%	46.60%	14.05%	2.49%	8.73%	20.51%	6.29%
EMU	2	36.17%	36.61%	37.05%	0.62%	18.57%	20.04%	21.51%	2.08%	4.92%	7.19%	9.47%	3.22%
WLK	2	42.18%	43.48%	44.78%	1.84%	19.62%	37.84%	56.06%	25.77%	8.63%	11.74%	14.85%	4.40%
NIL	3	32.06%	34.04%	35.51%	1.78%	-	-	-	-	2.56%	6.85%	11.31%	4.38%
LGP	2	73.47%	76.41%	79.34%	4.16%	-	-	-	-	63.16%	70.76%	78.36%	10.75%
KLG	6	25.66%	26.92%	28.39%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GER	6	25.08%	26.71%	27.80%	1.06%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 20: Summary Table of the allocations based on single year time frames for the Current, Original and Proposed calculation criteria. Note that the fleet results presented here do not distinguish between Wind Fleet 1 or 2.

Summay Table for Reserve Capacity allocations based on single year time frames													
Site	Avail. data points	PJM				IRCR				RCRM			
		Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.
BRS	8	54.65%	59.43%	63.87%	2.89%	10.93%	62.71%	100.00%	27.29%	45.38%	52.38%	69.88%	9.11%
CDD	8	27.27%	32.92%	37.80%	3.97%	8.67%	24.80%	45.01%	13.42%	25.40%	28.93%	31.05%	1.85%
CPN	8	51.30%	58.78%	65.13%	4.89%	15.90%	28.95%	53.80%	14.20%	51.06%	53.29%	55.69%	1.51%
GIN	8	45.18%	49.18%	53.15%	2.70%	15.90%	41.01%	54.89%	12.55%	25.94%	28.07%	30.80%	1.95%
GRD	8	63.10%	68.52%	72.91%	4.02%	25.00%	43.29%	70.99%	16.19%	38.21%	40.52%	44.29%	2.42%
HPT	8	56.11%	62.00%	65.43%	3.39%	54.89%	77.80%	94.34%	14.87%	35.68%	38.80%	41.12%	1.61%
KBD	8	12.41%	17.43%	20.77%	2.58%	1.83%	13.31%	27.44%	9.20%	14.35%	16.31%	17.21%	1.05%
NWP	5	23.71%	28.79%	36.78%	5.68%	5.26%	15.13%	31.78%	9.88%	14.99%	18.29%	20.59%	2.51%
ALB	7	34.13%	40.75%	45.15%	3.91%	17.82%	47.12%	72.92%	20.29%	29.21%	33.93%	36.30%	2.51%
EMU	2	43.59%	46.74%	49.89%	4.45%	24.98%	36.33%	47.68%	16.05%	37.48%	37.91%	38.35%	0.61%
WLK	2	57.87%	59.07%	60.27%	1.70%	36.86%	38.66%	40.47%	2.56%	43.54%	45.57%	47.61%	2.88%
NIL	3	57.01%	61.48%	65.90%	4.44%	38.92%	54.70%	64.55%	13.81%	42.17%	43.95%	45.84%	1.84%
LGP	2	79.24%	81.86%	84.49%	3.71%	78.35%	82.91%	87.46%	6.44%	79.17%	81.38%	83.59%	3.13%
KLG	6	56.60%	68.58%	76.48%	6.58%	50.00%	91.67%	100.00%	20.41%	37.77%	43.56%	55.38%	6.19%
GER	6	80.99%	84.28%	90.14%	3.69%	100.00%	100.00%	100.00%	0.00%	41.21%	43.35%	45.93%	2.01%

Table 21: Summary Table of the allocations based on single year time frames for the PJM, IRCR and RCRM calculation criteria. Note that the fleet results presented here do not distinguish between Wind Fleet 1 or 2.

Summay Table for Reserve Capacity allocations based on three year time frames*													
Site	Avail. data points	Current				Original				Proposed			
		Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.
BRS	6	37.70%	39.13%	42.03%	1.52%	-	-	-	-	5.26%	8.03%	10.78%	1.86%
CDD	6	21.39%	22.18%	23.51%	0.84%	0.00%	5.28%	11.20%	5.13%	0.00%	1.68%	2.77%	1.23%
CPN	6	50.60%	51.71%	52.33%	0.61%	15.37%	20.49%	27.37%	4.41%	3.79%	6.11%	8.67%	1.70%
GIN	6	18.45%	19.14%	19.80%	0.53%	6.23%	11.69%	16.61%	3.93%	2.77%	3.99%	5.26%	1.34%
GRD	6	26.53%	28.06%	29.77%	1.39%	24.95%	34.95%	48.48%	9.28%	7.90%	11.16%	17.68%	5.05%
HPT	6	29.11%	30.11%	30.87%	0.68%	70.79%	79.00%	86.65%	7.00%	18.93%	25.81%	31.47%	4.32%
KBD	6	13.60%	13.87%	14.10%	0.20%	0.00%	0.00%	0.00%	0.00%	0.00%	0.15%	0.90%	0.37%
NWP	3	15.32%	15.58%	15.91%	0.30%	-	-	-	-	0.90%	1.19%	1.78%	0.51%
ALB	5	31.83%	32.77%	34.20%	1.04%	7.15%	16.80%	25.62%	7.88%	3.18%	5.12%	8.11%	1.97%
KLG	4	26.88%	27.10%	27.31%	0.18%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
GER	3	26.75%	27.10%	27.38%	0.32%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Table 22: Summary Table of the allocations based on three year time frames for the Current, Original and Proposed calculation criteria. Note that the fleet results presented here do not distinguish between Wind Fleet 1 or 2. *Where data is unavailable for three years the longest available time frame is shown.

Summay Table for Reserve Capacity allocations based on three year time frames*													
Site	Avail. data points	PJM				IRCR				RCRM			
		Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.	Min	Ave	Max	Std. Dev.
BRS	6	57.39%	58.78%	60.48%	1.19%	34.89%	48.61%	59.94%	10.65%	46.63%	50.42%	58.12%	4.15%
CDD	6	28.66%	32.11%	34.78%	2.35%	12.21%	25.27%	35.77%	9.36%	27.29%	28.64%	29.84%	1.01%
CPN	6	56.33%	59.09%	61.48%	1.88%	5.26%	19.29%	48.67%	15.52%	52.62%	53.30%	53.84%	0.44%
GIN	6	46.97%	48.34%	50.01%	1.09%	27.05%	39.83%	47.45%	8.65%	26.05%	27.43%	29.06%	1.16%
GRD	6	67.10%	68.62%	69.63%	0.95%	25.00%	44.19%	70.99%	19.60%	39.44%	40.58%	42.07%	1.27%
HPT	6	59.69%	61.38%	63.15%	1.15%	40.39%	65.79%	79.81%	14.43%	37.49%	38.61%	39.18%	0.60%
KBD	6	15.23%	16.91%	18.74%	1.56%	9.91%	16.79%	27.44%	7.06%	15.45%	16.03%	16.61%	0.54%
NWP	3	24.95%	28.19%	31.62%	3.34%	4.59%	10.16%	18.93%	7.69%	17.03%	18.02%	18.53%	0.85%
ALB	5	37.22%	39.74%	41.39%	1.62%	25.71%	48.93%	56.31%	13.08%	32.19%	33.45%	34.40%	0.87%
KLG	4	65.27%	70.49%	72.65%	3.52%	100.00%	100.00%	100.00%	0.00%	40.68%	42.08%	44.25%	1.56%
GER	3	84.45%	85.23%	86.21%	0.90%	100.00%	100.00%	100.00%	0.00%	43.06%	43.89%	44.60%	0.78%

Table 23: Summary Table of the allocations based on three year time frames for the PJM, IRCR and RCRM calculation criteria. Note that the fleet results presented here do not distinguish between Wind Fleet 1 or 2. *Where data is unavailable for three years the longest available time frame is shown.

13.1 Appendix C1: Individual Site Results – Wind Generation

As discussed above, results are shown for single year and three year time frames for individual wind generation sites where three year time frames are shown as period ending.

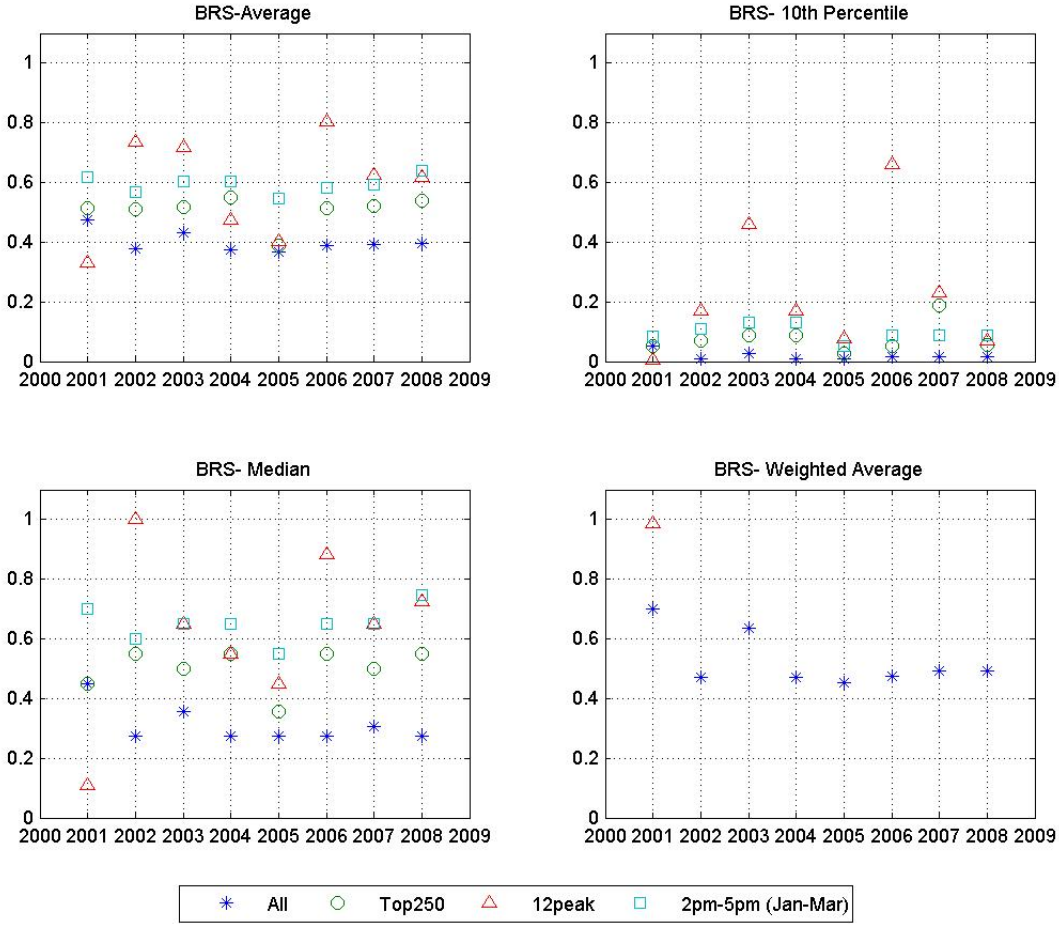

Figure 36: Comparison of results found when calculating Reserve Capacity based on all methodologies for BRS modelled wind generation over single year time frames.

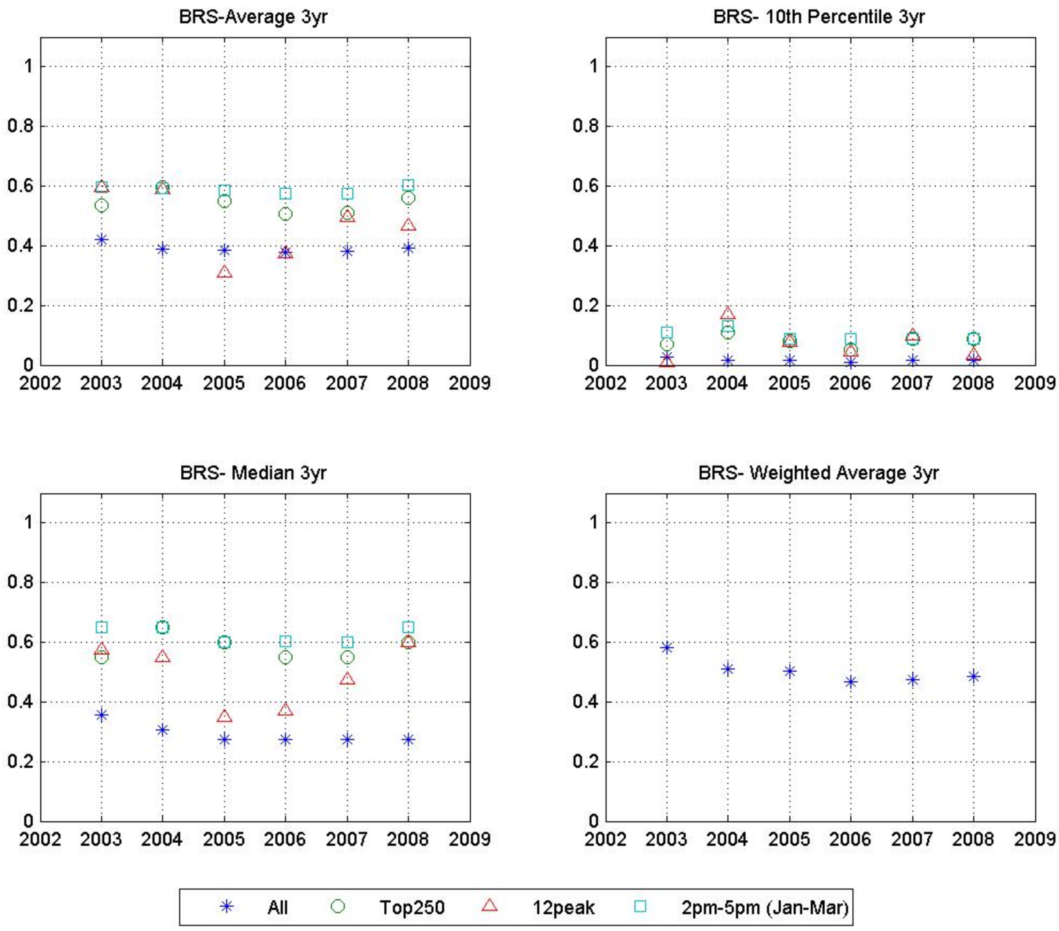

Figure 37: Comparison of results found when calculating Reserve Capacity based on all methodologies for BRS modelled wind generation over three year time frames.

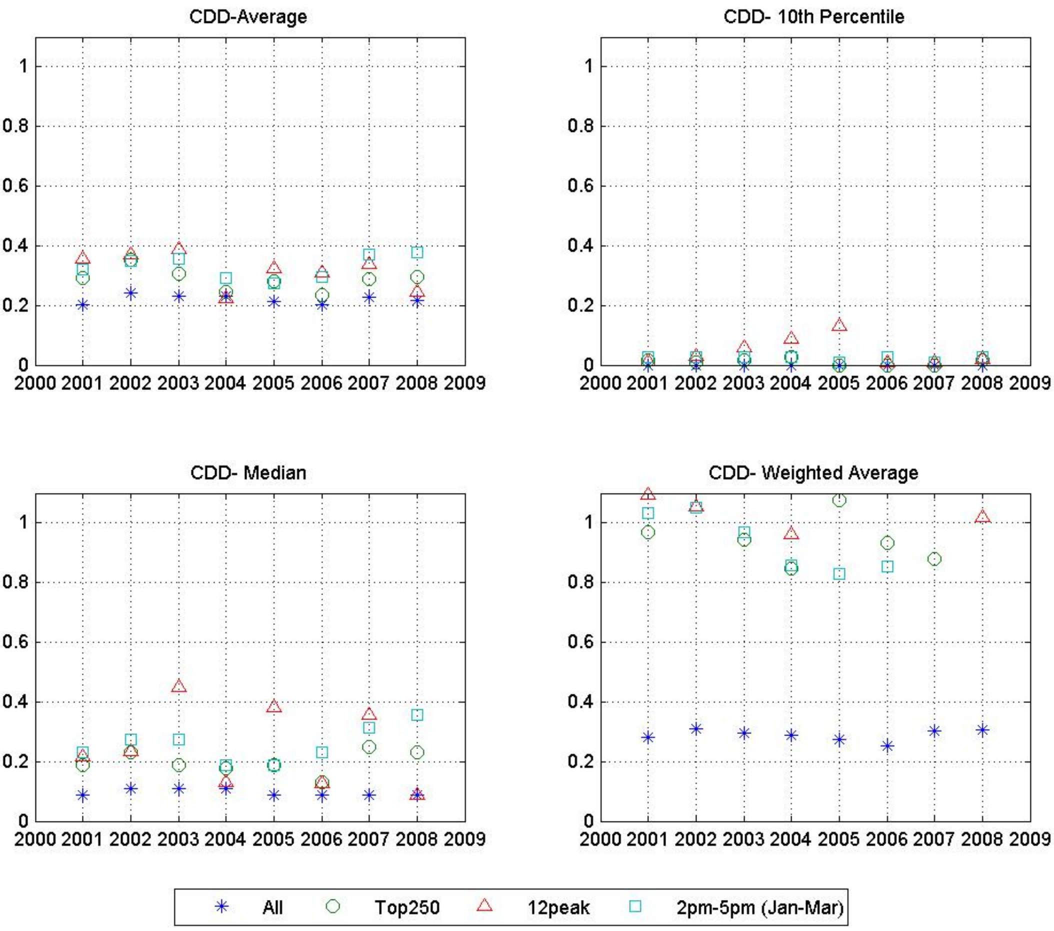

Figure 38: Comparison of results found when calculating Reserve Capacity based on all methodologies for CDD modelled wind generation over single year time frames.

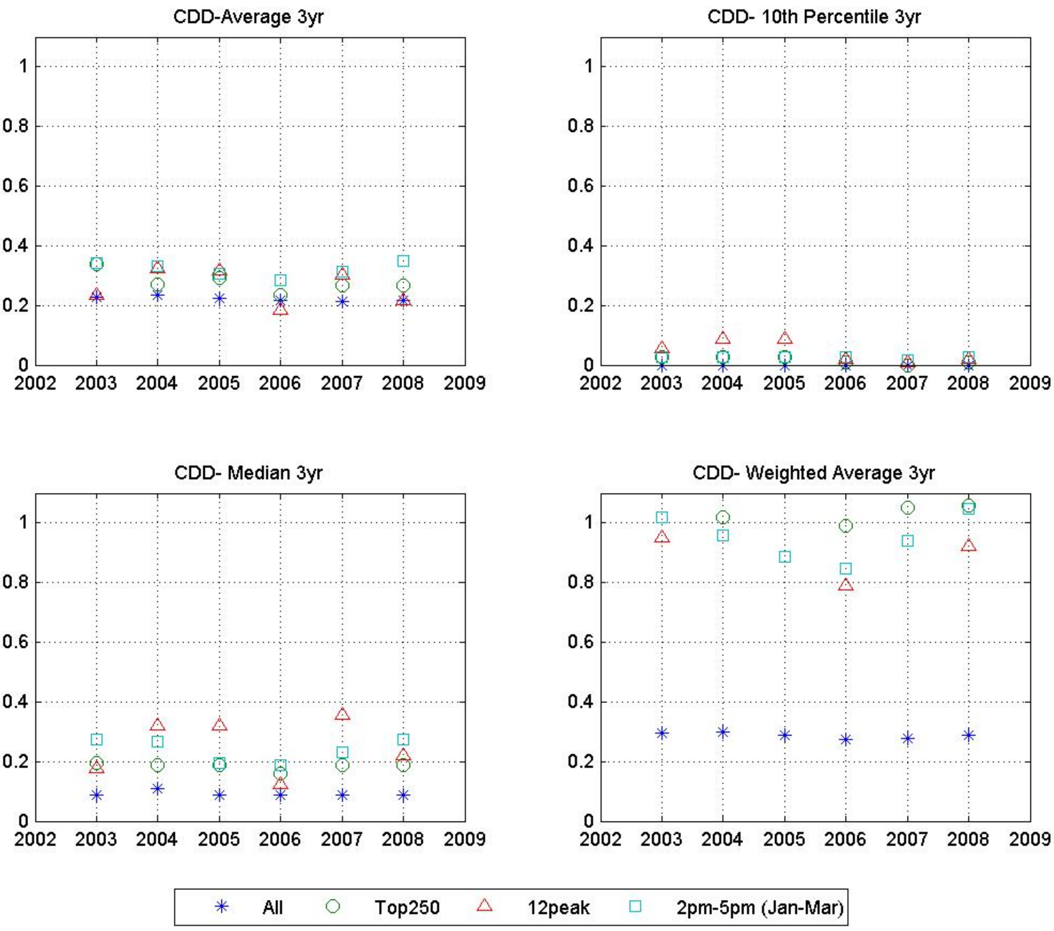

Figure 39: Comparison of results found when calculating Reserve Capacity based on all methodologies for CDD modelled wind generation over three year time frames.

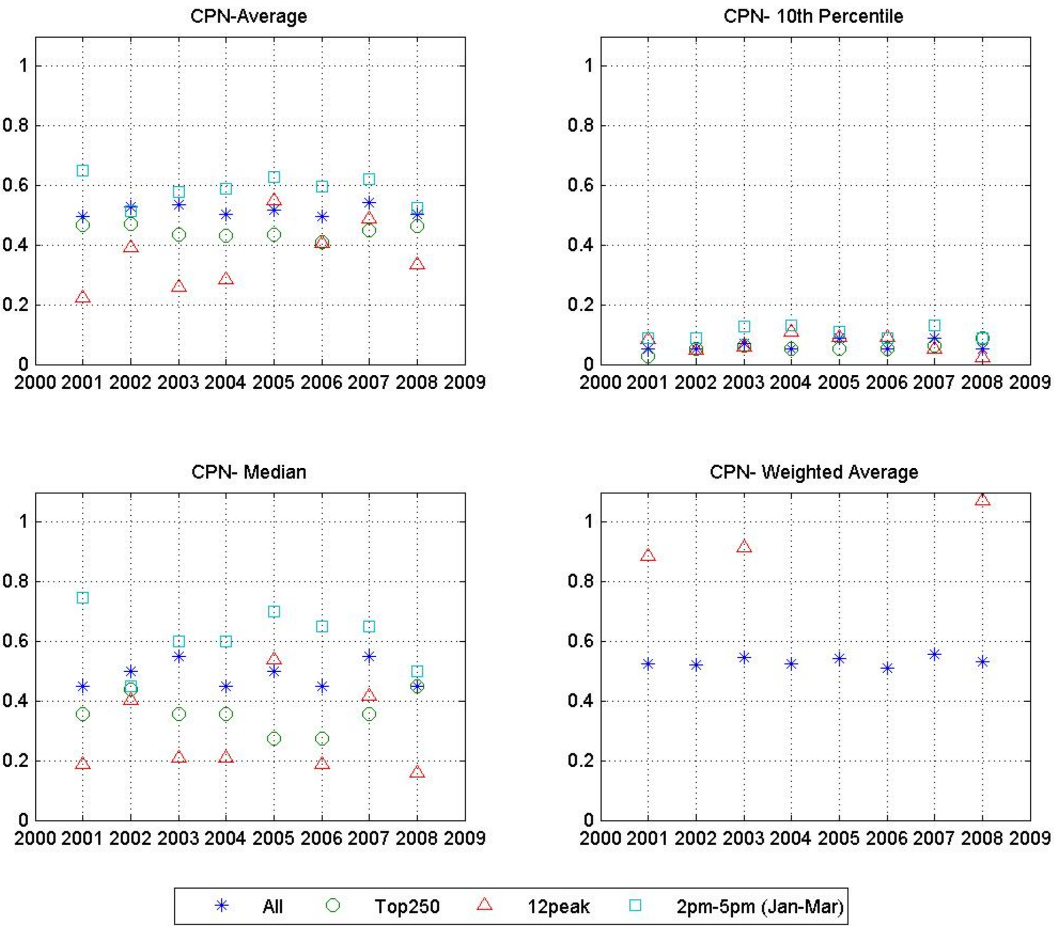

Figure 40: Comparison of results found when calculating Reserve Capacity based on all methodologies for CPN modelled wind generation over single year time frames.

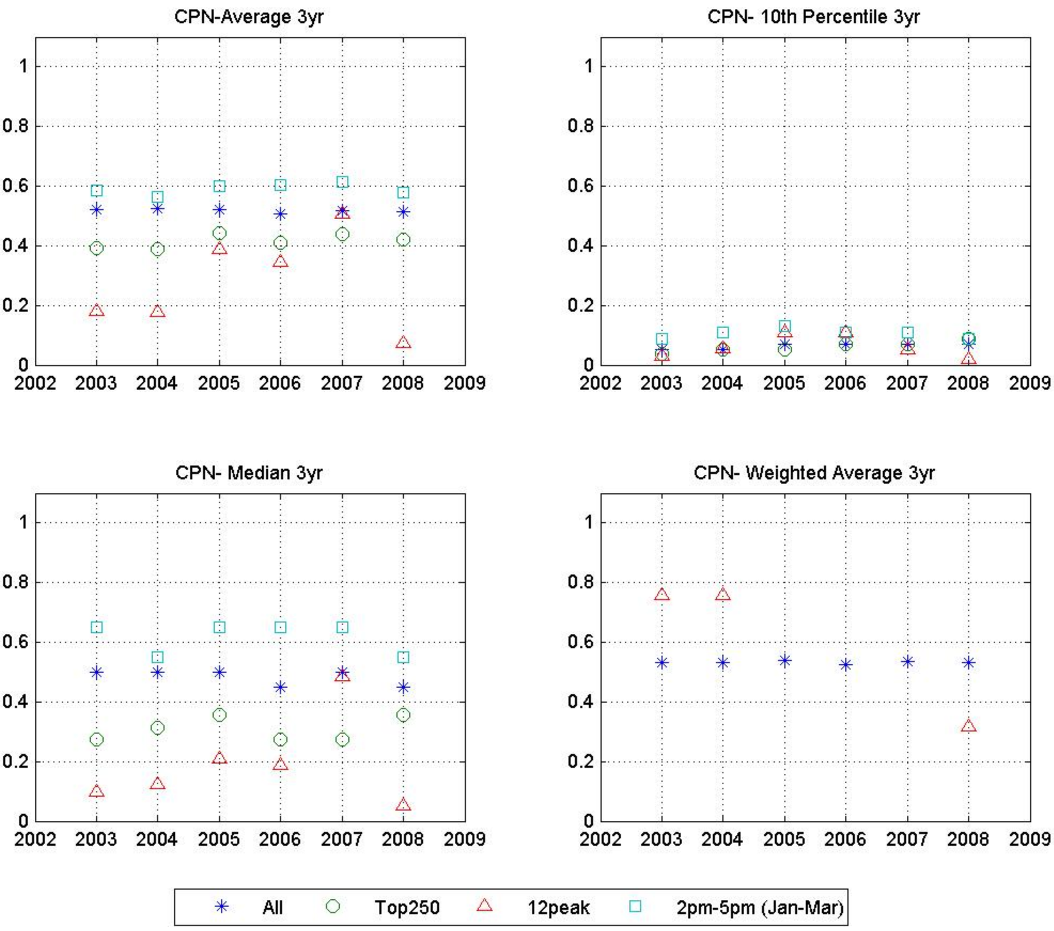

Figure 41: Comparison of results found when calculating Reserve Capacity based on all methodologies for CPN modelled wind generation over three year time frames.

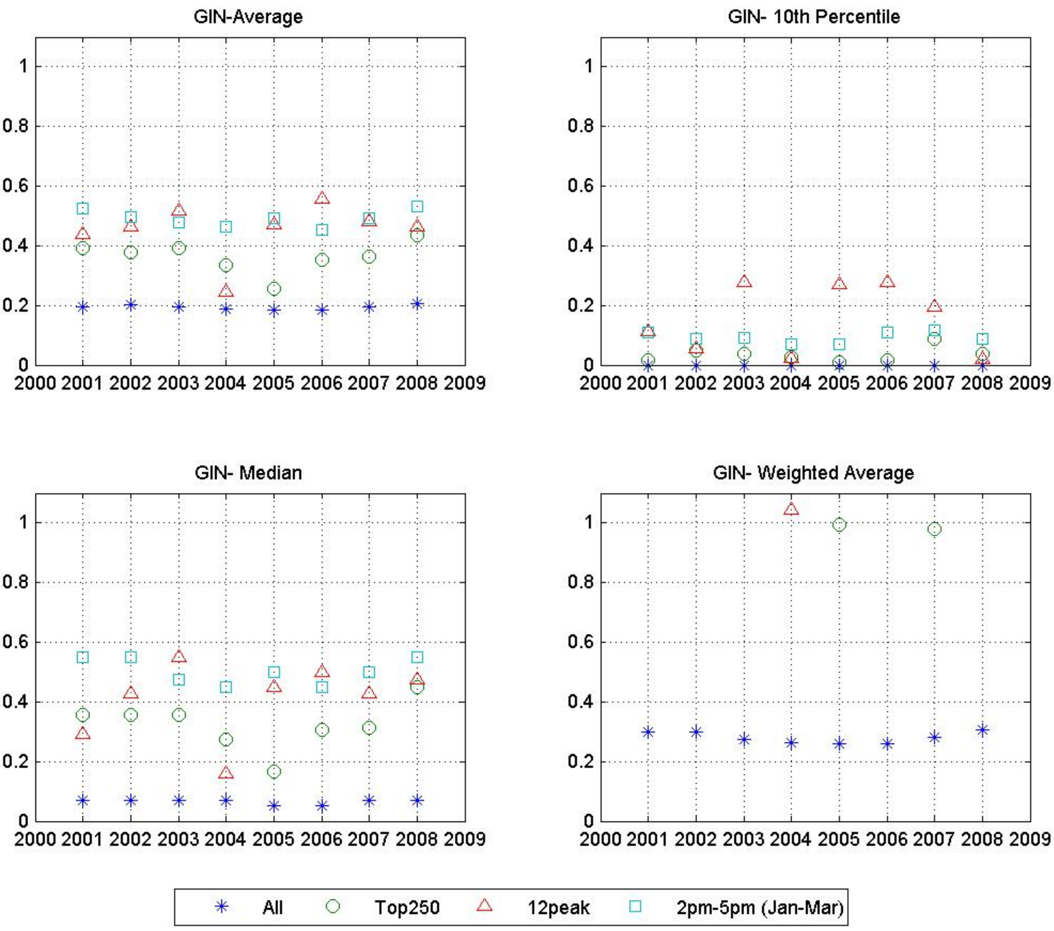

Figure 42: Comparison of results found when calculating Reserve Capacity based on all methodologies for GIN modelled wind generation over single year time frames.

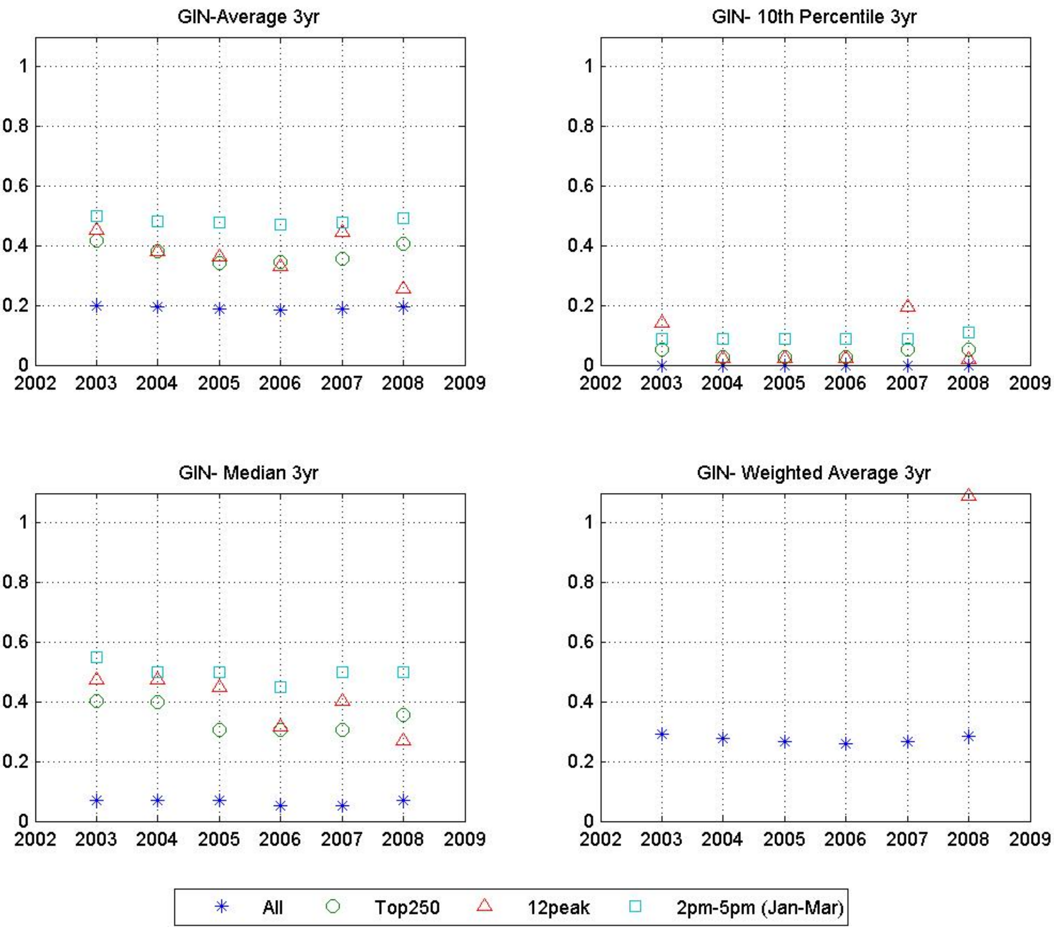

Figure 43: Comparison of results found when calculating Reserve Capacity based on all methodologies for GIN modelled wind generation over three year time frames.

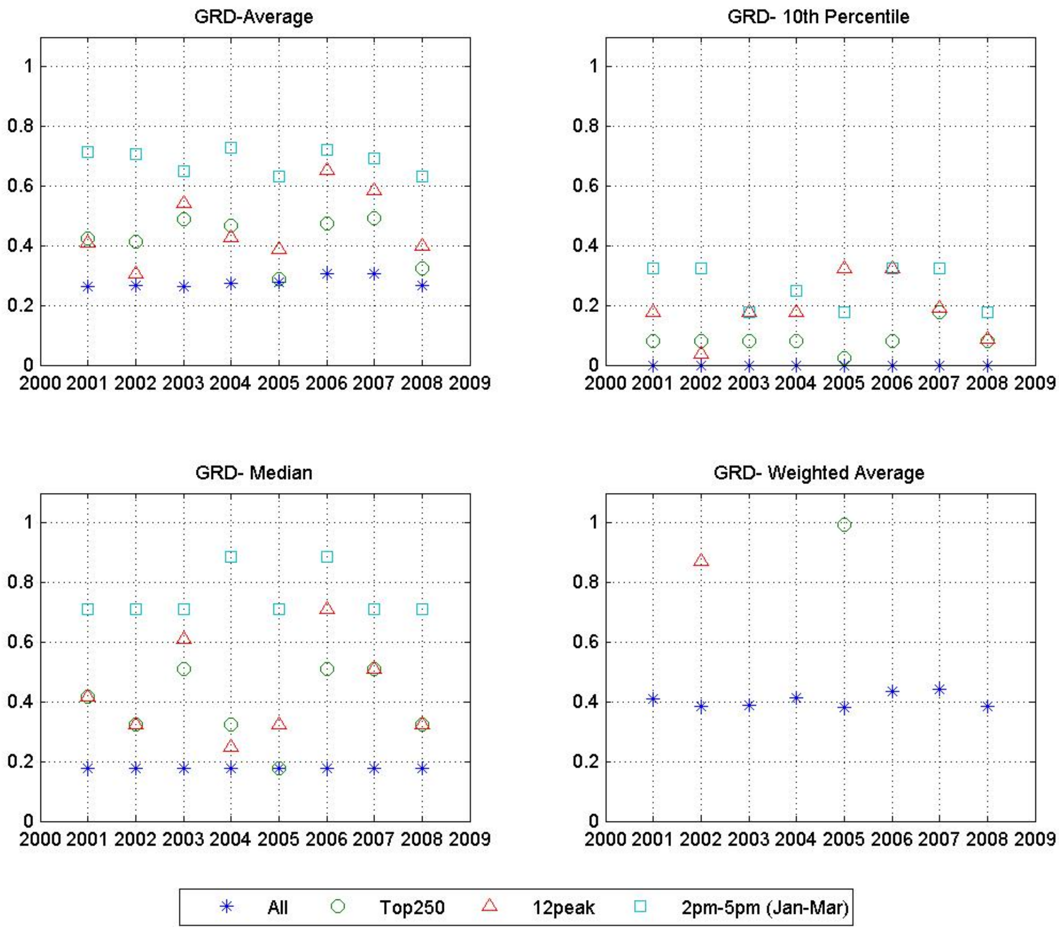

Figure 44: Comparison of results found when calculating Reserve Capacity based on all methodologies for GRD modelled wind generation over single year time frames.

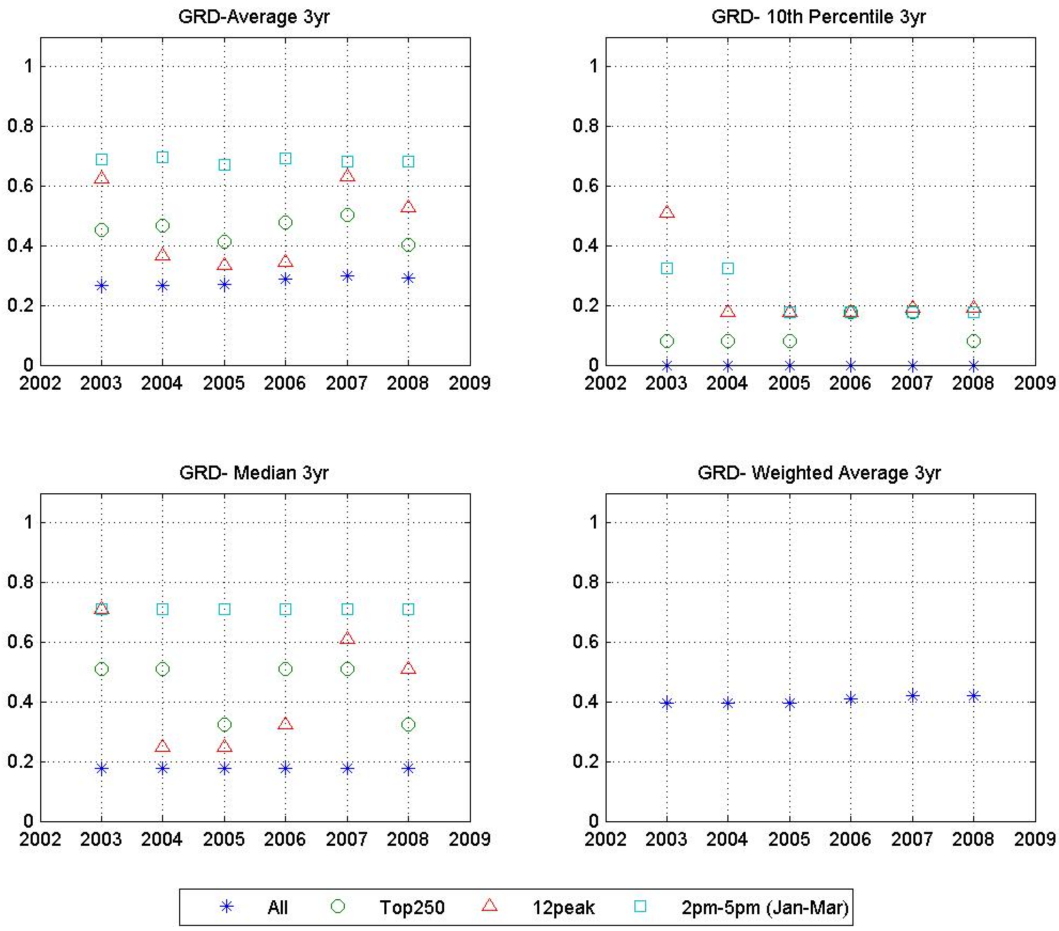

Figure 45: Comparison of results found when calculating Reserve Capacity based on all methodologies for GRD modelled wind generation over three year time frames.

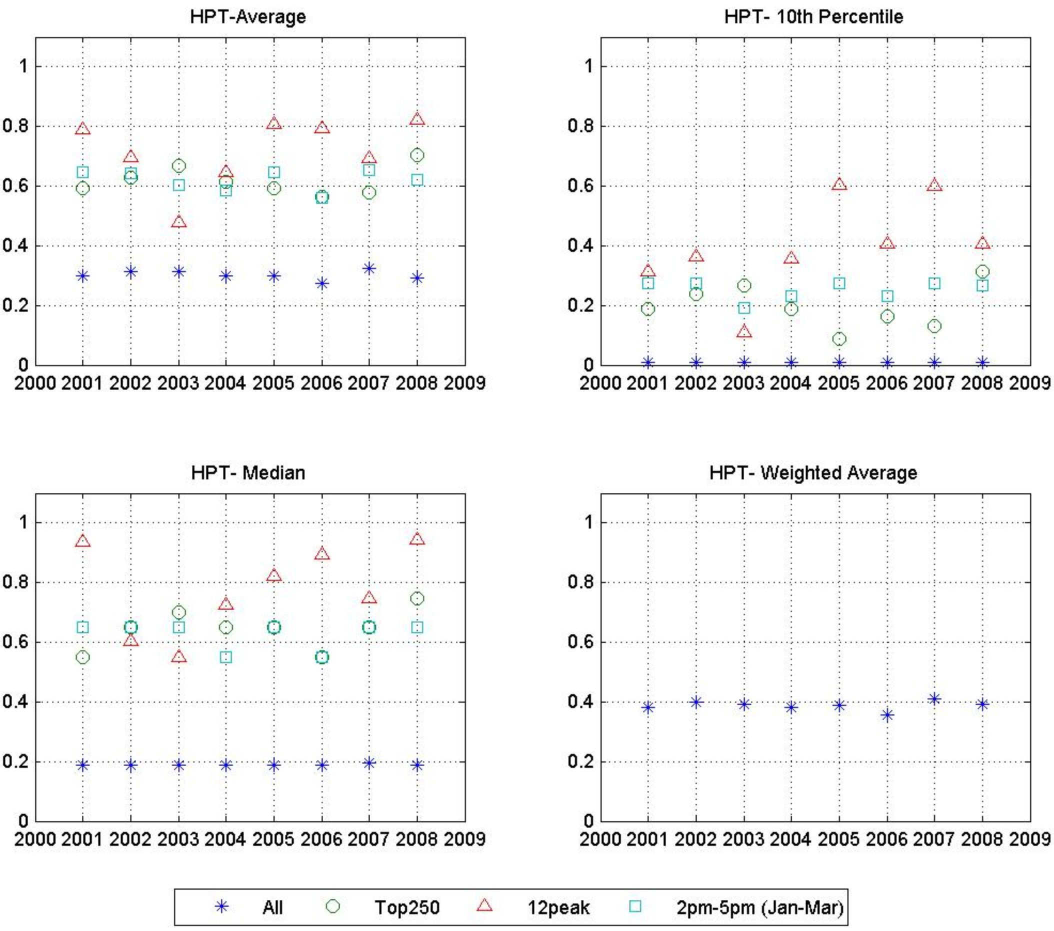

Figure 46: Comparison of results found when calculating Reserve Capacity based on all methodologies for HPT modelled wind generation over single year time frames.

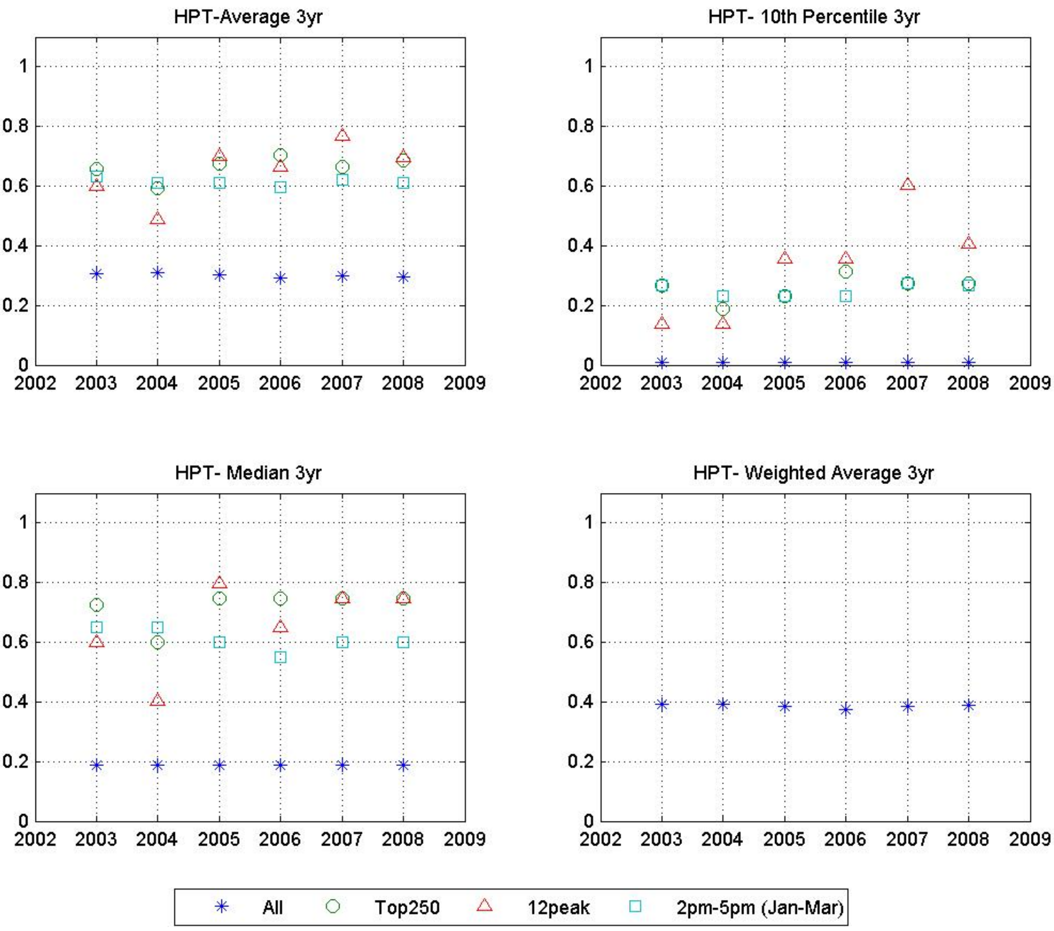

Figure 47: Comparison of results found when calculating Reserve Capacity based on all methodologies for HPT modelled wind generation over three year time frames.

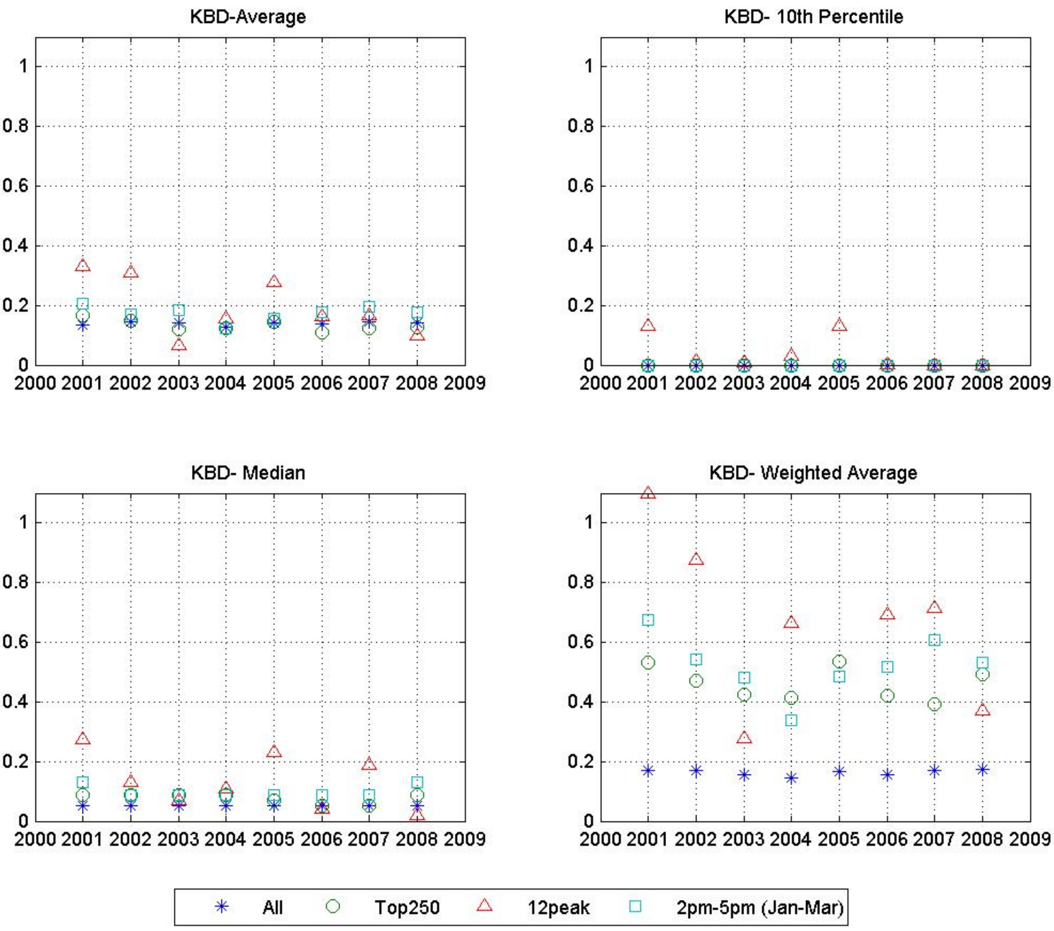

Figure 48: Comparison of results found when calculating Reserve Capacity based on all methodologies for KBD modelled wind generation over single year time frames.

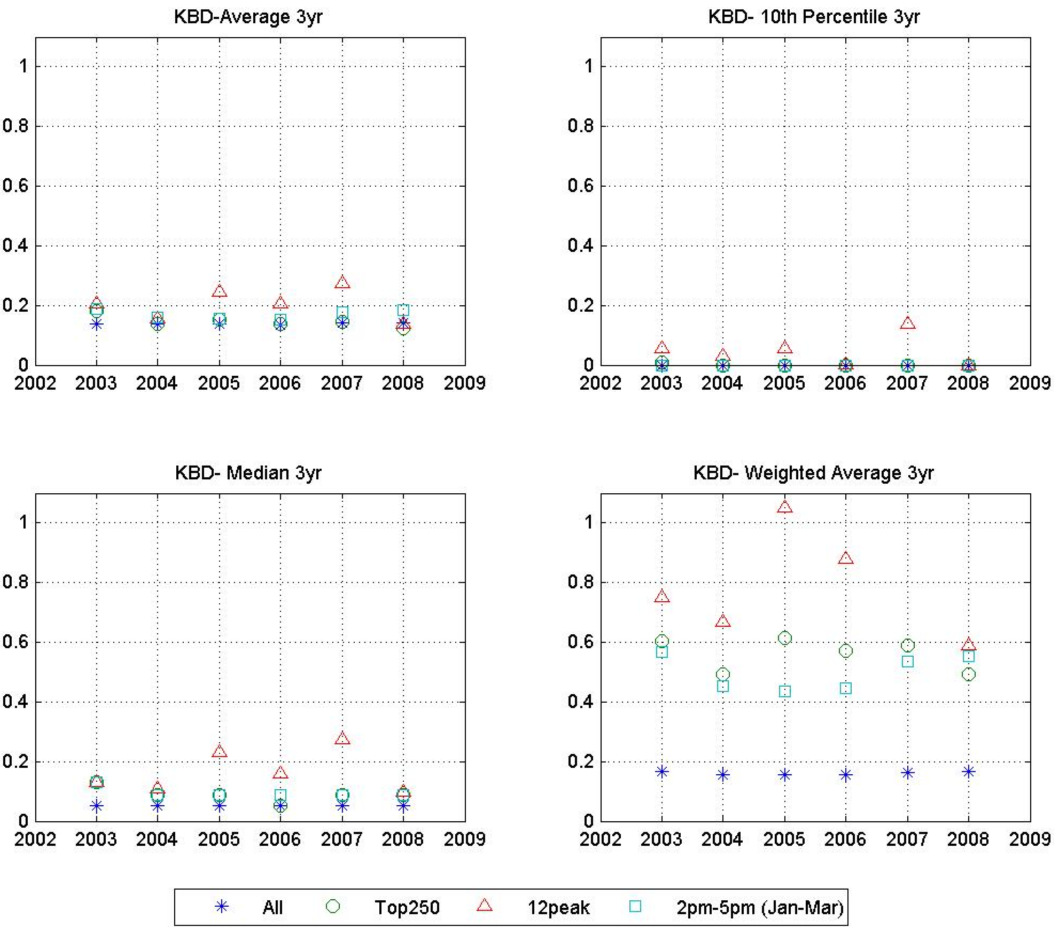

Figure 49: Comparison of results found when calculating Reserve Capacity based on all methodologies for KBD modelled wind generation over three year time frames.

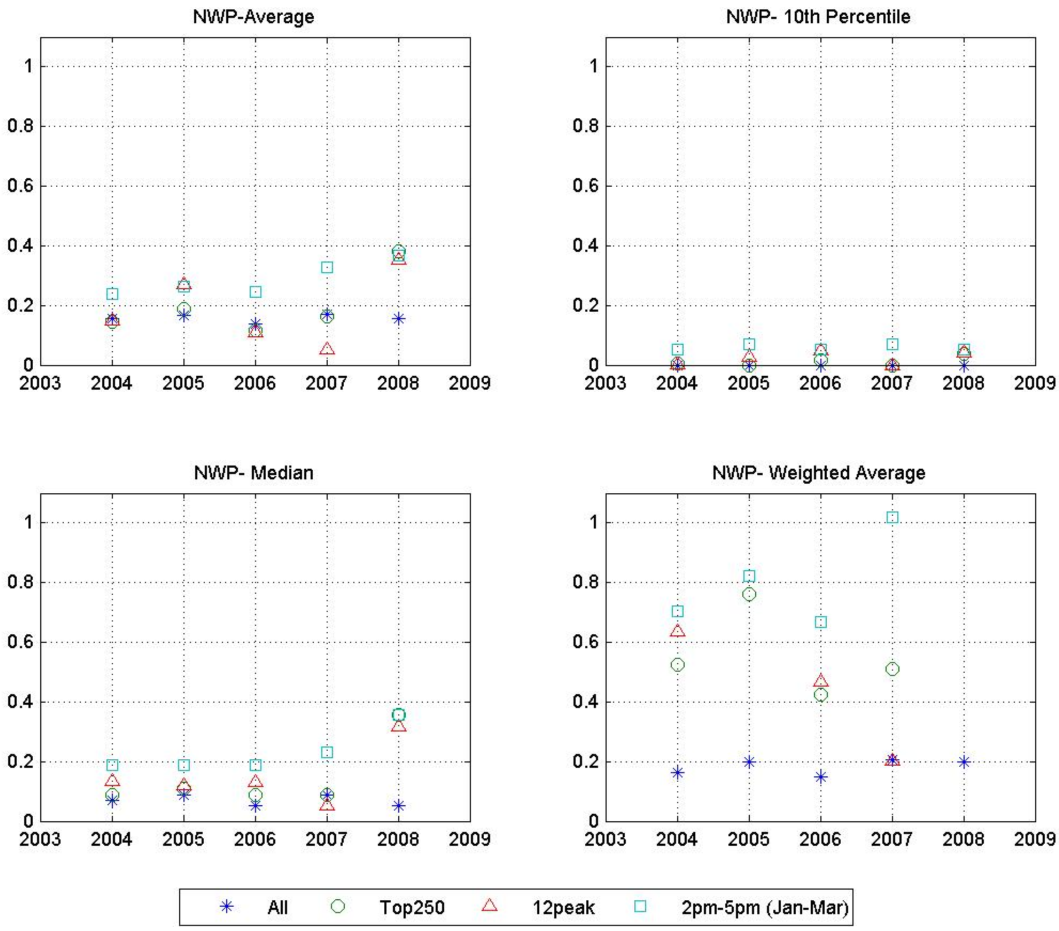

Figure 50: Comparison of results found when calculating Reserve Capacity based on all methodologies for NWP modelled wind generation over single year time frames.

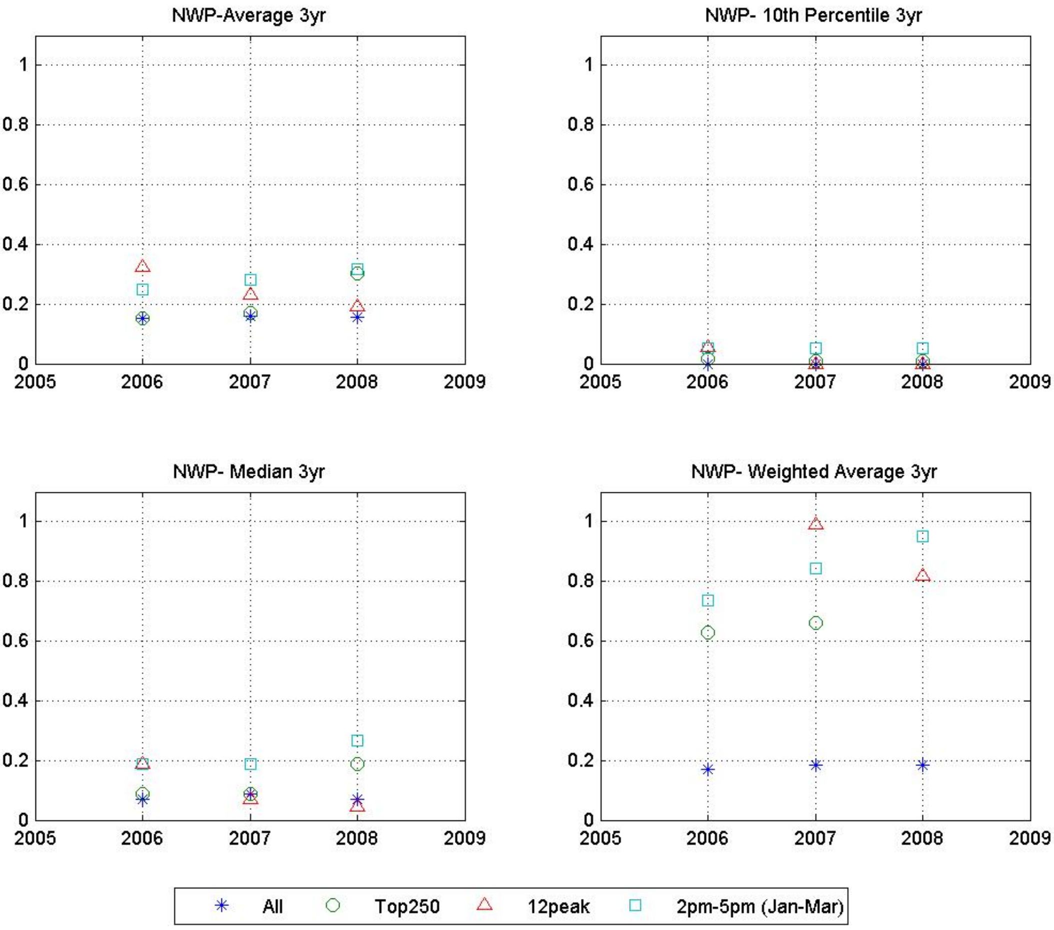

Figure 51: Comparison of results found when calculating Reserve Capacity based on all methodologies for NWP modelled wind generation over three year time frames.

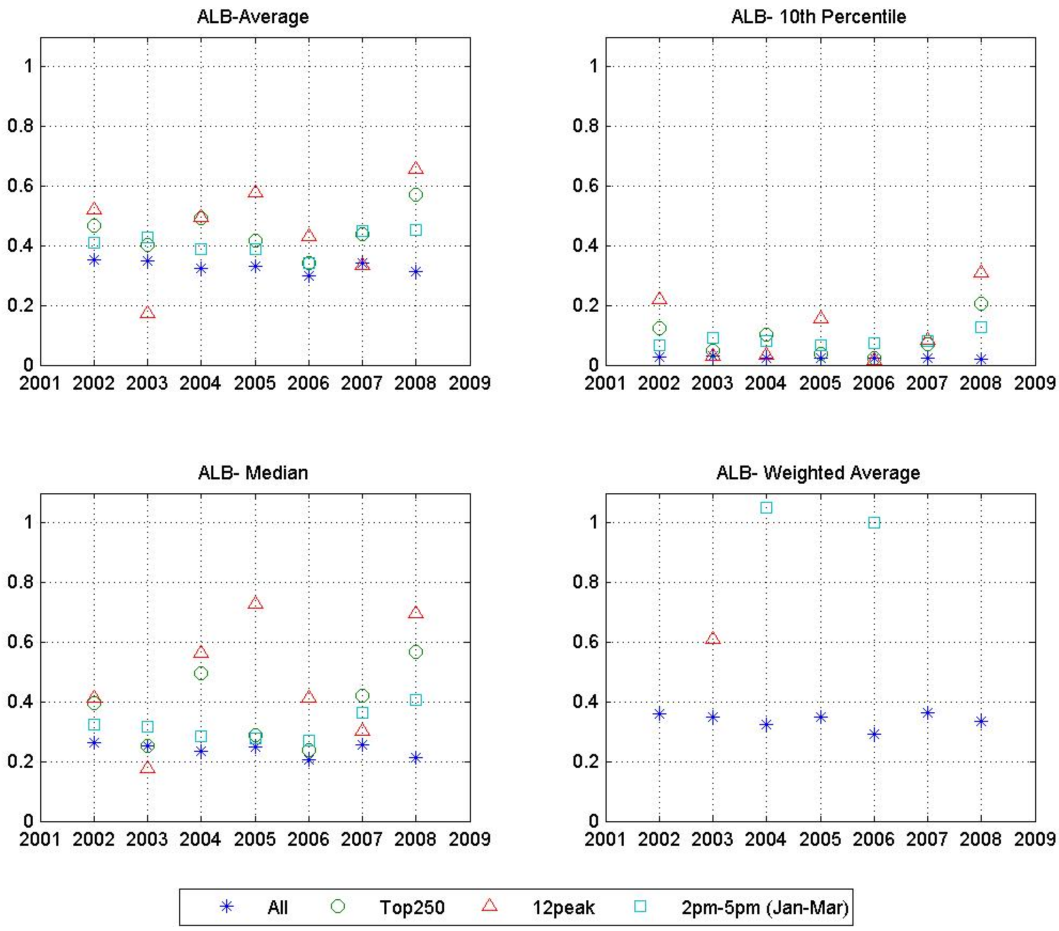

Figure 52: Comparison of results found when calculating Reserve Capacity based on all methodologies for ALB wind generation over single year time frames.

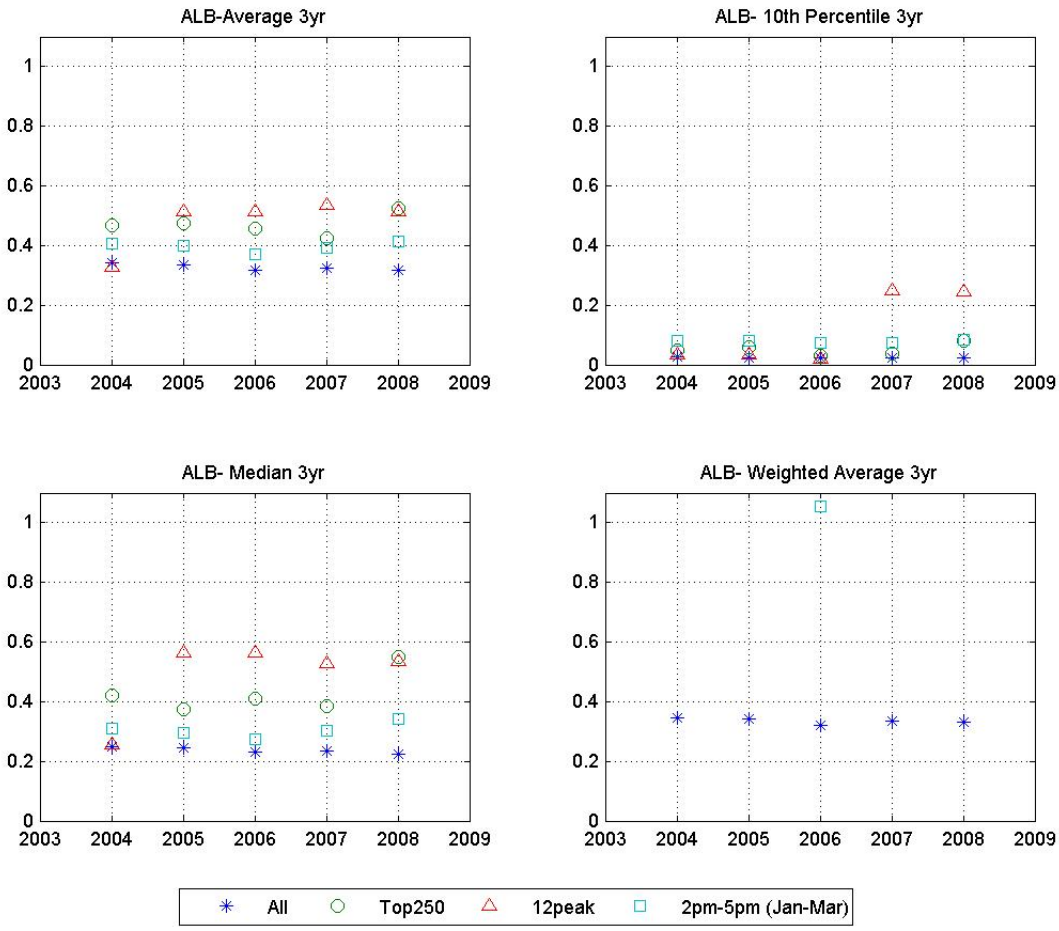

Figure 53: Comparison of results found when calculating Reserve Capacity based on all methodologies for ALB wind generation over three year time frames.

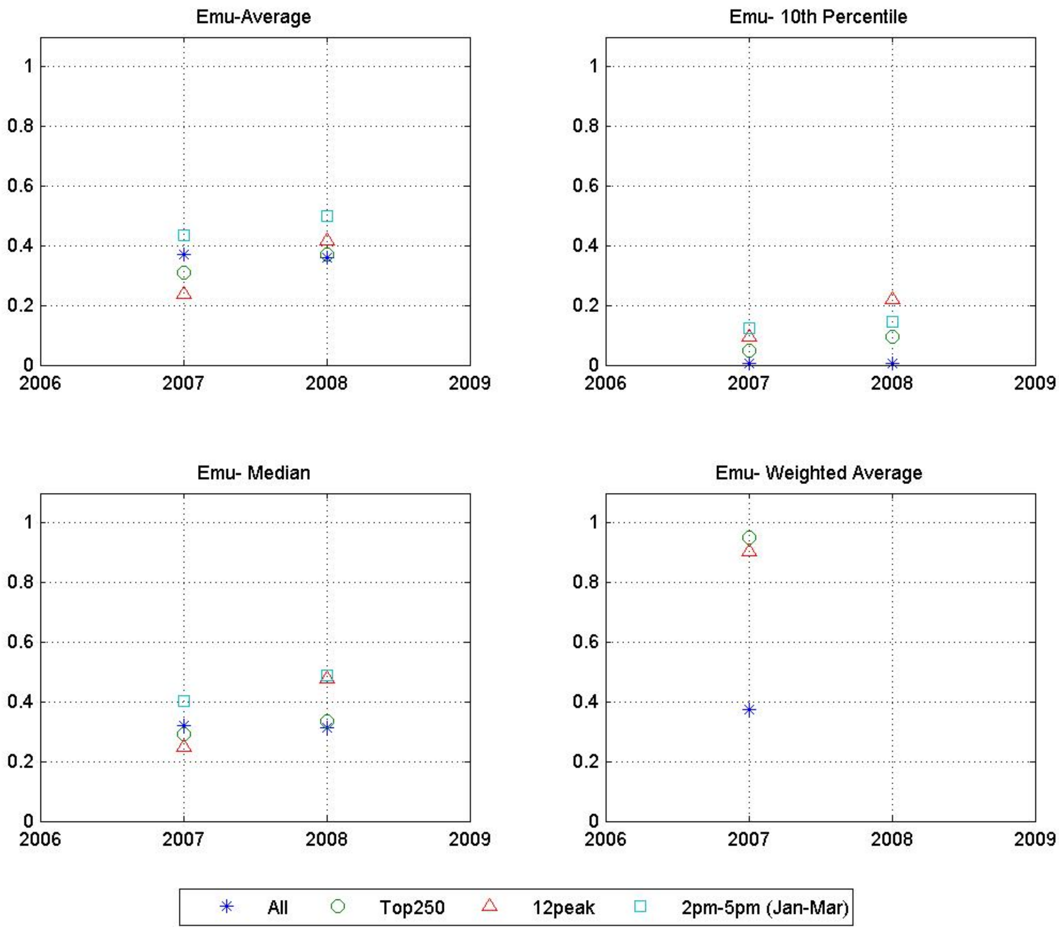

Figure 54: Comparison of results found when calculating Reserve Capacity based on all methodologies for EMU wind generation over single year time frames.

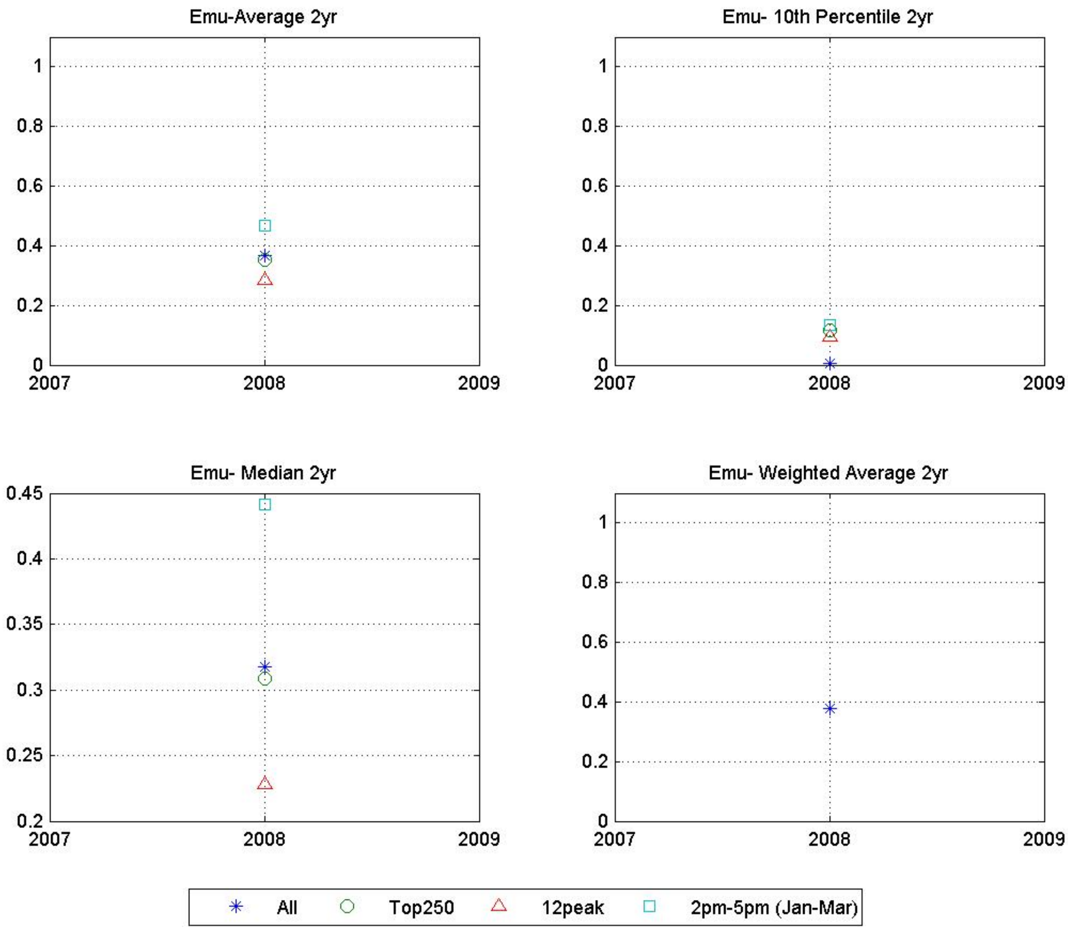

Figure 55: Comparison of results found when calculating Reserve Capacity based on all methodologies for EMU wind generation over three year time frames.

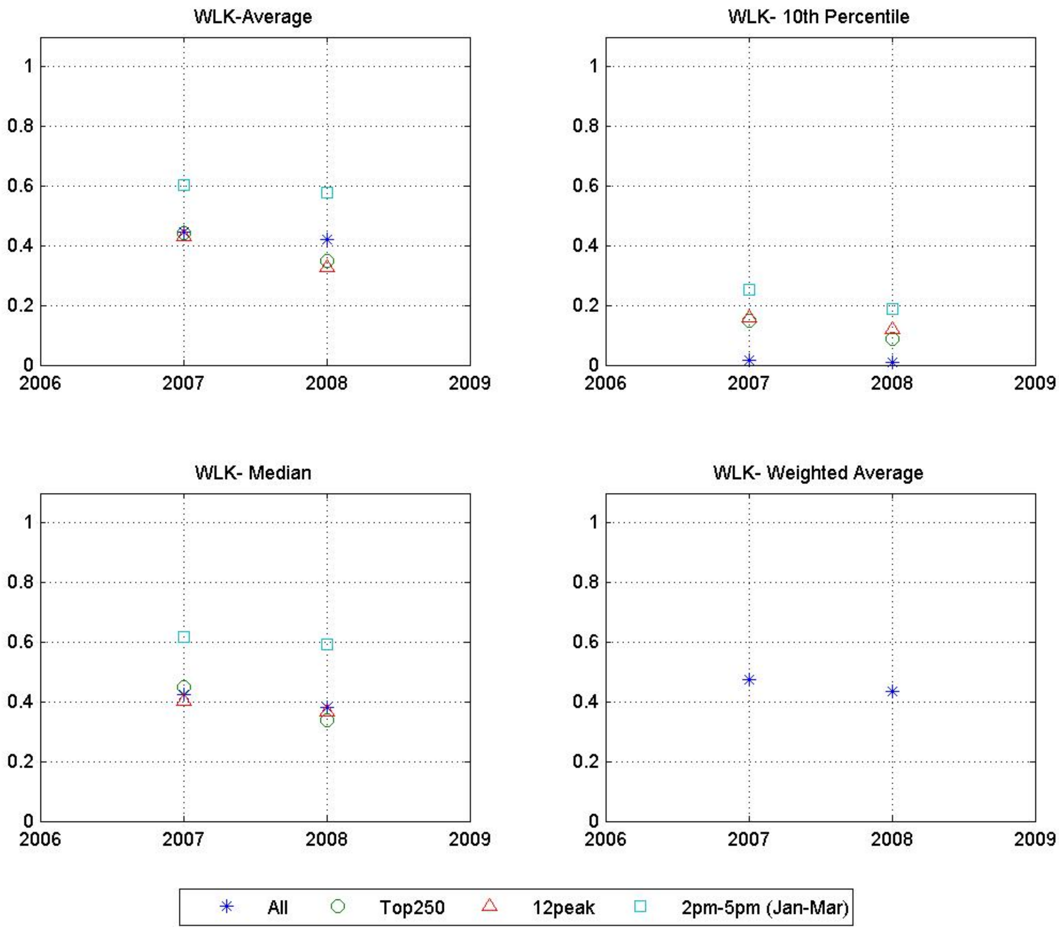

Figure 56: Comparison of results found when calculating Reserve Capacity based on all methodologies for WLK wind generation over single year time frames

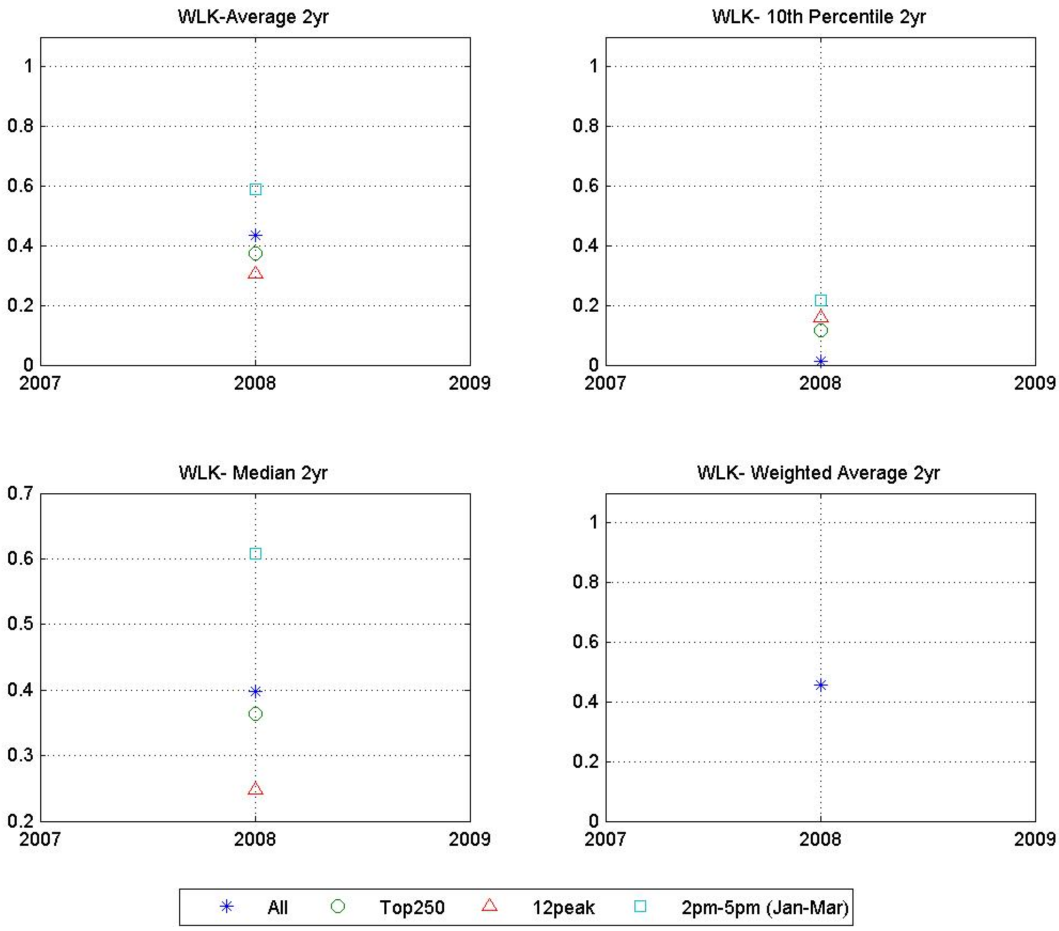

Figure 57: Comparison of results found when calculating Reserve Capacity based on all methodologies for WLK wind generation over three year time frames.

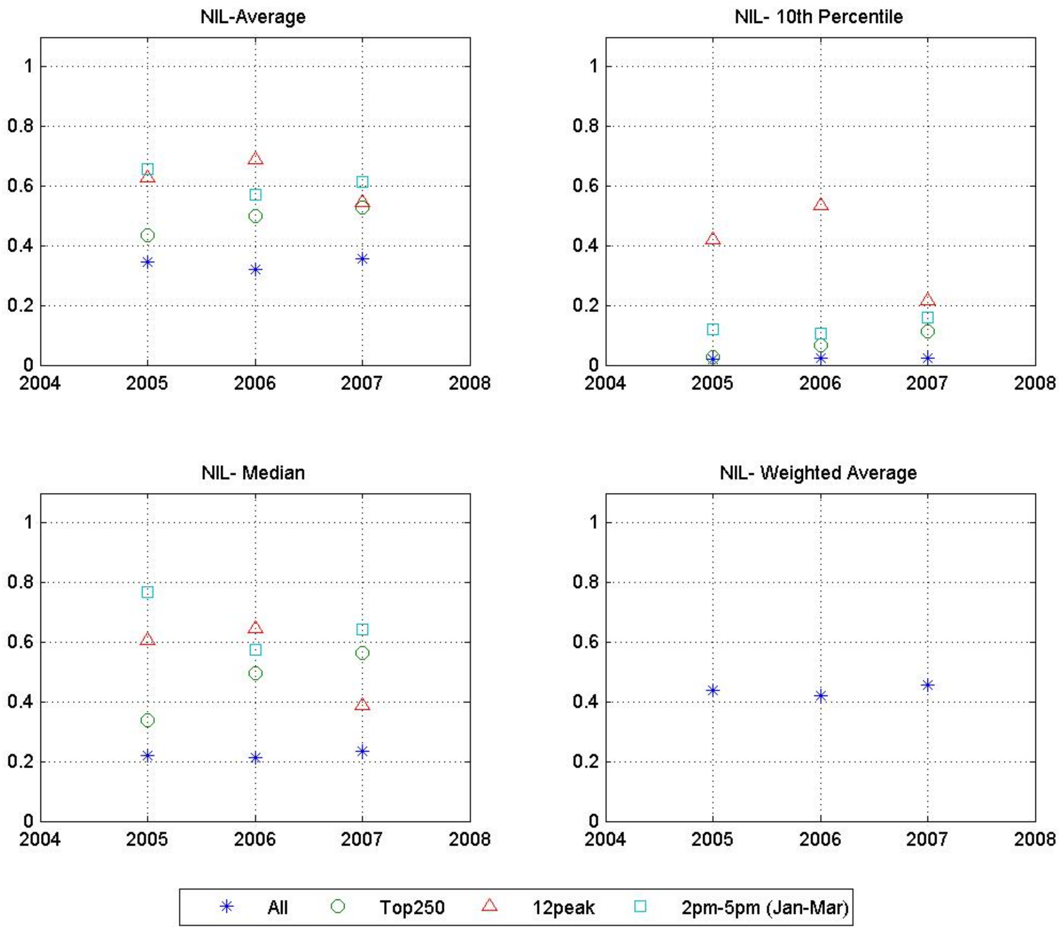

Figure 58: Comparison of results found when calculating Reserve Capacity based on all methodologies for NIL wind generation over single year time frames.

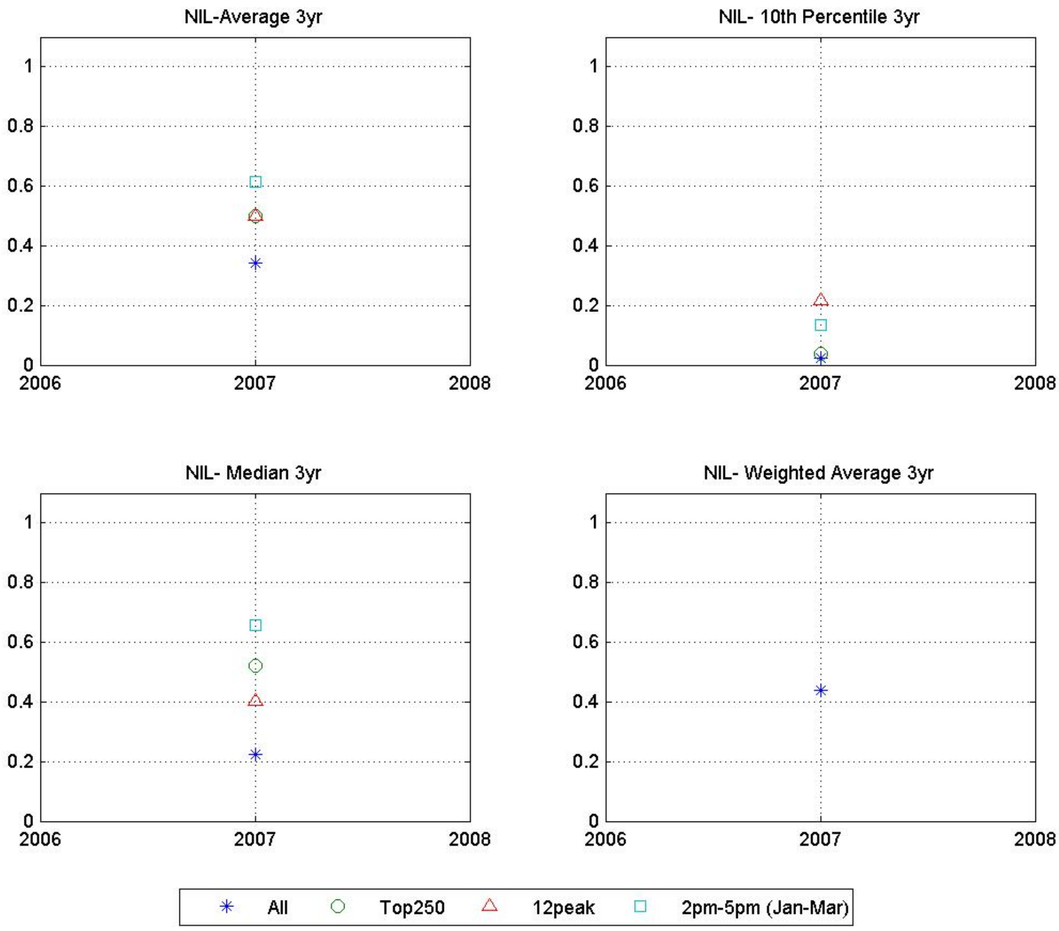

Figure 59: Comparison of results found when calculating Reserve Capacity based on all methodologies for NIL wind generation over three year time frames.

13.2 Appendix C2: Individual Site Results – Landfill Gas Generation

As discussed, results are shown for single year and three year time frames for landfill gas generation sites. Where years are noted on each plot for three year time frames reference is being made to the year in which the time frame ends.

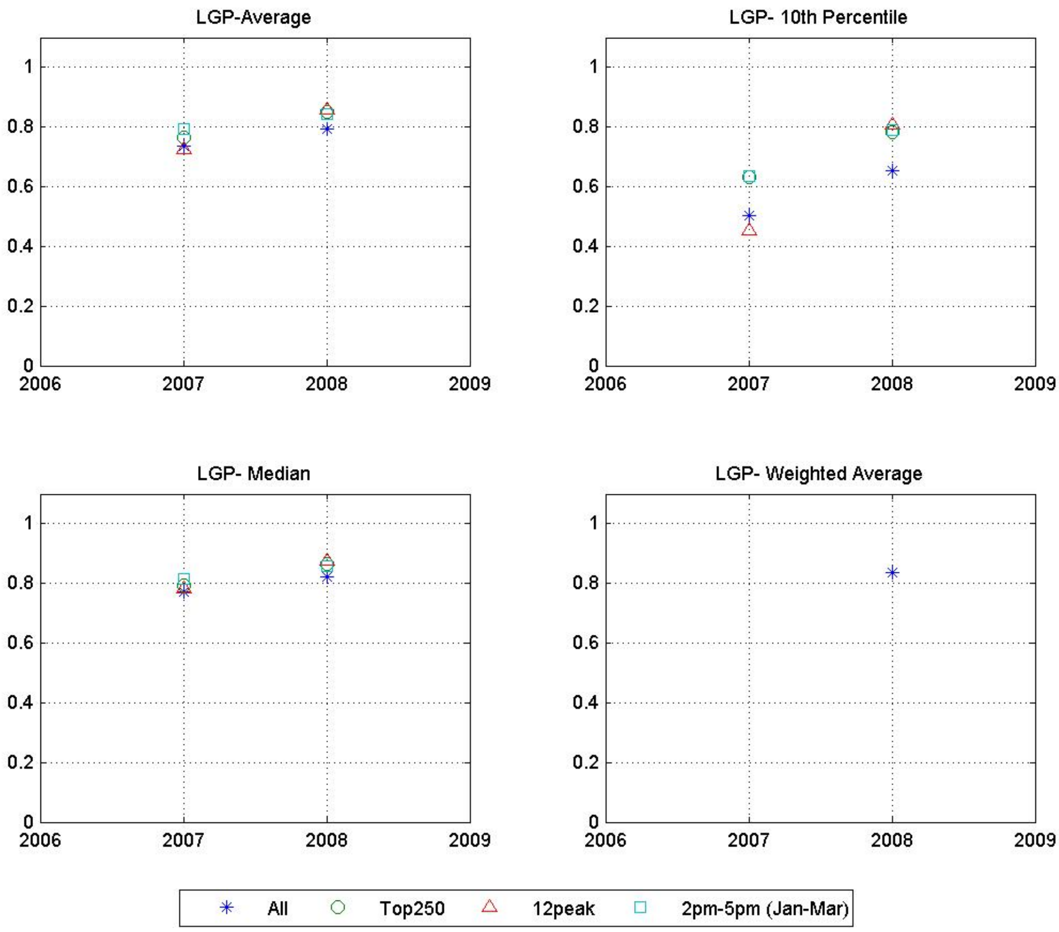

Figure 60: Comparison of results found when calculating Reserve Capacity based on all methodologies for LGP landfill gas generation over single year time frames.

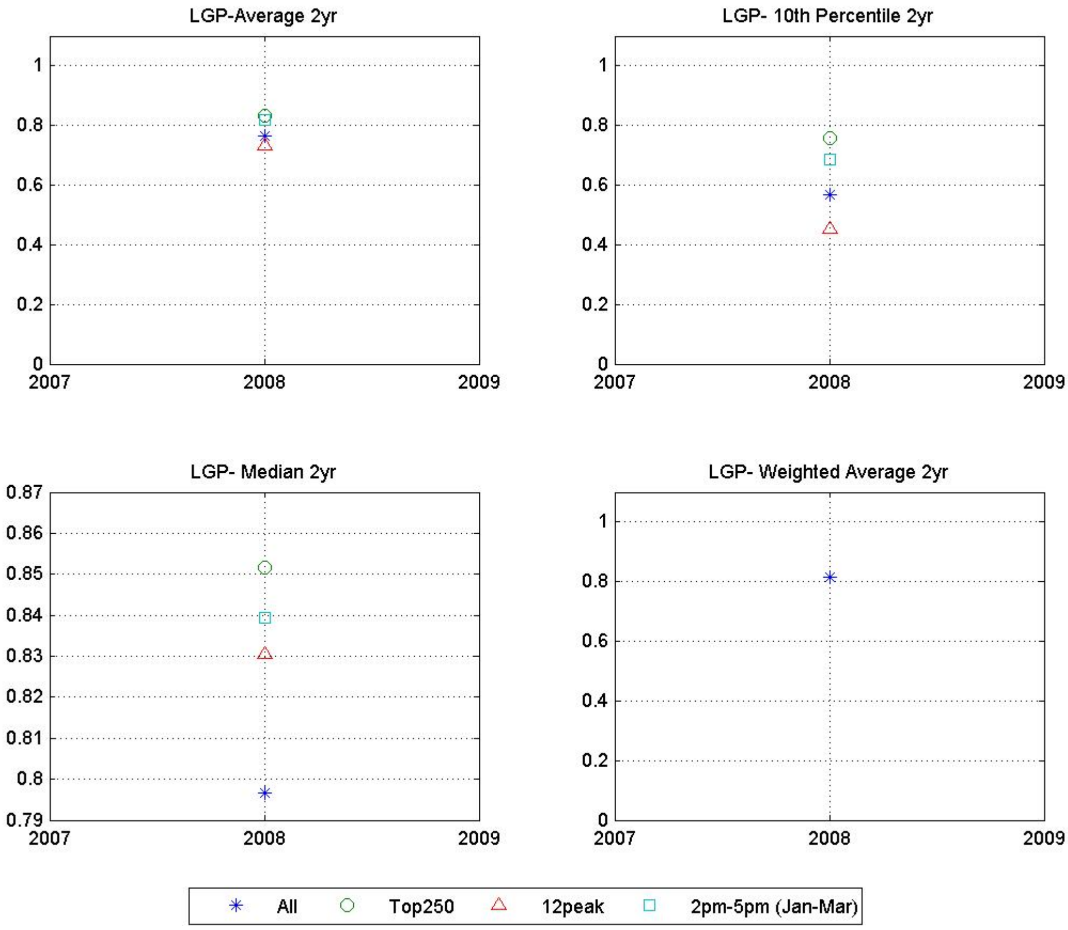

Figure 61: Comparison of results found when calculating Reserve Capacity based on all methodologies for LGP landfill gas generation over three year time frames.

13.3 Appendix C3: Individual Site Results – Solar Thermal Generation

As discussed, results are shown for single year and three year time frames for solar thermal generation sites. Where years are noted on each plot for three year time frames reference is being made to the year in which the time frame ends.

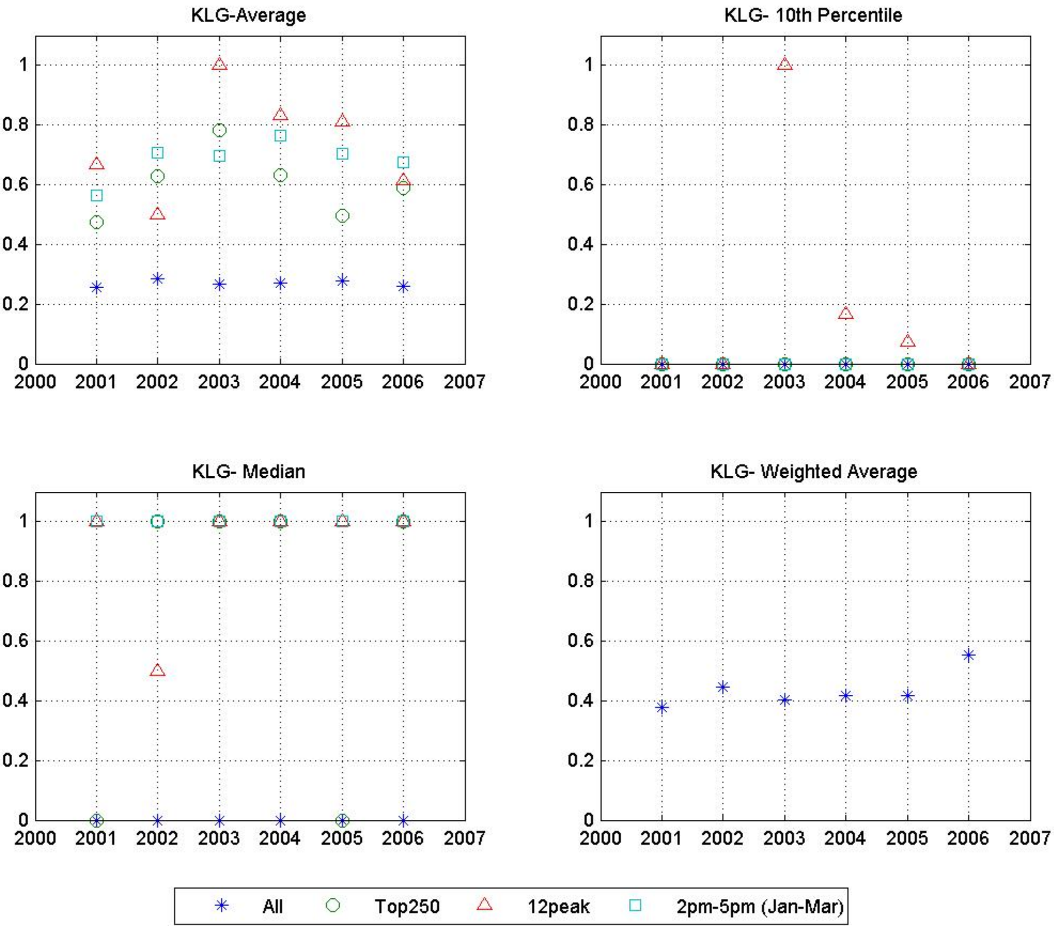

Figure 62: Comparison of results found when calculating Reserve Capacity based on all methodologies for KLG solar thermal generation over single year time frames.

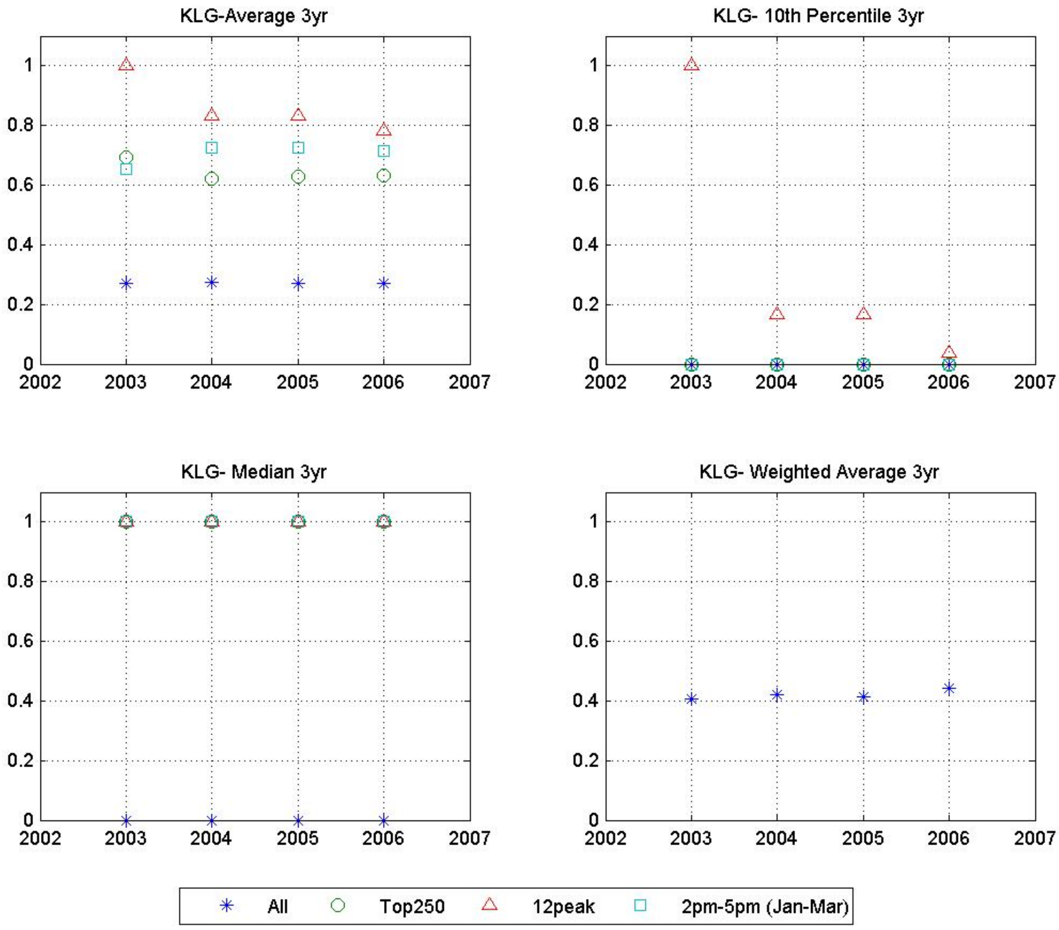

Figure 63: Comparison of results found when calculating Reserve Capacity based on all methodologies for KLG solar thermal generation over three year time frames.

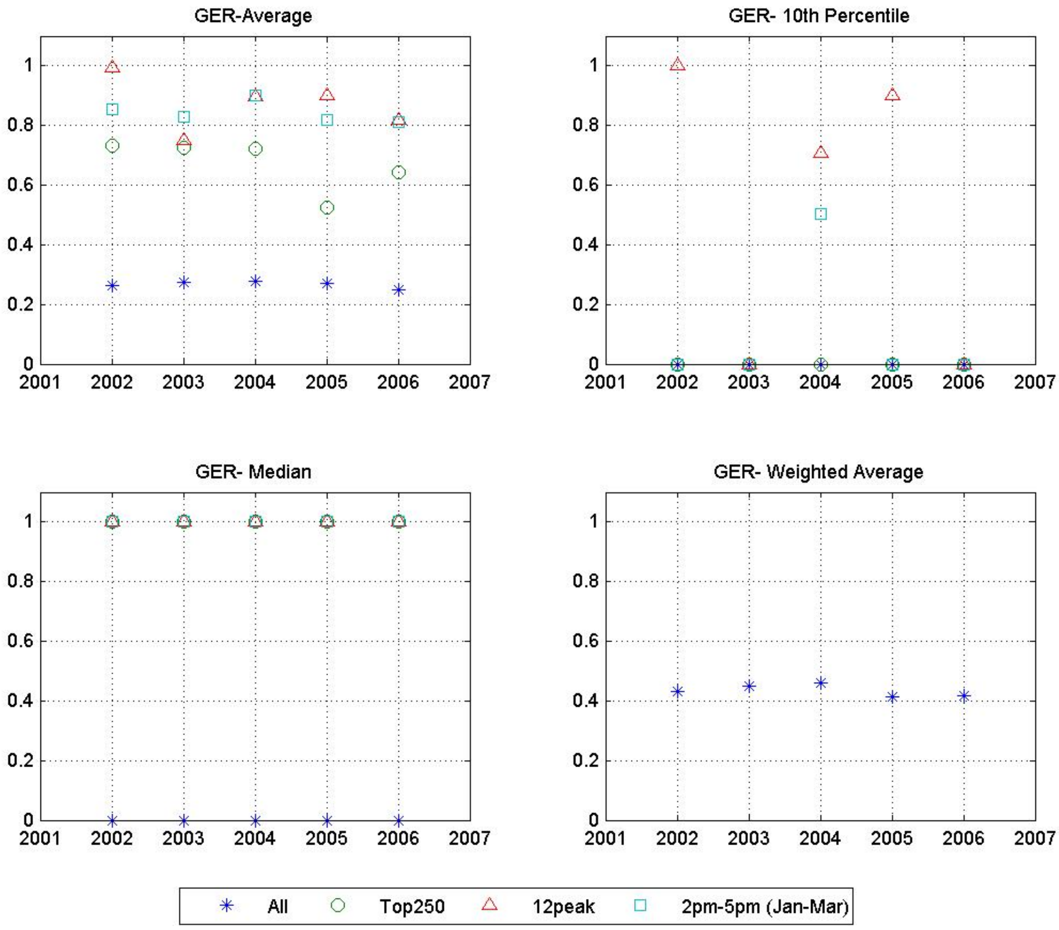

Figure 64: Comparison of results found when calculating Reserve Capacity based on all methodologies for GER solar thermal generation over single year time frames.

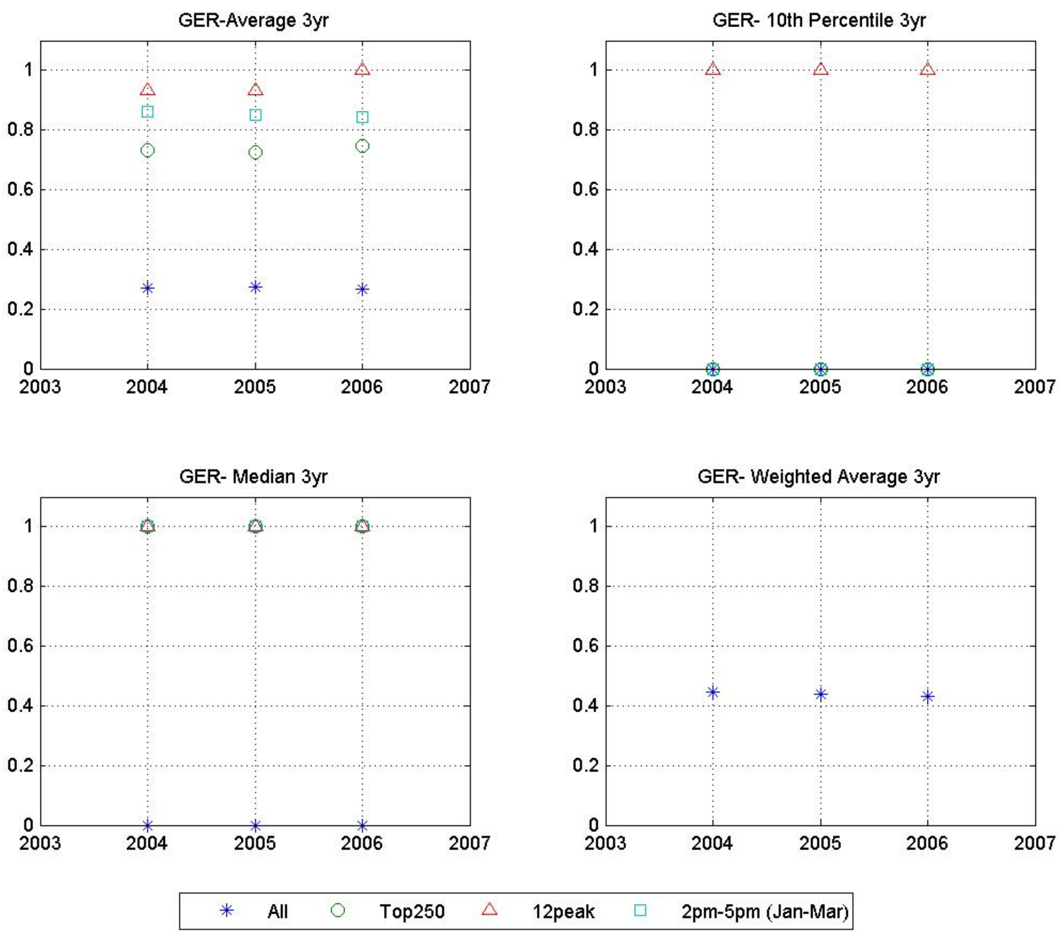

Figure 65: Comparison of results found when calculating Reserve Capacity based on all methodologies for GER solar thermal generation over three year time frames.

13.4 Appendix C4: Solar Thermal Generation with Thermal Storage

As discussed in Section 5.5.4 as one of the secondary calculations included in the study considerations have been made for solar thermal generation which includes the option for four hours of thermal storage. The resulting Reserve Capacity allocations are displayed below.

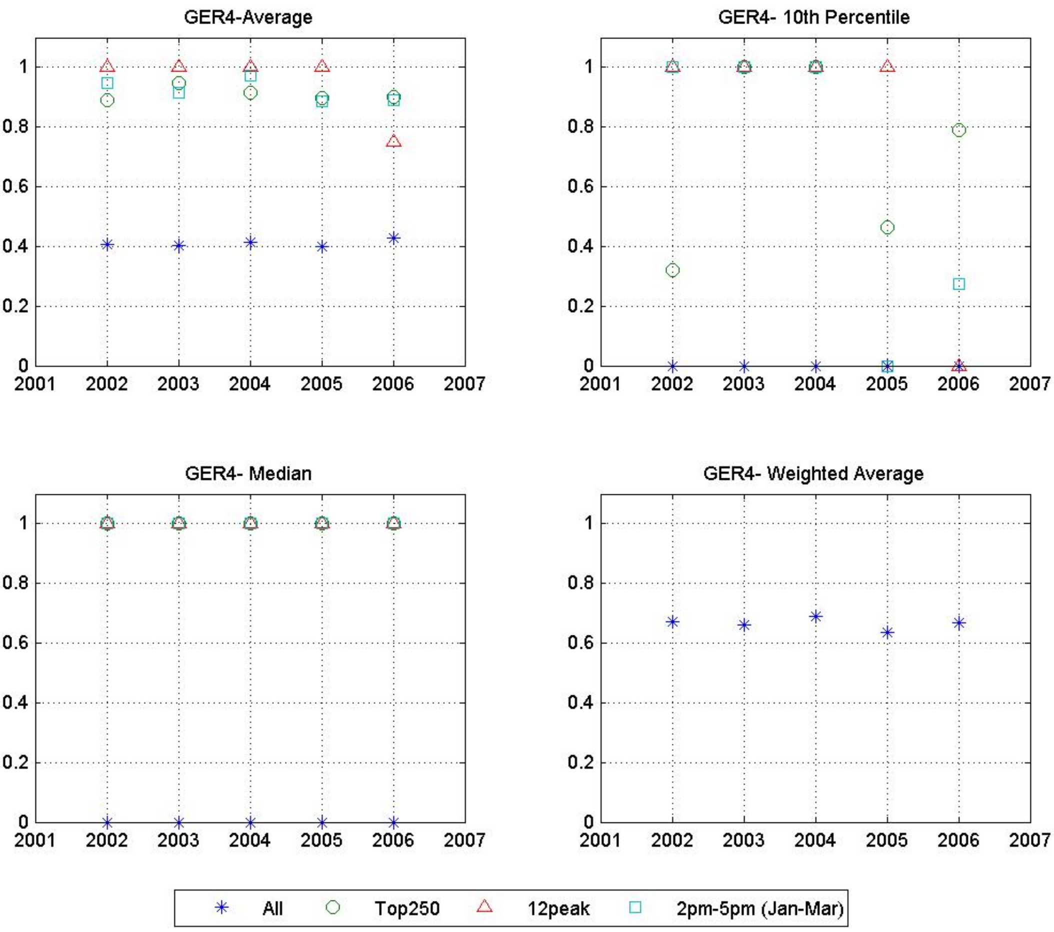

Figure 66: Comparison of results found when calculating Reserve Capacity based on all methodologies for GER solar thermal generation over single year time frames when considering thermal storage potential for four hours of generation without effective irradiance.

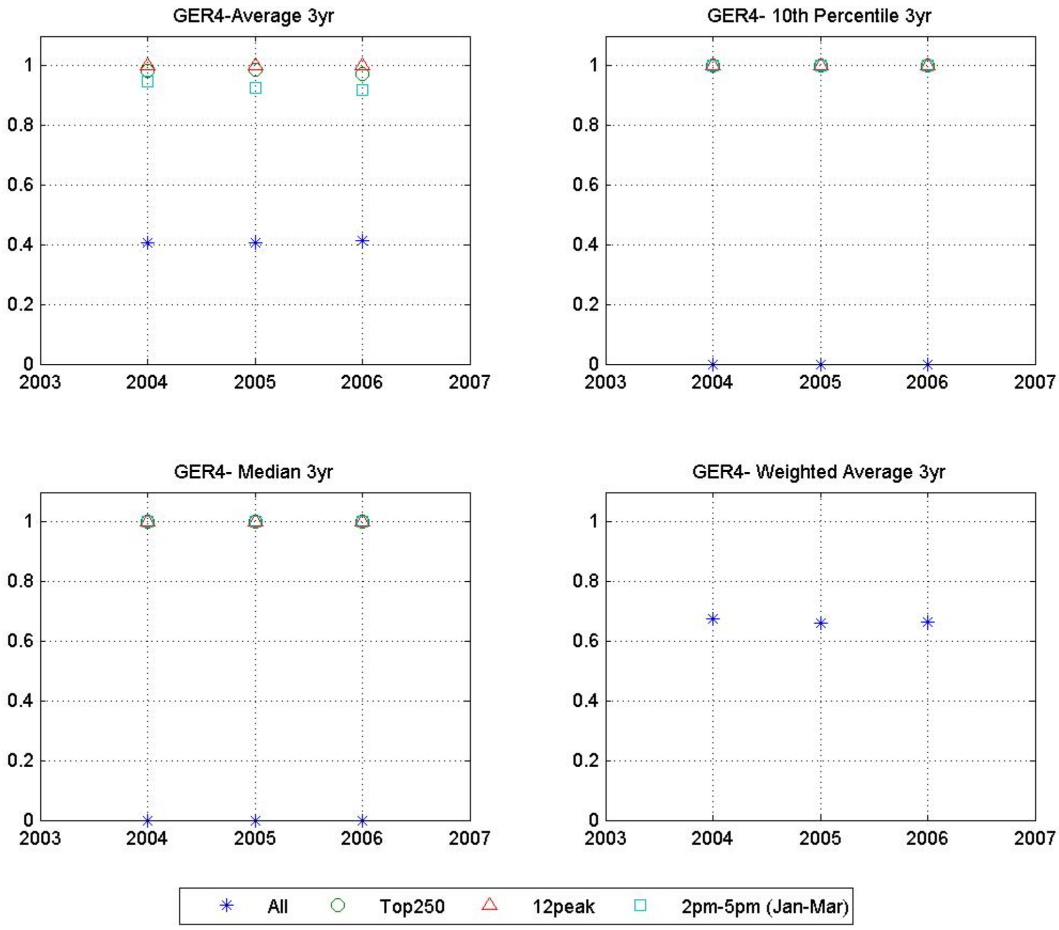

Figure 67: Comparison of results found when calculating Reserve Capacity based on all methodologies for GER solar thermal generation over three year time frames when considering thermal storage potential for four hours of generation without effective irradiance.

13.5 Appendix C5: Individual Site Results – Fleet Generation

As discussed, results are shown for single year and three year time frames for all fleet sites. Where years are noted on each plot for three year time frames reference is being made to the year in which the time frame ends.

The following results are grouped according to each fleet utilised and as defined in Section 3.6.

13.5.1 Wind Fleet 1: 2002 – 2006

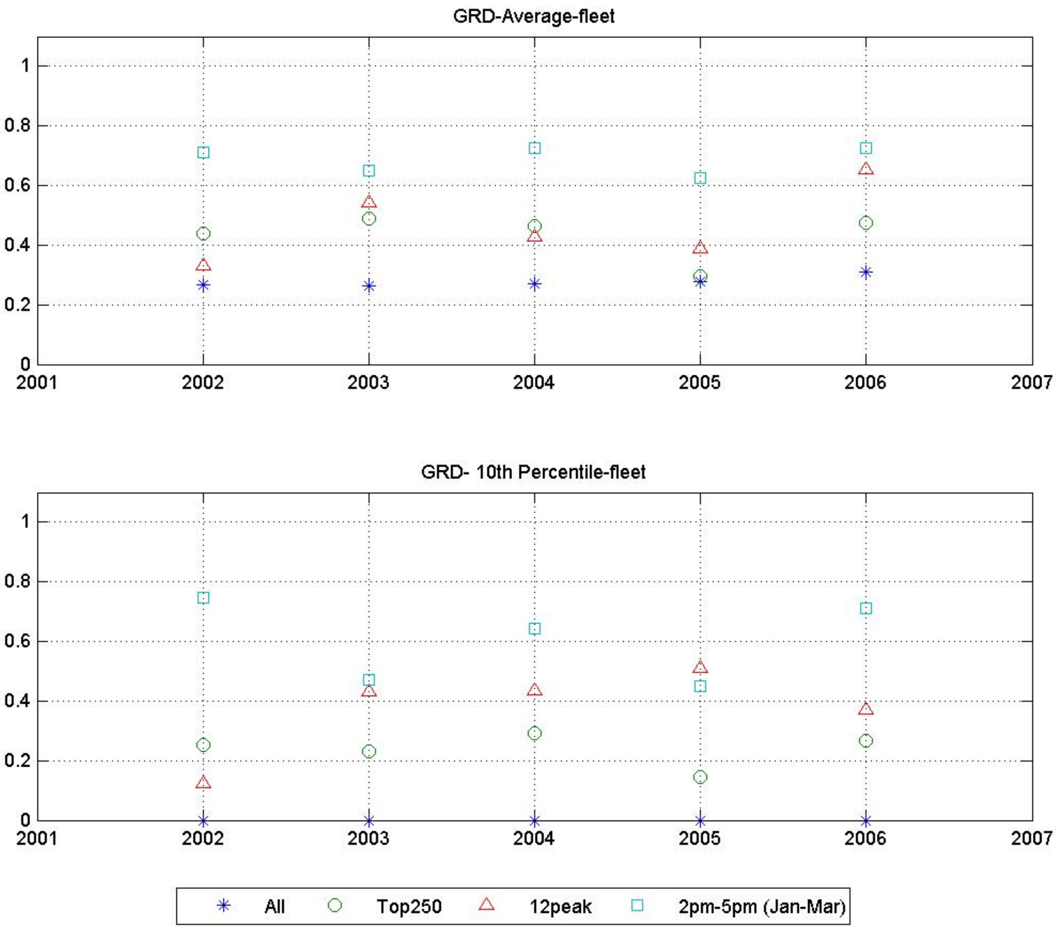

Figure 68: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for GRD modelled wind generation over single year time frames as a contributory to Wind Fleet 1.

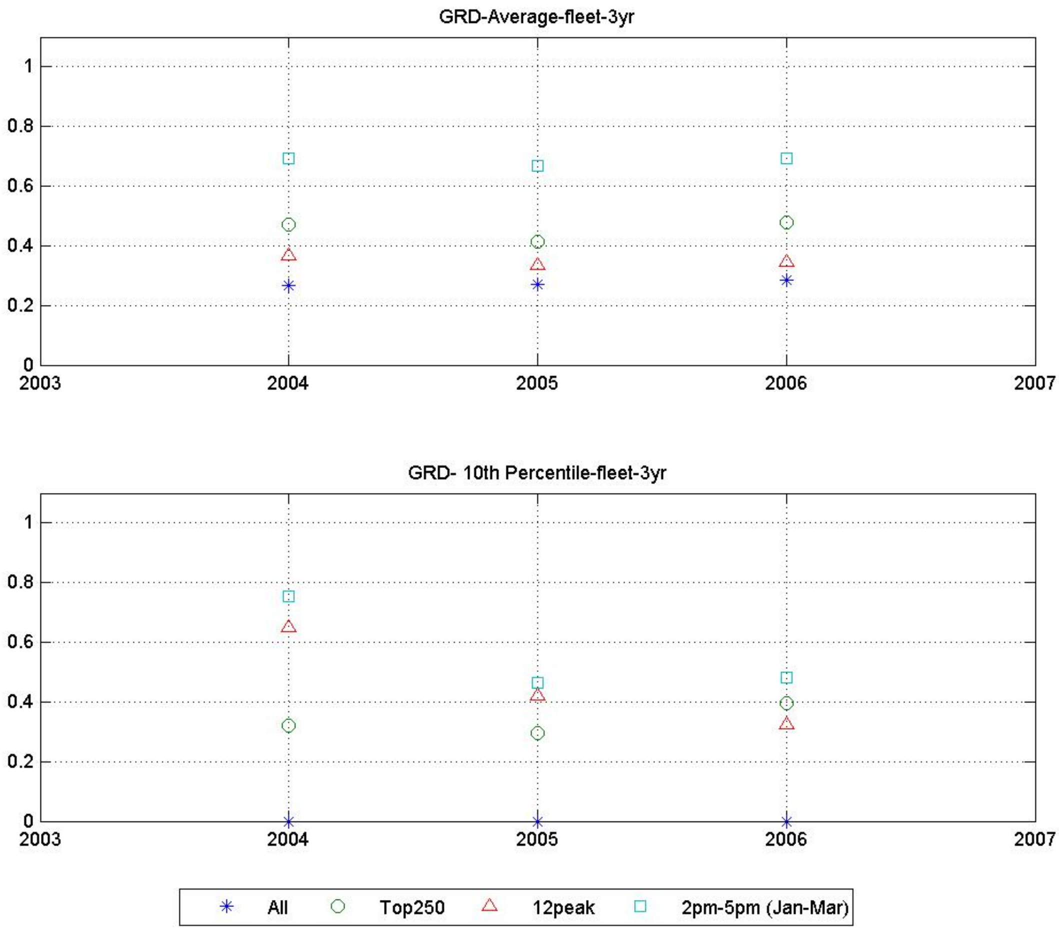

Figure 69: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for GRD modelled wind generation over three year time frames as a contributory to Wind Fleet 1.

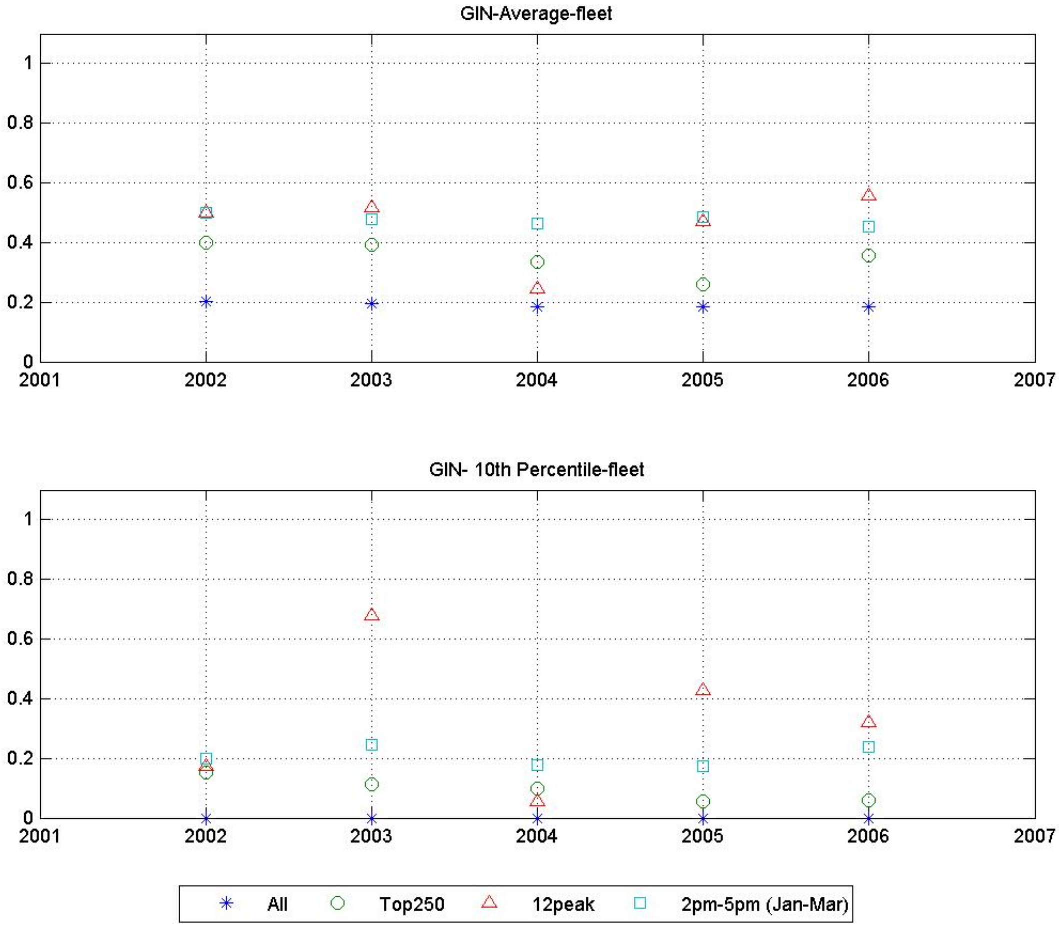

Figure 70: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for GIN modelled wind generation over single year time frames as a contributory to Wind Fleet 1.

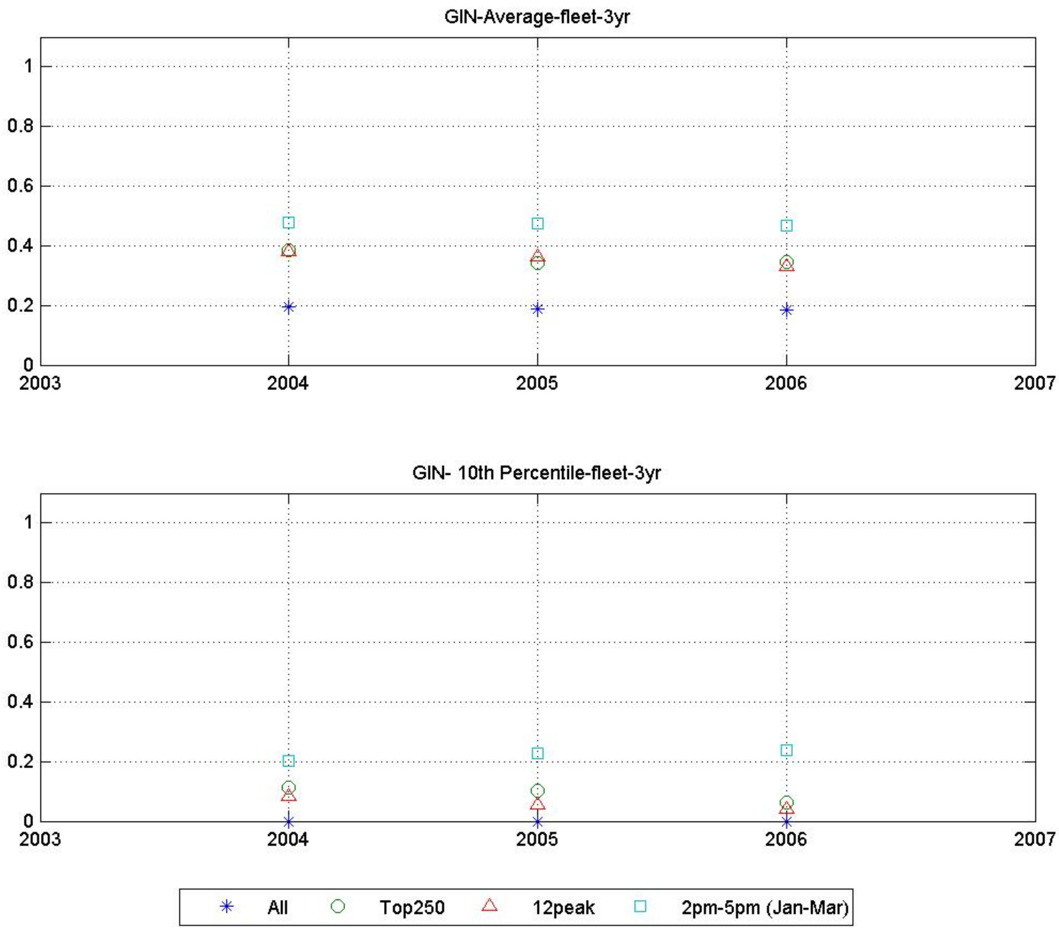

Figure 71: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for GIN modelled wind generation over three year time frames as a contributory to Wind Fleet 1.

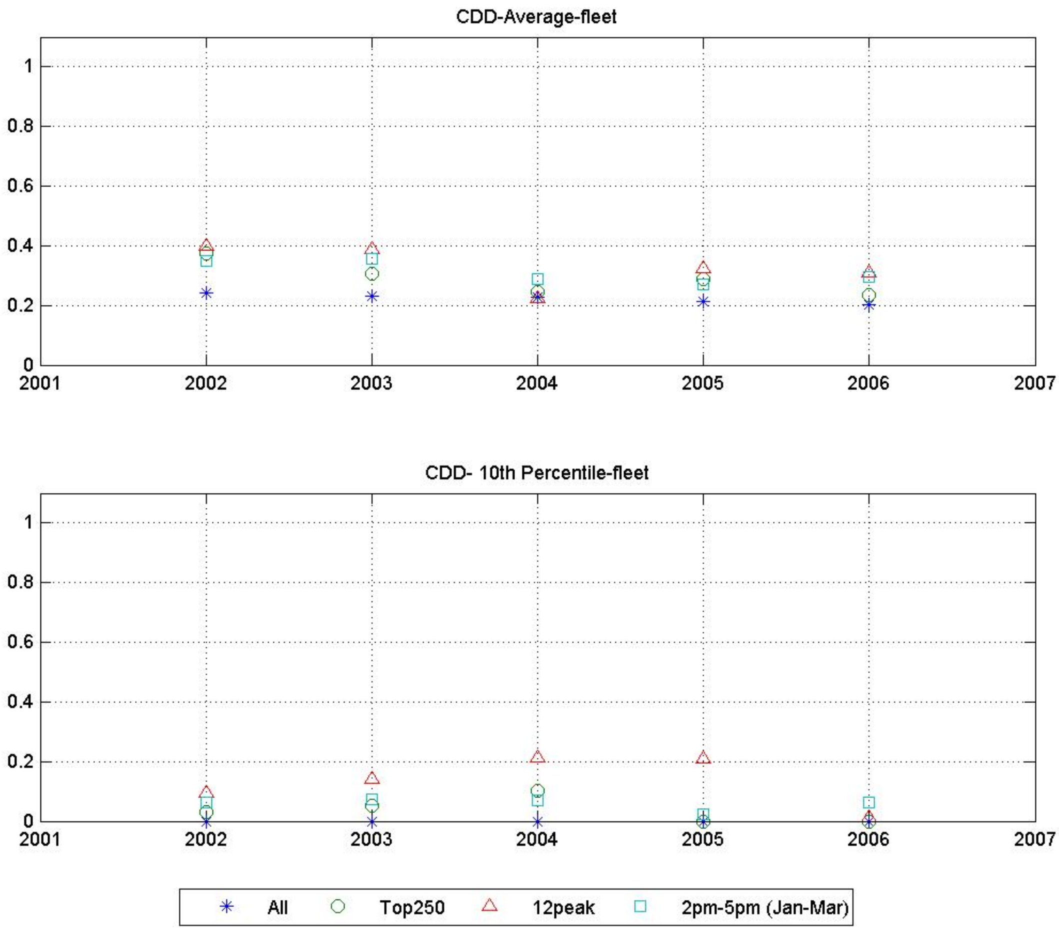

Figure 72: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for CDD modelled wind generation over single year time frames as a contributory to Wind Fleet 1.

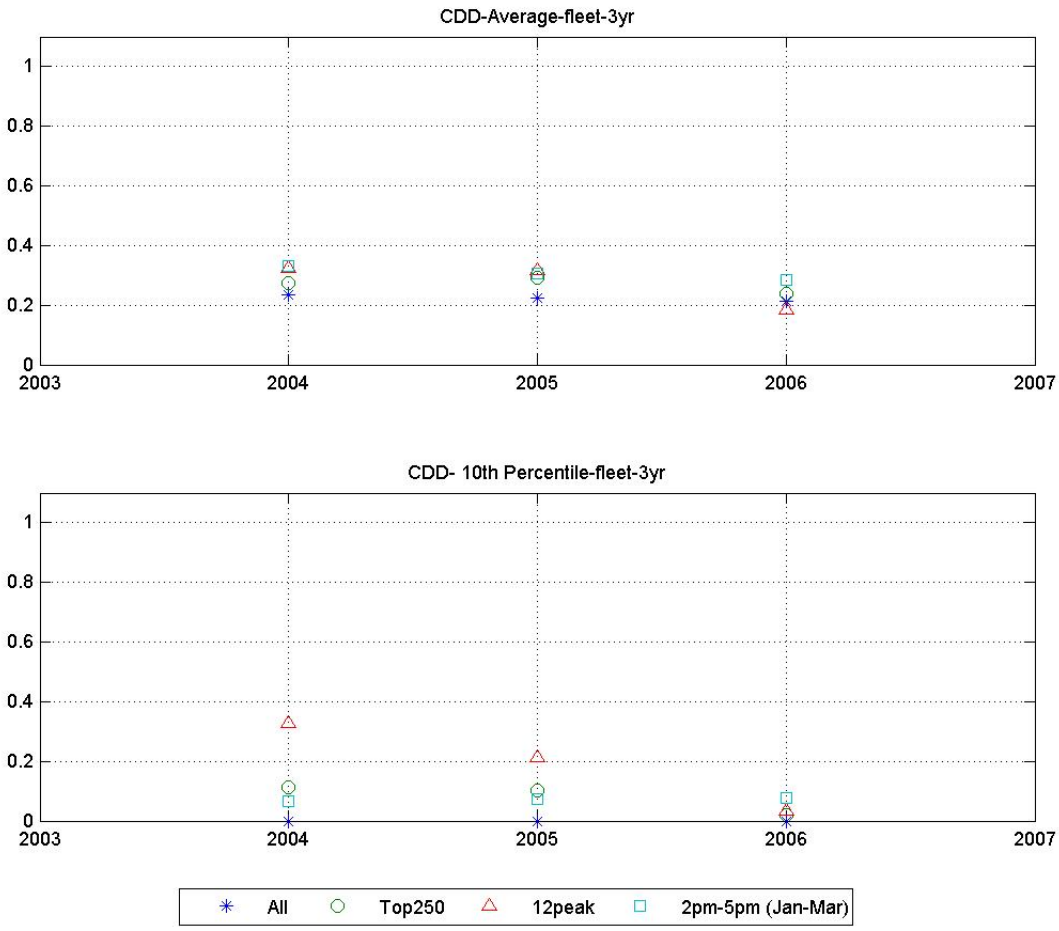

Figure 73: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for CDD modelled wind generation over three year time frames as a contributory to Wind Fleet 1.

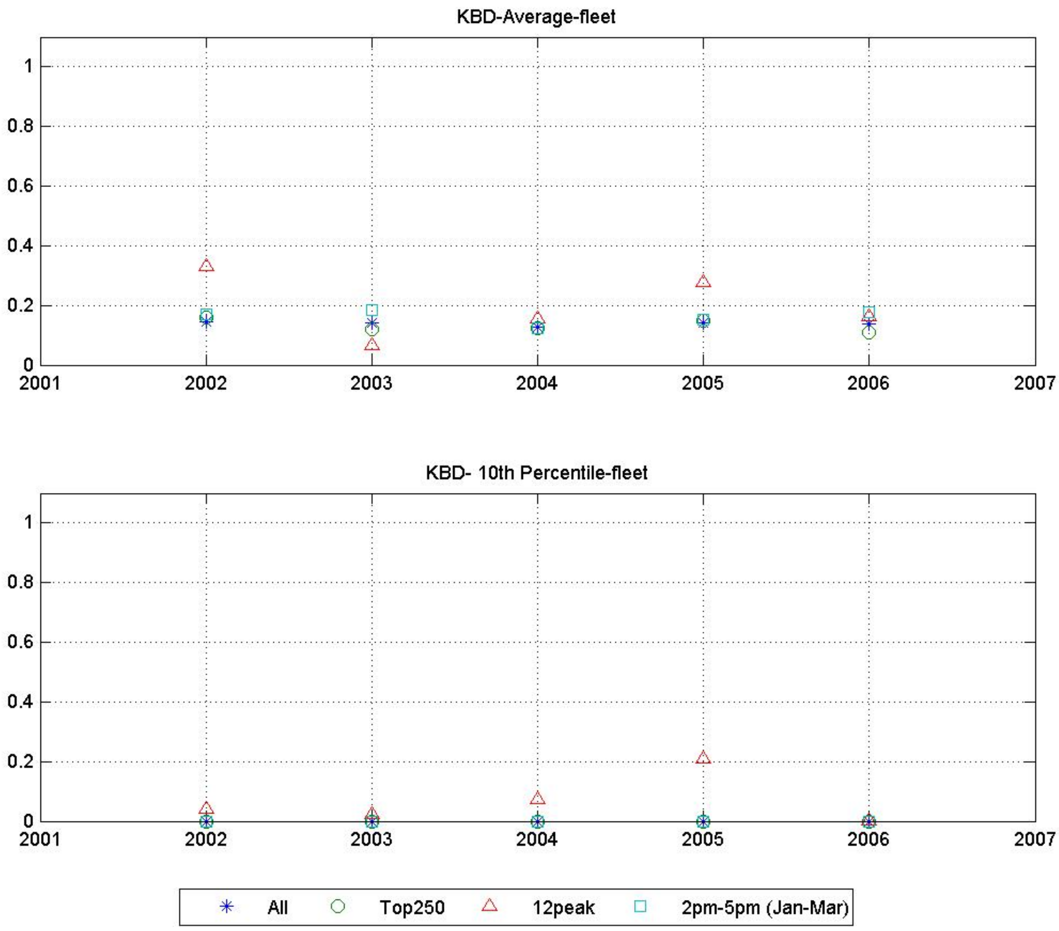

Figure 74: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for KBD modelled wind generation over single year time frames as a contributory to Wind Fleet 1.

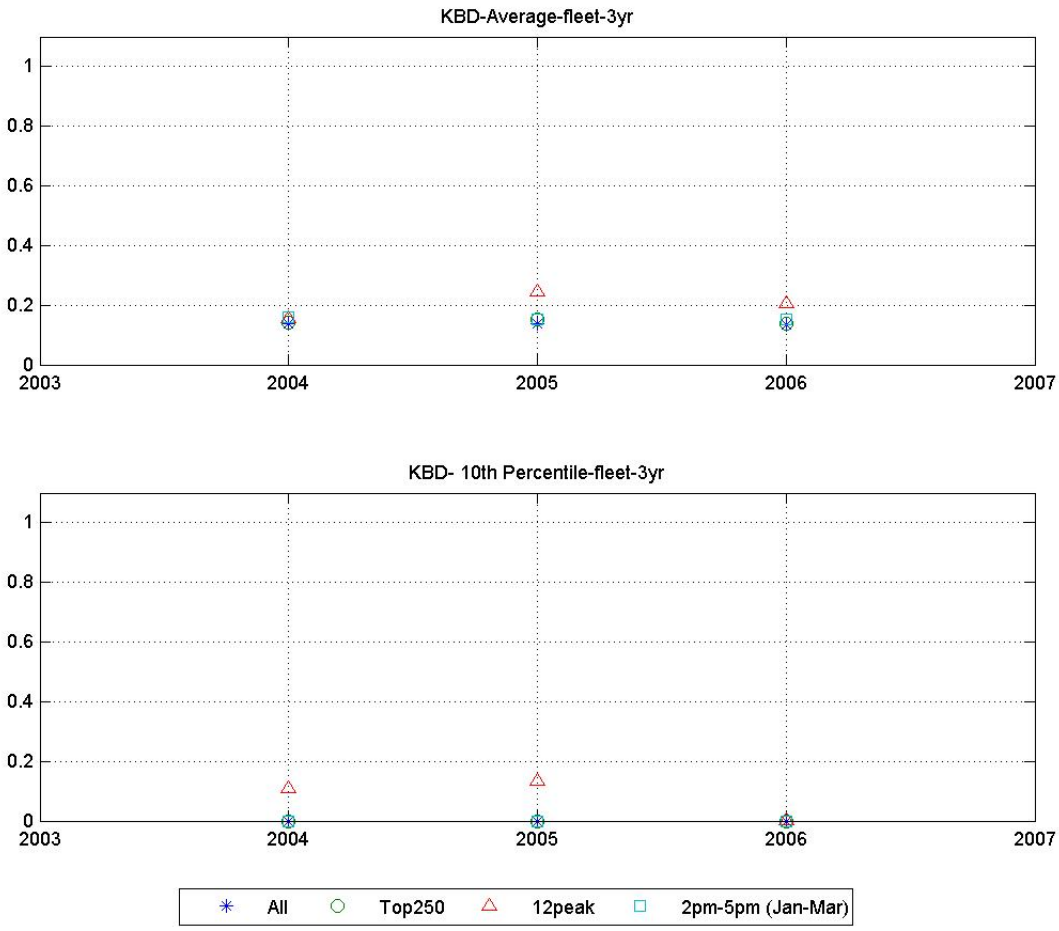

Figure 75: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for KBD modelled wind generation over three year time frames as a contributory to Wind Fleet 1.

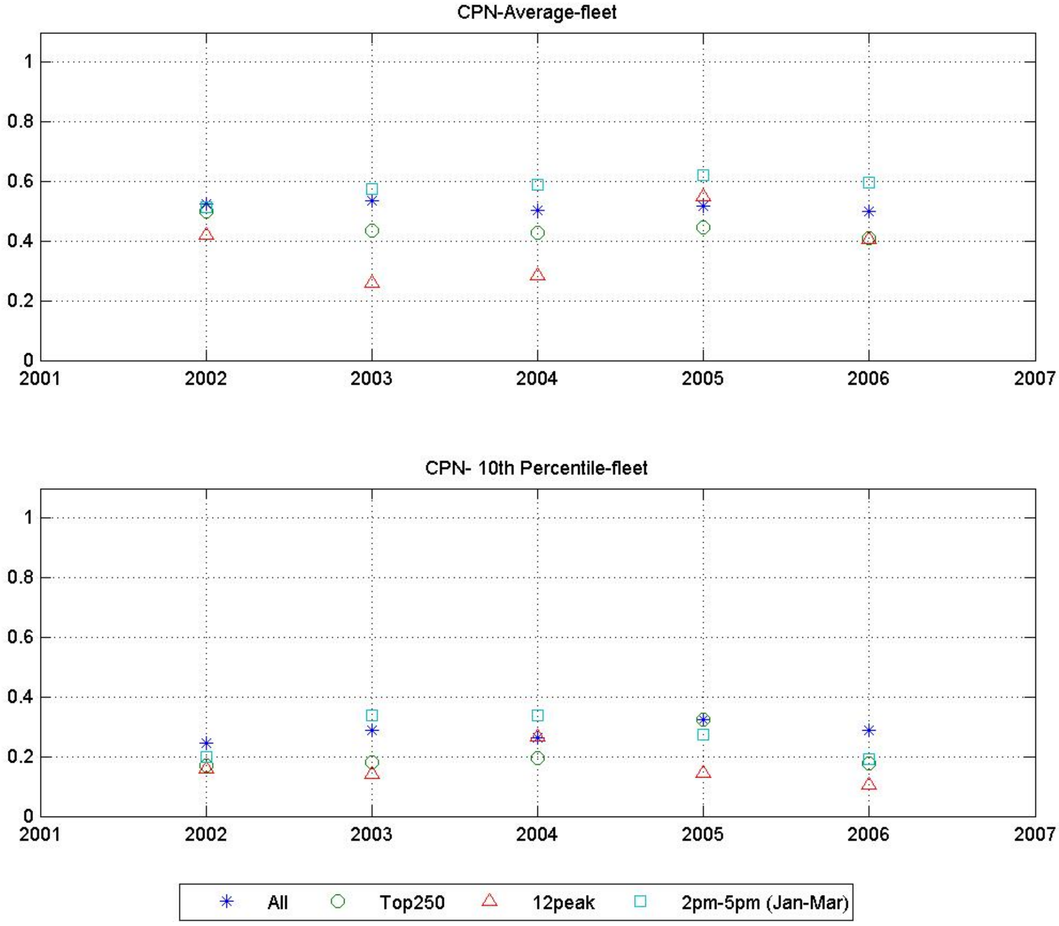

Figure 76: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for CPN modelled wind generation over single year time frames as a contributory to Wind Fleet 1.

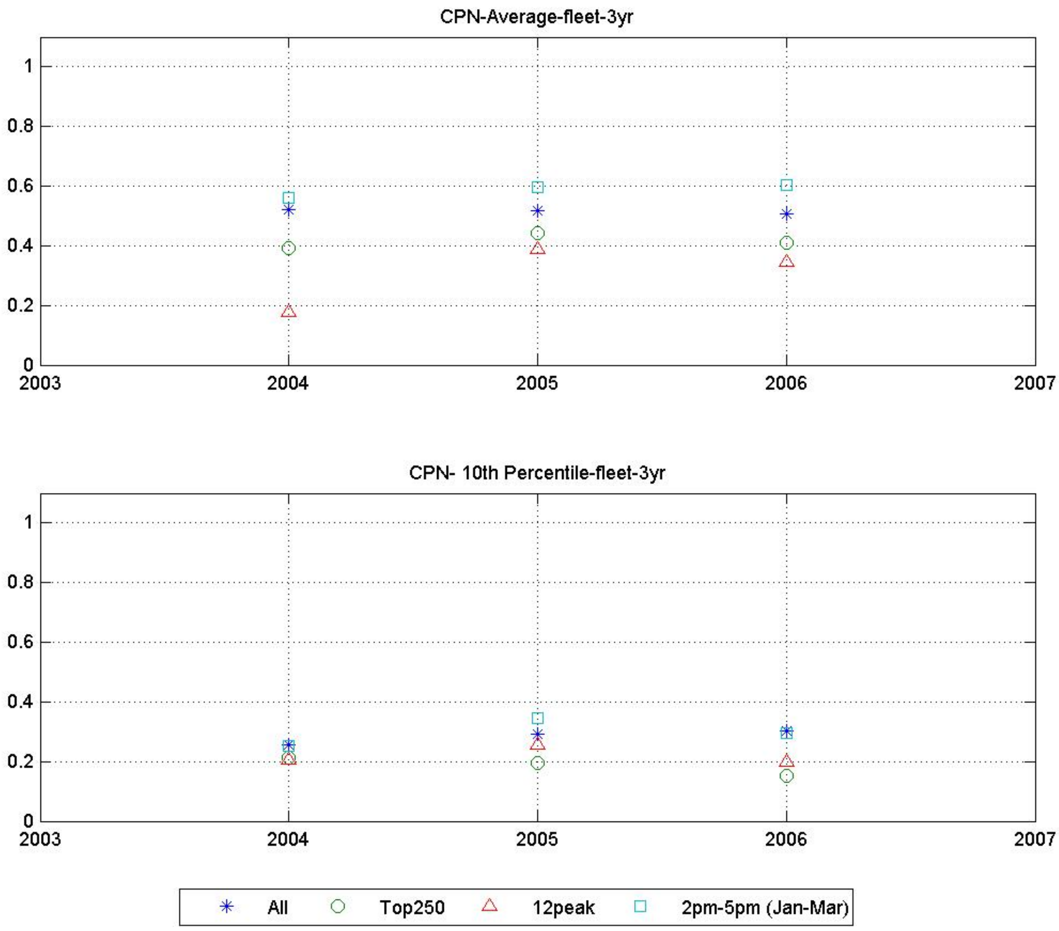

Figure 77: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for CPN modelled wind generation over three year time frames as a contributory to Wind Fleet 1.

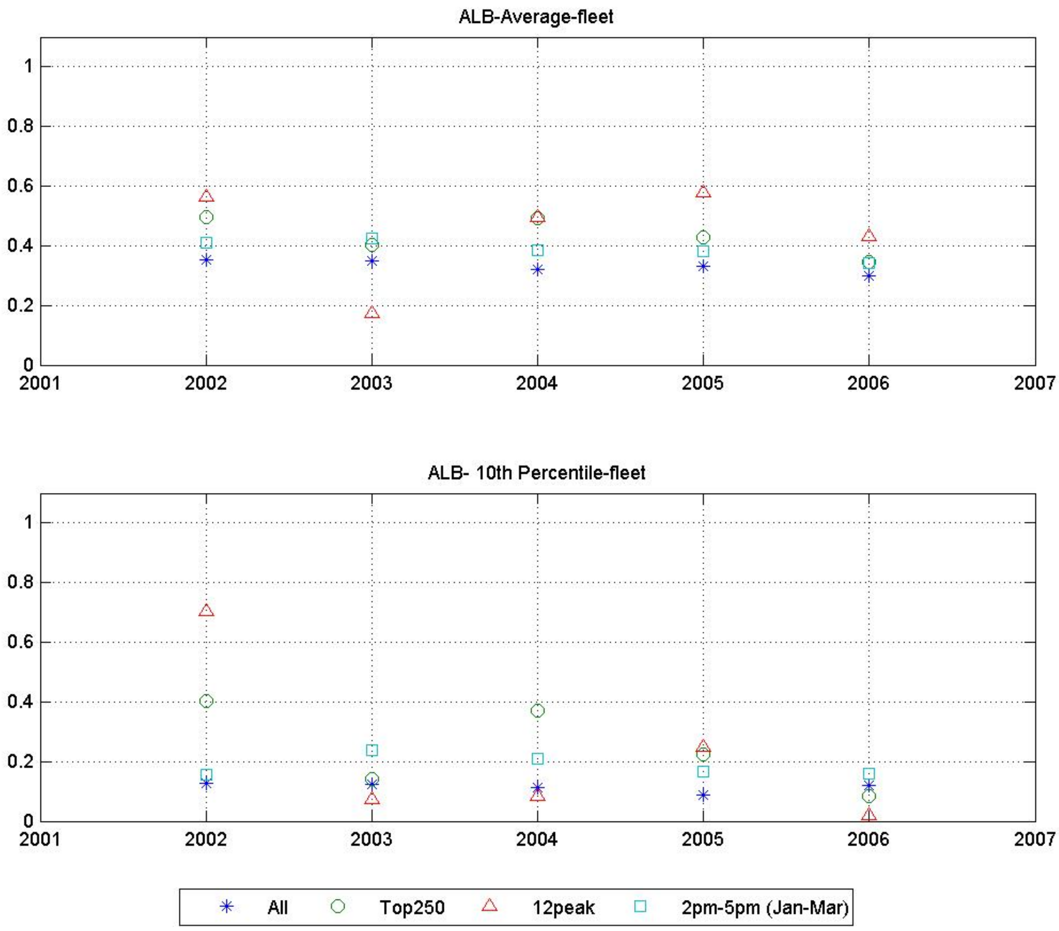

Figure 78: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for ALB wind generation over single year time frames as a contributory to Wind Fleet 1.

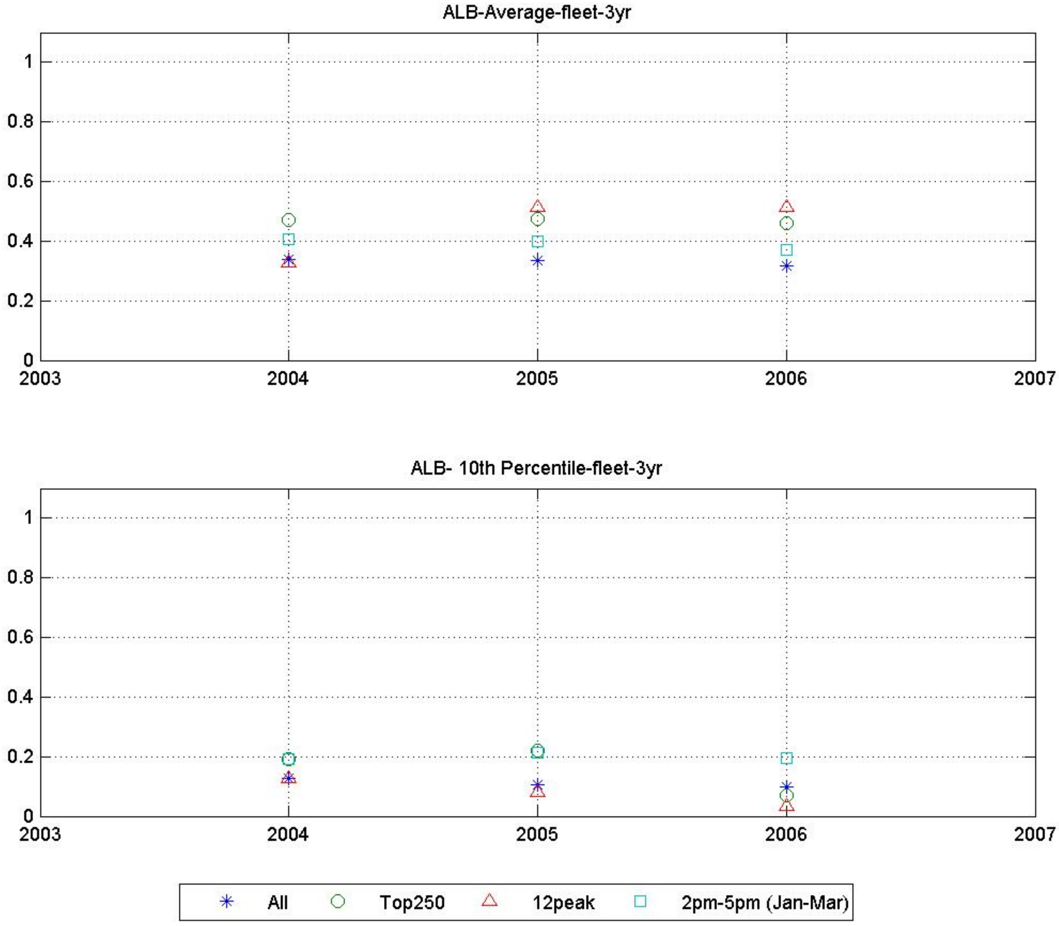

Figure 79: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for ALB wind generation over three year time frames as a contributory to Wind Fleet 1.

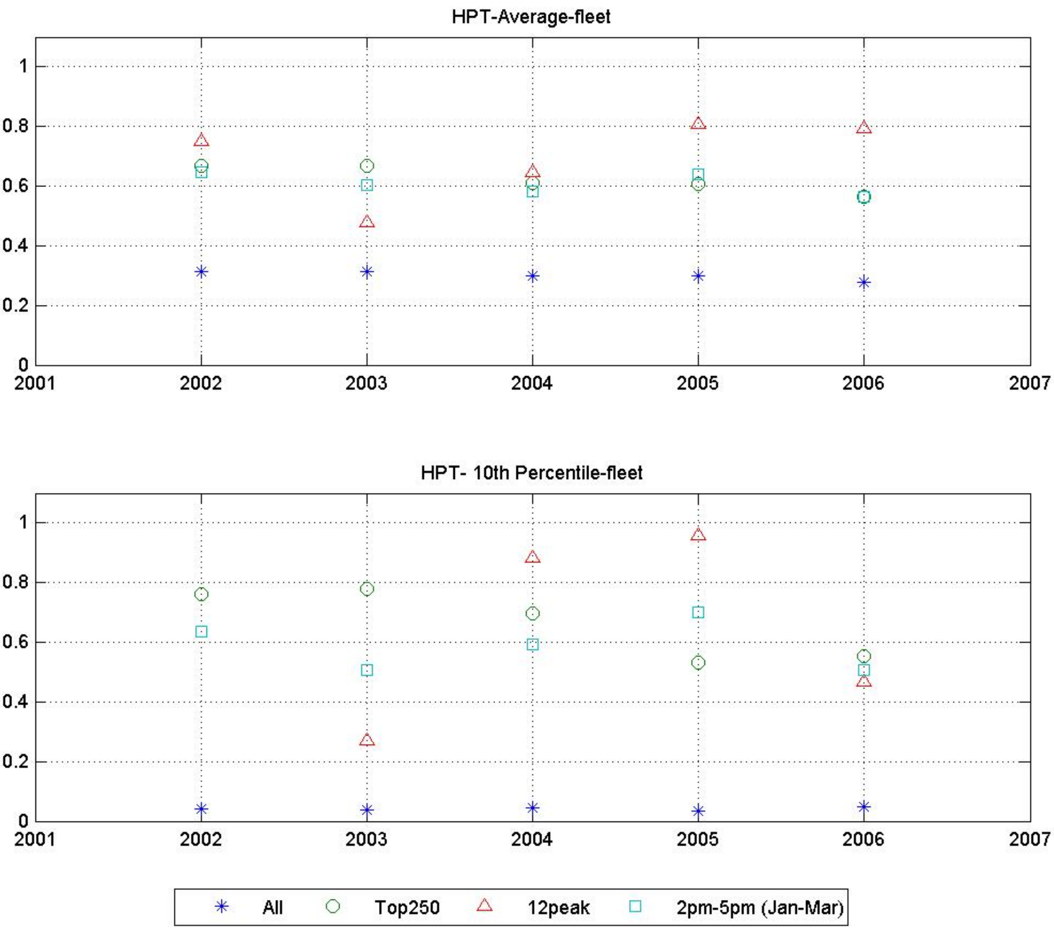

Figure 80: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for HPT modelled wind generation over single year time frames as a contributory to Wind Fleet 1.

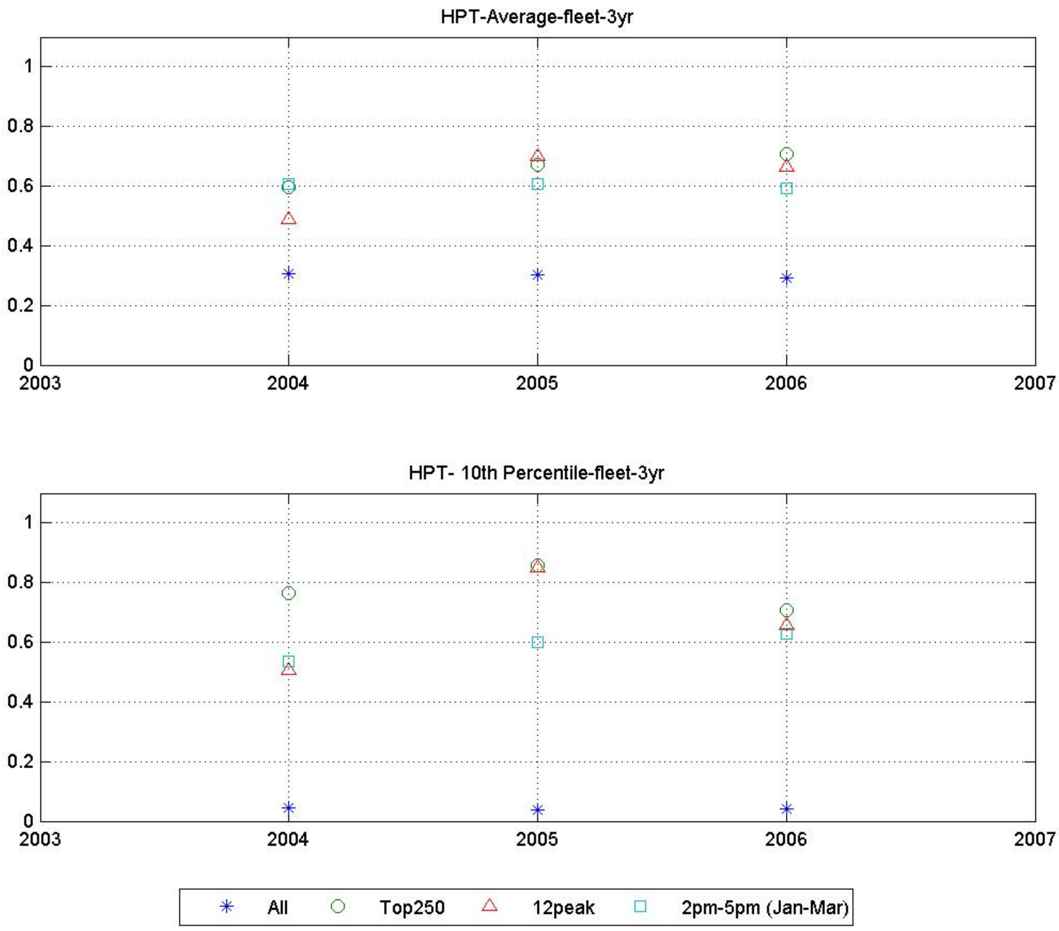

Figure 81: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for HPT modelled wind generation over three year time frames as a contributory to Wind Fleet 1.

13.5.2 Wind Fleet 2: 2007 – 2008

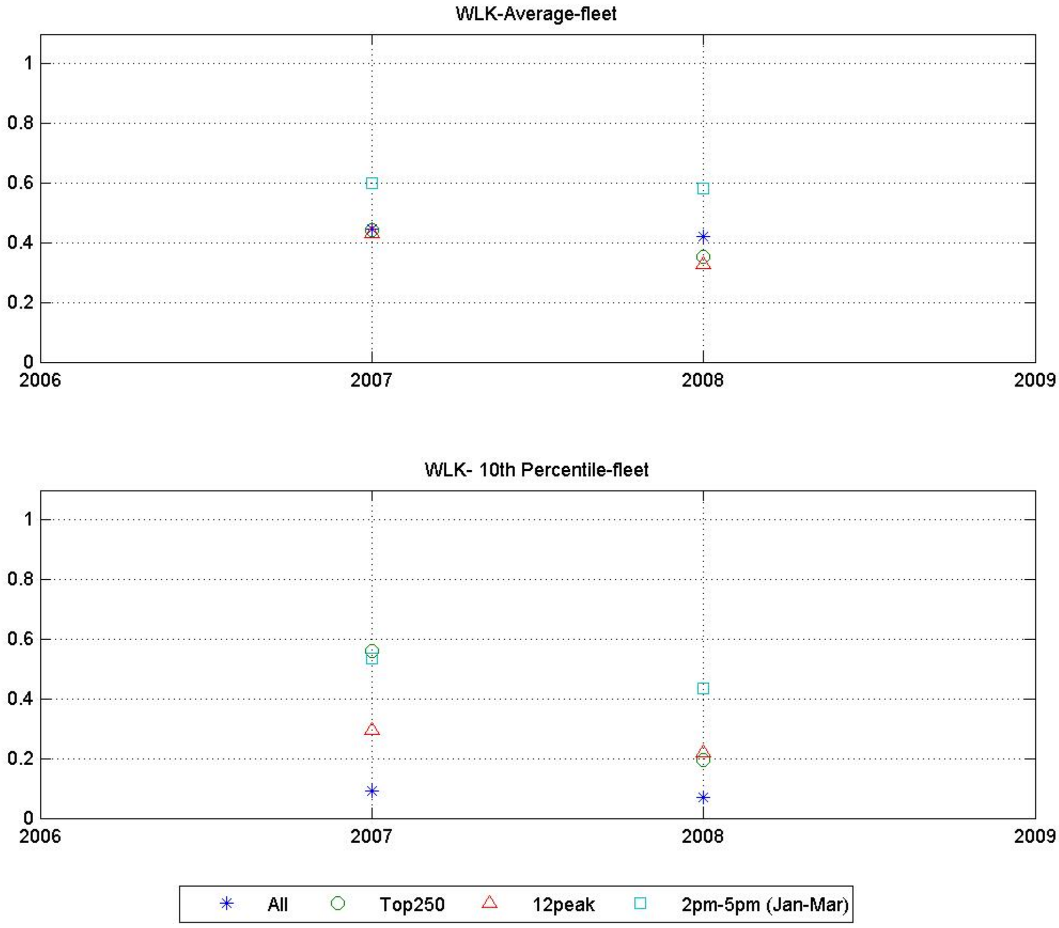

Figure 82: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for WLK modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

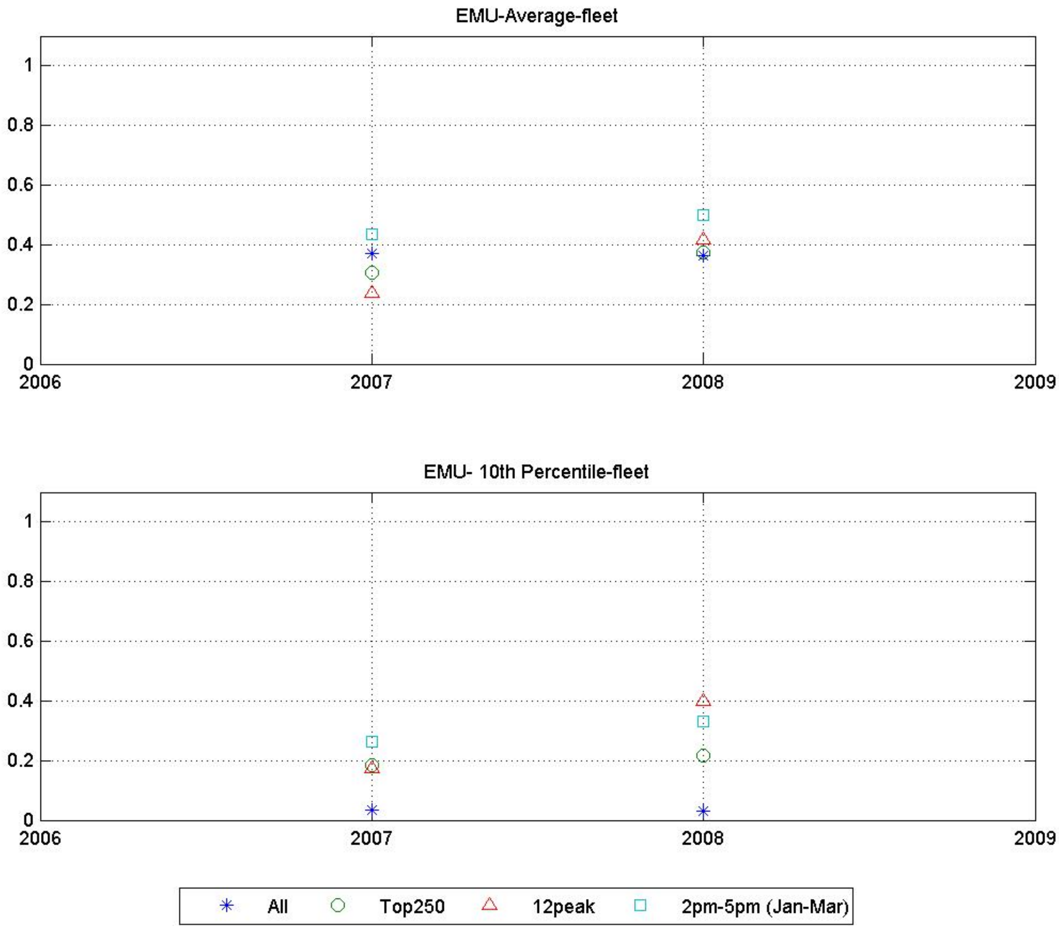

Figure 83: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for EMU modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

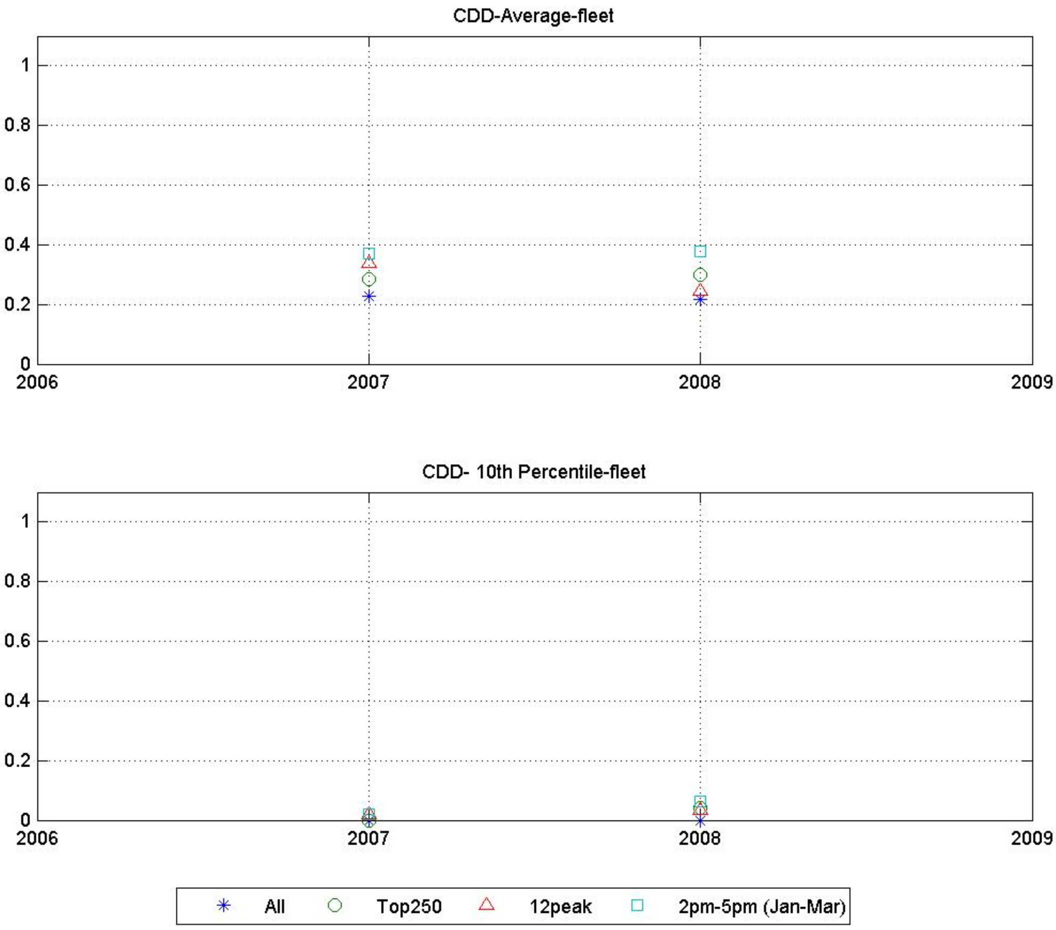

Figure 84: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for CDD modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

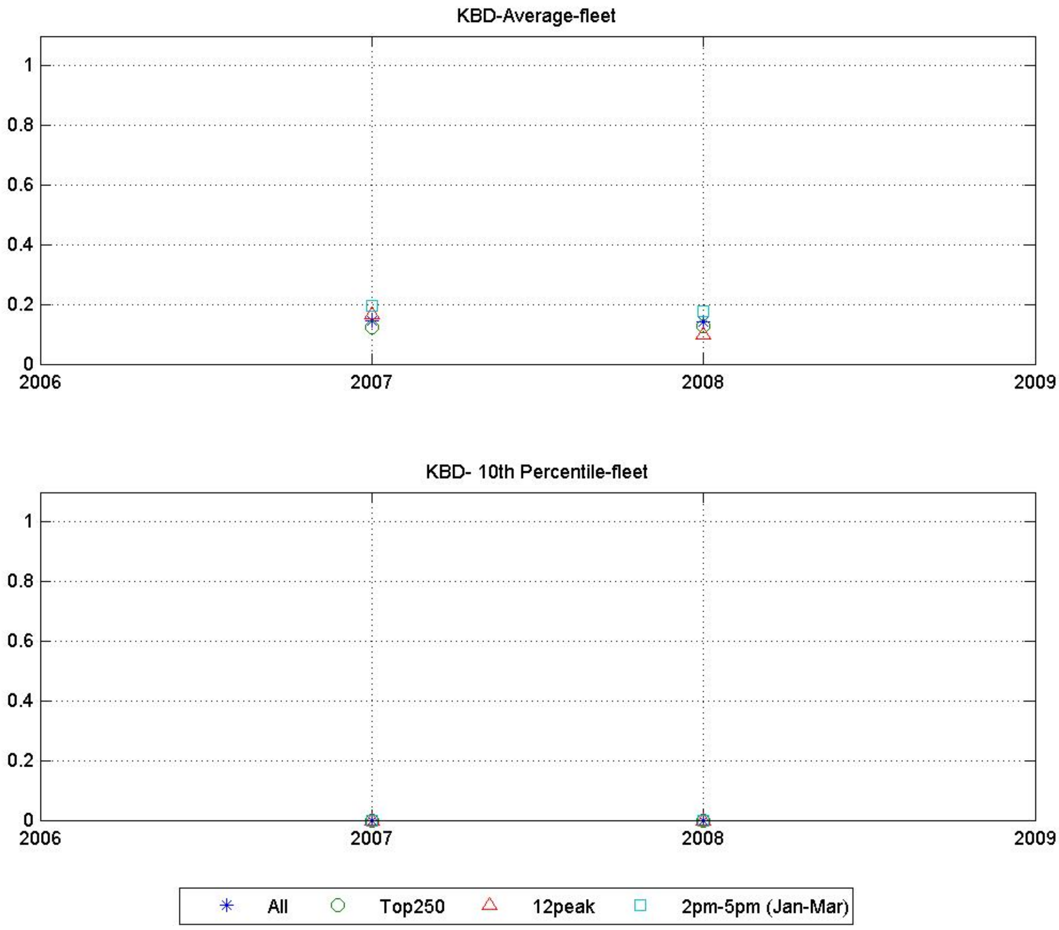

Figure 85: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for KBD modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

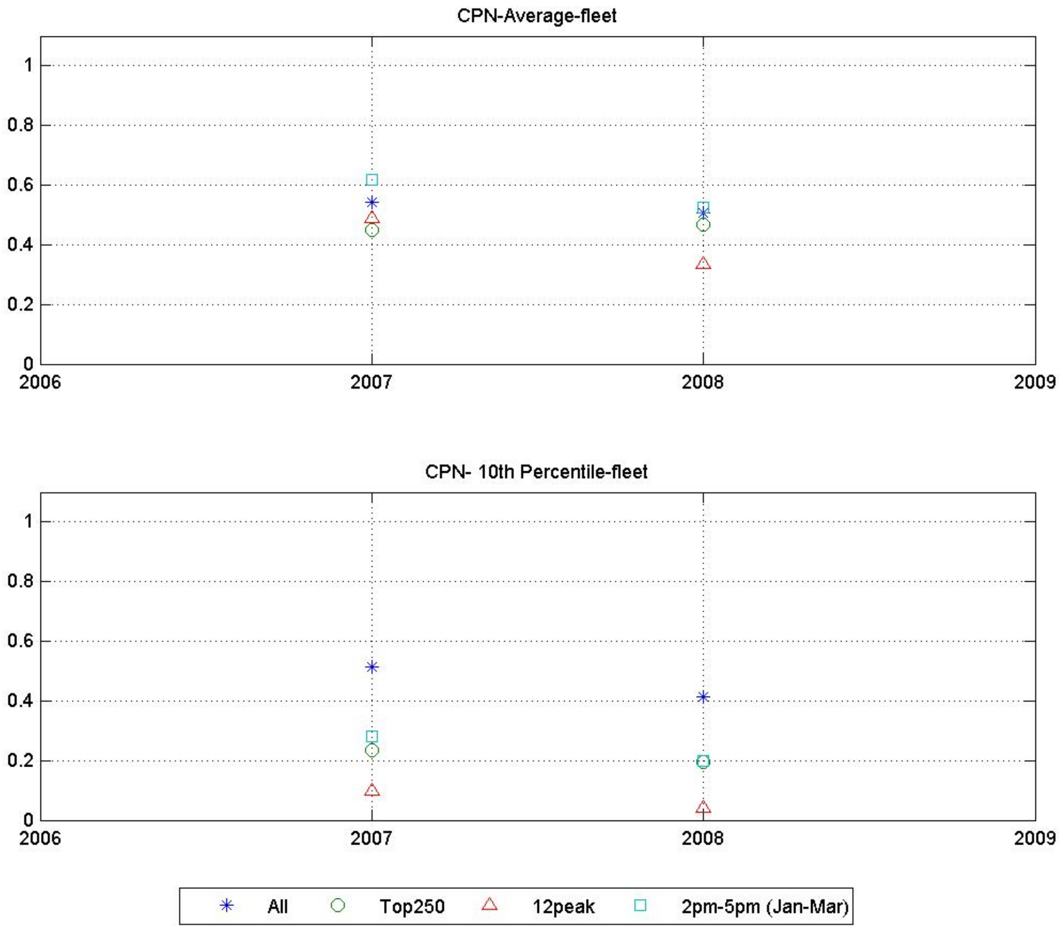

Figure 86: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for CPN modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

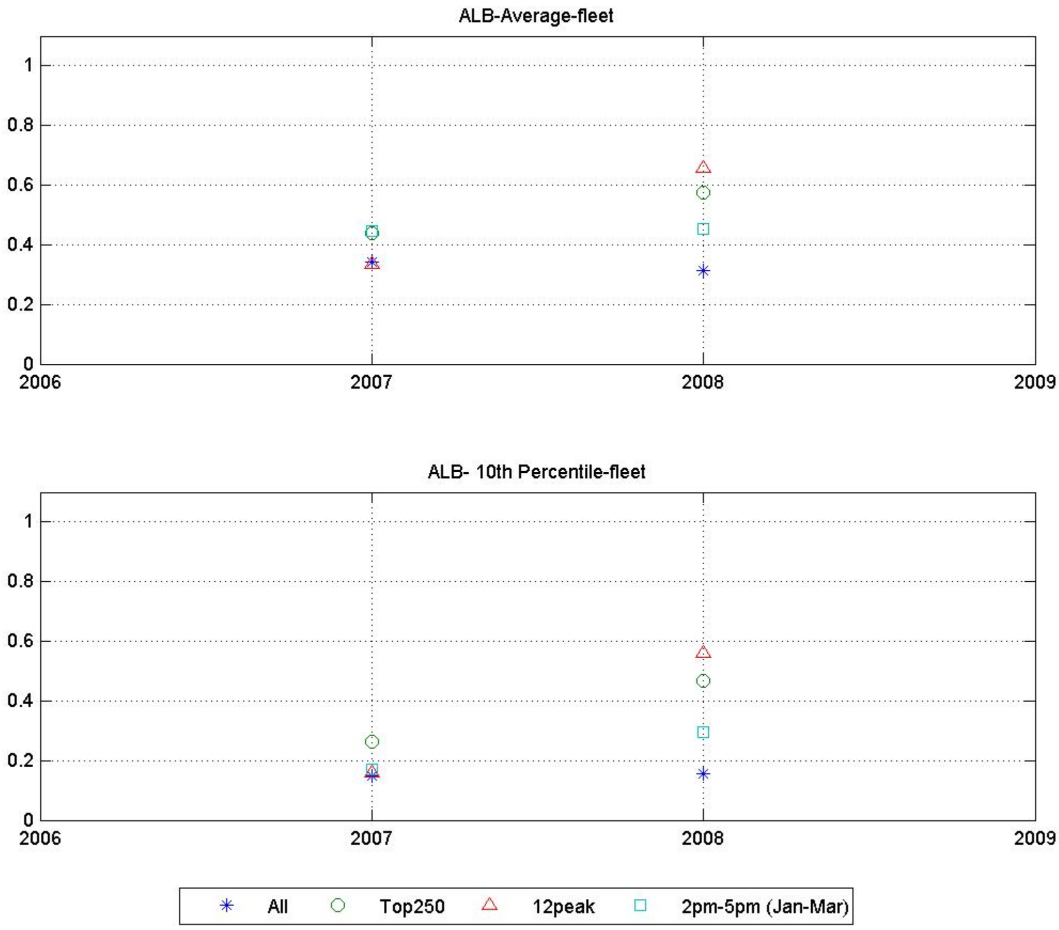

Figure 87: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for ALB modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

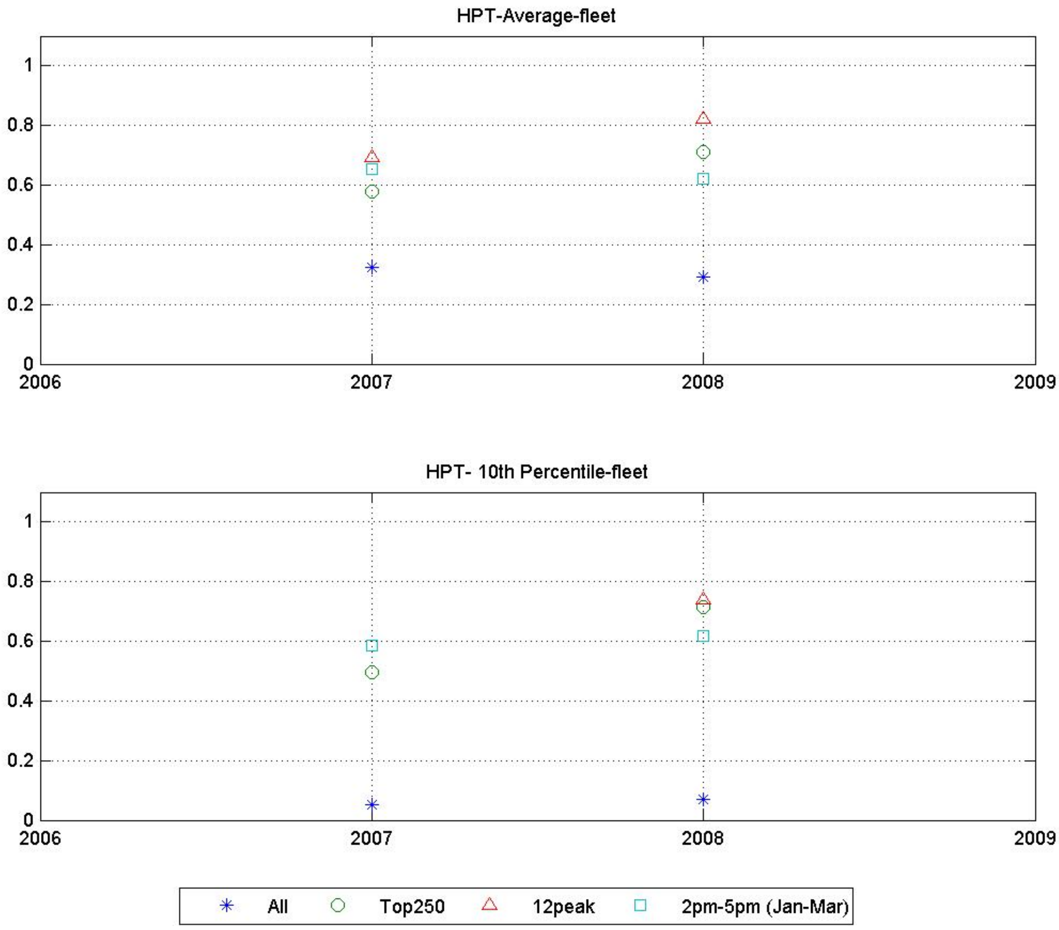

Figure 88: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for HPT modelled wind generation over single year time frames as a contributory to Wind Fleet 2.

13.5.3 Solar Thermal Fleet: 2002 – 2006

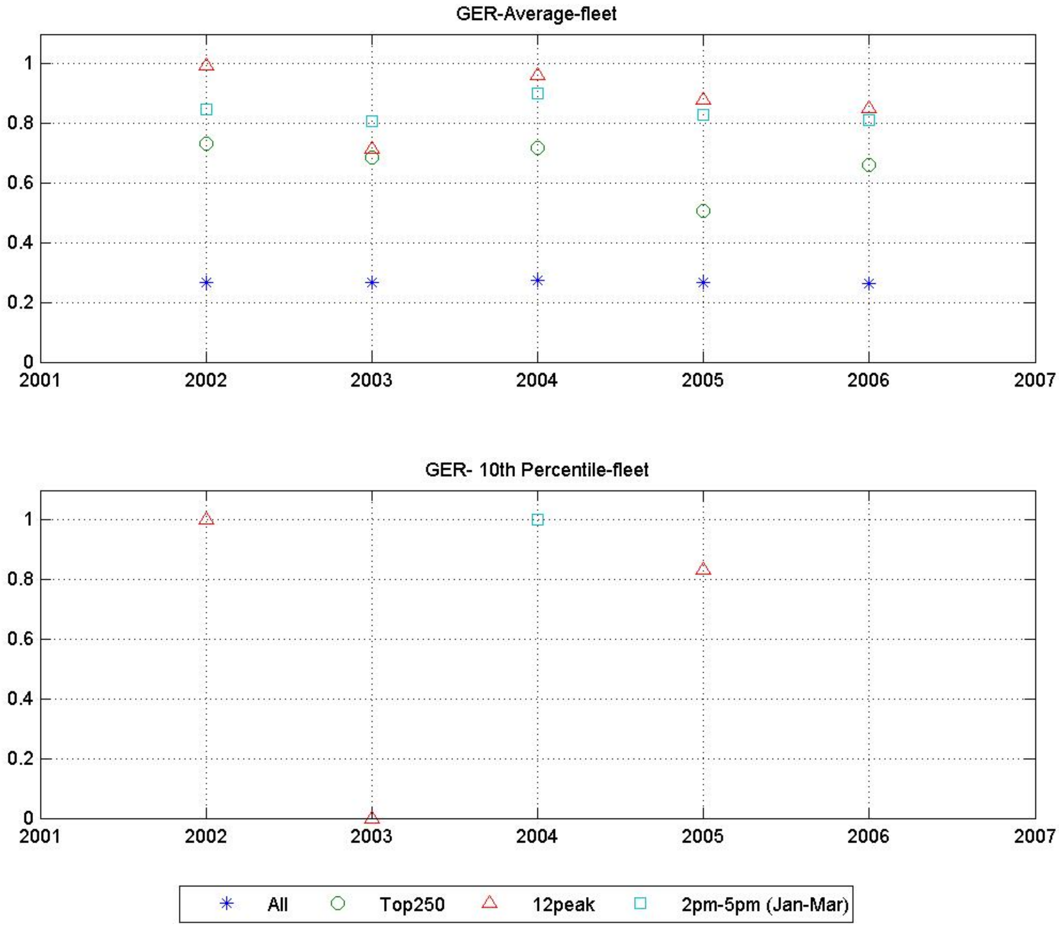

Figure 89: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for GER modelled solar thermal generation over single year time frames as a contributory to the Solar Thermal Fleet.

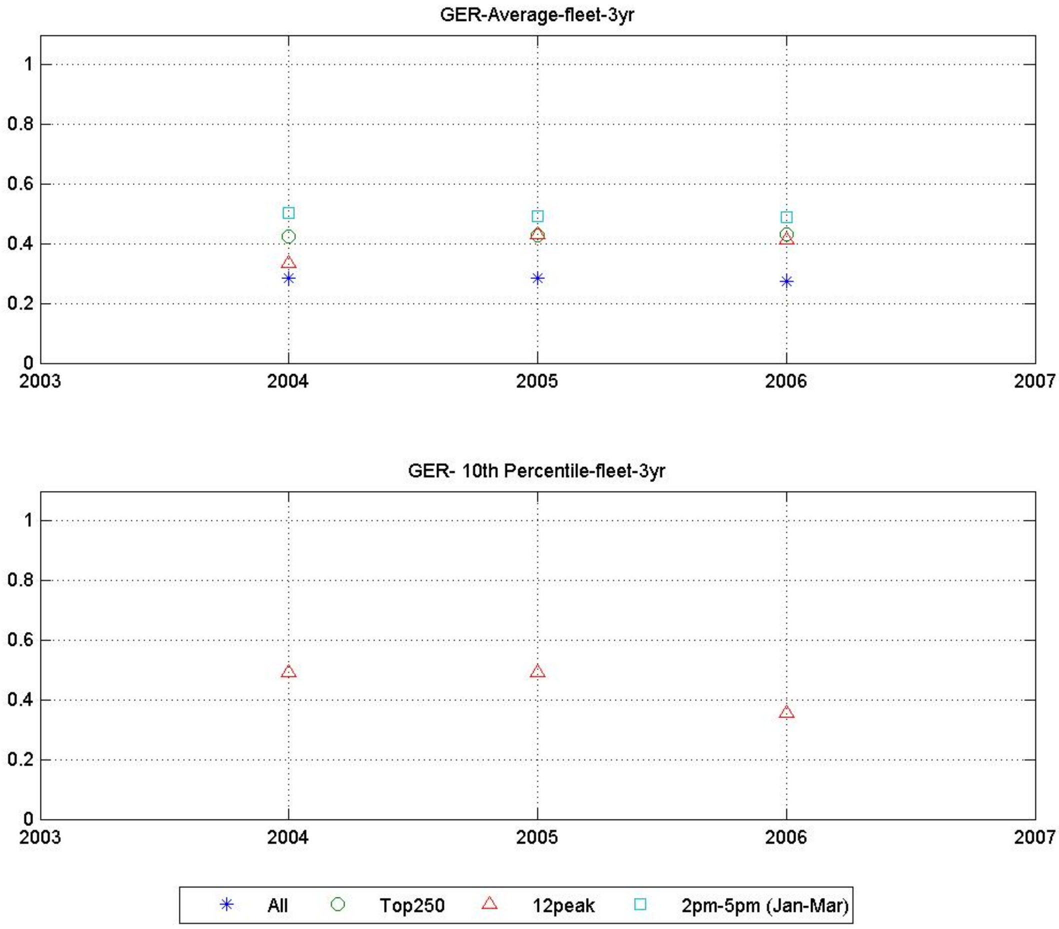

Figure 90: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for GER modelled solar thermal generation over three year time frames as a contributory to the Solar Thermal Fleet.

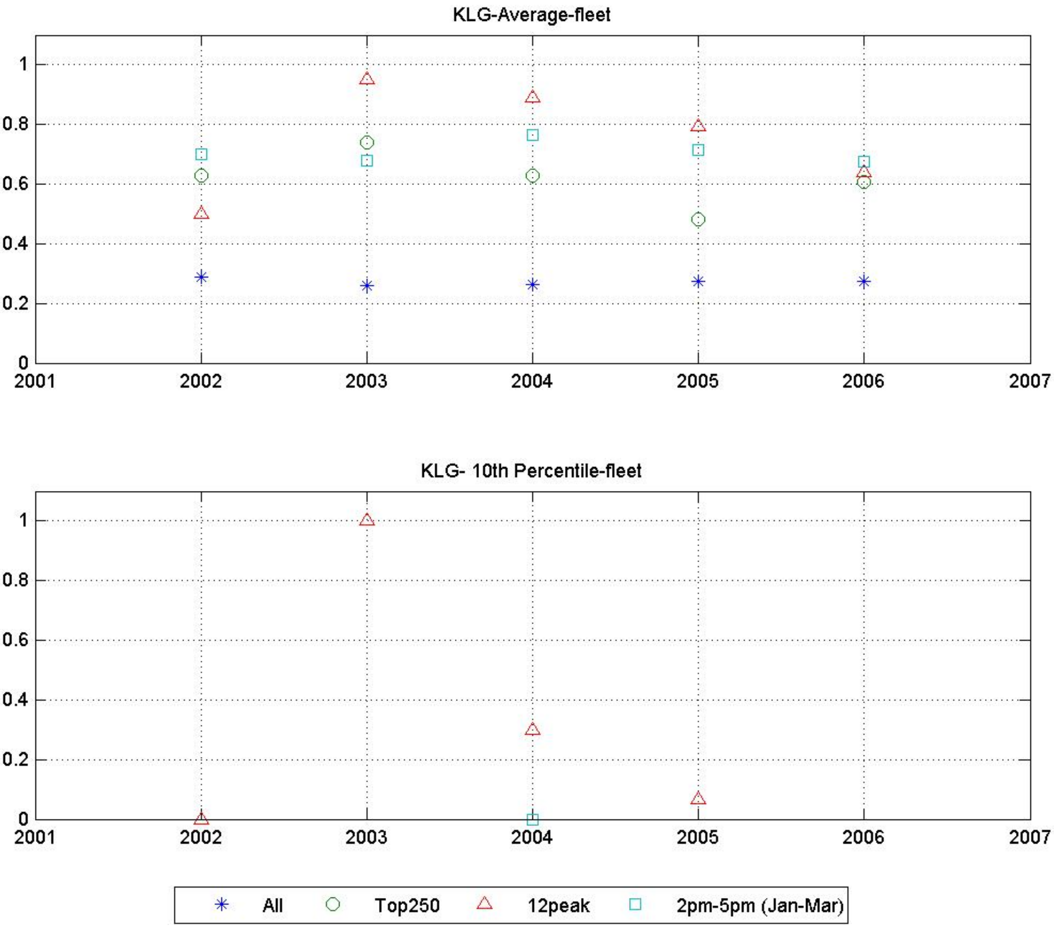

Figure 91: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for KLG modelled solar thermal generation over single year time frames as a contributory to the Solar Thermal Fleet.

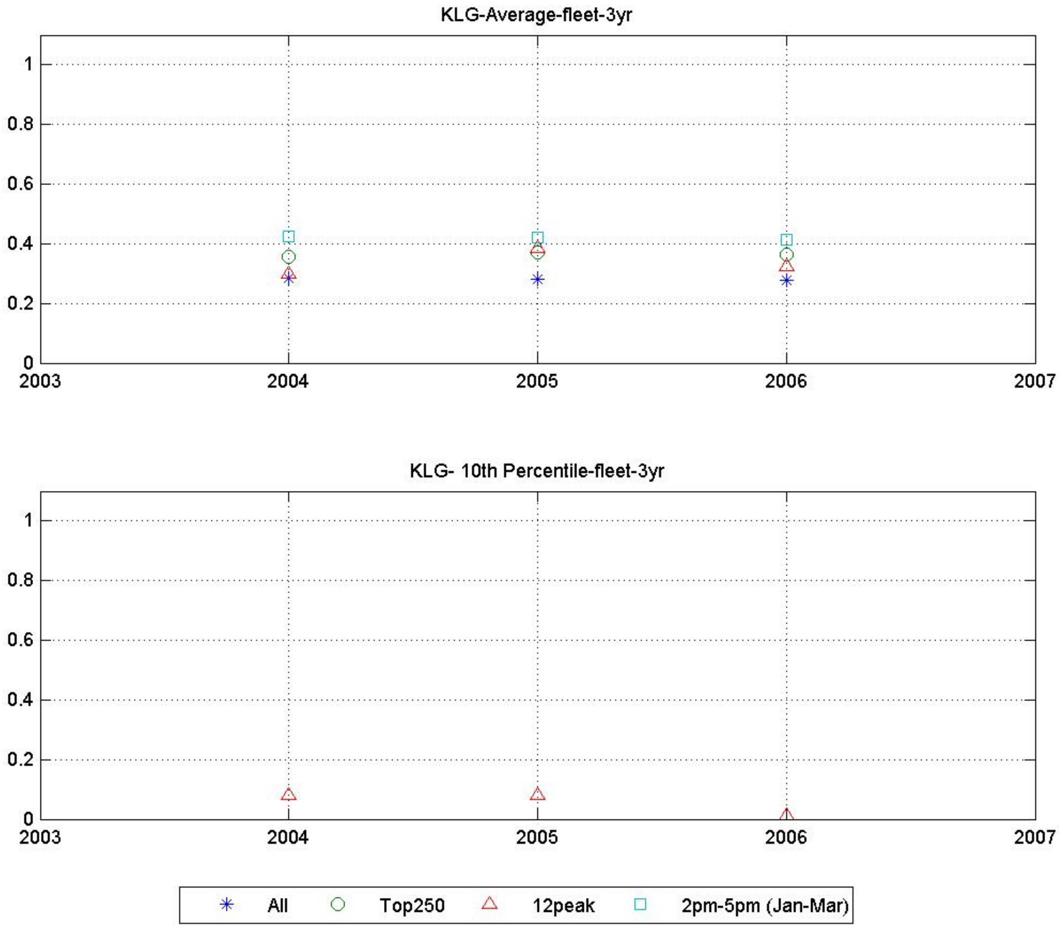

Figure 92: Comparison of results found when calculating Reserve Capacity based on the average and tenth percentile methodologies for KLG modelled solar thermal generation over three year time frames as a contributory to the Solar Thermal Fleet.

13.6 Appendix C6: Individual Site Results – Tabulated Multiple Year Results

Given the close relationship between results derived from three year data sets and those derived from longer time frames the latter is not considered to be as crucial to the study outcomes. However, the longer time frames were calculated in order to ensure that there is consistency in the overall results for all of the sites. All results are tabulated below noting that where sites were limited by the number of years of available data the longest available time frame was applied.

Reserve Capacity [MWh] Albany Wind Farm: 2002-2008				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	33.06%	55.54%	54.20%	40.75%
10th Percentile	2.39%	11.78%	25.07%	8.20%
Median	23.90%	59.48%	56.91%	32.02%
Weighted Average	33.93%	223.44%	231.07%	119.59%

Reserve Capacity [Capacity Factor] Walkaway Wind Farm: 2007-2008				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	43.48%	37.59%	30.80%	59.06%
10th Percentile	1.21%	11.65%	15.98%	21.52%
Median	39.80%	36.37%	24.82%	60.84%
Weighted Average	45.57%	144.18%	131.31%	172.13%

Reserve Capacity [Capacity Factor] Emu Downs Wind Farm: 2007-2008				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	36.61%	35.16%	28.43%	46.76%
10th Percentile	0.45%	11.56%	9.39%	13.52%
Median	31.78%	30.85%	22.79%	44.13%
Weighted Average	37.91%	136.47%	121.21%	140.70%

Reserve Capacity [Capacity Factor] Nilgen Wind Farm (132.5 MWh Max Capacity): 2005-2007				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	34.04%	49.86%	50.06%	61.48%
10th Percentile	2.24%	3.67%	21.68%	13.39%
Median	22.27%	52.18%	40.38%	65.60%
Weighted Average	43.95%	191.88%	213.40%	183.40%

Reserve Capacity [Capacity Factor] Landfill Gas and Power (Red Hill, Tamala Park, and Canning Vale): 2007-2008				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2PM-5PM (Jan-Mar)
Average	76.41%	83.28%	73.43%	81.88%
10th Percentile	56.63%	75.75%	45.16%	68.54%
Median	79.66%	85.16%	83.06%	83.95%
Weighted Average	81.39%	324.82%	313.02%	245.03%

Reserve Capacity [Capacity Factor] Geraldton Solar Thermal: 2002-2006				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2PM-5PM (Jan-Mar)
Average	26.79%	76.42%	100.00%	84.37%
10th Percentile	0.00%	0.00%	100.00%	0.00%
Median	0.00%	100.00%	100.00%	100.00%
Weighted Average	43.44%	317.63%	426.29%	248.03%

Reserve Capacity [Capacity Factor] Kalgoorlie Solar Thermal: 2001-2006				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2PM-5PM (Jan-Mar)
Average	26.98%	67.93%	78.27%	68.71%
10th Percentile	0.00%	0.00%	3.92%	0.00%
Median	0.00%	100.00%	100.00%	100.00%
Weighted Average	42.36%	279.23%	333.64%	208.82%

Reserve Capacity [Capacity Factor] Hopetoun Simulated Wind Farm: 2001-2008				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2PM-5PM (Jan-Mar)
Average	30.16%	69.27%	68.11%	61.99%
10th Percentile	0.90%	31.47%	36.69%	26.66%
Median	18.93%	74.87%	74.87%	65.00%
Weighted Average	38.80%	276.58%	290.34%	182.35%

Reserve Capacity [Capacity Factor] Badgingarra Simulated Wind Farm: 2001-2008				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2PM-5PM (Jan-Mar)
Average	39.50%	56.01%	53.97%	59.39%
10th Percentile	1.78%	8.67%	23.42%	8.67%
Median	30.64%	59.94%	59.94%	65.00%
Weighted Average	50.98%	222.69%	230.08%	178.48%

Reserve Capacity [Capacity Factor] Cape Naturaliste Simulated Wind Farm: 2001-2008				
Calculation Methodology	**Intervals Selected**			
	All	**Top 250 Loads**	**12 Peak Intervals**	**2PM-5PM (Jan-Mar)**
Average	51.58%	43.76%	9.38%	58.87%
10th Percentile	6.83%	8.67%	5.26%	10.78%
Median	45.01%	35.77%	8.67%	65.00%
Weighted Average	53.29%	168.89%	40.00%	174.59%

Reserve Capacity [Capacity Factor] Walpole Simulated Wind Farm: 2001-2008				
Calculation Methodology	**Intervals Selected**			
	All	**Top 250 Loads**	**12 Peak Intervals**	**2PM-5PM (Jan-Mar)**
Average	15.73%	31.14%	9.98%	29.17%
10th Percentile	0.00%	0.90%	0.00%	5.26%
Median	6.83%	19.25%	4.59%	19.57%
Weighted Average	18.33%	125.90%	42.56%	88.11%

Reserve Capacity [Capacity Factor] Geraldton Simulated Wind Farm: 2001-2008				
Calculation Methodology	**Intervals Selected**			
	All	**Top 250 Loads**	**12 Peak Intervals**	**2PM-5PM (Jan-Mar)**
Average	27.86%	40.31%	43.63%	68.53%
10th Percentile	0.00%	7.90%	17.68%	17.68%
Median	17.68%	32.31%	41.60%	70.99%
Weighted Average	40.52%	163.45%	185.97%	201.86%

Reserve Capacity [Capacity Factor] Gingin Simulated Wind Farm: 2001-2008				
Calculation Methodology	**Intervals Selected**			
	All	**Top 250 Loads**	**12 Peak Intervals**	**2PM-5PM (Jan-Mar)**
Average	19.37%	40.41%	32.68%	49.18%
10th Percentile	0.00%	3.92%	16.21%	8.67%
Median	6.83%	35.77%	29.46%	49.89%
Weighted Average	28.04%	158.60%	139.32%	145.48%

Reserve Capacity [Capacity Factor] Cunderdin Simulated Wind Farm: 2001-2008				
Calculation Methodology	**Intervals Selected**			
	All	**Top 250 Loads**	**12 Peak Intervals**	**2PM-5PM (Jan-Mar)**
Average	22.09%	27.81%	22.43%	32.89%
10th Percentile	0.00%	1.78%	1.88%	2.77%
Median	8.67%	18.93%	23.18%	26.66%
Weighted Average	28.93%	110.97%	95.64%	98.52%

Reserve Capacity [Capacity Factor] Kalgoorlie Airport Simulated Wind Farm: 2001-2008				
Calculation Methodology	**Intervals Selected**			
	All	**Top 250 Loads**	**12 Peak Intervals**	**2PM-5PM (Jan-Mar)**
Average	13.90%	14.77%	21.67%	17.42%
10th Percentile	0.00%	0.00%	0.90%	0.00%
Median	5.26%	13.19%	23.18%	8.67%
Weighted Average	16.30%	60.15%	92.37%	52.29%

14 Appendix D: Correlation Coefficients

As discussed in Section 5.1 correlation coefficients have been calculated between load and temperature, generation and temperature, and generation and load. The resulting outcomes are tabulated below.

Correlations between peak daily SWIS load and temperature

Summer Load Correlation Coeffecients (Non-Business Days Adjusted to Business Days)		
Year	Peak Load : Max Temperature	Peak Load : Min. Temperature
2001	0.846	0.822
2002	0.865	0.630
2003	0.840	0.730
2004	0.859	0.800
2005	0.855	0.669
2006	0.888	0.713
2007	0.919	0.734
2008	0.896	0.713

Table 24: Annual correlations between the peak daily SWIS load and maximum daily temperature in the summer months were the non-business days have been scaled in order to represent business days as discussed in Section 5.5.4. Load growth has not been removed here.

Load Correlation Coeffecients (All Data with Non-Business Days Adjusted to Business Days)		
Year	Peak Load : Max Temperature	Peak Load : Min. Temperature
2001–2008 (2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008)	0.179	0.077

Load Correlation Coeffecients (All Data with Non-Business Days Adjusted to Business Days and Load Growth Removed)		
Year	Peak Load : Max Temperature	Peak Load : Min. Temperature
2001–2008 (2001, 2002, 2003, 2004, 2005, 2006, 2007, 2008)	0.239	0.120

Table 25: Comparison of the correlation of peak daily SWIS load and maximum daily temperature over the full study period where the non-business days have initially been adjusted for business days and correlation coefficients are calculated both before and after the removal of the exponential load growth as discussed in Section 5.5.4. Note the improved correlation coefficients.

Load Correlation Coeffecients (Business Days Only with Load Growth Removed)		
Year	Peak Load : Max Temperature	Peak Load : Min. Temperature
2001	0.309	0.187
2002		
2003		
2004		
2005		
2006		
2007		
2008		

Table 26: Correlation coefficients found when comparing the peak daily SWIS load with the maximum daily temperature during all business days over the study period where the exponential load growth has been removed as discussed in Section 5.5.4.

Load Correlation Coeffecients (All Summer Days Data with Non-Business Days Adjusted to Business Days and Load Growth Removed)		
Year	Peak Load : Max Temperature	Peak Load : Min. Temperature
2001	0.810	0.698
2002		
2003		
2004		
2005		
2006		
2007		
2008		

Table 27: Correlation coefficients found when comparing the peak daily SWIS load with the maximum daily temperature during all summer days over the study period where the exponential load growth has been removed and non-business days have been scaled in order to represent business days as discussed in Section 5.5.4.

Correlations between peak daily generation, peak daily temperature and peak daily SWIS load

ALB Generation Correlation Coefficients (Calculated annually over all summer days only)			
Year	Peak Generation : Max Temp	Peak Generation : Min Temp	Peak Generation : Peak Load
2002	0.019	0.206	0.087
2003	0.068	0.304	0.217
2004	0.141	0.250	0.316
2005	0.173	0.315	0.308
2006	0.069	0.430	0.326
2007	-0.249	-0.090	-0.184
2008	0.008	0.178	0.018

Table 28: Correlation between the peak ALB wind farm generation and the maximum and minimum daily temperature calculated over summer days only. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

ALB Generation Correlation Coefficients (Calculated over all trading intervals available)			
Year	Peak Generation : Max Temp	Peak Generation : Min Temp	Peak Generation : Peak Load
2002	-0.059	0.140	0.082
2003			
2004			
2005			
2006			
2007			
2008			

Table 29: Correlation between the peak ALB wind farm generation and the maximum and minimum daily temperature calculated over all trading intervals. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

ALB Generation Correlation Coefficients (Calculated over all dusiness days only)			
Year	Peak Generation : Max Temp	Peak Generation : Min Temp	Peak Generation : Peak Load
2002	-0.079	0.143	0.087
2003			
2004			
2005			
2006			
2007			
2008			

Table 30: Correlation between the peak ALB wind farm generation and the maximum and minimum daily temperature calculated over all business day trading intervals. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

ALB Generation Correlation Coefficients at Peak Load Intervals		
Year	Peak Load : Generation (Intervals: 2-5PM Jan-Mar)	Peak Load : Generation (Intervals: Top 250)
2002	0.027	-0.078
2003	-0.189	-0.145
2004	0.020	0.255
2005	-0.019	0.270
2006	-0.044	-0.020
2007	0.020	-0.031
2008	0.173	0.278

Table 31: Correlation between the peak load and ALB wind farm generation during the corresponding peak load intervals. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

GER Generation Correlation Coefficients (Calculated annually over all summer days only)			
Year	Peak Generation : Max Temp	Peak Generation : Min Temp	Peak Generation : Peak Load
2002	0.013	-0.139	-0.060
2003	0.175	-0.065	0.078
2004	0.188	-0.144	0.027
2005	0.014	-0.015	-0.026
2006	0.294	0.028	0.243

Table 32: Correlation between the peak GER solar thermal generation and the maximum and minimum daily temperature calculated over summer days only. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

GER Generation Correlation Coefficients (Calculated over all trading intervals available)			
Year	Peak Generation : Max Temp	Peak Generation : Min Temp	Peak Generation : Peak Load
2002	0.112	-0.031	-0.056
2003			
2004			
2005			
2006			

Table 33: Correlation between the peak GER solar thermal generation and the maximum and minimum daily temperature calculated over all trading intervals. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

GER Generation Correlation Coefficients (Calculated over all dusiness days only)			
Year	Peak Generation : Max Temp	Peak Generation : Min Temp	Peak Generation : Peak Load
2002	0.135	-0.005	-0.064
2003			
2004			
2005			
2006			

Table 34: Correlation between the peak GER solar thermal generation and the maximum and minimum daily temperature calculated over all business day trading intervals. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

ALB Daily Average Generation Correlation Coefficients (Calculated annually over all summer days only)			
Year	Generation : Max Temp	Generation : Min Temp	Generation : Peak Load
2002	0.030	0.220	0.146
2003	-0.052	0.204	-0.014
2004	0.196	0.334	0.329
2005	0.119	0.152	0.101
2006	-0.032	0.251	0.126
2007	0.013	0.222	0.110
2008	0.242	0.328	0.277

Table 35: Correlation between the daily average ALB wind farm generation and the maximum and minimum daily temperature calculated over summer days only. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

GER Daily Average Generation Correlation Coefficients (Calculated annually over all summer days only)			
Year	**Generation : Max Temp**	**Generation : Min Temp**	**Generation : Peak Load**
2002	0.153	-0.110	0.103
2003	0.230	-0.044	0.146
2004	0.182	-0.221	0.037
2005	0.193	-0.155	0.001
2006	0.336	0.060	0.250

Table 36: Correlation between the daily average GER solar thermal generation and the maximum and minimum daily temperature calculated over summer days only. Load has been adjusted for load growth while non-business days have been scaled up to represent business days as discussed in Section 5.5.4.

15 Appendix E: 2008 Interval Selection Histograms and Distributions

As discussed in Section 5.2 generation distribution histograms were developed for Wind Fleet 1 and KLG solar thermal generation for 2008, based on the generation available during the intervals selected by each calculation methodology.

The histograms show the frequency and cumulative probability of the occurrence of generation within a 10% range during the intervals selected by each calculation methodology. The percentage cumulative probability graph is also included in order to show the possibility for generation to be less than or equal to some specific value during chosen intervals. This indicates how a specific site performs in terms of its contribution during peak load intervals.

Note that each figure also includes the calculated Reserve Capacity allocations for each site whereby the cumulative probability curve can also be used to determine the probability of each allocation being met. For example, looking at Figure 93, we can say that the generation will be above average for ~55% of the time (alternatively: generation will be below average for ~45% of the time). One standard deviation is also shown in each figure, as the blue shaded area, in order to indicate the variability of the generation levels around the mean during the intervals selected.

In order to indicate the performance of the recorded and modelled generation the dark blue regions shown on the histograms represents the frequency of occurrence of generation at its limits (0 and 100 percent).

15.1 WLK Histograms and Distributions (Wind)

<u>All Intervals</u>

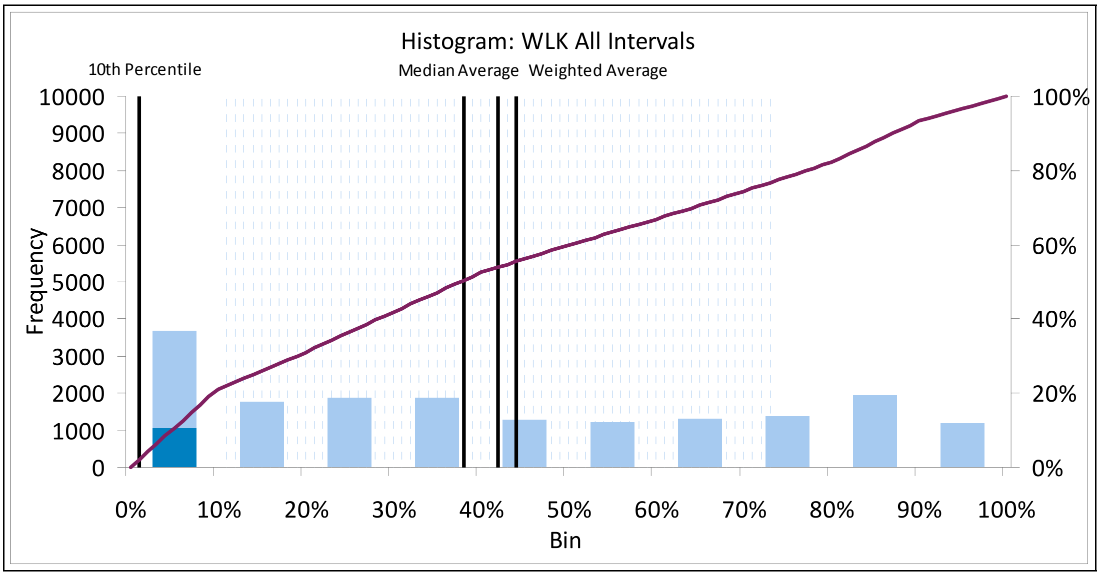

Figure 93: Generation distribution histogram considering all 2008 trading intervals for WLK. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

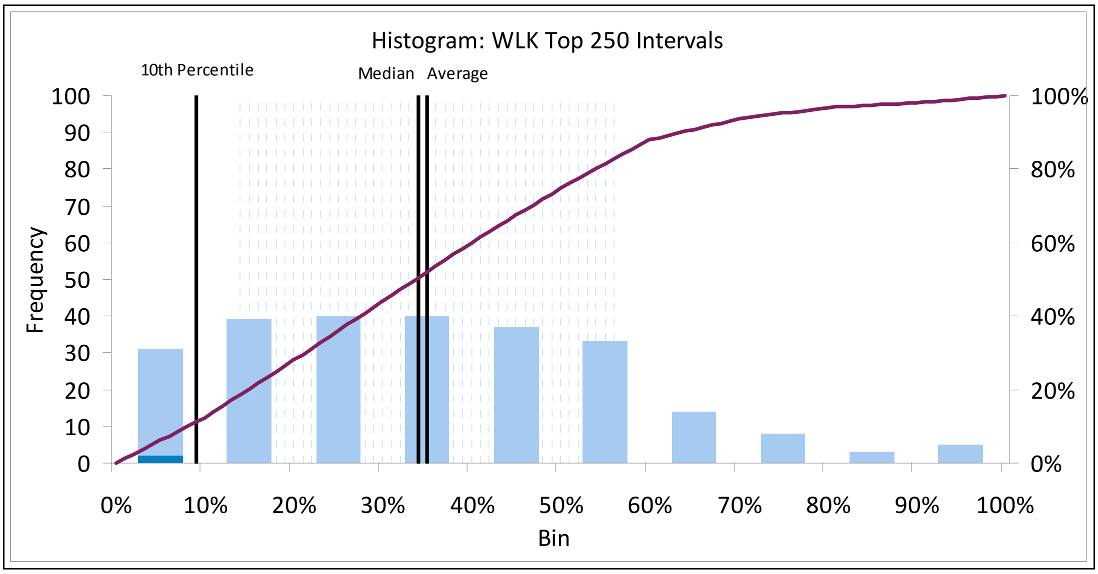

Figure 94: Generation distribution histogram considering the Top 250 2008 trading intervals for WLK. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

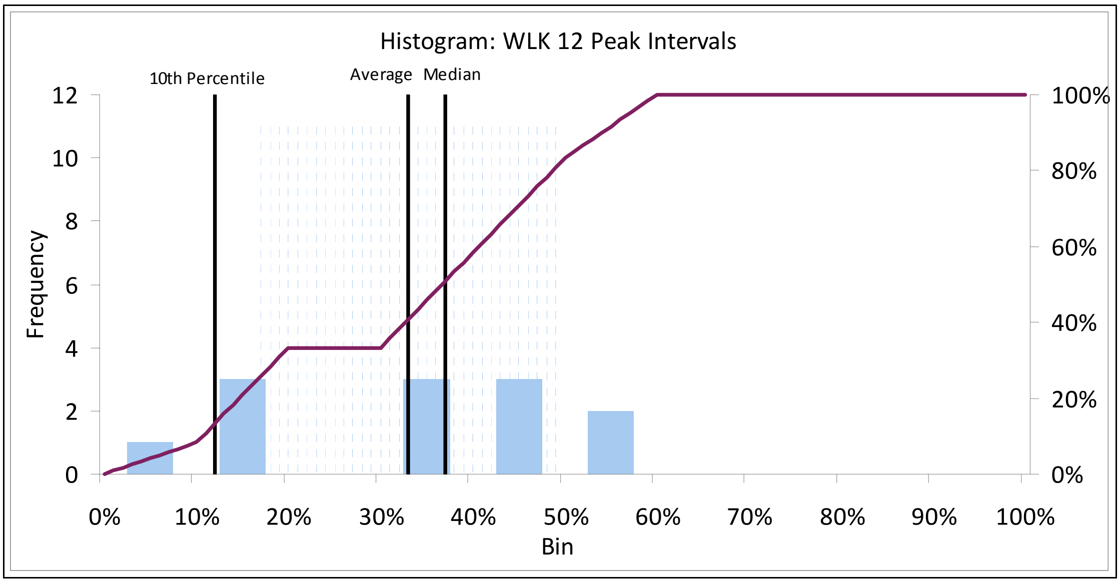

Figure 95: Generation distribution histogram considering the 12 Peak 2008 trading intervals for WLK. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

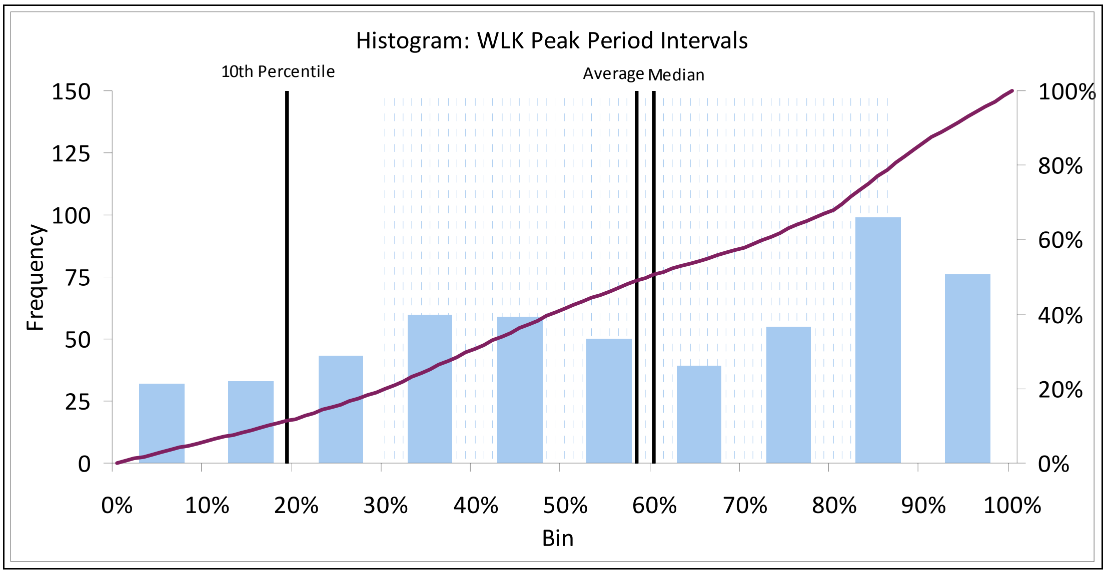

Figure 96: Generation distribution histogram considering the Peak Period 2008 trading intervals for WLK. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.2 EMU Histograms and Distributions (Wind)

All Intervals

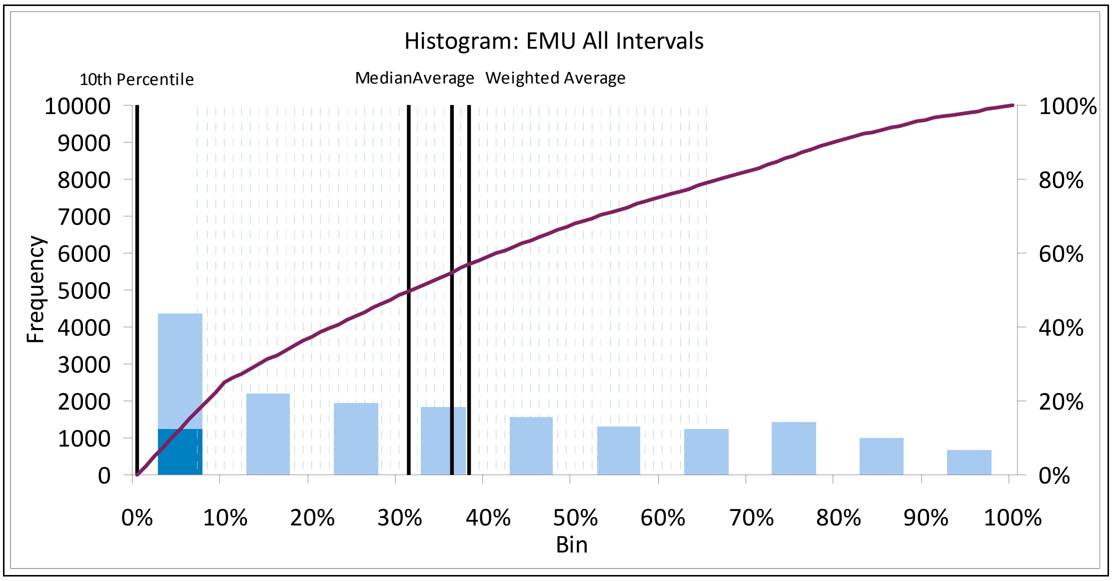

Figure 97: Generation distribution histogram considering all 2008 trading intervals for EMU. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

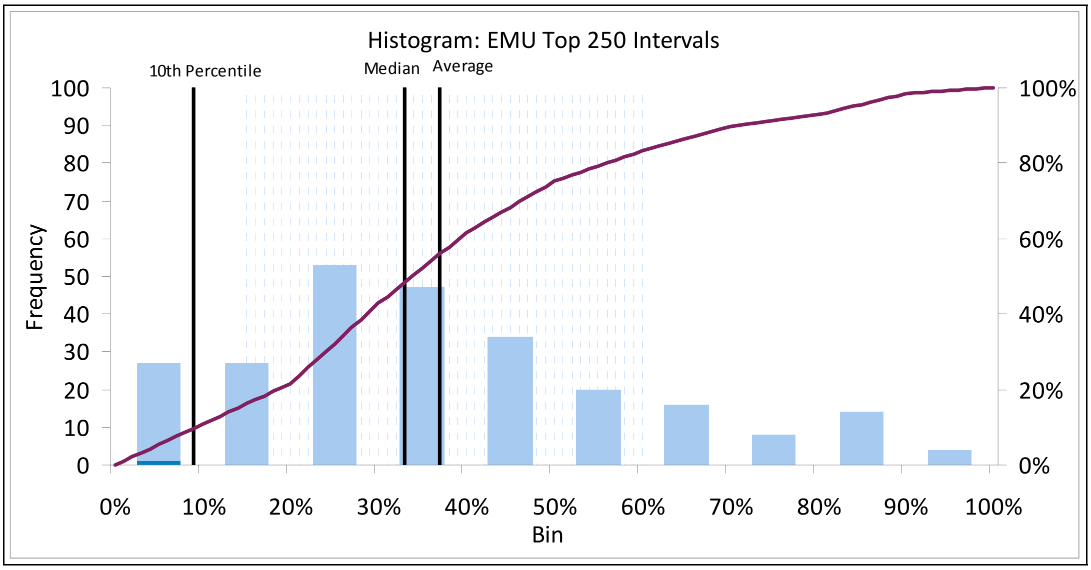

Figure 98: Generation distribution histogram considering the Top 250 2008 trading intervals for EMU. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

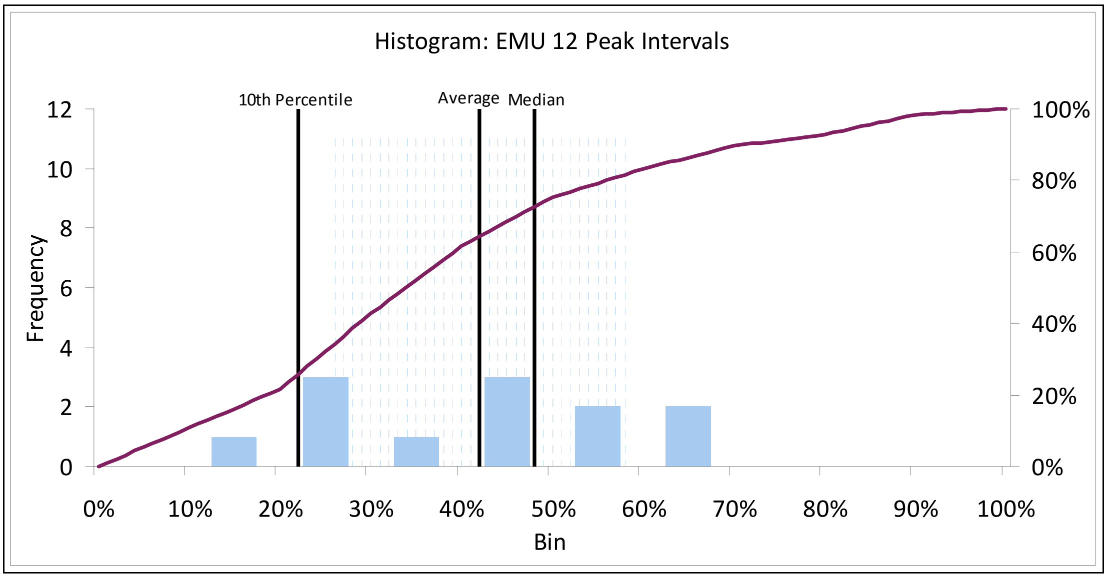

Figure 99: Generation distribution histogram considering the 12 Peak 2008 trading intervals for EMU. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

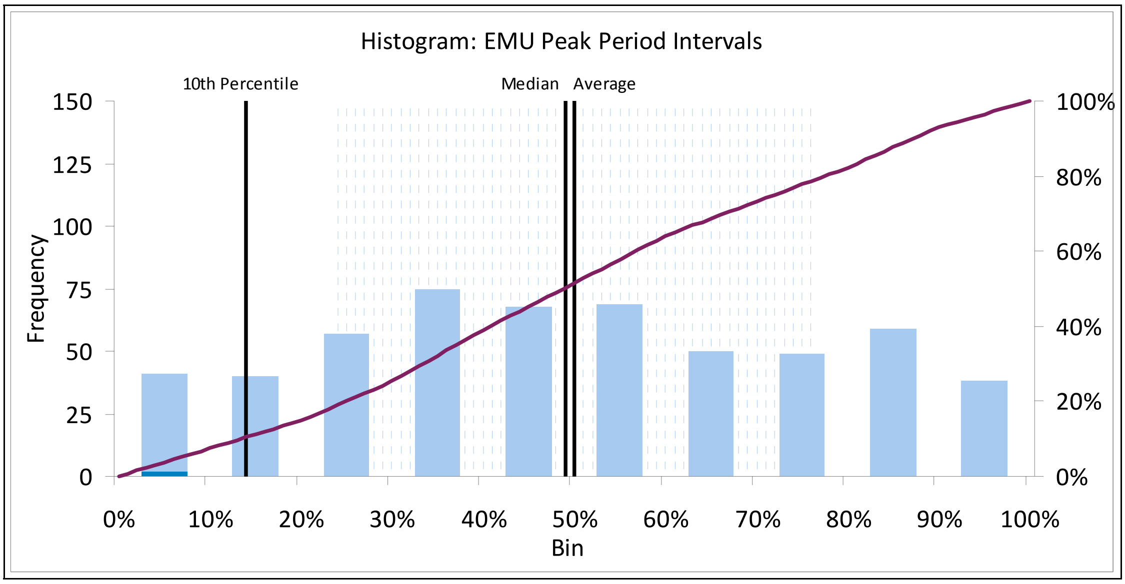

Figure 100: Generation distribution histogram considering the Peak Period 2008 trading intervals for EMU. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.3 CDD Histograms and Distributions (Wind)

All Intervals

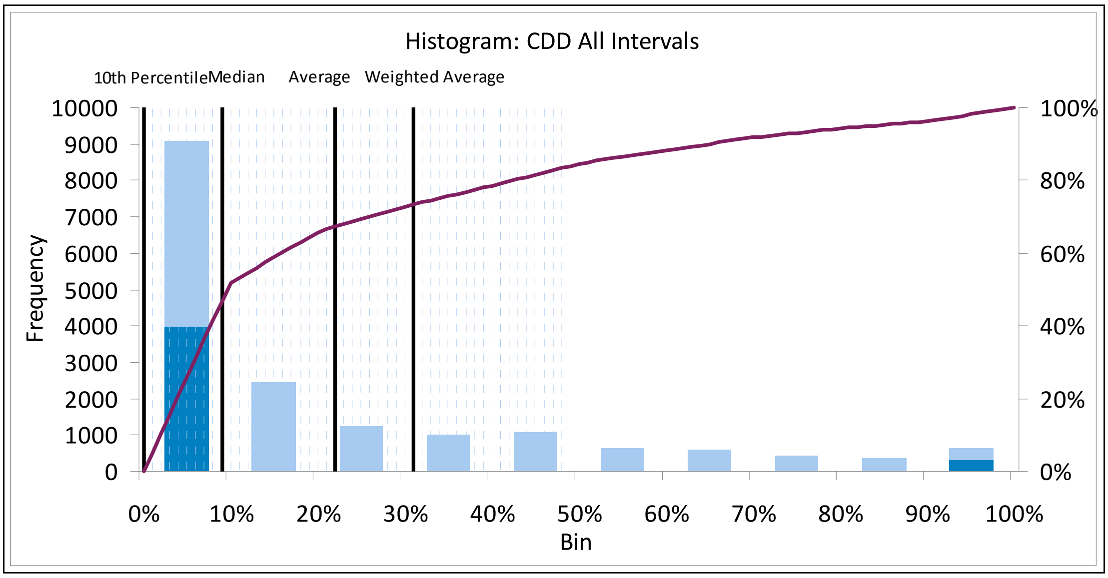

Figure 101: Generation distribution histogram considering all 2008 trading intervals for CDD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

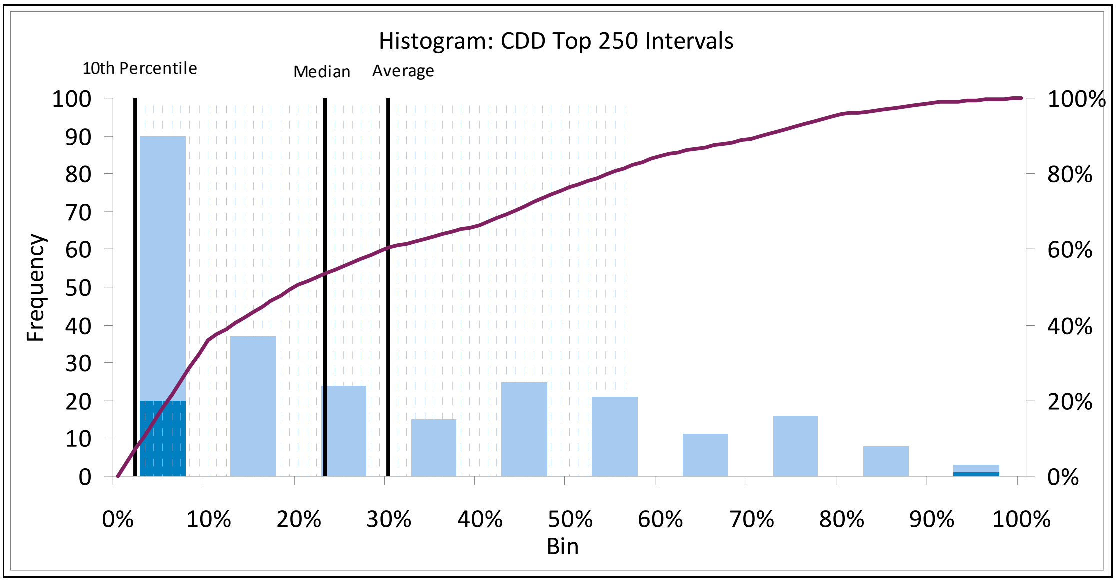

Figure 102: Generation distribution histogram considering the Top 250 2008 trading intervals for CDD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

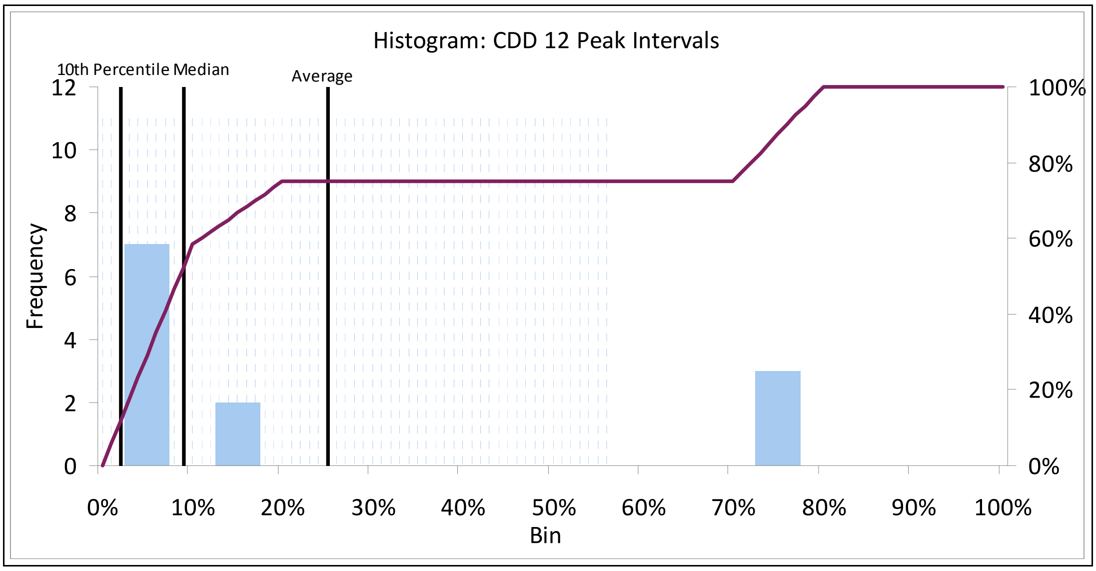

Figure 103: Generation distribution histogram considering the 12 Peak 2008 trading intervals for CDD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

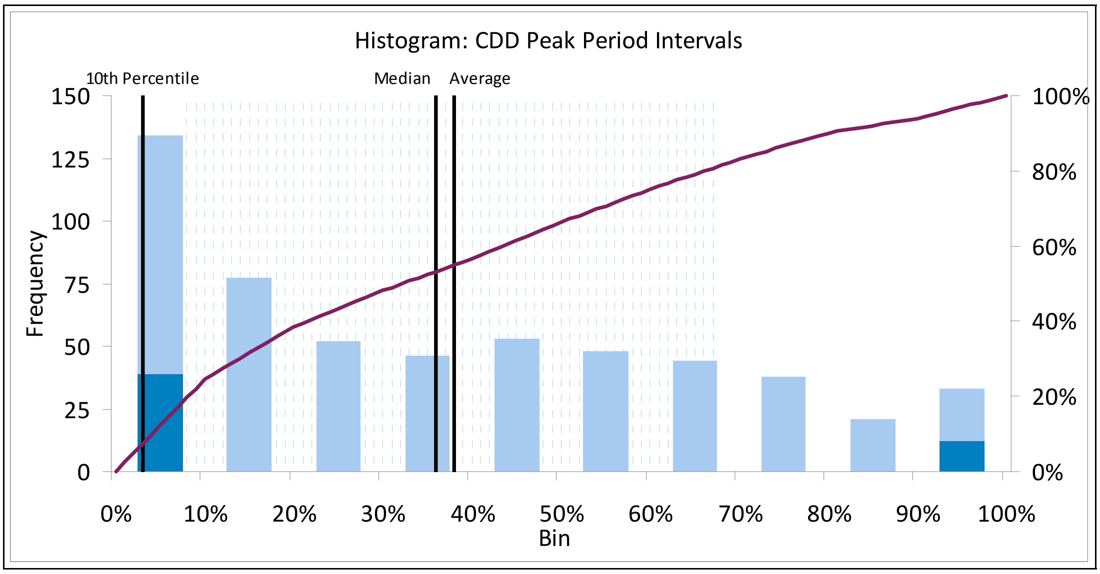

Figure 104: Generation distribution histogram considering the Peak Period 2008 trading intervals for CDD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.4 KBD Histograms and Distributions (Wind)

All Intervals

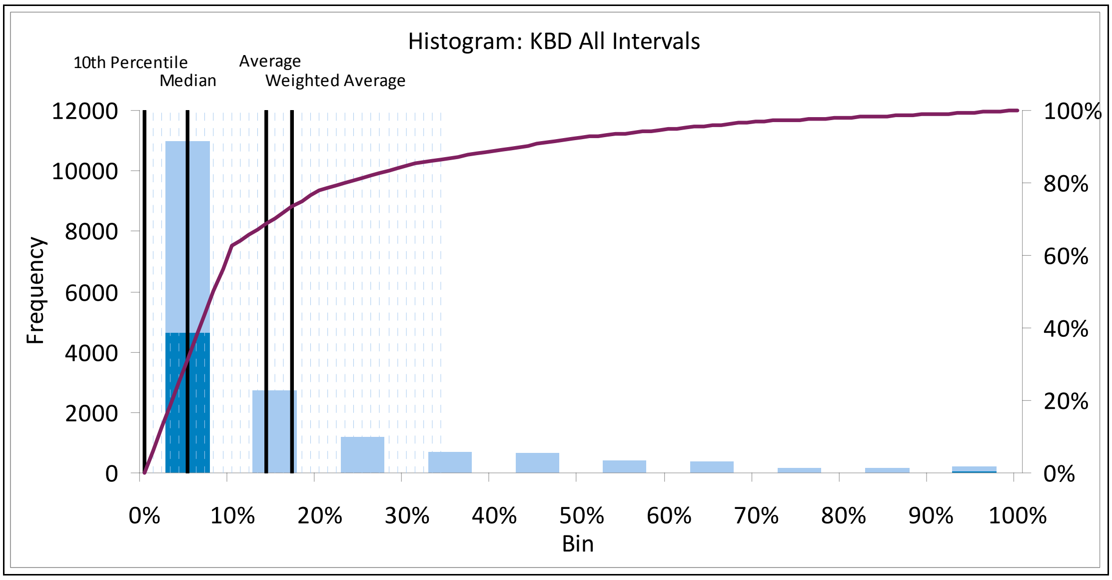

Figure 105: Generation distribution histogram considering all 2008 trading intervals for KBD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

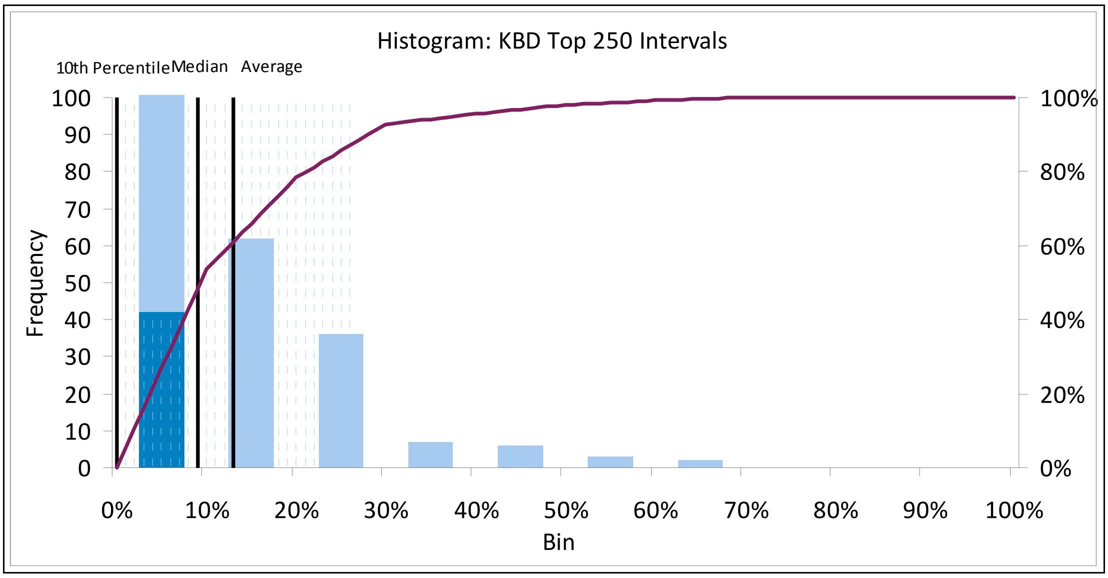

Figure 106: Generation distribution histogram considering the Top 250 2008 trading intervals for KBD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

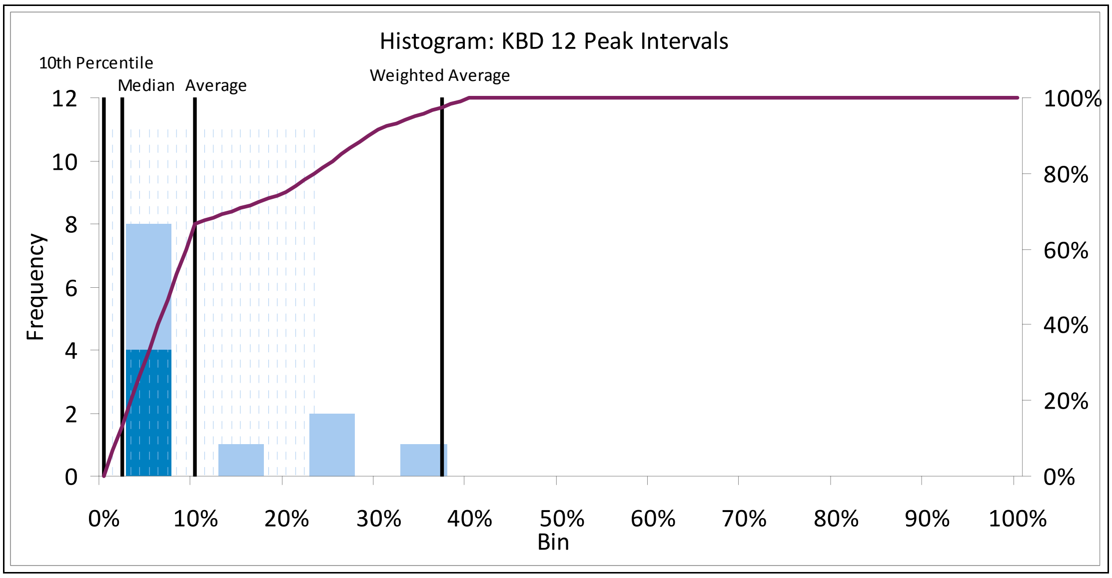

Figure 107: Generation distribution histogram considering the 12 Peak 2008 trading intervals for KBD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

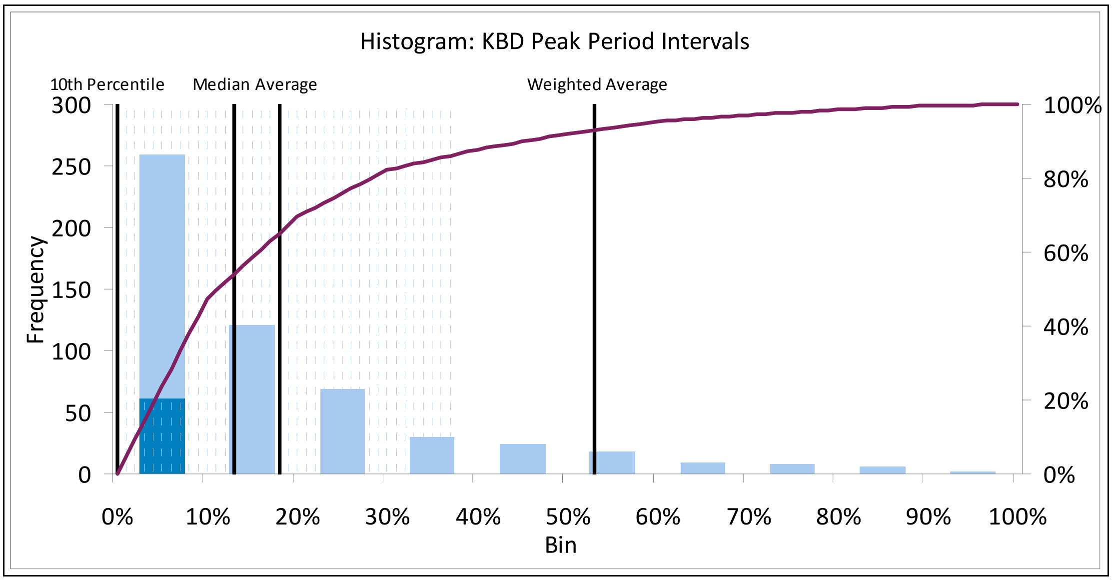

Figure 108: Generation distribution histogram considering the Peak Period 2008 trading intervals for KBD. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.5 CPN Histograms and Distributions (Wind)

All Intervals

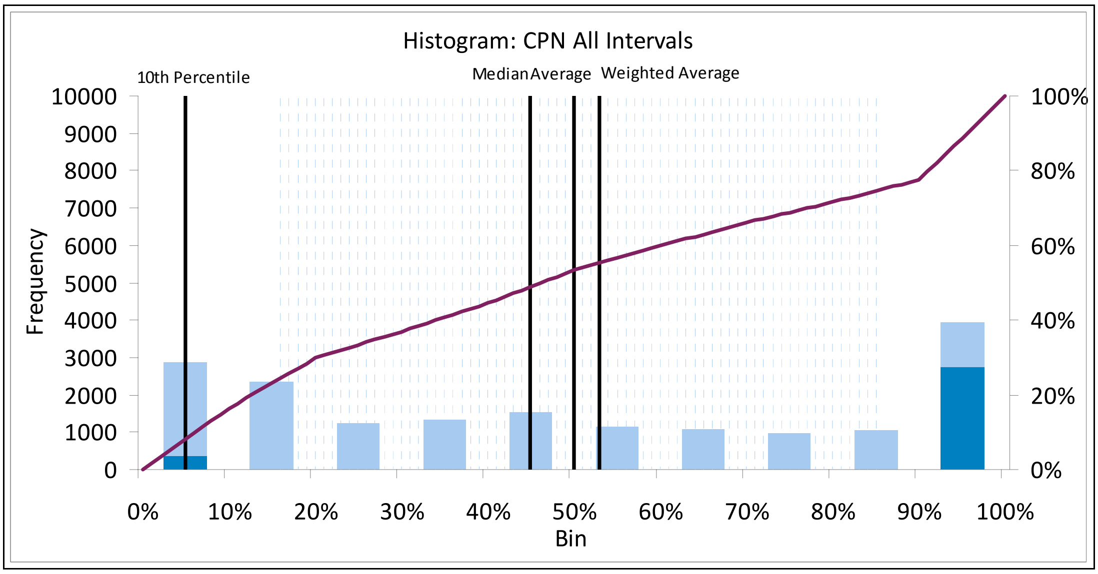

Figure 109: Generation distribution histogram considering all 2008 trading intervals for CPN. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

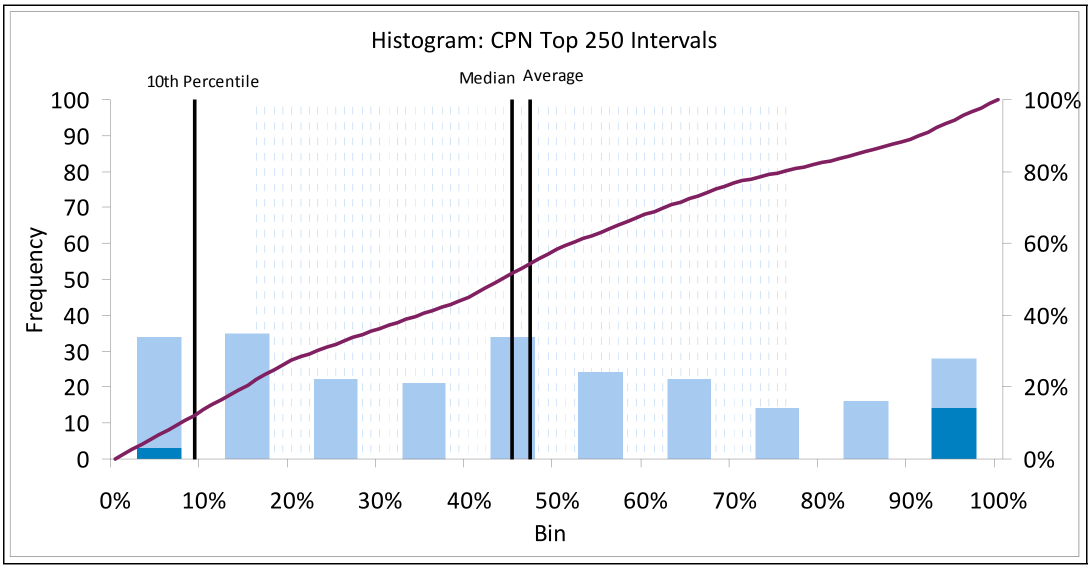

Figure 110: Generation distribution histogram considering the Top 250 2008 trading intervals for CPN. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

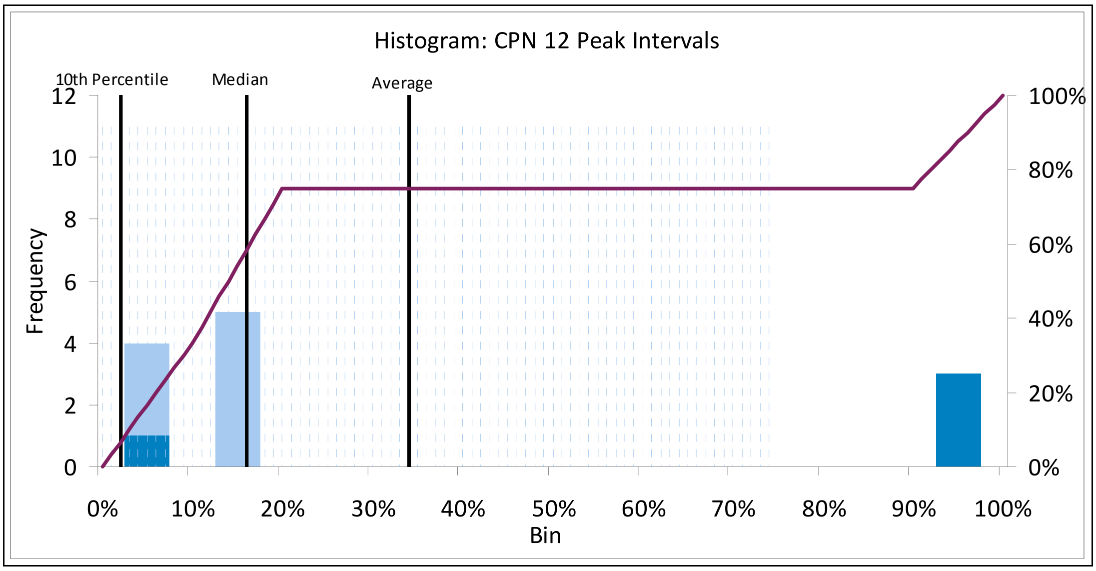

Figure 111: Generation distribution histogram considering the 12 Peak 2008 trading intervals for CPN. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

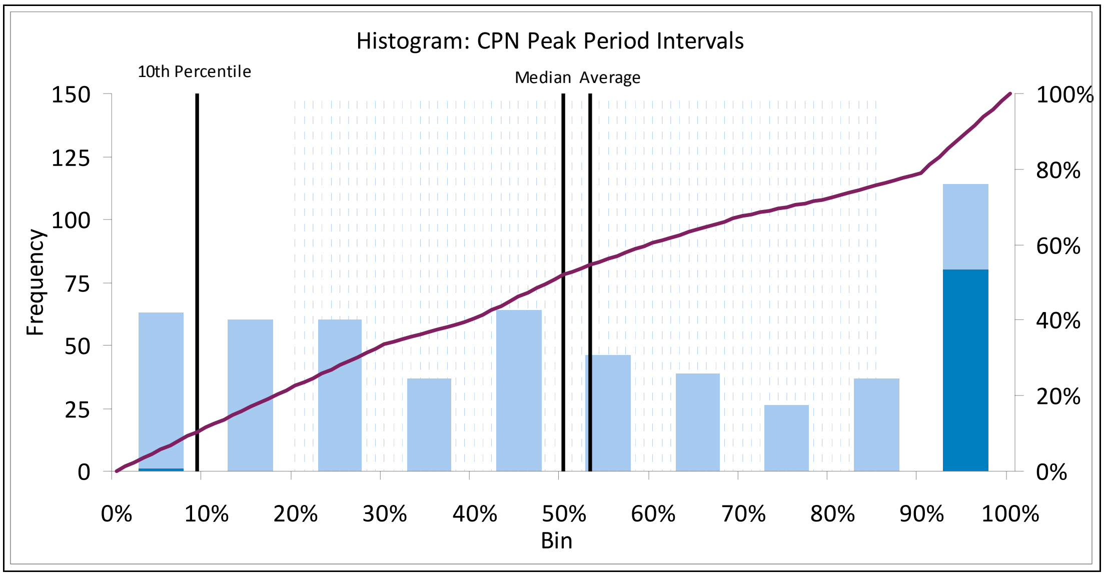

Figure 112: Generation distribution histogram considering the Peak Period 2008 trading intervals for CPN. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.6 ALB Histograms and Distributions (Wind)

All Intervals

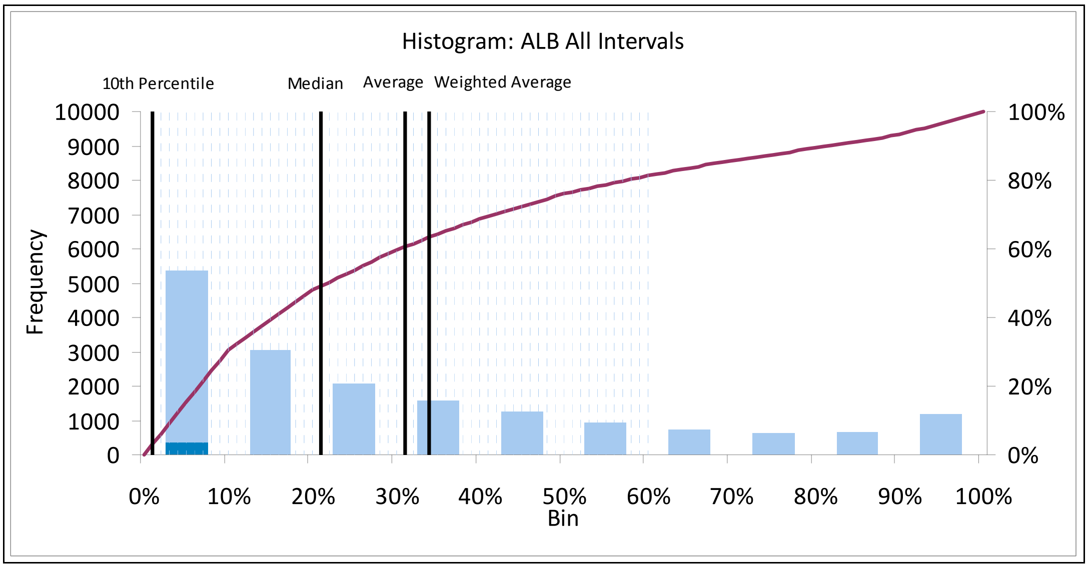

Figure 113: Generation distribution histogram considering all 2008 trading intervals for ALB. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

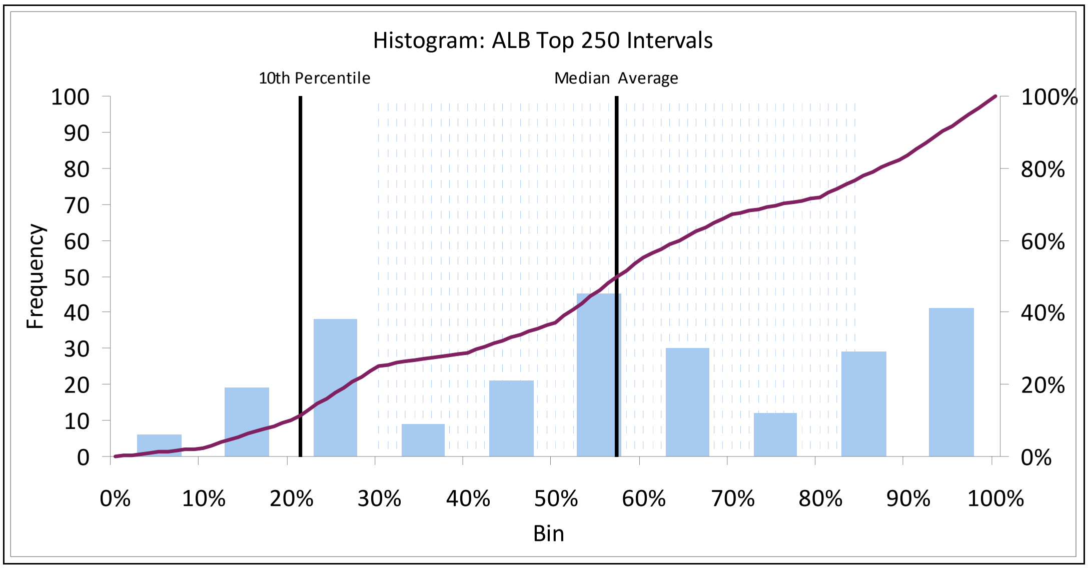

Figure 114: Generation distribution histogram considering the Top 250 2008 trading intervals for ALB. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

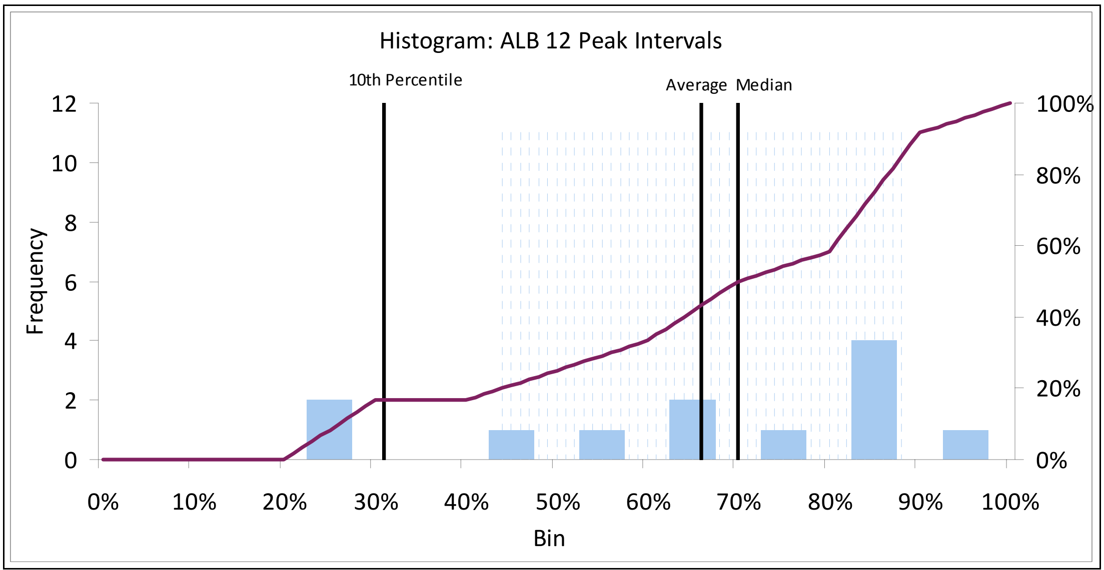

Figure 115: Generation distribution histogram considering the 12 Peak 2008 trading intervals for ALB. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

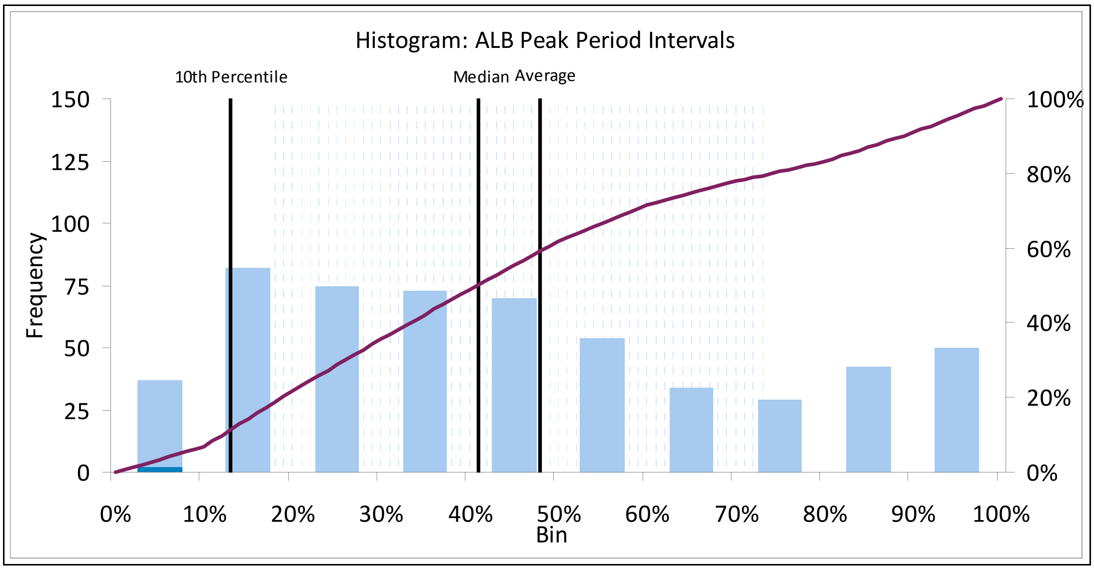

Figure 116: Generation distribution histogram considering the Peak Period 2008 trading intervals for ALB. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.7 HPT Histograms and Distributions (Wind)

All Intervals

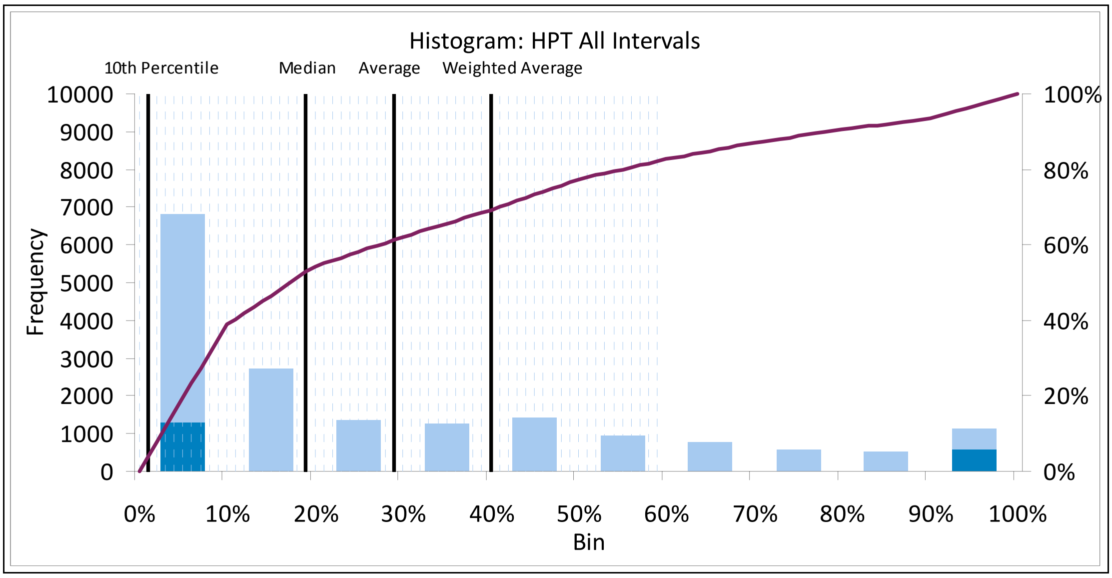

Figure 117: Generation distribution histogram considering all 2008 trading intervals for HPT. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

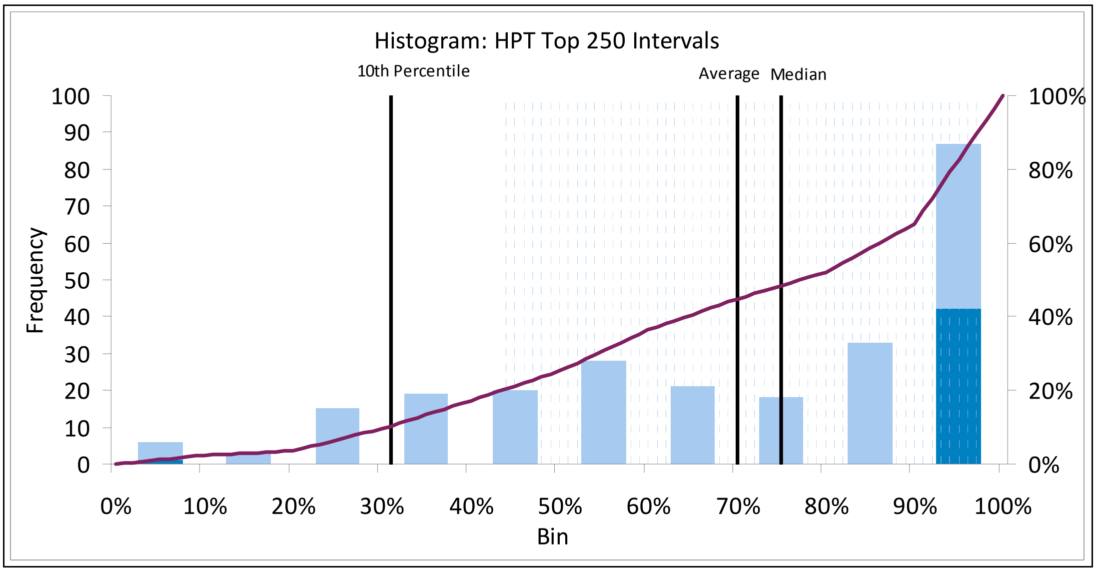

Figure 118: Generation distribution histogram considering the Top 250 2008 trading intervals for HPT. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

12 Peak Intervals

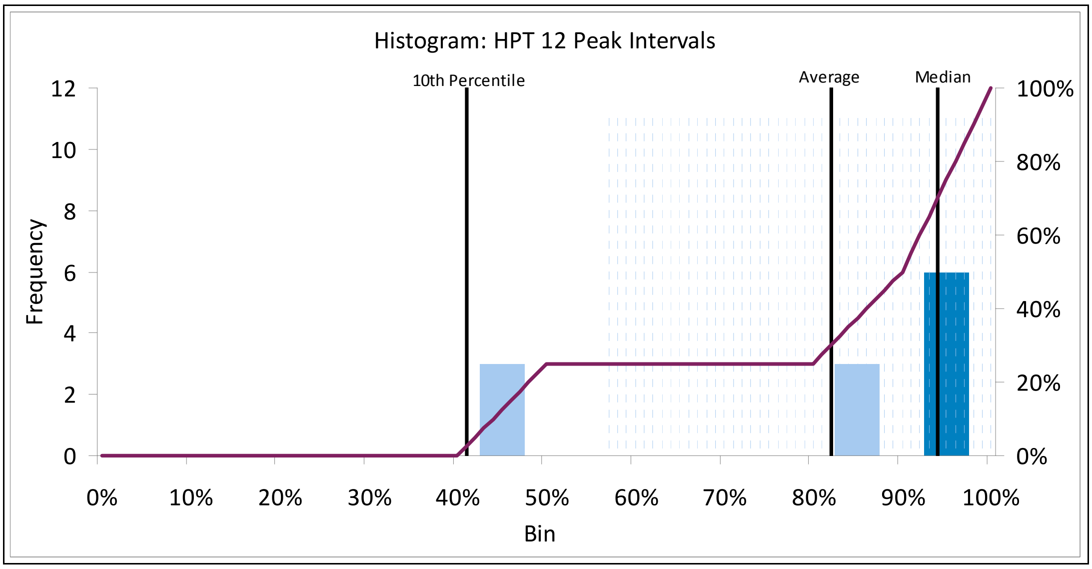

Figure 119: Generation distribution histogram considering the 12 Peak 2008 trading intervals for HPT. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

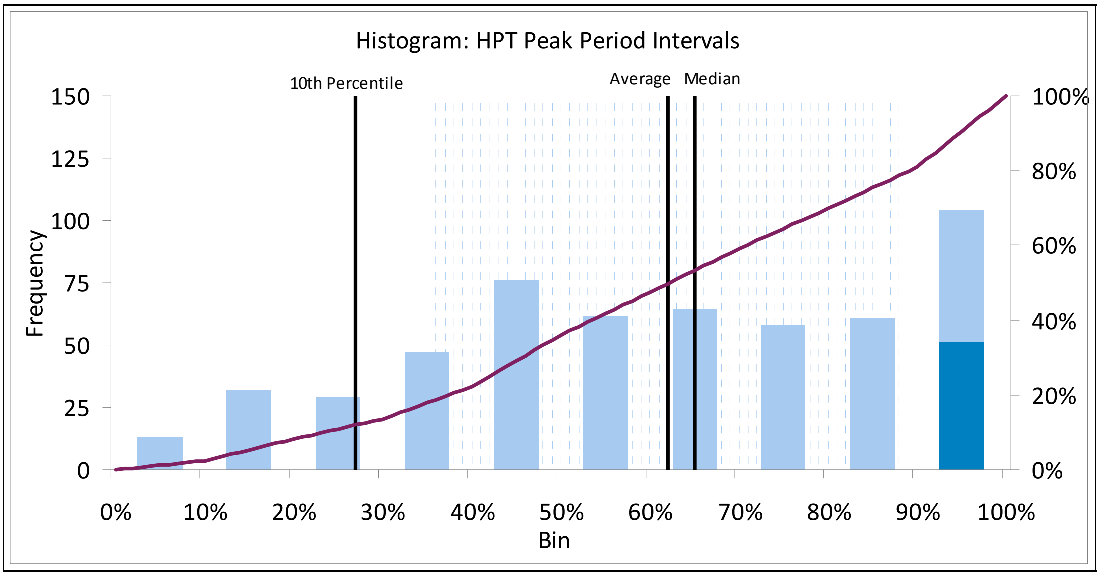

Figure 120: Generation distribution histogram considering the Peak Period 2008 trading intervals for HPT. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

15.8 KLG Histograms and Distributions (Solar Thermal)

All Intervals

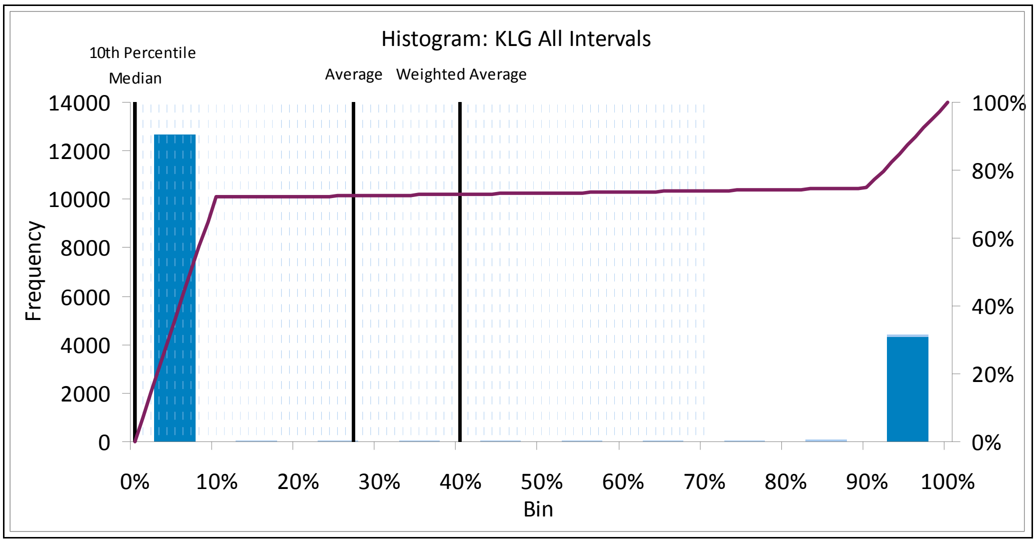

Figure 121: Generation distribution histogram considering all 2005 trading intervals for KLG. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Top 250 Intervals

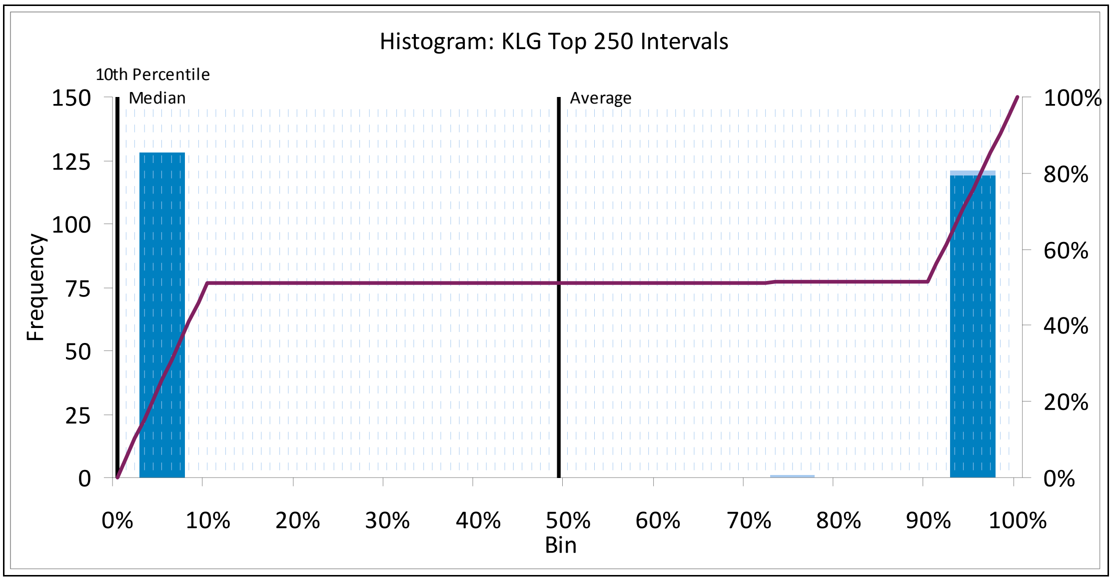

Figure 122: Generation distribution histogram considering the Top 250 2005 trading intervals for KLG. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).v

12 Peak Intervals

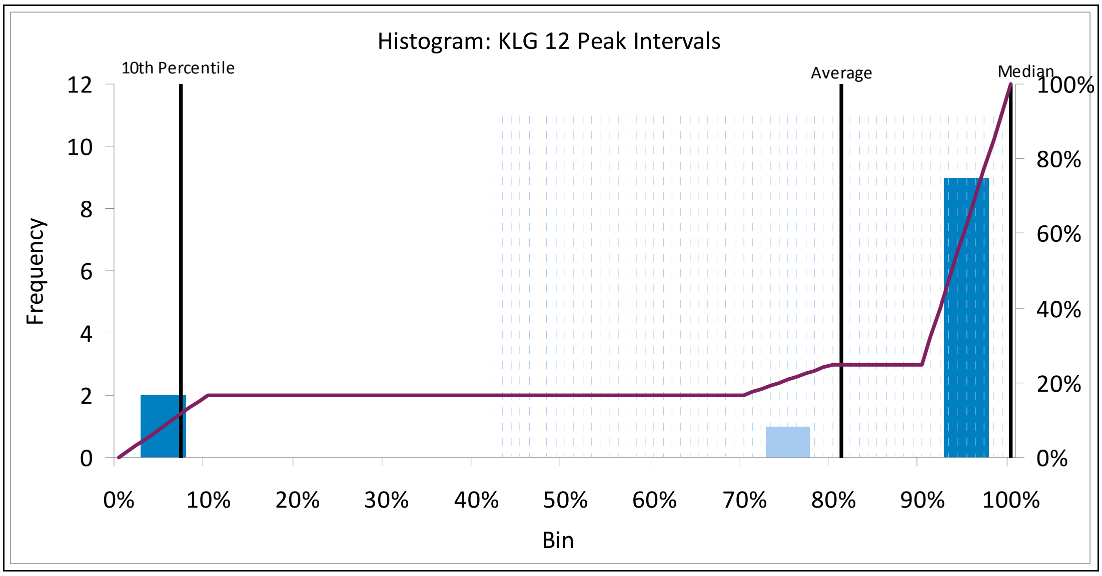

Figure 123: Generation distribution histogram considering the 12 Peak 2005 trading intervals for KLG. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

Peak Period Intervals

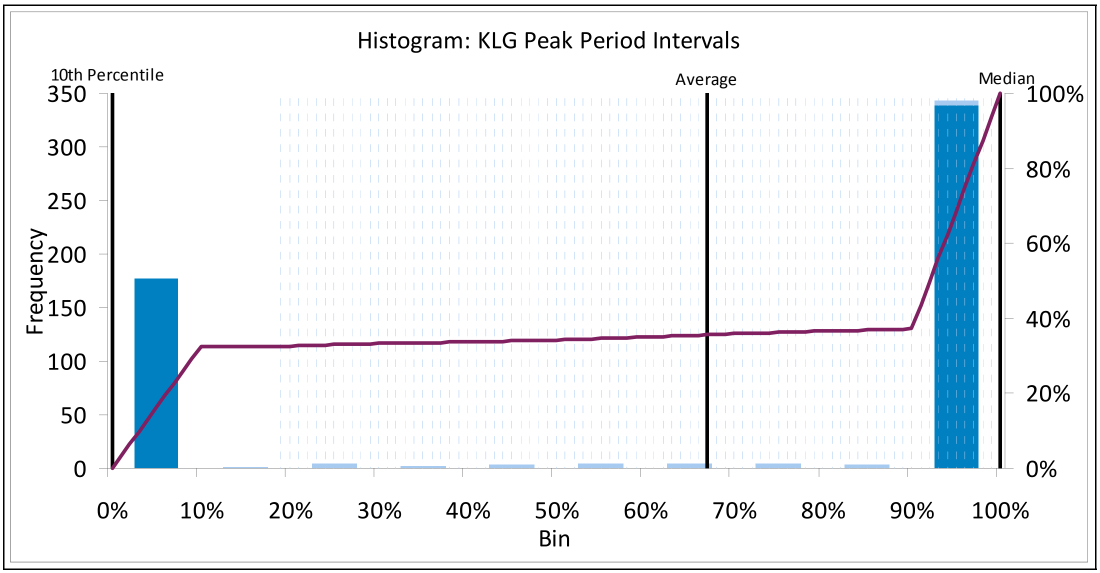

Figure 124: Generation distribution histogram considering the Peak Period 2005 trading intervals for KLG. The 2008 single year Reserve Capacity allocations are shown for each calculation methodology along with the cumulative probability function reflected in the right hand y axes. Note that the x axes is normalised generation showing bin end points for the histogram function and generation for the cumulative probability function and calculated Reserve Capacity allocations. One standard deviation from the mean is shown by the blue shaded area and the dark blue regions on the histogram represent the frequency of generation occurring at its limits (0 and 100 percent respectively).

16 Appendix F: Fleet Diversity Impacts Investigation Results

The Fleet Diversity Impacts Investigation considered the impact of the expansion of a base wind fleet, located in the Perth / Geraldton region into alternative regions in terms of the resource and diversity impacts and the effect of regional weather patterns. This section of the Appendix contains the full results of the Fleet Impacts investigation.

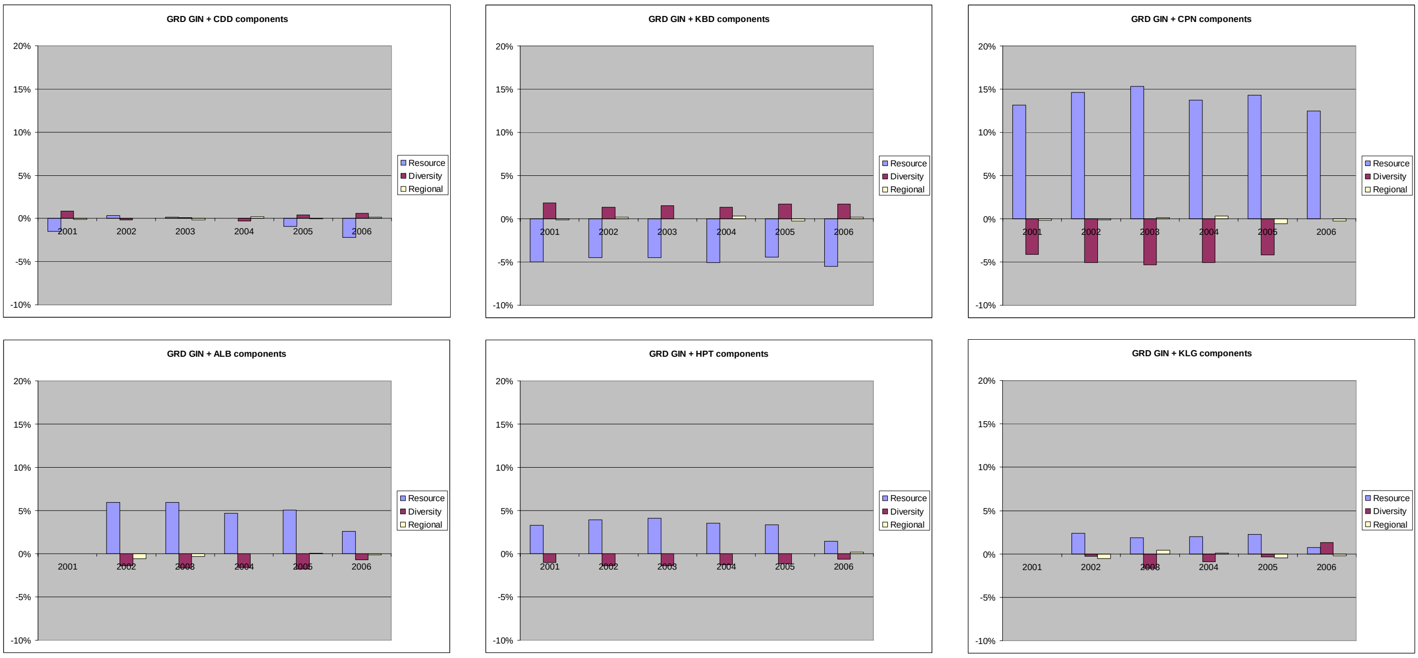

Figure 125: Fleet Impacts investigation results based on the Current method. Base fleet: GRD and GIN.

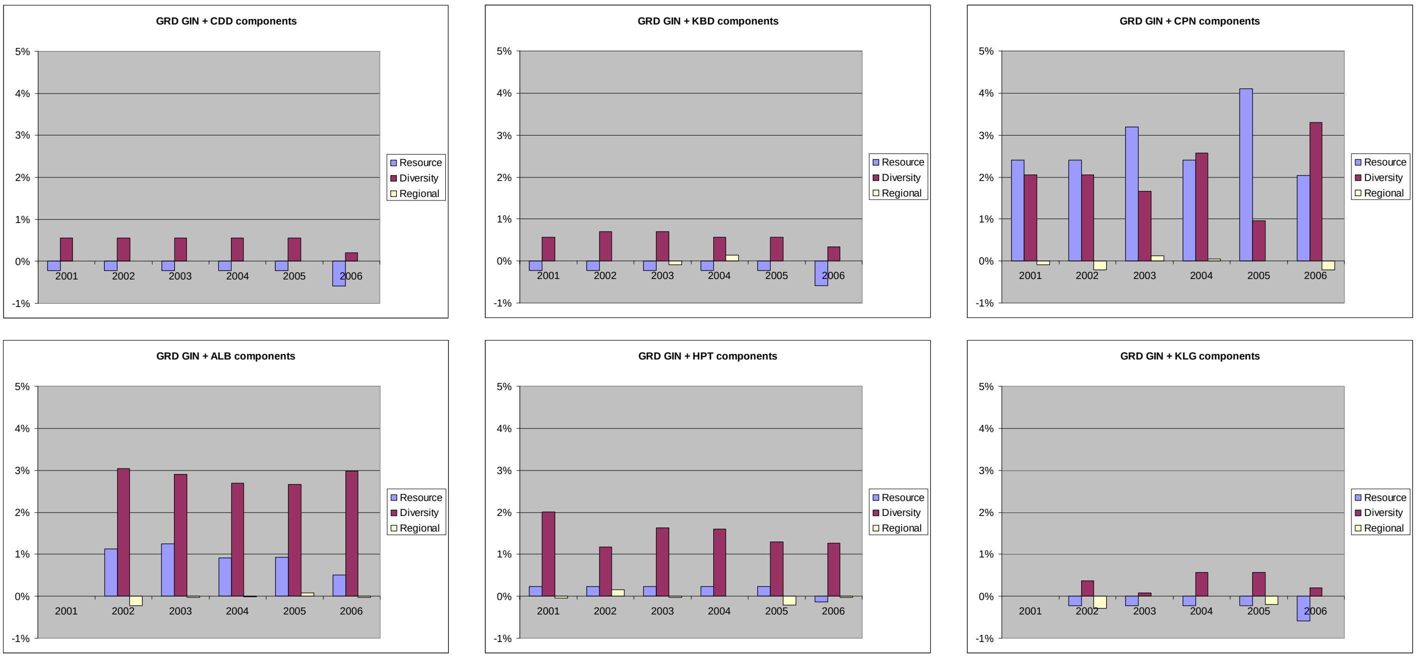

Figure 126: Fleet Impacts investigation results based on the 10th percentile of All intervals. Base fleet: GRD and GIN.

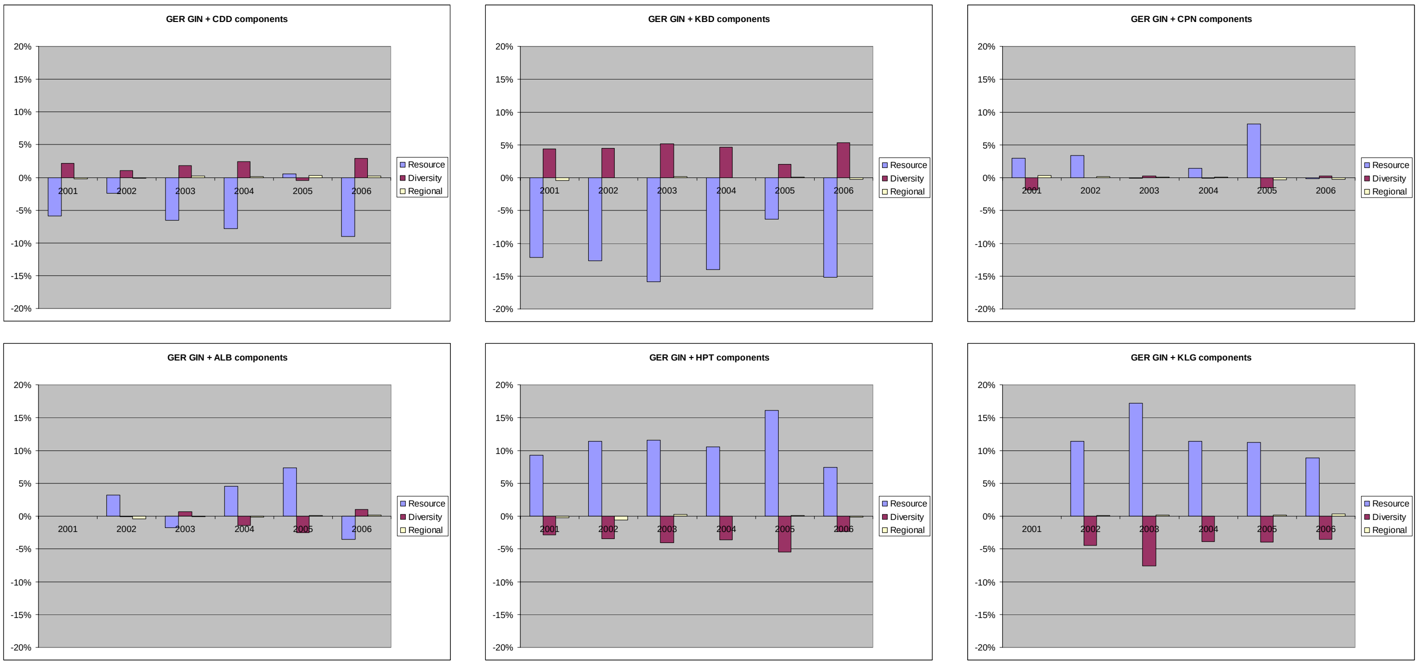

Figure 127: Fleet Impacts investigation results based on the average of the Top 250 intervals. Base fleet: GRD and GIN.

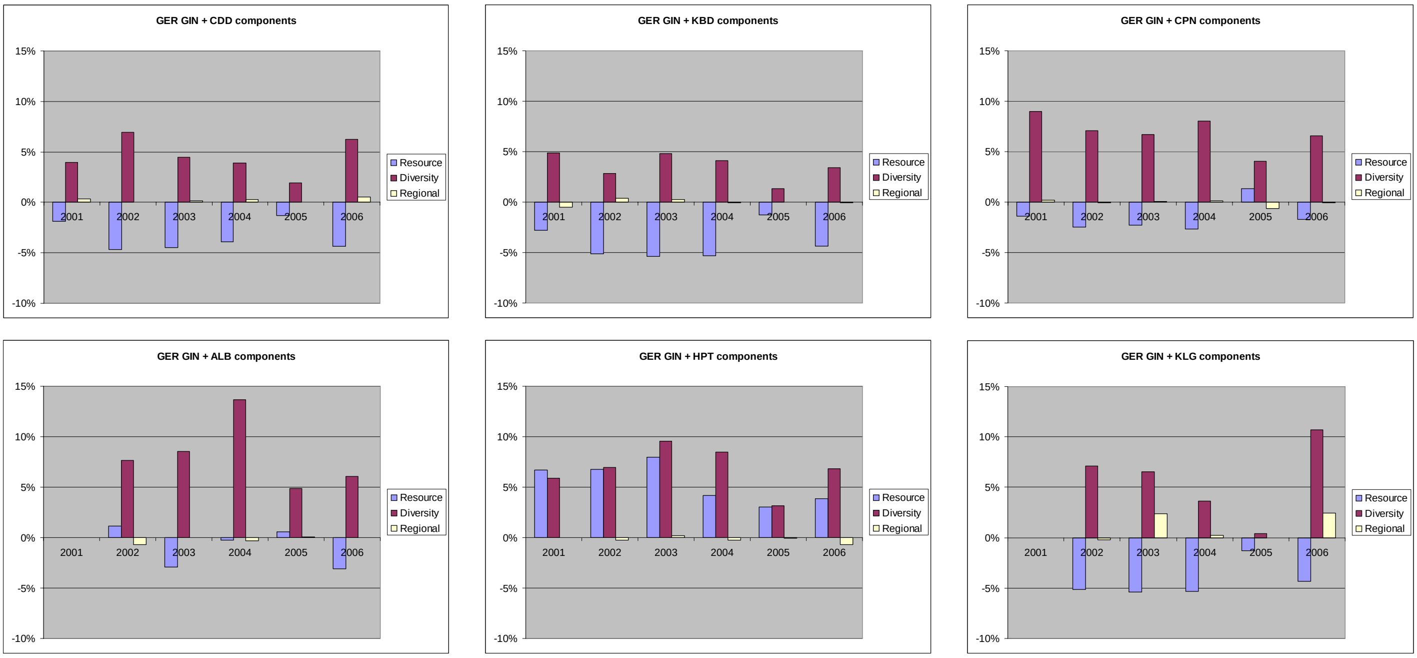

Figure 128: Fleet Impacts investigation results based on the Proposed method. Base fleet: GRD and GIN.

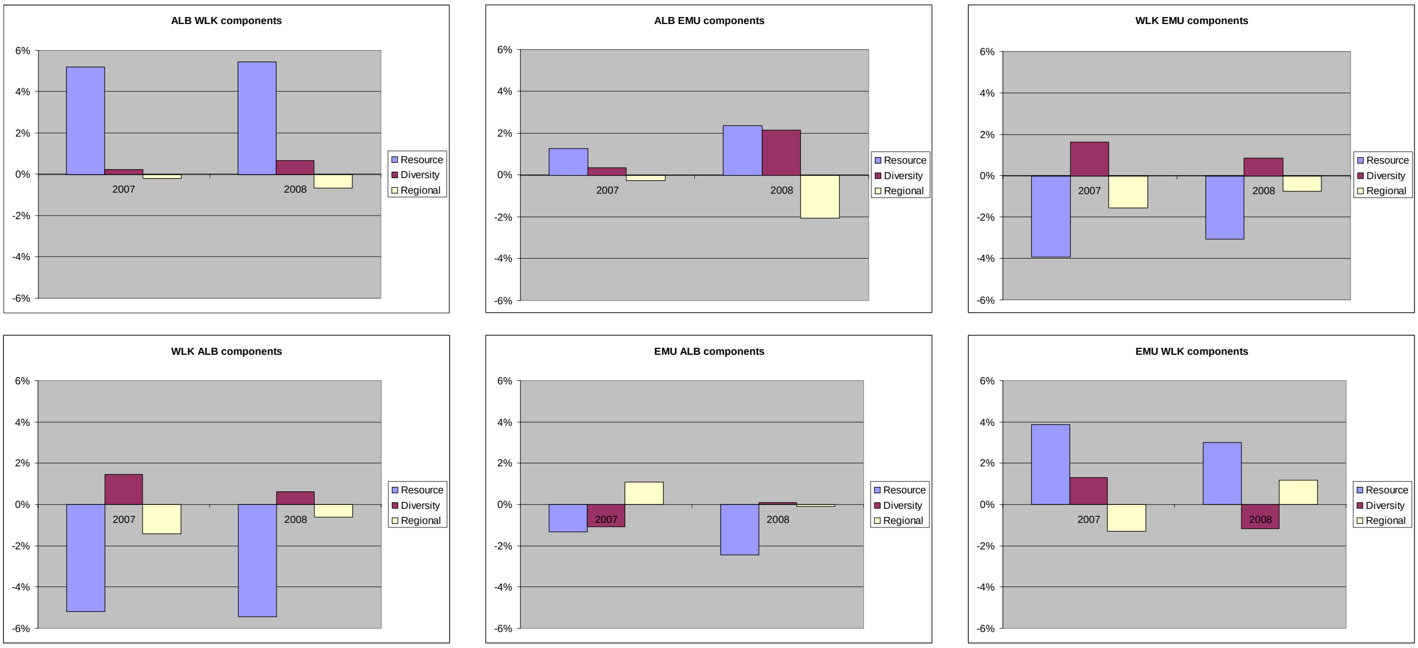

Figure 129: Fleet Impacts investigation results based on the Current method for the existing wind fleet.

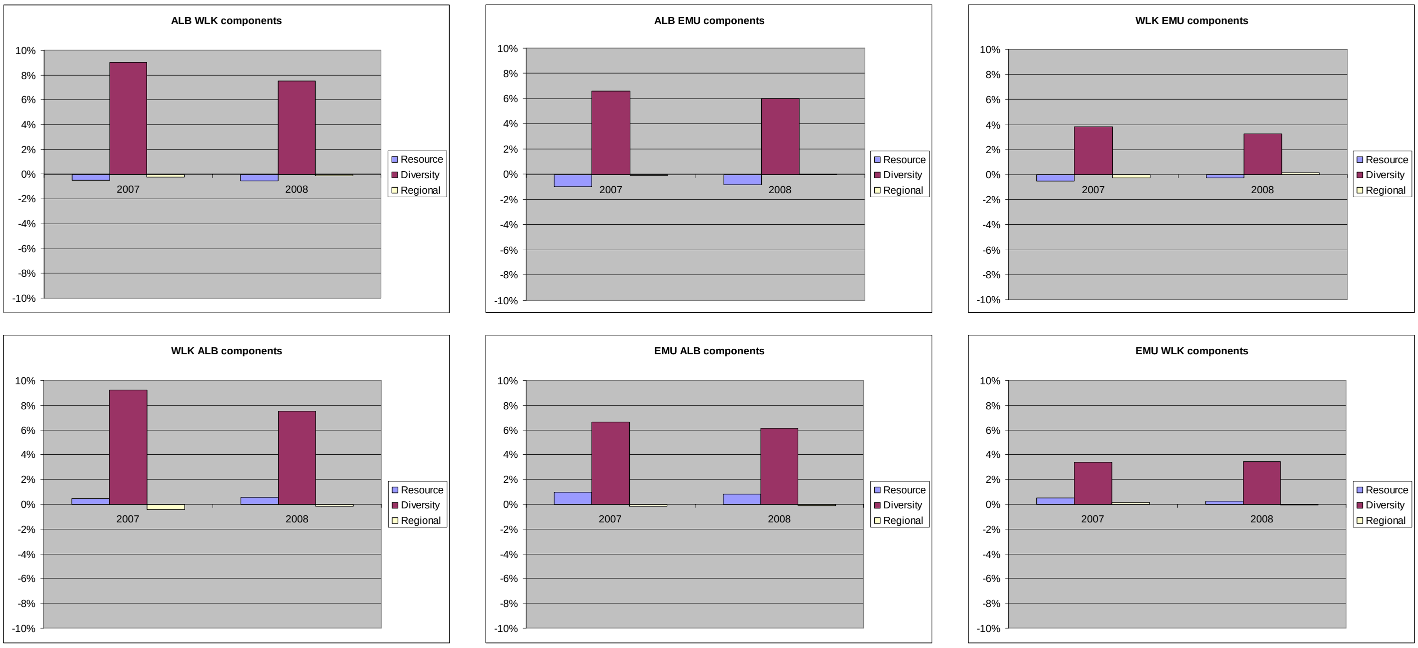

Figure 130: Fleet Impacts investigation results based on the 10th percentile of All intervals for the existing wind fleet.

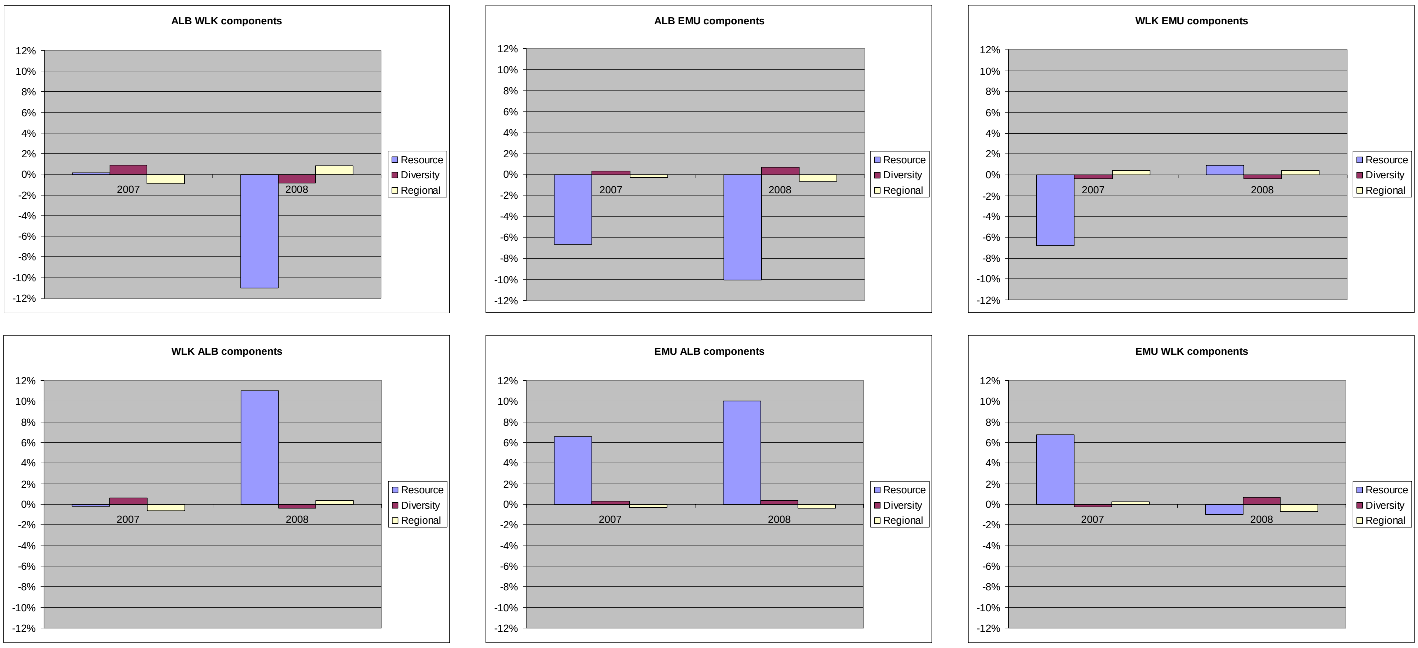

Figure 131: Fleet Impacts investigation results based on the average of the Top 250 intervals for the existing wind fleet.

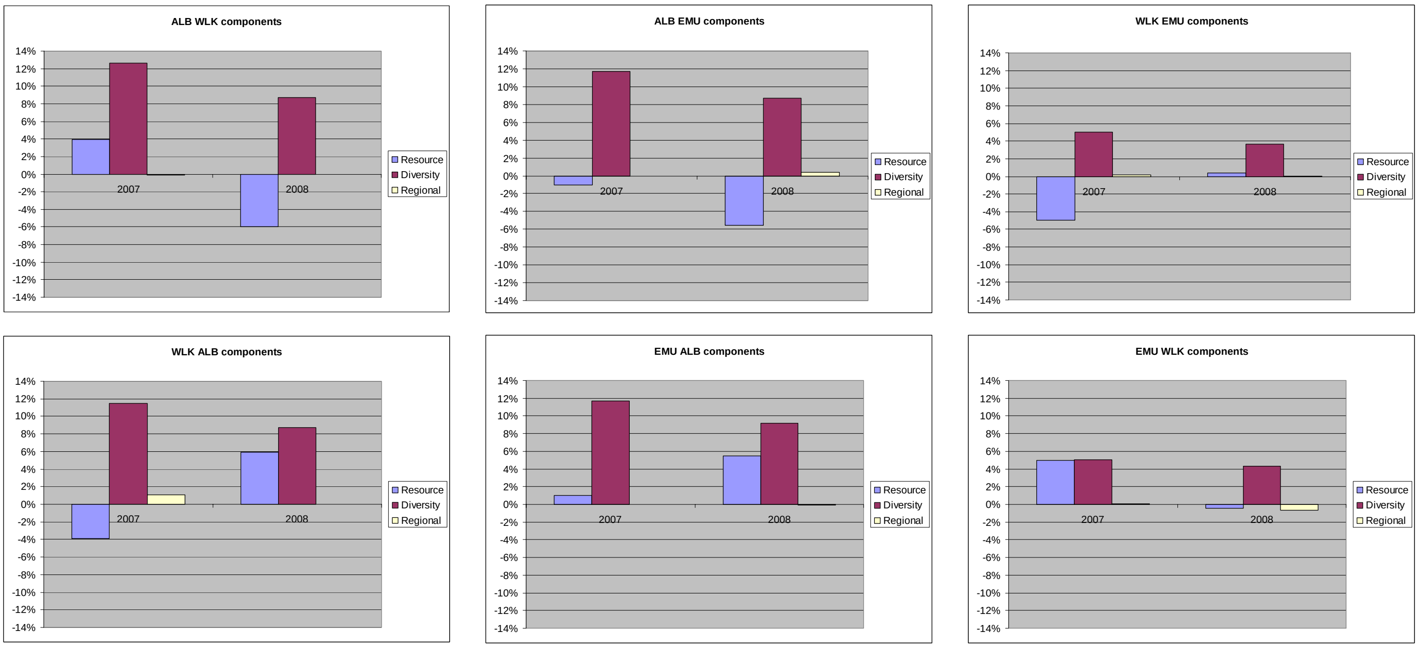

Figure 132: Fleet Impacts investigation results based on the Proposed method for the existing wind fleet.

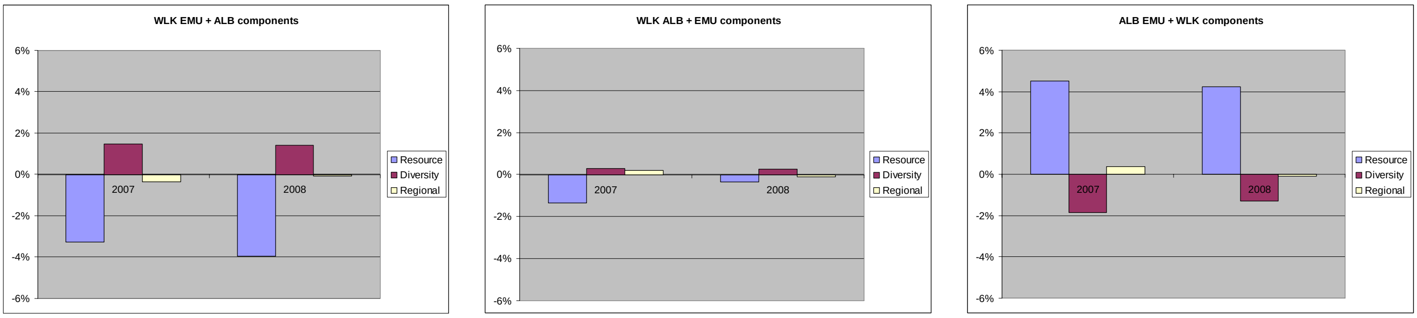

Figure 133: Fleet Impacts investigation results based on the Current method for the existing wind fleet where the base fleet varies.

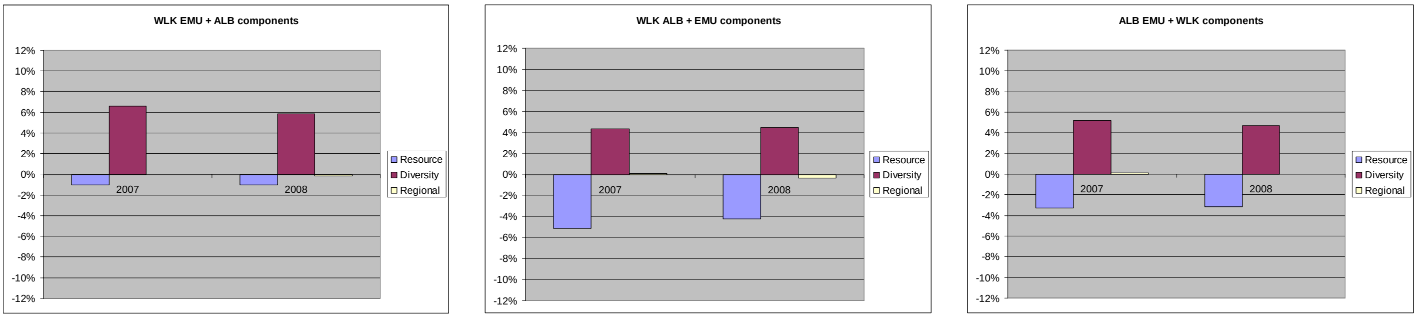

Figure 134: Fleet Impacts investigation results based on the 10th percentile of All intervals for the existing wind fleet where the base fleet varies.

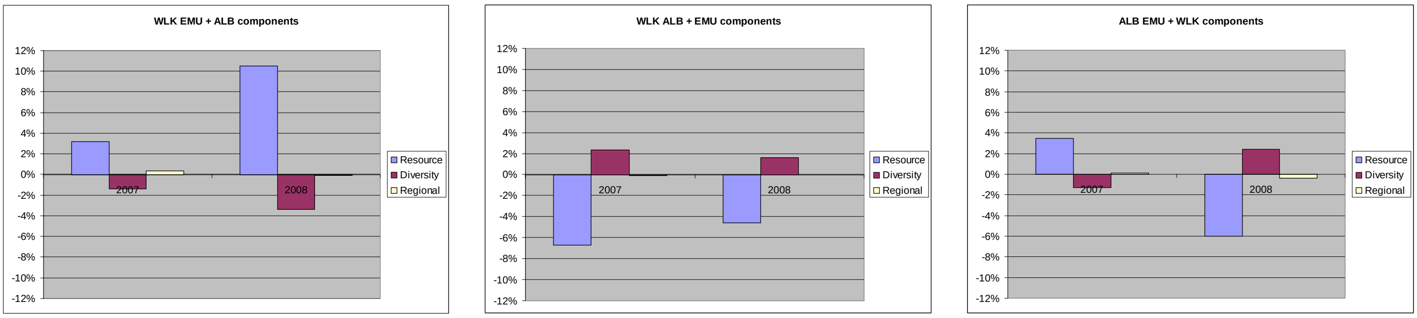

Figure 135: Fleet Impacts investigation results based on the average of the Top 250 intervals for the existing wind fleet where the base fleet varies.

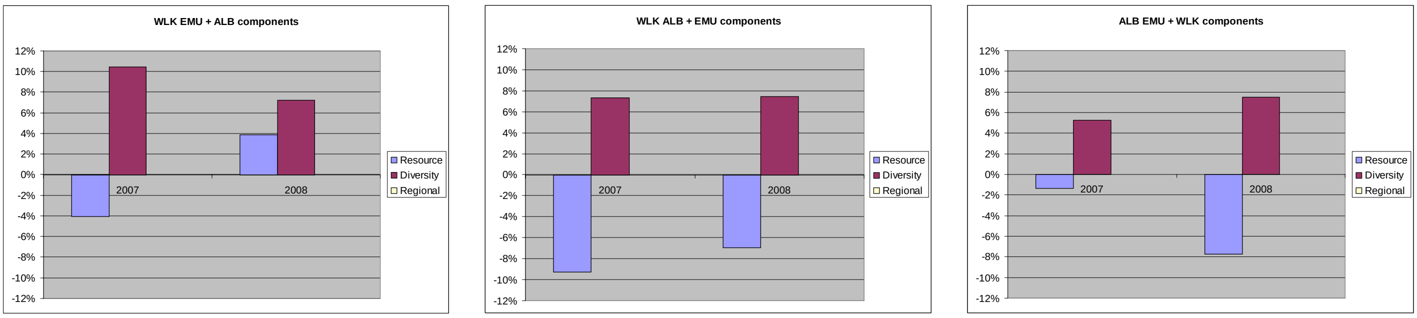

Figure 136: Fleet Impacts investigation results based on the Proposed method for the existing wind fleet where the base fleet varies.

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17 Appendix G: Comparison of Calendar and Capacity Year Results

As discussed in Section 5.5.3 Reserve Capacity calculations were re-run for one wind generator for the 2005-7 Capacity Years. Table 13 contains a summary of the error between the corresponding years while Table 37 and Table 38 contain the resulting Reserve Capacity allocations for each year. Note that there is a strong likeness between calendar years and Capacity Years as the Capacity Year is simply an average of the encompassing calendar years, and vice versa.

Reserve Capacity Allocation (P/Pmax) CalendarYear 2005				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	33.28%	41.85%	57.73%	38.73%
10th Percentile	2.31%	3.66%	15.71%	6.56%
Median	24.97%	28.78%	72.92%	27.66%
Weighted Average	35.09%	147.59%	246.10%	111.37%
Reserve Capacity Allocation (P/Pmax) CalendarYear 2006				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	29.87%	34.37%	43.29%	34.13%
10th Percentile	2.18%	2.49%	1.70%	7.27%
Median	20.73%	23.75%	41.34%	26.93%
Weighted Average	29.21%	129.66%	184.52%	100.03%
Reserve Capacity Allocation (P/Pmax) CalendarYear 2007				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	34.40%	43.98%	33.53%	44.85%
10th Percentile	2.50%	6.99%	8.54%	7.98%
Median	25.65%	42.23%	30.28%	36.20%
Weighted Average	36.30%	131.10%	139.39%	141.71%

Table 37: Tabulated results for one wind generator as derived from the utilisation of the 2005-7 calendar years.

Reserve Capacity Allocation (P/Pmax) Capacity Year 2005				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	33.91%	47.28%	57.73%	38.73%
10th Percentile	2.34%	5.55%	15.71%	6.56%
Median	25.83%	44.44%	72.92%	27.66%
Weighted Average	34.61%	155.68%	246.10%	111.37%
Reserve Capacity Allocation (P/Pmax) Capacity Year 2006				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	30.29%	33.56%	43.29%	34.13%
10th Percentile	2.11%	1.74%	1.70%	7.27%
Median	21.34%	24.03%	41.34%	26.93%
Weighted Average	31.02%	128.57%	184.52%	100.03%
Reserve Capacity Allocation (P/Pmax) Capacity Year 2007				
Calculation Methodology	Intervals Selected			
	All	Top 250 Loads	12 Peak Intervals	2-5PM (Jan-Mar)
Average	34.55%	45.13%	33.53%	44.85%
10th Percentile	2.89%	6.99%	8.54%	7.98%
Median	25.99%	42.92%	30.28%	36.20%
Weighted Average	36.61%	140.61%	139.39%	141.71%

Table 38: Tabulated results for one wind generator as derived from the utilisation of the 2005-7 Capacity Years.