The Treatment of Solar Generating Facilities in the SWIS Reserve Capacity Market

Review of Certified Reserve Capacity Calculation Methodologies for Solar Generating Facilities

Senergy Econnect Project No: 2426

Prepared For	Independent Market Operator Level 3, Governor Stirling Tower 197 St Georges Terrace PERTH WA 6000

	Name	Date	Signature
Prepared By	Tom Butler	15 / 4 / 2009	
Checked By	Tony Morton	16 / 4 / 2009	
Approved By	Robert Holmes	16 / 4 / 2009	

Document History		
Issue No	**Description**	**Date**
00B	Draft Document Issue – Tabulated Results and Modelling Details.	8 / 4 / 2009
00H	Final Draft Issue	16 / 4 / 2009
001	Final Document Issue	16 / 4 / 2009

Senergy Econnect Australia
ABN: 89 103 102 138
Level 2, 55 Swanston Street, Melbourne VIC 3000
PO Box 468 Flinders Lane 8009

Ph: +61 3 9650 1124
Fax: +61 3 9650 1174
www.econnect.com

Table of Contents

1 Executive Summary

This work has considered calculation options for the allocation of the relevant levels of reserve capacity for Solar Generating Facilities (SGF) operating in Western Australia's South West Interconnected System. The main drivers of this work include the proposed Rule Change 31 to Rule 4.11.3 of the Wholesale Electricity Market Rules [1] and the preliminary results of work being conducted by Senergy Econnect Australia (SEA) for the Office of Energy. These preliminary results were presented to relevant parties (including the IMO) on Tuesday the 4th of March 2009. They suggested that, were SGF to not operate with high capacity factors that would necessitate the inclusion of some form of energy storage, the calculation methodology proposed by Rule Change 31 might not deliver the expected outcome.

This study focuses on modelled generation profiles from Photovoltaic and Solar Thermal generators which incorporate thermal storage based on publicly available solar resource data from the capacity years over 2001 to 2008. The results confirm and strengthen the earlier finding that the proposed Rule Change 31, by considering numerous periods in which SGF is unlikely to be generating at significant levels, is unlikely to deliver the intended outcome for SGF.

Although the alternative reserve capacity calculation methodology proposed by Rule Change 31 is intuitively correct, the results clearly point to the limitations of a restricted data set which only considers a single year of data. Should a Rule Change to the present Rule 4.11.3 focus on SGF, an alternative method should be proposed to that of Rule Change 31.

Some alternative calculation methodologies are shown to be similarly liable to large variations from year to year. It is found that these variations can be mitigated if the data sets utilised for the calculation of reserve capacity are sufficiently large, while avoiding the consideration of night time load intervals.

Generally, the outcomes indicate that averages or means will provide similar results when considering peak load intervals or periods, and interval selections over these time frames produce well distributed data sets. Furthermore, a large data set that does not include night time load intervals will generally produce a consistent result across years.

There is also the opportunity for the development of an effective weighted average calculation methodology for these calculations. While the method implied by the present Reserve Capacity Refund Mechanism is not found to represent well the real contribution from SGF, there is every likelihood that a redesigned method of the same general type would deliver better results.

2 Introduction

Australian energy markets are rapidly changing as a result of present targets promoting large increase in the utilisation of renewable energies. Western Australia is widely recognised to hold one of the worlds best resource potentials for the two most widely utilised of such energy sources: wind and solar.

At present, industry is recognising both the resource potential in WA and the incentives behind the development of these resources such as the Federal Government's REC scheme. One of the pressing issues associated with the rapid expansion of such generation technologies in the ability of present regulatory frameworks adapting to meet the requirements of generators which are no longer fully dispatchable.

The Wholesale Electricity Market in the SWIS is divided into the Energy and Capacity markets. This division structures the market such that Energy is traded bilaterally through the Short Term Electricity Market, while the Capacity Market provides an additional revenue stream promoting investment into new capacity in the SWIS to meet future electricity consumption growth projections.

At present the Capacity market allocates Reserve Capacity Credits to generators with the intention of reflecting a generator's contribution to the SWIS peak demand. Under Wholesale Electricity Market Rule 4.11.3, Reserve Capacity Credits have the potential to provide a significant revenue stream to generators while penalising dispatchable generators for failing to deliver power on demand [1]. Intermittent generators are not treated any differently to dispatchable generators in the allocation of Capacity Credits; however they are not subject to penalties for not delivering power on demand.

SEA has been contracted as an independent expert to review potential Reserve Capacity Calculation methodologies in respect of Solar Generating Facilities (SGF) through simulating generation profiles based on long term recorded solar radiation data. The outcomes of the analysis include recommendations on the potential impact of the selection of these methodologies in terms of the proposed Rule Change 31 and in regard of the Wholesale Electricity Market Objectives.

2.1 Project Background

This work seeks to undertake a review of potential Certified Reserve Capacity calculation methodologies, which would determine the level of Reserve Capacity for SGF participating in the SWIS Reserve Capacity Market. The main drivers of this work include the proposed Rule Change 31 to Rule 4.11.3 of the Wholesale Electricity Market Rules [1], and the preliminary results of work being conducted by SEA for the Office of Energy. These preliminary results were presented to relevant parties (including the IMO) on Tuesday the 4th of March 2009.

In December 2008, energy retailer Synergy proposed a change to the Wholesale Electricity Market Rules which proposed new Reserve Capacity allocation procedures tailored to SGF. More specifically the amendment put forth was to insert a new Rule 4.11.3B which defined a new Capacity Credit calculation procedure intended as an option for SGF. The driver for this amendment is that the present allocation process of Rule 4.11.3A assigns capacity credits to all generators based on the average generation across all trading intervals over the last three years.

In their submission Synergy proposed an optional calculation methodology specifically intended for SGF which assigns capacity credits based on the lowest 10th percentile of the top 250 peak load intervals from the previous full hot season.

In the submission to Rule Change 31 Synergy proposed that their amendment should be accepted because the present method of Rule 4.11.3A disadvantages SGF as it is limited by a resource which is not present over all trading intervals. Furthermore, the present method fails to recognise the important contribution that SGF can make toward the Reserve Capacity Market by inherently closely matching high demand periods.

It has been accepted by the IMO that the amendment would permit the Wholesale Market Objectives (b) and (c) to better address the objectives and that Synergy's proposed amendment should be incorporated into Rule 4.11.3 as Rule 4.11.3B [6]. In its submission, Synergy expressed a degree of urgency for the rule change to proceed in order to permit SGF wishing to participate in the 2011/2012 capacity year to do so without being disadvantaged.

SEA is currently undertaking a project for the Office of Energy which is considering Reserve Capacity calculation methodologies for intermittent generation technologies in the SWIS. The preliminary results of this study were delivered at a presentation which the IMO attended on March 4th of 2009. These results suggested that, were SGF to not operate with high capacity factors necessitating the inclusion of some form of energy storage, the reserve capacity calculation method proposed by Rule Change 31 may not deliver the expected outcome.

Were this initial conclusion to be sustained, there would be a risk that the proposed rule change may not bring the expected outcomes for SGF, and fail to satisfy Wholesale Market Objective (c) which intends to prevent the Rules from discriminating between different generating technologies. The object of the present study, then, is to test this initial conclusion in the light of a more detailed analysis with additional data.

3 Project Scope

The scope of work for this work includes the development and utilisation of solar thermal modelling techniques by applying MATLAB modelling software in order to model solar thermal plant with thermal storage options for 0, 4, 10 and 16 hours of generation without an effective solar resource. These models will have been used to derive generation profiles from direct irradiation data recorded at both Geraldton and Kalgoorlie over the 2001 to 2006 capacity years. Solar thermal plant capacities are considered here with the expectation of generation capacities above 50MW.

Correspondingly, appropriate models for Photovoltaic (PV) Generating Plant under the consideration of broadly distributed medium sized facilities in the size range of 1-2MW [3] have been developed. Simulated generation profiles for PV are based on half hourly Global and Direct solar irradiation data recorded at Kalgoorlie and Geraldton for the years 2001–2006. As an expansion of this model further analysis will incorporate daily Global irradiation data derived from daily synoptically modelled data records available from the Bureau of Meteorology (BOM). This data will be utilised to approximate half-hourly irradiation based on the solar altitude angle which represents the diurnal variation of the solar resource at different latitudes and extend the study to consider Perth, Badgingarra, Hopetoun and Walpole. Note that this model will only represent highly distributed PV systems which are subject to an averaging effect in aggregated generation profiles. The impact of atmospheric effects such as cloud passing is not considered due to the lack of available data for such analysis.

Further to the modelling procedures outlined above, results are presented for each generating technology and site in order to provide a comparison of different SGF and their expected contribution to the Reserve Capacity planning criterion and Capacity Credit allocations under each of the criteria listed above. These results include:

- the statistical analysis as required to calculate the proposed methodologies and a summary of the outcomes in terms of the Wholesale Market Objectives, along with
- a discussion on the impacts of the proposed rule change in terms of alternative technologies and their option to select the new Rule 4.11.3B, and
- commentary as an independent expert on submissions to the rule change as put forward by Alinta and Landfill Gas and Power.

Further, the data applied in the study is documented in regard to BOM site locations and codes and disclosure of the assumptions and procedures involved in the development of SGF models.

4 Reserve Capacity Calculation Methodologies

There are a number of different methodologies which could be utilised in the calculation of the level of reserve capacity. SEA has performed statistical analysis of the load and simulated generation data in order to calculate reserve capacity for SGF based on the following criteria:

1. Current Method of Rule 4.11.3A (Current): Average generation over all trading intervals for the preceding three years.
2. Proposed Method of Rule 4.11.3B (Proposed): The 10th percentile of generation during the top 250 load intervals of the preceding hot season only, where the hot season begins on December 1 of each capacity year and ends on the following April 1 [1].
3. Original Method of Rule 4.11.3, prior to 2005 (Original): The 10th percentile of the top 250 load intervals of the preceding hot or intermediate season [4].
4. PJM Method (PJM): Average generation for intervals between 2PM and 5PM and over the three summer months of January, February and March for the preceding three years. This time interval has been determined to represent the peak load months by SEA as a reflection of the PJM method applied in North America and these time periods will be used for all calculations.
5. Individual Reserve Capacity Requirements (IRCR): The median value of the 12 peak trading intervals taken as the three highest demand intervals of the four highest demand days in the proceeding peak demand season [1].
6. Reserve Capacity Refund Mechanism (RCRM): Weighted average over all intervals, with weighting based on business versus non-business 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 and are normalised to maintain the correct amount of reserve capacity credits across the market as shown in Table 1.

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 CY02 = 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 1: 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 for SGF.

In order to compare the different calculation methodologies, calculations have been performed across the six calculation methodologies above by comparing each statistical technique against each interval selection technique. Table 2 indicates each combination of calculation methodology considered along with the position of the six criteria listed above.

Further to the individual calculation methodologies the analysis has considered time periods of the full data availability, three year intervals and individual years for all sites and for each of the calculation methods. These groups will be based on the capacity years ending 2001 to 2008. SWIS load data has been adjusted to accommodate exponential growth over the study period and daylight savings has also been considered in the analysis. As plant capacities are unknown at this point, simulated generation will be represented as a percentage of the nominal capacity or a 'capacity factor' of the modelled SGF plant.

Calcualtion Methodology	Load Intervals Selected for Reserve Capacity Calculation Methodologies				
	All	Top 250 (Summer)	Top 250 (Intermediate)	12 Peak	2-5pm (Jan. - Mar.)
Average	Current	X	X	X	PJM
10th Percentile	X	Proposed / Original	Original	X	X
Median	X	X	X	IRCR	X
Weighted Average	RCRM	X	X	X	X

Table 2: Calculation Methodologies and Intervals Selected for Analysis. 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.

5 Data Management and Modelling Details

5.1 Load Data and Load Growth Adjustment

In order to correlate load with generation for data sets exceeding one year it is necessary to remove the load growth over the period. Accordingly, a simple exponential characteristic has been 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 0. This exponential fit has been found to be

$$e^{-57.4362+8.867\times10^{-5}t}$$

Removing this exponential growth will leave only the periodic trends in the load, which will then be correlated with the appropriate generation data. Growth in load for the single year time-series will be ignored. A comparison of the original and adjusted loads over the 2001 to 2008 calendar years is shown in Figure 1.

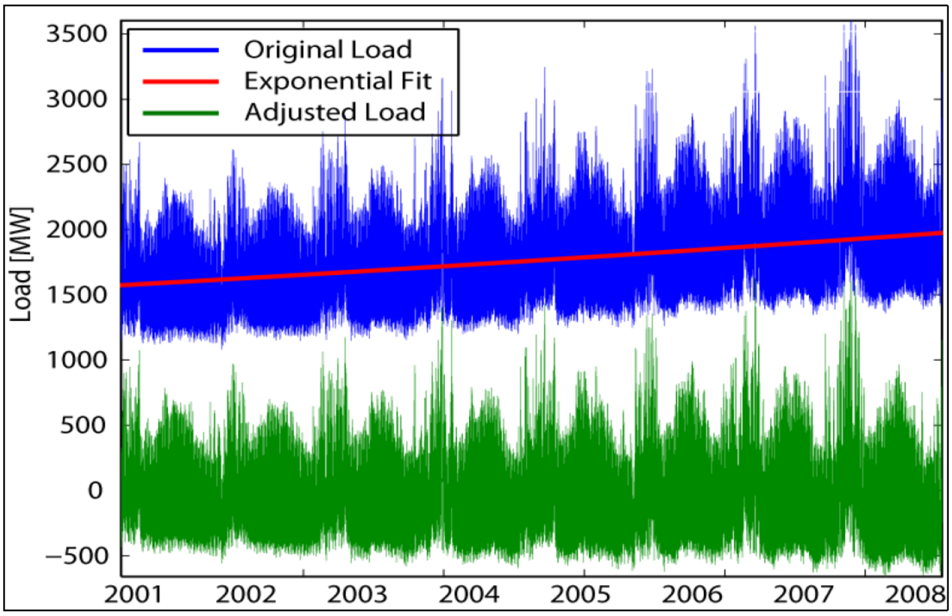


Figure 1: Load data comparison with and without exponential growth removed as required for long term calculations.

After removing exponential growth from the load data it is adjusted to account for the differences in load between business and non-business days in order to increase the effective size of the data set. This was taken into consideration in conjunction with the weighted averaging of the Refund Mechanism [1] in order understand what would occur if a particular hot non-business day happened to occur instead on a business day. In order to do this, a scaling factor for has been derived by taking a ratio of the average of all business and non-business days' daily peaks. All non-business days load intervals were adjusted using this scaling factor. Figure 2 represents the conversion between non-business and business days.

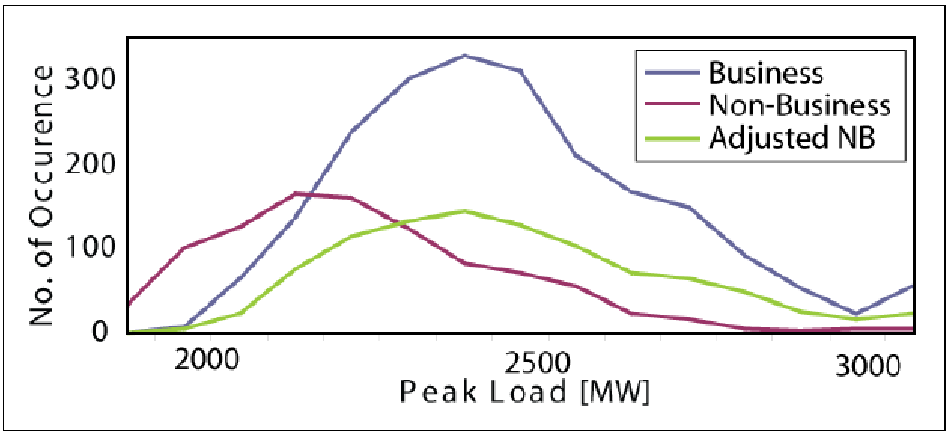


Figure 2: Histogram showing the conversion of non-business days to reflect approximated business days.

5.2 Resource Data and Data Validation

While it is widely recognised that the solar resource in Western Australia is extensive and can be classed as one of the worlds best at present there is very little accurately recorded data available for this resource. The availability of information across an area as broad as the SWIS is limited to total daily irradiation derived from synoptically modelled weather characteristics and limits its application in modelling. Furthermore, in WA the availability of accurate data detailing the daily variation in irradiance is limited to two sites at Geraldton and Kalgoorlie which can provide half-hourly irradiation records for Direct and Global irradiation on the horizontal plane. Both of these meteorological stations ceased recording irradiation in mid 2006.

Table 3 shows the details of the data utilised in this study, the location and codes of the BOM meteorological stations where the data was recorded from and the time scales over which that data was utilised.

Bureau of Meteorology Weather Station Sites and Data Availability from Each Site as Initially Considererd prior to Data Validation Procedures						
Site	Abbreviation / Technology	BoM Station #	Site Latitude	Site Longitude	Data Available	Capacity Years of Available Data
Kalgoorlie	KPV - Photovoltaic	12038	-30.5°	121.3°	Half hourly Global & Direct Irradiation	2001-2006
Geraldton	GER	8051	-28.5°	114.5°	Half hourly Global & Direct Irradiation	2001-2006
Perth	PER	9225	-31.6°	115.5°	Daily Synoptically Modelled Irradiation	2001-2008
Badgingarra	BDG	9037	-30.4°	115.5°	Daily Synoptically Modelled Irradiation	2001-2008
Hopetoun	HPT	9961	-34.0°	120.1°	Daily Synoptically Modelled Irradiation	2001-2008
Walpole	WLP	9998	-35.0	116.7°	Daily Synoptically Modelled Irradiation	2001-2008

Table 3: Details of the BOM meteo station codes and locations where the data applied to this study was recorded along with the time frames over which that data is applied.

While the available data is comprehensive it is subject to some inconsistencies where data is simply not present for varying time scales ranging from hours to multiple days and months in one case. In the worst case the data available from Geraldton is not present for the first 235 days of the 2001 capacity year which has rendered it unusable. Further to this a large portion of data (~70%) is missing from the Kalgoorlie records over the summer of 2002/2003. In terms of the results here this missing data is not changed and results derived from 2003 peak periods for Kalgoorlie should be considered cautiously.

Another issue was found in the fact that the data available for all records from Geraldton and Kalgoorlie cease in mid June 2006. In order to overcome this problem and to ensure that an acceptable amount of data was utilised for the study the missing data was arbitrarily replaced with that which occurred on the corresponding days in 2002. Thus 103 and 111 days of data have been appended to the 2006 capacity year data for all records from Geraldton and Kalgoorlie. The impact of this amalgamation is expected to be minor due to the time frame in question (mid June to end September) and in terms of the summer peaking demand nature of the SWIS load and the corresponding peak load and period interval selections typically applied here.

There are a number of single days for which data is not present and in these cases the data has been ‘borrowed’ from the following day in order to ensure the outcomes are not influenced heavily and to maintain the expected resource variation. Note, however that this is only applied where single days are missing and where sequential days of data are not available data points are removed from the results entirely and results are presented with this data removed.

Table 4 shows the quality of the raw data available from the BOM and the data recovery rate of the final modelled generation data which results from the adjustments outlined above.

Days of missing data records from BOM solar irradiance data 2001-2008 for all sites				
Site	Resource Data		Generation Data	
	Missing Days	Data Recovery	Missing Days	Data Recovery
KPV	148	93.2%	74	96.6%
GPV	363	83.4%	18	99.0%
PER	95	96.7%	74	97.5%
BDG	95	96.7%	74	97.5%
HPT	97	96.7%	74	97.5%
WLP	99	96.6%	74	97.5%
KST0-16 (2001-2006)	247	88.7%	72	96.7%
GST0-16 (2001-2006)	403	81.6%	12	99.3%

Table 4: Details of the quality of data available from the BOM for the sites selected and the impact of the data management procedures outlined. Note the impact of omitting 2001 from the Geraldton data set and duplicating the data to provide a complete 2006 capacity year.

5.3 Solar Resource Variation

While WA is considered to have an excellent solar resource there can be a considerable variation seen across the years and sites considered. Table 5 summarises the solar irradiation for each site and capacity years considered in this study.

Total Annual Global POA Solar Irradiation for all Sites Based on Capacity Years (MWh/m-2)						
Capacity Year	**KAL**	**GER**	**PER**	**BDG**	**HPT**	**WLP**
2001	1.96	-	2.09	2.10	1.91	1.67
2002	1.82	2.16	2.06	2.05	1.81	1.63
2003	1.90	2.11	2.03	2.02	1.83	1.65
2004	2.13	2.12	2.11	2.16	1.80	1.60
2005	2.12	2.02	2.02	2.09	1.90	1.72
2006	2.17	2.10	1.63[1]	1.64[1]	1.5[1]	1.36[1]
2007	-	-	2.11	2.18	2.04	1.82
2008	-	-	2.16	2.19	2.08	1.84
Average[2]:	2.02	2.10	2.08	2.11	1.91	1.71

Table 5: Summary of the Plane of Array Solar irradiation (see below) for all sites and capacity years considered. Notes: [1] A significant amount of data is missing from the BOM synoptic records for these sites such that these years do not represent typical years. [2] The averages are calculated with 2006 removed for accuracy.

5.4 Solar Resource Modelling

In order to maximise the generation from PV arrays they are typically optimally installed with an azimuth that sees them facing the equator and elevated at a tilt angle from the horizontal that equals the local latitude (i.e. $\beta = \phi$ while $\gamma = 0$). As solar radiation data is almost always provided as that which falls on a horizontal surface a conversion to that which falls on the Plane of Array (POA) surface is necessary.

For the Geraldton and Kalgoorlie sites, available data consists of Global and Direct irradiation on the horizontal plane recorded at half hour intervals. However, for the remaining sites it is necessary to distinguish between the Direct and Diffuse irradiation on the horizontal plane because data is only available as synoptically derived daily Global irradiation on the horizontal surface.

The methodology applied fro the synoptic irradiation sites calculates the daily Diffuse Fraction with the method defined by Collares-Pereira and Rabl [10] whereby the Diffuse Fraction is dependant on the daily average Clearness Index K_T by the relationship illustrated in Figure 3.

$$\frac{H_D}{H} = \begin{cases} = 0.99 & \text{for } K_T <= 0.17 \\ = 1.188 - 2.272 * K_T + 9.473 * K_T^2 - 21.856 * K_T^3 + 14.648 * K_T^4 & \text{for } 0.17 < K_T <= 0.75 \\ = -0.54 * K_T + 0.632 & \text{for } 0.75 < K_T <= 0.80 \\ = 0.20 & \text{for } K_T > 0.80 \end{cases}$$

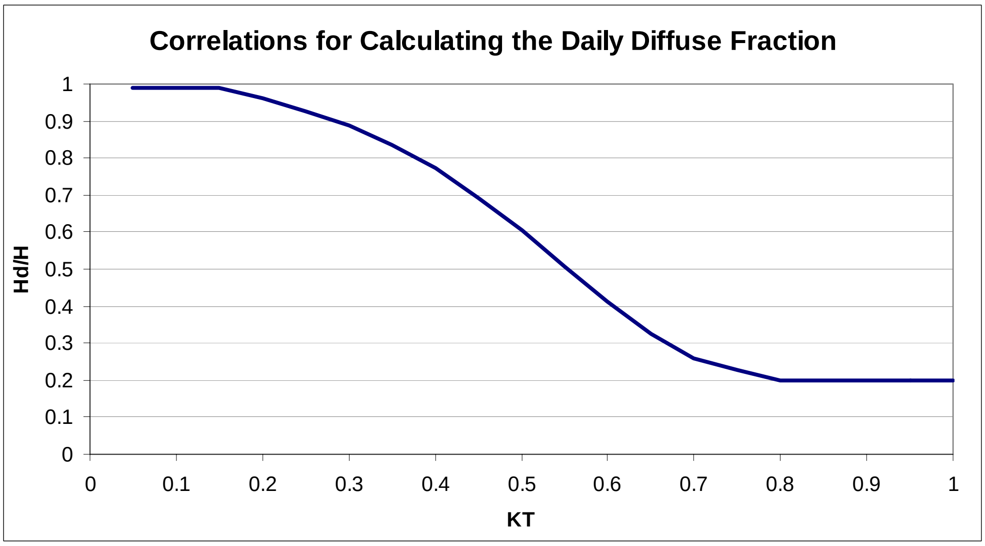


Figure 3: Piecewise and graphical representation of the correlation of the Daily Average Clearness Index with the daily Diffuse Fraction as derived by Collares-Pereira and Rabl [10].

In the application of the Rabl method above the daily Clearness Index is defined as the ratio of daily extraterrestrial radiation H_0 to daily terrestrial radiation H or

$$K_T = \frac{H_0}{H}$$

Where H_0 is calculated by

$$H_0 = G_{SC} \times \frac{24}{\pi} \times \left[1 + 0.033\cos\left(\frac{360n}{365}\right)\right] \times \left(\cos\phi\cos\delta\sin\omega_s - \omega_s\cos\phi\cos\delta\cos\omega_s\right)$$

where G_{SC} is the Solar Constant of 1367W/m^2.

The application of the Rabl correlation method provides approximate values for the daily Diffuse and Direct components of the synoptically modelled daily Global Horizontal irradiance. In order to derive approximate values of the half hourly irradiance for each site the daily Diffuse and Direct Horizontal values are then distributed across each day by normalizing to the Solar Altitude angle throughout the day by

$$I_D = H_D \frac{\alpha}{\int_0^t \alpha \, dt} \quad \text{and} \quad I_B = H_B \frac{\alpha}{\int_0^t \alpha \, dt}$$

respectively. Here the Solar Altitude angle α is calculated by

$$\alpha = \cos^{-1}\left[\sin\delta\sin\phi + \cos\delta\cos\phi\cos\omega\right]$$

where δ is the solar declination and is equivalent to

$$\delta = 0.4093 \sin\left(2\pi \frac{284+n}{365}\right).$$

This method provides an approximation of the daily distribution of both the Diffuse and Direct Horizontal irradiance based on synoptically derived daily Global Horizontal irradiance. However it fails to represent the variation of irradiance across the day due to atmospheric influences such as clouds passing by a particular site. As a result, the outcome is strictly limited to represent the aggregated irradiance as would be seen by widely distributed PV generators which are typically subject to an averaging effect in generation profiles [11].

The half hourly Direct Horizontal irradiation components of both the synoptically modelled and recorded data can now be converted into half hourly Direct POA irradiation. The method applied here is the Telecom method as detailed by Green Et. Al. [9] whereby a geometric factor R_b is derived as

$$R_b = \frac{\sin\left(\frac{\pi}{2} - |\phi| - \delta + \beta\right)}{\sin\left(\frac{\pi}{2} - |\phi| - \delta\right)}$$

such that the half hourly Direct POA irradiation is

$$I_{B_{POA}} = R_b \times I_B .$$

Note that the Telecom method is only strictly true at solar noon and the application across a daily distribution introduces a small error. However, it was validated against the more complex incident angle ratio method and the average error between the outcomes was found to be 7% when considering six years of data at one site. The Telecom method was selected due to the alternative showing poor performance in results for the late afternoon at some times in the year.

Finally, under the assumption of an isotropic sky whereby the half hourly Diffuse irradiation component is independent of the array tilt angle [9], the half hourly Global POA irradiation is the sum of the Diffuse Global and Direct POA irradiation components or

$$I_{POA} = I_{B_{POA}} + I_D .$$

Figure 4 and Figure 5 show comparisons of the daily irradiance profiles resulting from both techniques where Perth represents irradiance derived from synoptically derived irradiation and Kalgoorlie is recorded half hourly irradiation. Time axes represent solar time.

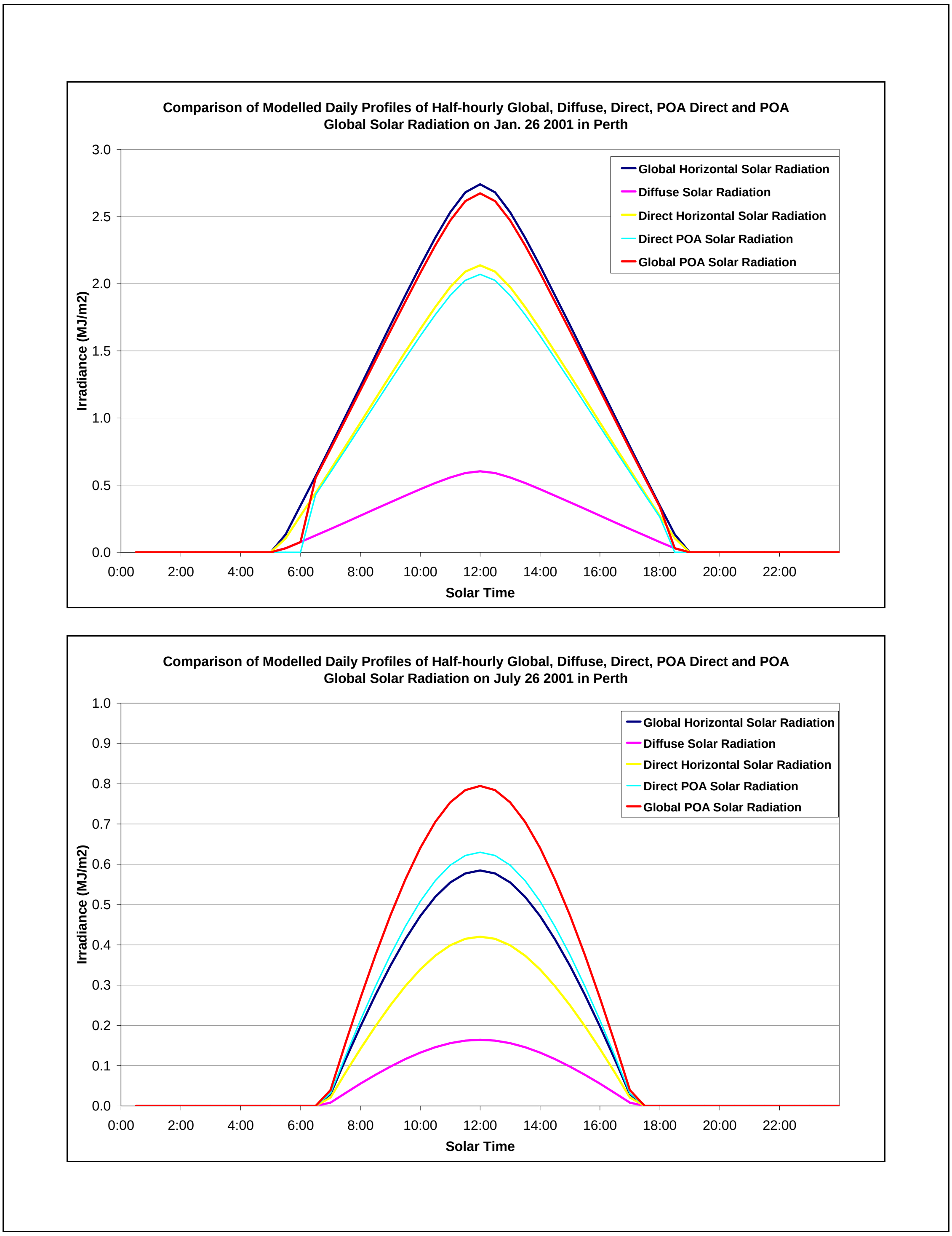


Figure 4: Comparison of Daily Profiles of Modelled Global, Diffuse and Direct solar irradiance on the horizontal plane and POA Direct and POA Global irradiance for Perth on January 26 and July 26 2001 based on solar time. Note that the contribution from the Direct irradiance component is subject to limitations due to the solar altitude angle in the morning and evening of each day.

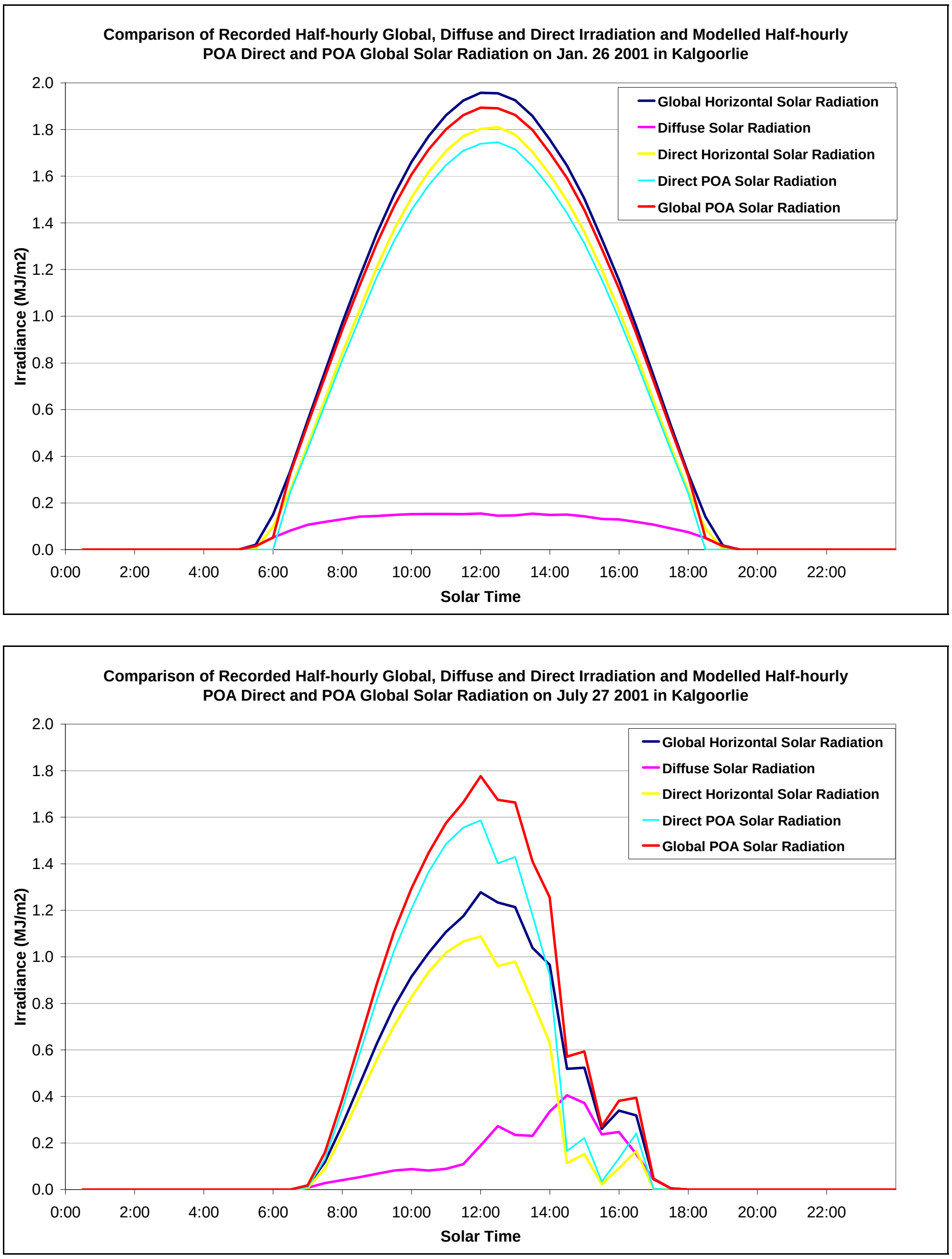


Figure 5: Comparison of Daily Profiles of recorded Global, Diffuse and Direct solar irradiance on the horizontal plane and modelled POA Direct and POA Global irradiance for Kalgoorlie on January 26 and July 27 2001 based on solar time. Note that the contribution from the Direct irradiance component is subject to limitations due to the solar altitude angle in the morning and evening of each day.

5.5 Adjustment for Time Differences across the SWIS and Daylight Savings

The availability of the solar resource at any given location is dependent on the solar time at the location in question. Solar time is defined by having a noon time that corresponds both to the sun passing across the local meridian at the site and the highest solar altitude angle of the day.

The western and eastern extremities of the SWIS can be defined by Geraldton on the western side and Kalgoorlie in the east. These two cities are separated by approximately 7° which translates to a solar time difference of 28 minutes. However, Western Australian standard time is defined by the solar time seen at a longitude of 120° which lies approximately 140km west of Kalgoorlie.

The implications of these differences are not only that the load is recorded at standard time intervals and effectively concentrates around the movements of people in greater Perth and that the solar data is recorded in solar time. They also extend to the consideration that while the morning load is occurring in Perth where there may not be any effective solar radiation yet, Kalgoorlie may be experiencing effective radiation.

The relationship between local time and solar time in WA is given by

$$t_{WST} = t_{ST} - 4(L - 120) - E$$

where L is the site's longitude and E is the Equation of Time, defined as

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

Figure 6 shows the variation in time difference between the solar time and WA Standard Time 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 time difference is rounded to the nearest half hour and then added to the solar time. Solar irradiation data is shifted in accordance with this time difference as can be seen in Figure 7 for March 1 2002 in Geraldton.

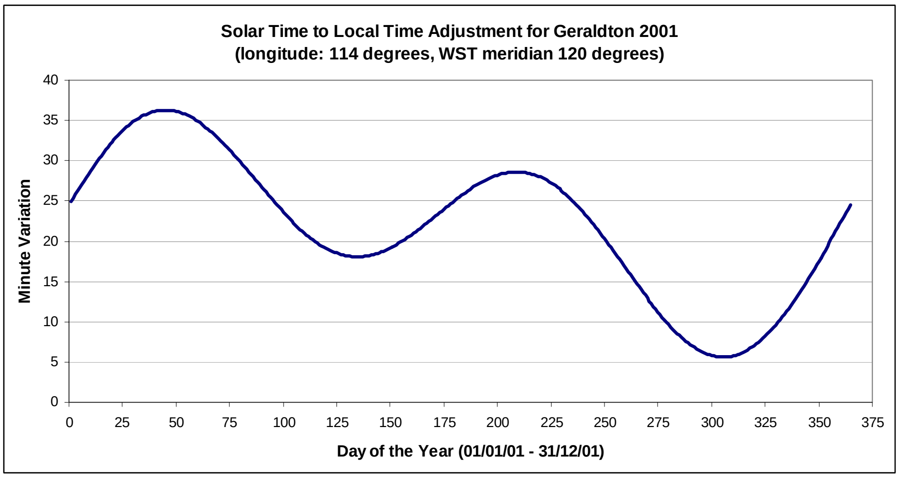


Figure 6: Minute variation from WST for Geraldton throughout the year. Adjustments to the solar radiation data are made in order to accommodate this difference for each day of each year. Half hour intervals are shifted according to the time adjustment above rounded to the nearest half hour.

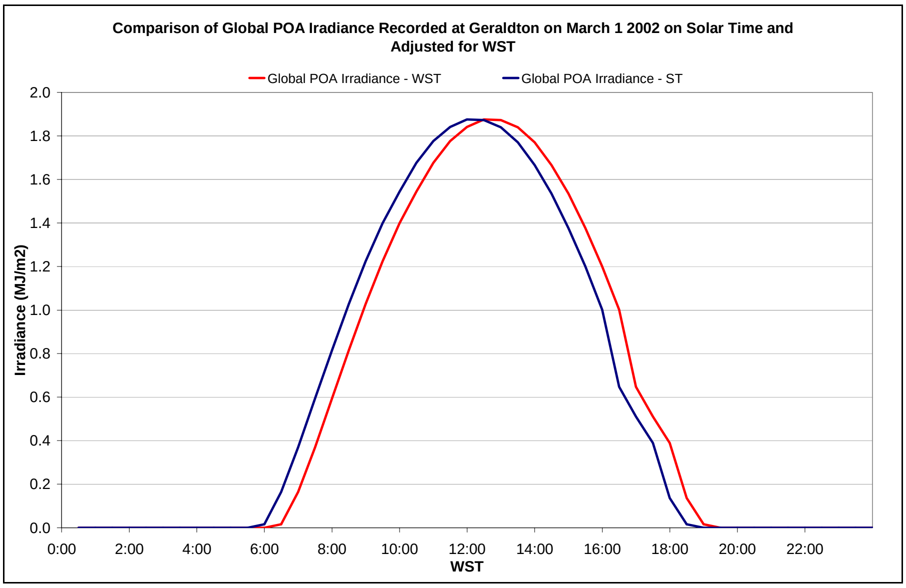


Figure 7: Comparative illustration of the impact of adjustments made to the daily solar irradiance profiles to compensate for time differences across the SWIS where ST and WST are Solar Time and Western Standard Time respectively for March 1 2002.

Corresponding to the adjustments made to the solar radiation data to compensate for the time at the local meridian of each site, adjustments are also made to compensate for the recent application of daylight savings in WA. Daylight savings began on December 3 2006 in WA 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 and solar radiation data have been adjusted accordingly.

5.6 Photovoltaic (PV) Generator Model Development and Assumptions

Photovoltaic generators considered here are classified as those with capacities in the range of 1-2MW. Such generators are typically installed with optimum characteristics such as those described in Section 5.4 where the PV array is arranged with an azimuth that faces all modules northward and with a tilt slope approximately equal to the magnitude of the site latitude.

PV cells have a generation characteristic by which an almost constant DC voltage is generated when sufficient irradiance is incident on the cell while a variable DC current is generated in proportion to the irradiance incident on the cell. Thus the DC power generated by a PV module varies instantaneously under varying irradiance due to an instantaneously varying current [9]. Furthermore, PV modules are designed with a nominal power rating which corresponds to Standard Test Conditions of an incident irradiance of 1kW/m^2 such that an array rated at 1MW$_P$ will generate 1MWh when exposed to a full hour of Global POA irradiation of, or in excess of 3.6MJ/m^2 [9]. PV cell temperature effects are neglected.

As AC generators, PV arrays are interfaced with the electrical grid via inverters which are typically characterised by an AC to DC power conversion efficiency that is low at a low DC power and increases toward the maximum at approximately 20% of rated power. Here a piecewise approximation of typical inverter efficiency curve is applied in order to model the AC generation from hypothetical PV arrays as shown in Figure 8. Note that, in reality an inverter efficiency of 100% is not possible and here it is assumed that PV generators are sized according to their AC generation potential and PV arrays are oversized to overcome the inverter efficiency. This assumption also maintains the appropriate range of generator capacity factor between 0 and 100 percent.

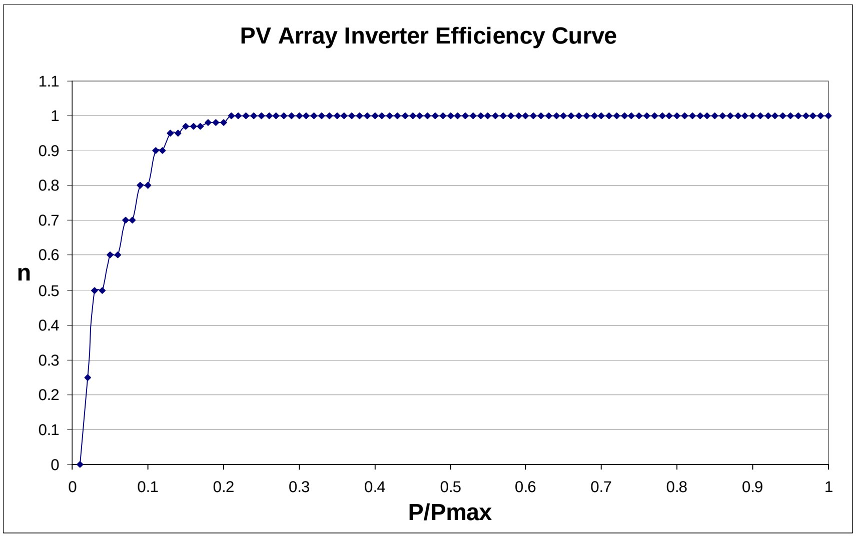


Figure 8: The piecewise approximation of an inverter efficiency curve applied to modelled PV generation. Note that the maximum efficiency of 100% is present due to the assumption of PV arrays being sized to their AC output rather such that the array size is large enough to overcome inverter losses.

Figure 9 exemplifies the generation profiles as compared to the modelled POA irradiance across three summer days in 2002. Noting that the impact of using synoptically derived daily irradiation is evident in that the daily irradiation is distributed across the daylight hours and no variation is seen on a half-hourly basis as described above.

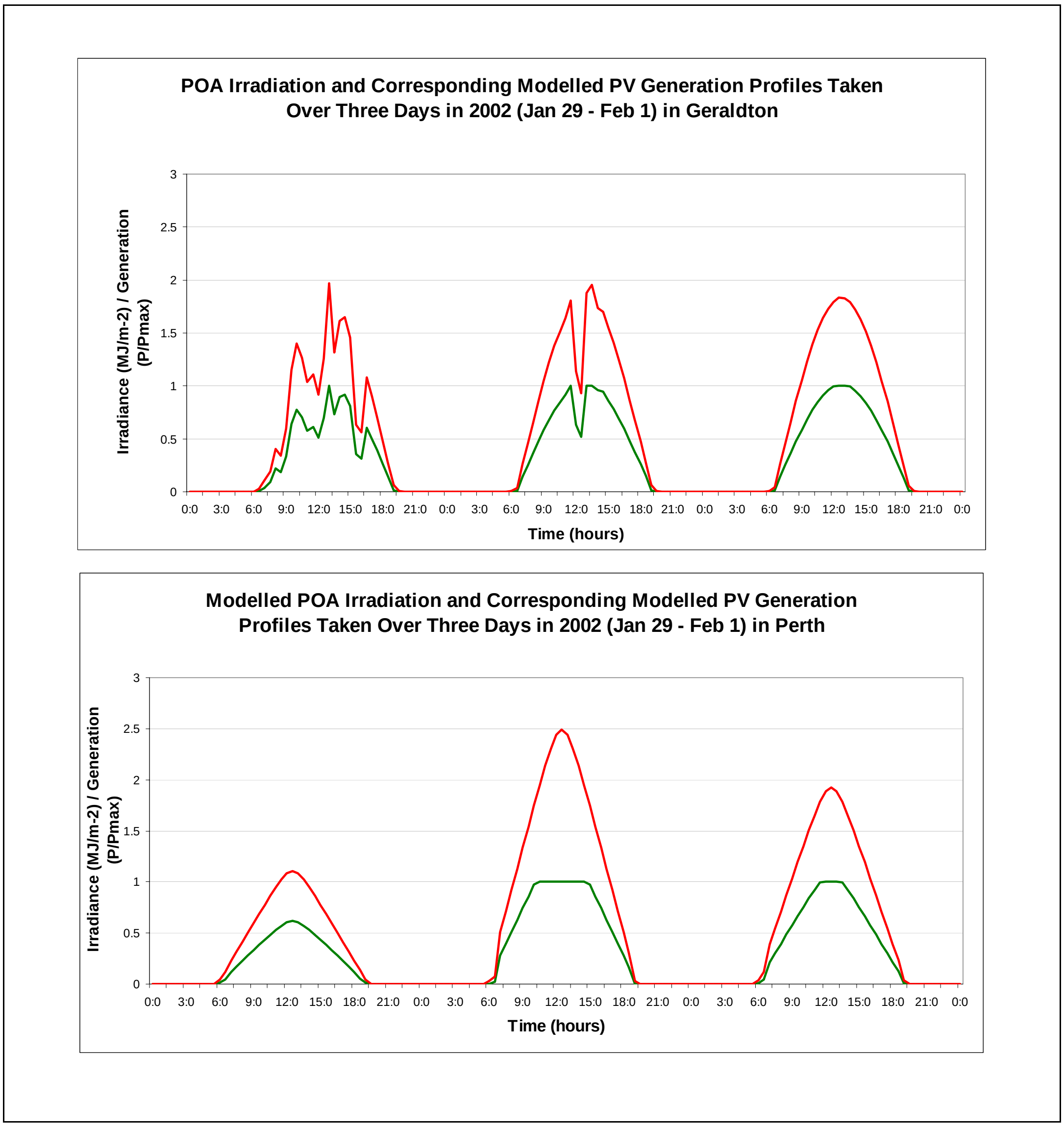


Figure 9: Example generation profiles for Geraldton and Perth. Note that the irradiation taken from Geraldton is recorded from Geraldton meteorological station while the Perth irradiation is modelled from synoptically derived daily irradiation.

5.7 Solar Thermal Generator Model Development and Assumptions

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 a appropriately simplified yet approximate model 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. Some other technologies utilise thermal fluids to transfer energy from the collector to the generator and the selection of DSG here is considered to be arbitrary in terms of the outcomes reported. Thermal storage options considered include 4, 10 and 16 hours of operation without sufficient irradiation for operation which is achieved by over-sizing the generator's collector. The following two sections detail the relevant assumptions applied in the development of DSG solar thermal models.

5.8 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 as enough energy is collected to operate during low irradiance periods while excess energy is dumped during high irradiance periods by slightly tilting lenses off-focus. Given this it is assumed that a SM1 collector will generate its 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. However, with the consideration of additional losses resulting from additional steam transport due to increased collector size it is assumed that an irradiance of 500W/m^2 is required to operate at capacity. Thus 250Wh/m^2 (0.90MJ/m^2) must have been recorded in a half-hourly record for the generator to have operated at capacity for that half hour.

The ability of Linear Fresnel Solar Thermal plant to generate during sunrise and sunset hours is limited by the angle of incidence on the collector surface which is dependant on 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 half-hourly Direct Irradiation.

Inside the correct operating hours the minimum irradiation for a SM2 collector field to generate effective steam is 0.38MJ/m^2 or 106Wh/m^2 in a half-hourly record (based on an assumed minimum irradiance of 425W/m^2). This minimum value is assumed to correspond to steam turbine generator operation at a minimum capacity of 25% [7].

The DSG collector has an assumed thermal time constant or approximately 15 minutes. As data is recorded as half hourly irradiation this shall be expressed as a part of the last half hourly record. Thus, where the radiation is reducing there is a slower decrease in generation. This factor is not as evident in cases where the radiation is increasing as a delay is inherent in the model due to the half-hourly record providing information for the previous half hour.

In order to compensate for thermal time constant of the plant as a whole the case where the half hourly Direct irradiation falls from a value above the maximum to a value below the minimum is accounted 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.

Given the above assumptions, the solar thermal plant steam turbine generator has a generation profile which corresponds to the following restrictions:

- 0% below an irradiation of 0.38MJ/m^2, 25% at 0.38MJ/m^2 and 100% at and above 0.90MJ/m^2.
- Linear variation between 0.38MJ/m^2 and 0.90MJ/m^2 which is derived through linearly interpolating the data record within these values.

---

* 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 [6].

5.9 Solar Thermal Plant Including Thermal Storage

The following assumptions outline the development of the solar thermal model which includes the potential for 4 hours of thermal storage given acceptable irradiation as an example. Similar assumptions are made in regard to models which include 10 and 16 hours of thermal storage potential.

In the case of four hours of storage, it is assumed that a Solar Multiple of 3 (SM3) is used for the collector size as this will permit the plant to operate with a high capacity factor while collecting enough energy to maintain 4 hours of thermal storage rather than dumping excess energy [6]. Also, repeating the assumption that an SM1 collector will generate its capacity at a direct irradiance of 900W/m^2 an SM3 field is expected to operate at capacity under direct irradiance of one third of 450W/m^2 for the previous half hour. However, due to the additional plant size it is assumed that losses now equate to 75W/m^2 which requires 525W/m^2 for the ST plant to operate at capacity. 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.

Inside the correct operating hours 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). This minimum value is also assumed to correspond to steam turbine generator operation at a minimum capacity of 25% [7].

As in the case without thermal storage the collector is subject to a limitation on effective irradiation due to the solar altitude angle and the previous assumptions are repeated here.

The DSG collector has an assumed thermal time constant or approximately 15 minutes. As data is recorded as half hourly irradiation this shall be expressed as a part of the last half hourly record. Thus, where the radiation is reducing there is a slower decrease in generation. This factor is not as evident in cases where the radiation is increasing as a delay is inherent in the model due to the half-hourly record providing information for the previous half hour.

In order to compensate for thermal time constant of the plant as a whole the case where the half hourly Direct irradiation falls from a value above the maximum to a value below the minimum is accounted 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.

The storage in the system is accounted for by absorbing any half hourly Direct irradiation above 0.63MJ/m^2, and also when it is below 0.26MJ/m^2, as the generator cannot use this. Effectively this is stored and accumulates as time passes 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 previously explained). It is assumed that the previously 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 – once the stored irradiation is expired the generator cannot operate.

Given the above assumptions, the ST plant steam turbine generator has a generation profile which corresponds to the following restrictions where the irradiation is the stored and collected value combined as required:

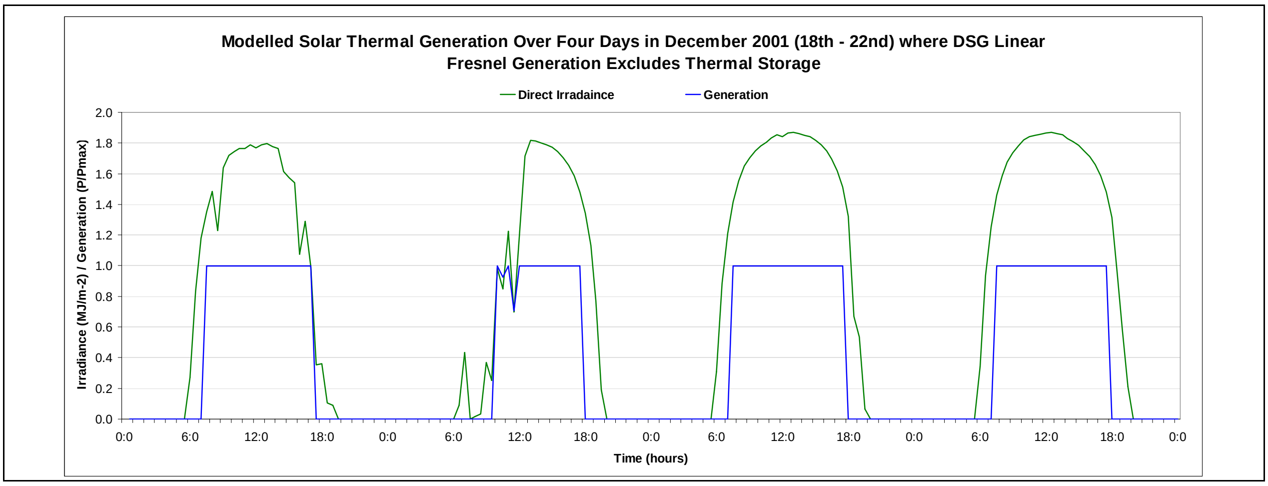
- 0% below an irradiation of 0.26MJ/m^2 where stored energy cannot be applied 25% at 0.38MJ/m^2 and 100% at and above 0.63MJ/m^2.
- Linear variations between 0.26MJ/m^2 and 0.63MJ/m^2 which is derived through linearly interpolating the data record within these values.

5.10 Solar Thermal Generation Characteristics

Table 6 gives details of the required half hourly irradiation values for operation of the Solar Thermal DSG plant both with an without thermal storage as derived from the assumptions outlined above. Following that Figure 10 shows example generation profiles from all solar generator models over a four day period in 2001.

Half_hourly Irradiation Values Requried for Effective Solar Thermal Model Operation Along with Storage Times and Plant Solar Multiples			
Storage Time	**Solar Multiple**	**Half-hourly irradiation required for nominal generation (MJ/m-2)**	**Half-hourly irradiation required for minimum generation (MJ/m-2)**
Base	**SM1**	**1.8**	**0.72**
0 hours	**SM2**	**0.9**	**0.38**
4 hours	**SM3**	**0.63**	**0.26**
10 hours	**SM4**	**0.5**	**0.2**
16 hours	**SM5**	**0.4**	**0.16**

Table 6: Half-hourly irradiation required for the effective operation of modelled solar thermal generation and the corresponding solar multiples for generator collector sizing.



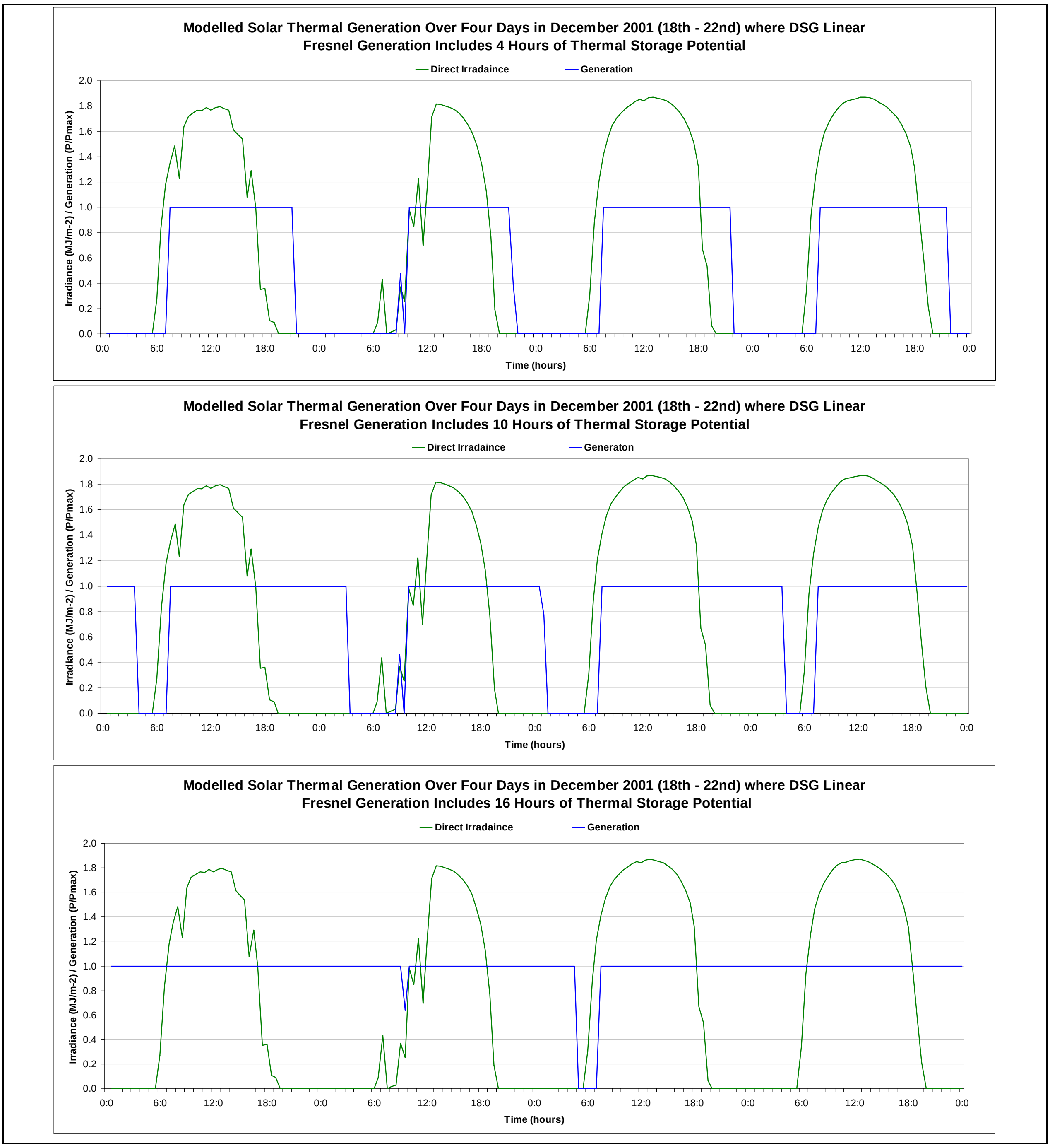


Figure 10: Example generation profiles as modelled over four days in December 2001. The models behave as expected with the storage option maintaining generation over the expected time periods under the condition of an excess of irradiation in the previous day. This is particularly evident in the case of 16 hours of storage where the generator is unable to collect enough energy to operate for 16 hours following day 2 of the sample period.

6 Results

The aims of this study are to represent the outcomes of the potential reserve capacity allocation procedures in terms of the proposed Rule Change 31 [6] and the Wholesale Market Objectives, rather than to selectively determine the optimum methodology in terms of SGF and the following results are presented accordingly. In doing so there are a number of outcomes which have been singled out as being of high importance and the presentation of results considers these above others.

In terms of the level of reserve capacity allocated these outcomes focus on the consistency of levels allocated over different years rather then considering the magnitude of the relevant level which is governed by the quality of the solar resource at the site. Accordingly, the ranges in magnitude are assessed as an indication of the expected relevant levels allocated.

As there is a significant amount of data analysed in this study results are initially presented by comparing calculation methodologies across the technologies considered, time frames and interval selections. Further discussion assesses the impact of the selection of time frame and load intervals. Following this assessment Appendix B provides graphical representations of the outcomes for a selection of sites and technologies along with tabulated data for all of the results.

6.1 Averages

Under the selection of single capacity years the use of a simple average can provide a relatively consistent outcome given an appropriate size of interval samples. Furthermore, this outcome is also consistent across years for each site as, when considering all intervals, it effectively represents the availability of the solar resource at a particular site. However, when considering interval selection methods which result in small data sets the outcomes are highly varied from year to year and appear to be misrepresenting the actual contribution that SGF could make to peak demand. Particularly in the case of the top 250 intermediate season load intervals due to variable spring weather patterns from year to year.

In the case of Solar Thermal generation considering single year sample periods a similar result as was found with PV has been found in the volatility of smaller interval samples. Given the inclusion of storage options the relevant levels allocated tend to increase with increased storage time frames as is particularly evident when considering the 12 peak intervals. However, with smaller interval samples, this increase is more evident when just 4 hours of storage are added and the benefits of increasing storage capacities are no longer as clear.

Table 7 summarises the outcomes from calculating averages for each interval selection period over one year time frames for modelled PV and Solar Thermal generation.

Outcome	Interval Selections for Average Methodology - Single Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	26.1%	72.6%	69.2%	81.4%	80.4%
Minimum Allocation	17.0%	45.4%	27.6%	27.8%	44.9%
Max. Range Over Years	4.1%	21.4%	39.1%	47.7%	25.1%
Min. Range Over Years	1.2%	14.9%	5.4%	30.1%	4.1%

Outcome	Interval Selections for Average Methodology - Single Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	70.8%	98.8%	96.0%	100.0%	98.8%
Minimum Allocation	26.5%	50.7%	46.4%	50.0%	52.7%
Max. Range Over Years	5.5%	24.9%	21.8%	50.0%	20.9%
Min. Range Over Years	1.1%	5.7%	8.9%	0.0%	6.5%

Table 7: Summary of results derived from the consideration of Averages over single year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

When considering time frames across three years the results tend to stabilise significantly as the impact of outlying days or months is dampened. The selection of all intervals remains rigid in its stability across sites and years which corresponds to the results for the afternoon summer intervals of 2-5pm as both of these data sets are relatively large. In all cases the utilisation of 250 load intervals results in a less volatile reserve capacity allocation when comparing to single year time frames. However there is still some significant susceptibility to outlying years as is evident in the 2001-2004 timeframe for synoptically modelled PV generation as 2004 was a high irradiation year. Solar thermal generators give similar results where storage is not considered, however where storage is included the outcomes tend to push toward plant capacities under smaller peak period interval samples.

Table 8 summarises the outcomes from calculating averages for each interval selection period over three year time frames for modelled PV and Solar Thermal generation.

Outcome	Interval Selections for Average Methodology - Multiple (3) Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	25.5%	72.7%	73.4%	70.8%	73.6%
Minimum Allocation	17.7%	49.7%	53.8%	30.4%	48.1%
Max. Range Over Years	1.6%	17.9%	17.3%	33.2%	14.6%
Min. Range Over Years	0.4%	2.6%	2.0%	7.9%	0.6%

Outcome	Interval Selections for Average Methodology - Multiple (3) Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	68.1%	100.0%	97.2%	100.0%	96.6%
Minimum Allocation	26.7%	58.5%	54.4%	58.3%	61.2%
Max. Range Over Years	1.9%	10.7%	12.6%	41.7%	8.3%
Min. Range Over Years	0.5%	0.4%	8.4%	0.0%	1.9%

Table 8: Summary of results derived from the consideration of Averages over three year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

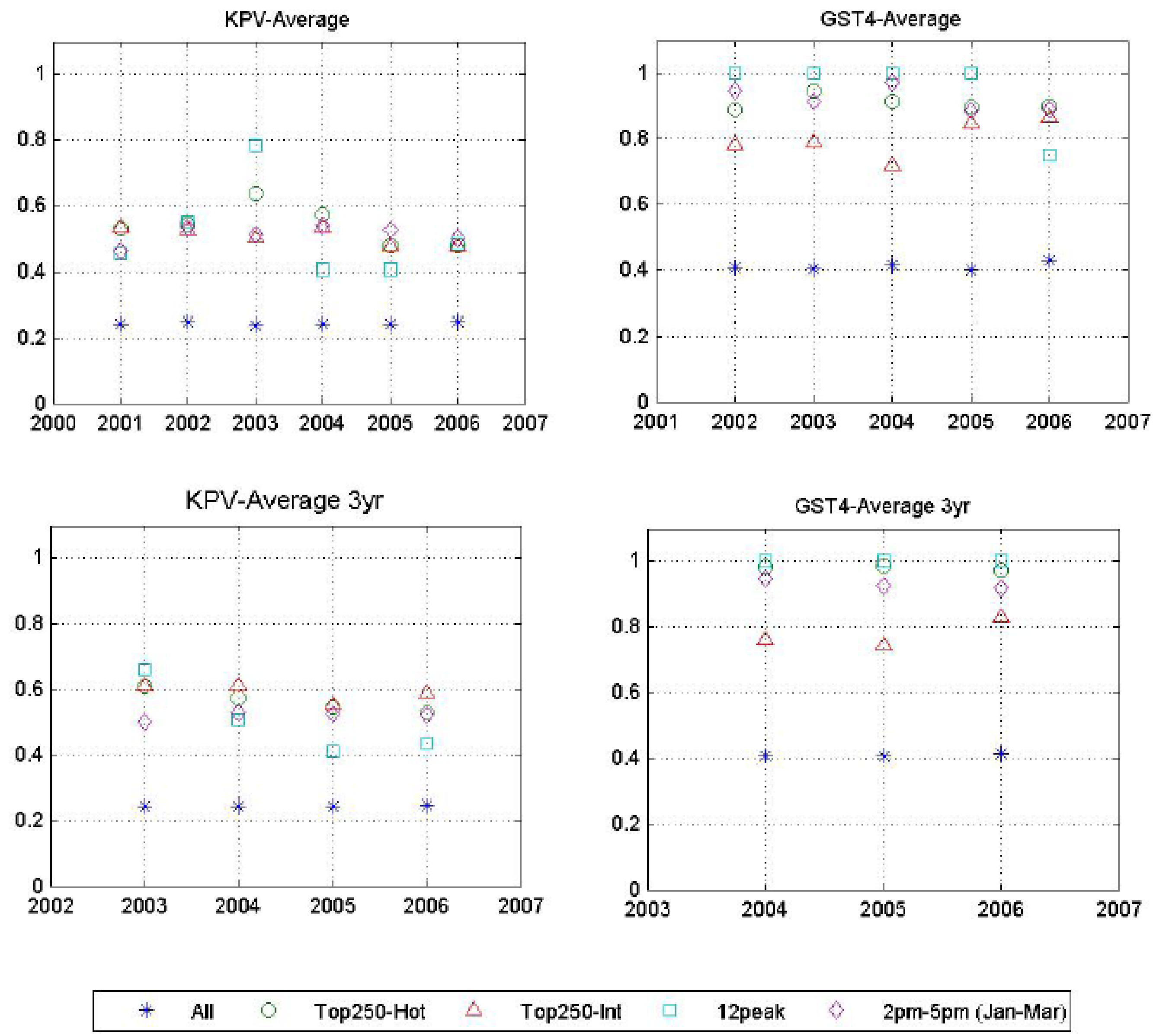


Figure 11: Example comparison of the results found when calculating reserve capacity based on averages. The sites have been arbitrarily selected to show the differences between single and three time frames and represent Kalgoorlie PV and Geraldton Solar Thermal generation with four hours of storage. More detailed plots of alternative sites can be found Section 12.1.

6.2 Tenth Percentiles

The impact of limiting the assessment of potential solar generation to the tenth percentile has been found to be insufficient in almost all cases where the data set is large and especially where overnight intervals are considered. Furthermore, results are showing very large variations across years when either PV or Solar Thermal generators are considered with the only exception being PV under the selection of the afternoon intervals of 2-5pm as is shown in Table 9 and Table 10.

Outcome	Interval Selections for 10th Percentile Methodology - Single Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	0.0%	25.1%	2.5%	60.2%	54.2%
Minimum Allocation	0.0%	0.0%	0.0%	4.3%	15.0%
Max. Range Over Years	0.0%	25.1%	2.5%	47.4%	27.2%
Min. Range Over Years	0.0%	4.2%	0.0%	23.8%	8.5%

Outcome	Interval Selections for 10th Percentile Methodology - Single Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	0.0%	100.0%	100.0%	100.0%	100.0%
Minimum Allocation	0.0%	0.0%	0.0%	0.0%	0.0%
Max. Range Over Years	0.0%	100.0%	100.0%	100.0%	100.0%
Min. Range Over Years	0.0%	0.0%	0.0%	0.0%	0.0%

Table 9: Summary of results derived from the consideration of Tenth Percentiles over single year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

Outcome	Interval Selections for 10th Percentile Methodology - Multiple (3) Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	0.0%	33.5%	28.3%	44.7%	41.5%
Minimum Allocation	0.0%	0.0%	0.0%	8.1%	17.4%
Max. Range Over Years	0.0%	33.5%	28.3%	26.0%	14.3%
Min. Range Over Years	0.0%	7.7%	0.0%	6.8%	0.6%

Outcome	Interval Selections for 10th Percentile Methodology - Multiple (3) Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	0.0%	100.0%	100.0%	100.0%	100.0%
Minimum Allocation	0.0%	0.0%	0.0%	0.0%	0.0%
Max. Range Over Years	0.0%	100.0%	100.0%	100.0%	26.9%
Min. Range Over Years	0.0%	0.0%	0.0%	0.0%	0.0%

Table 10: Summary of results derived from the consideration of Tenth Percentiles over three year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

While it is apparent that the selection of three year time frames limits this variability in some cases the limitations of the tenth percentile are clear. It is evident that, in the cases of the smaller data sets these limitations can be put down to a methodology which always reduces the available data set to one tenth of its original size. In the most extreme case this outcome sometimes shows no apparent correlation from year to year for individual sites under the selection of 12 peak intervals.

Despite this, it is clear from the figures in Section 12.1 that the utilisation of tenth percentiles with 2-5pm and 12 peak interval selections gives the only outcomes showing realistic results. However, while the 2-5pm interval selection can be singled out as having the most consistent outcome over three year time frames the 12 peak still presents some significant variability.

Under the consideration of longer time frames that consider all possible years it is apparent that the selection of the tenth percentile still cannot give a result that is consistent across technologies and sites. All reasonable results appear to reflect a similar outcome as was found with three year time frames.

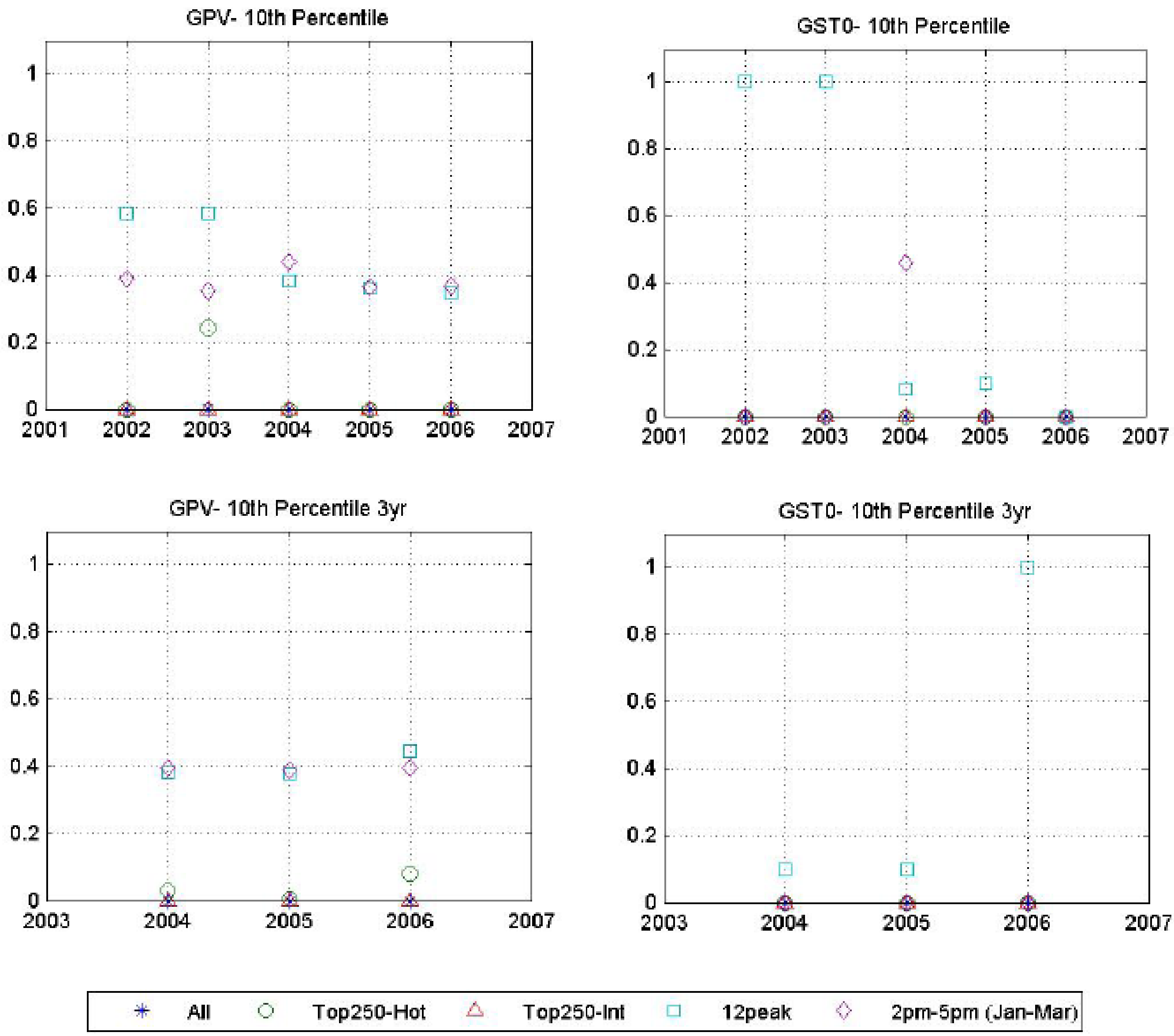


Figure 12: Example comparison of the results found when calculating reserve capacity based on Tenth Percentiles. The sites have been arbitrarily selected to show the differences between single and three time frames and represent Geraldton PV and Geraldton Solar Thermal generation without storage. More detailed plots of alternative sites can be found Section 12.1.

6.3 Medians

In a similar light to averages, medians tend to offer some advantage in the stability of results derived from larger data sets. This is due to results being reliant on the probability of high generation during peak intervals and that the peak interval or period data sets are well distributed.

It is evident that the median gives varied results while considering single year time frames. However, the ranges in outcomes from year to year for specific sites are typically slightly increased when comparing to the use of averages while corresponding reserve capacity allocation can tend to be similar.

Outcome	Interval Selections for Median Methodology - Single Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	0.0%	82.8%	85.9%	96.4%	84.2%
Minimum Allocation	0.0%	44.4%	0.0%	27.7%	41.7%
Max Range Over Years	0.0%	31.0%	85.9%	57.1%	29.5%
Min Range Over Years	0.0%	15.6%	12.3%	35.4%	3.6%

Outcome	Interval Selections for Median Methodology - Single Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	100.0%	100.0%	100.0%	100.0%	100.0%
Minimum Allocation	0.0%	64.3%	29.6%	50.0%	75.2%
Max Range Over Years	23.3%	35.7%	70.4%	50.0%	24.8%
Min Range Over Years	0.0%	0.0%	0.0%	0.0%	0.0%

Table 11: Summary of results derived from the consideration of Medians over single year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

Where three year time frames are considered it becomes evident that the outcomes become more consistent and appear to present a higher reliability as a result which is clear when comparing the figures in Section 12.1. Once again, the selection of smaller data sets derives results that are more varied than larger data sets with both PV and Solar Thermal excluding storage. However, the application of storage facilities with Solar Thermal generators tends to represent the likelihood that they will be generating at a high capacity during the intervals in question as is evident in Table 12 and Figure 13.

Outcome	Interval Selections for Median Methodology - Multiple (3) Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	0.0%	80.5%	88.5%	70.8%	77.0%
Minimum Allocation	0.0%	48.7%	53.3%	29.8%	46.2%
Max Range Over Years	0.0%	23.1%	23.7%	30.7%	16.9%
Min Range Over Years	0.0%	4.3%	7.3%	4.1%	0.6%

Outcome	Interval Selections for Median Methodology - Multiple (3) Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	100.0%	100.0%	100.0%	100.0%	100.0%
Minimum Allocation	0.0%	100.0%	80.9%	100.0%	100.0%
Max Range Over Years	0.0%	0.0%	19.1%	0.0%	0.0%
Min Range Over Years	0.0%	0.0%	0.0%	0.0%	0.0%

Table 12: Summary of results derived from the consideration of Medians over three year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

Where results are based on all years considered it is apparent that smaller interval selection data sets typically represent a significant amount of variability with an exception found in the use of Solar Thermal storage facilities. Here the use of storage permits the plant to operate at much increased capacity factors resulting in a higher probability that generation is maximised during peak load intervals.

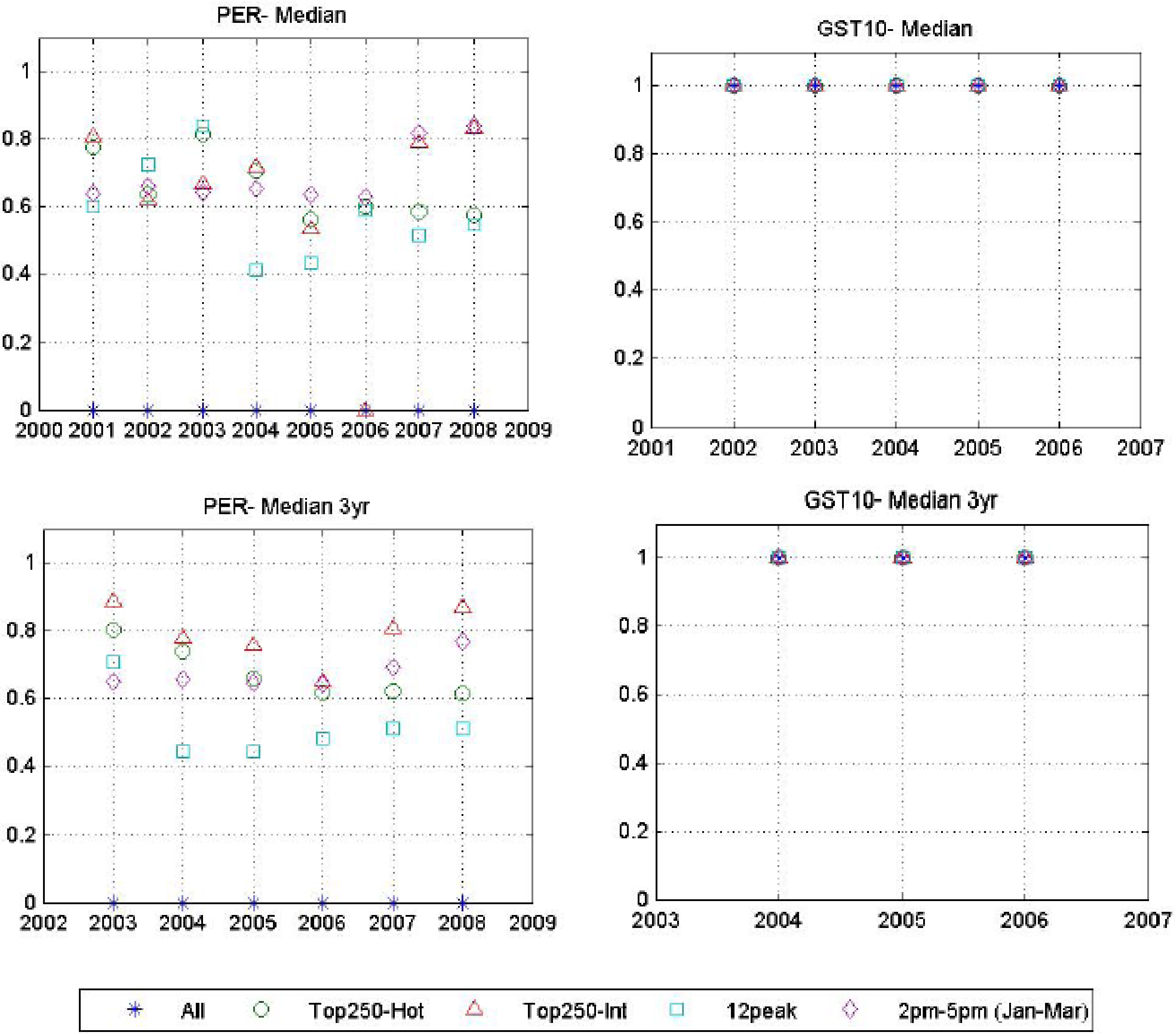


Figure 13: Example comparison of the results found when calculating reserve capacity based on Median. The sites have been arbitrarily selected to show the differences between single and three time frames and represent Perth PV and Geraldton Solar Thermal generation with ten hours of storage. More detailed plots of alternative sites can be found Section 12.1.

6.4 RCRM Weighted Averages

From the results presented it is apparent that the use of the normalised Reserve Capacity Refund Mechanism weighting system has over exaggerated the reserve capacity allocation when considering peak load intervals. This has resulted in the only realistic results being derived from all intervals (as the weightings are normalised) and the top 250 intermediate intervals (as the weighting is reduced during these times) with this calculation method.

Table 13 and Table 14 summarise the outcomes from the use of the adapted RCRM method. Although the allocations have a tendency to be exaggerated over peak load intervals the results show the same level of consistency as the use of averages as discussed in Section 6.1 as they are effectively derived as weighted averages. Given this, the use of this system over other interval selections such as all intervals and the top 250 intermediate intervals shows that it has potential to evolve into an effective means of reserve capacity allocation given more scrutiny of weightings.

Outcome	Interval Selections for RCRM Methodology - Single Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	42.2%	246.2%	84.8%	328.1%	242.3%
Minimum Allocation	30.4%	158.5%	28.4%	119.0%	130.0%
Max. Range Over Years	7.9%	71.4%	54.1%	184.4%	79.5%
Min. Range Over Years	2.1%	37.5%	13.6%	108.4%	18.6%

Outcome	Interval Selections for RCRM Methodology - Single Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	86.4%	388.0%	106.5%	428.0%	305.8%
Minimum Allocation	38.5%	180.0%	54.3%	214.0%	167.9%
Max. Range Over Years	8.6%	101.9%	18.9%	166.5%	57.2%
Min. Range Over Years	3.6%	43.0%	10.4%	71.3%	28.4%

Table 13: Summary of results derived from the consideration of RCRM Weighted Averages over single year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

Outcome	Interval Selections for RCRM Methodology - Multiple (3) Capacity Years - PV				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	41.3%	259.6%	79.8%	284.1%	222.4%
Minimum Allocation	31.1%	194.0%	57.6%	130.0%	142.1%
Max. Range Over Years	3.5%	40.9%	20.5%	122.7%	46.2%
Min. Range Over Years	0.5%	5.1%	1.5%	33.9%	3.4%

Outcome	Interval Selections for RCRM Methodology - Multiple (3) Capacity Years - Solar Thermal				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Max Allocation	84.6%	413.1%	102.6%	428.0%	298.8%
Minimum Allocation	40.2%	239.3%	58.2%	249.7%	191.5%
Max. Range Over Years	3.7%	78.0%	11.0%	130.8%	22.0%
Min. Range Over Years	0.7%	2.8%	6.9%	0.0%	8.7%

Table 14: Summary of results derived from the consideration of RCRM Weighted Averages over three year time frames. The maximum and minimum reserve capacity allocated over all individual years and sites for both modelled PV and Solar Thermal generators is presented along with maximum and minimum ranges over individual years for any single site which shows the volatility of the methodology to annual variations in solar resource.

Given the outcomes here it is apparent that there is some significant opportunity for a more appropriate Weighted Average reserve capacity calculation methodology to be derived. Comparing the average of the 2-5pm intervals to the results here indicates that this weighted average method understates the contribution to peak demand from SGF. Ideally this methodology would be based on all intervals and be applicable to all generation technologies.

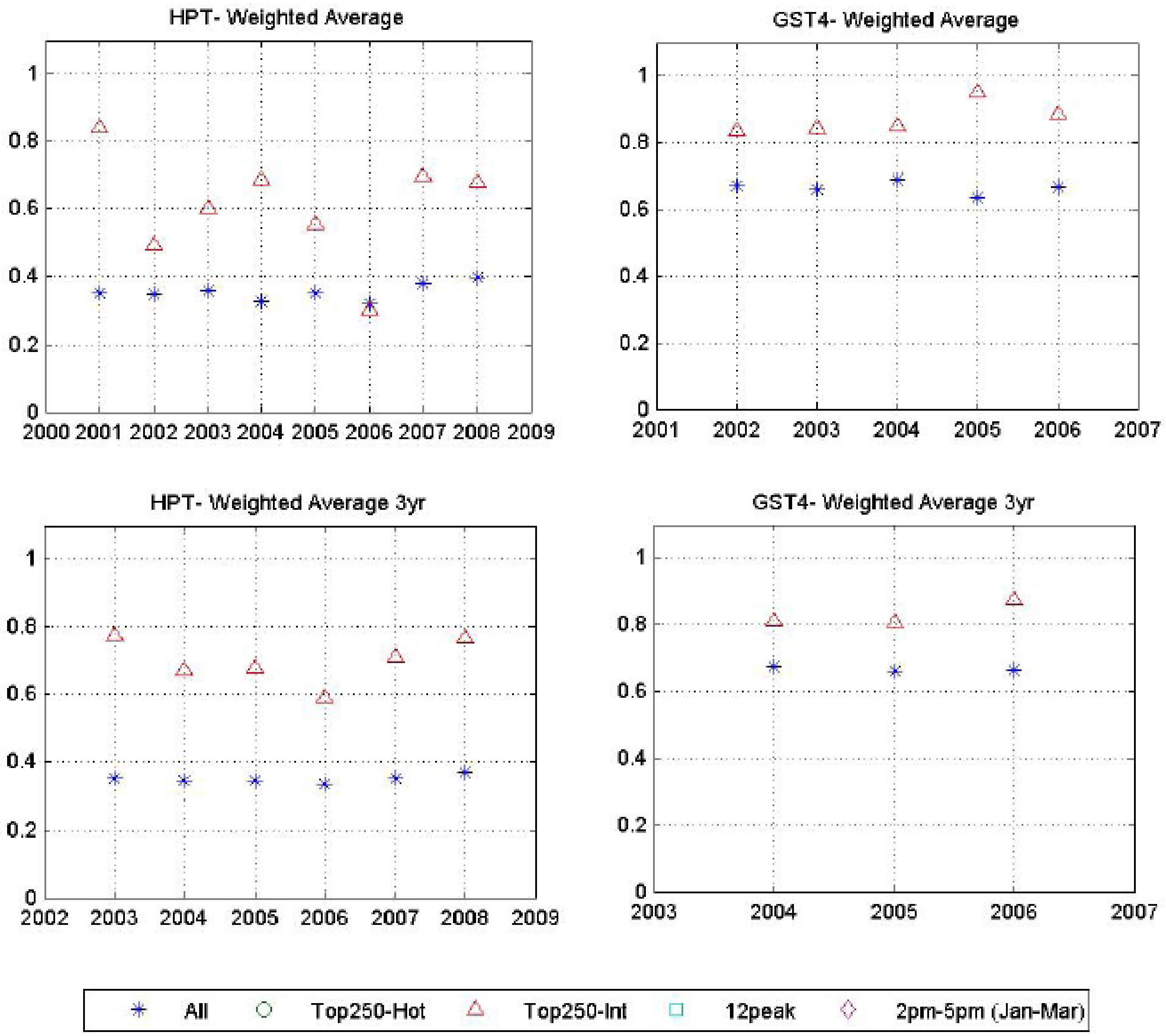


Figure 14: Example comparison of the results found when calculating reserve capacity based on the RCRM Weighted Average. The sites have been arbitrarily selected to show the differences between single and three time frames and represent Hopetoun PV and Geraldton Solar Thermal generation with four hours of storage. Note that many interval selection methods have generated results which exceed the y axis boundaries. More detailed plots of alternative sites can be found Section 12.1.

6.5 Interval and Time Frame Selections

In all of the study outcomes it is apparent that the correct selection of load interval is imperative to the results. The following summarises the general characteristics of each interval selection methodology in terms of solar generation.

Time Frame (Year) Selections

The results from this study indicate that, in general, the use of single capacity years for selecting the appropriate load and generation intervals is not desirable. Results can be highly varied from year to year when single years are selected while the use of multiple years reduces this variation and tends to promote consistency in reserve capacity allocations. However, there are some exceptions where smaller peak interval data sets are utilised over multiple years, as these can tend to focus on load intervals in a single year out of the years selected rather than across the number of years being considered.

All Intervals

As this interval selection method utilises those intervals where there is no solar resource it is apparent that it can only be useful where a weighted average calculation method such as the RCRM method can be applied or where a significant storage period is provided for Solar Thermal generators. Given this, the use of averages or weighted averages over all intervals appears to have some benefits in the consistency of outcomes, particularly where these outcomes are based on three year time frames.

Top 250 Hot Intervals

The selection of the Top 250 hot intervals tends to provide results that vary greatly from year to year when single years are selected. However, when considering the use of three year time frames the outcomes tend to stabilise and show slightly less variation while providing consistent reserve capacity allocations. This characteristic can effectively be put down to the increased likelihood that the data set of 250 load intervals all fall on days with clear skies and exceptional solar resources given longer time frames.

Top 250 Intermediate Intervals

Given the characteristic discussed above, the top 250 load intervals which fall in the months of October and November tend to derive reasonably consistent results from year to year at good solar resource sites. However, these months can be subject to large variations due to extended winter weather patterns into spring which is particularly evident at the Hopetoun site.

The reserve capacity allocation derived from these intervals has the potential to exceed that derived from the Top 250 Hot season intervals. The reason for this is that there is a tendency for load profiles to peak toward the month of February and March while the POA solar radiation peaks toward the summer solstice in December.

12 Peak Intervals

The selection of the 12 Peak load intervals for assessing reserve capacity has been found to be non-preferred due to highly inconsistent results found in PV and Solar Thermal generation where storage is not considered. This outcome is most evident in the use of the tenth percentile calculation method.

2-5pm Intervals from Jan. – Mar.

It is evident that the interval selection from 2-5pm in the months of January, February and March has a significant level of consistency in the reserve capacity allocations over all of the calculation techniques. Generally, this outcome could be put down to the expansion of the data set to 540 intervals which all occur at times where the load is consistently high but not necessarily peaking and the solar resource is typically high. Further analysis of the data finds a data set that is generally well distributed across any year selection as noted by comparing means to averages.

7 Study Outcomes and the Wholesale Market Objectives

Under the consideration of the proposed Rule Change 31 there are three main aspects of the Wholesale Market Objectives which should be considered in detail. In general the Objectives relate more closely to the intervals selected for the calculation methodologies rather than the methodologies themselves. The following paragraphs of Rule 1.2.1 [1] are considered to have the most relevance.

(b) To encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors.

(c) To avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions.

(d) To minimise the long-term cost of electricity supplied to customers from the South West interconnected system.

Objective (b)

At present the Capacity Market allocates reserve capacity credits to generators with the intention to encourage new generation by providing a significant revenue stream for its development to the extent that the market may wholly fund new generation plant. While this intention is considered to be fitting to dispatchable generators, results here show that there is a significant shortfall in allocations to SGF. While not defined as such by the Reserve Capacity Refund Mechanism it is evident that under the present capacity credit allocation procedure, this shortfall could be considered to be a penalty to SGF based on the choice of developing generation which is limited by a variable source of energy.

Thus, the present use of the average of all intervals for calculating reserve capacity for SGF is not acceptable in that the efficient entry of SGF is not facilitated to the extent that other generators are. The results here indicate that there is a significant difference between capacity credit allocations to SGF based on all intervals and those based around peak load intervals or periods. Correspondingly, any interval selection considering night time intervals will not meet this objective in regard to SGF unless an acceptable weighting calculation methodology is derived successfully.

Objective (c)

As discussed above the use of all trading intervals already discriminates against SGF due to the limited availability of the resource (as was the incentive behind Rule Change 31). However, the intention of Objective (c) is not only limited to the division between SGF and dispatchable generators in that SGF technologies should also be considered.

Here, a clear distinction has been found in the ability of SGF to closely match peak load times. It is evident that there is some division in outcomes between the models of Solar Thermal generators with and without thermal storage potential. Where storage is excluded generators show generation characteristics which vary rapidly with the incidence of Direct irradiance. Correspondingly, the inclusion of just four hours of storage capacity will greatly increase that generators reserve capacity allocation. The results show that if this storage capacity is increased to any time period above four hours the increase in the relevant level is marginal for methodologies that include peak period intervals. Conversely, where all intervals are considered the increase can be significant as the storage time increases. The implications of this suggest that the use of all trading intervals gives the most incentive to include longer storage times in Solar Thermal plant design. However, the selection of peak intervals or periods provides a larger allocation to generators with no storage than the present allocation methodology does to generators with 16 hours of storage.

Thus, while PV generators will always be discriminated against under any non-weighted calculation method which utilises all trading intervals, Solar Thermal generators are simply not recognised in their ability to meet peak demand periods irrespective of the technology applied and the use of all trading intervals can be considered to be insufficient to both technologies.

Objective (d)

In terms of SGF and Objective (d) one of the key issues is the inherently high cost involved in developing technologies. Since one of the applications of the Reserve Capacity Market is the potential to provide revenue for the development of new generation, some consideration must be given to the projected costs of Solar Thermal and PV generation when compared to the current development of gas plant.

The results of this study indicate that there are no opportunities for PV generators to receive capacity credits up to their installed capacity. Furthermore, the plant capacities considered are not expected to have a large impact on the implications of Objective (d). However, there are many results where Solar Thermal generators are allocated their nominal capacity which is comparable to gas fired peaking plant. The impact of this in terms of Objective (d) can be assessed by making a financial comparison against the two technologies.

Basing the following on the levelised electricity cost from individual generators the reported range of costs for gas generators is $38-53/MWh for combined cycle plant and $52-92/MWh for combined cycle plant including carbon capture and storage. Correspondingly, while presently the cheapest fuel source, coal fired generation is expected increase to a range of $52-108/MWh with the associated low emission technologies [12]. The recent New South Wales Solar Thermal Roadmap **Error! Reference source not found.** reported that the levelised cost of electricity for Solar Thermal generators is in the range of $55-80/MWh (depending on the technology considered) and is expected to decrease to $35-60/MWh by 2020.

The peaking capacity of Solar Thermal generators has been shown to be significant in the results here. This implies that such generation may offset the installation of gas peaking plant. The above comparison indicates that the expansion of Solar Thermal generation instead of gas plant could have an impact on reducing the cost of electricity in the long term while the contribution of PV is considered to be minimal.

Summary

In all cases the points above show that the selection of any calculation methodology which utilises all trading intervals over any time frame would effectively discriminate against SGF. Furthermore, in regard to long term planning, there is an indication that the expansion of SGF will reduce the electricity cost to the consumer.

Given these points a calculation methodology based on the selection of peak intervals or periods would satisfy the Wholesale Market Objectives. Alternatively, an appropriately developed weighted average methodology considering all intervals may suffice. Additional consideration should be given to the calculation methodology applied. Here, it has been shown that the methodology can be susceptible to some instability where data sets are small and the use of averages or medians offer the most consistency over three year time frames. However, the impact of the selection of calculation methodology on alternative generation technologies may need further investigation.

8 Rule Change Proposal Submissions

As indicated in the scope an assessment of the submissions to Rule Change 31 is made below. The basis for these submissions was the proposed amendment to Rule 4.11.3 as Rule 4.11.3 B. However, the results of this study indicate that the selection of the proposed method would not give the desired result as assumed in the initial proposal. The comments made by SEA below assess the concerns and statements in regard to an alternative calculation methodology to that proposed by Synergy.

8.1 Submission by Alinta Sales

The submission from Alinta Sales as reported in the IMO's Draft Rule Change Report of February 20 2009 [6] is as follows.

> *Alinta submits that, while the Rule Change Proposal has intuitive appeal, it notes that the proposed new rule would be available to all intermittent facilities, not just solar facilities.*
>
> *Further, Alinta notes that it has not been examined whether or not the proposal would, as stated, result in capacity certification for solar facilities being set at levels that more closely approximate the capacity that would be available from those facilities during periods of peak system demand.*
>
> *Consequently, Alinta considers that the proposal should not be approved as currently proposed. Instead Alinta proposes that:*
>
> - *The rules should be amended to apply only to intermittent solar facilities; and*
> - *The IMO should undertake a technical study to assist it and Market Participants in assessing whether the amendments proposed for the calculation of Certified Reserve Capacity for solar facilities is consistent with the Market Objectives and should therefore be approved.*
>
> *Alinta concludes that no evidence has been provided to allow an assessment to be made as to whether the proposal would amend the Market Rules in a manner that would better facilitate the Wholesale Market Objectives.*

The main points and summarised responses to these points resulting from this work are as follow.

"*The rules should be amended to apply only to intermittent solar facilities"*

> There is no supporting evidence that the selection of a new Rule 4.11.3 B will provide a benefit or otherwise to any other generation technologies. Moreover, the impact of alternative generation technologies selecting a new Rule 4.11.3 B based on these results should remain negligible given the appropriate calculation methodology is selected. Furthermore, Wholesale Market Objective (c) intends to avoid discrimination of different generation technologies and a statement such as this would be contrary.

senergy
alternative energy
econnect

8.2 Submission by Landfill Gas and Power

The submission from Landfill Gas and Power (LGP) as reported in the IMO's Draft Rule Change Report of February 20 2009 [6] is as follows.

> *LGP supports the proposed Rule Change Proposal on the grounds that it removes an existing inequity impeding solar generation in a manner that properly and rationally recognises its contribution to system capacity. This is without diminishing other facilities and technologies.*
>
> *LGP also supports Synergy's contention that the proposal supports market objectives (b) and (c). In particular, LGP submits that the proposal removes an inequity whereby solar generation would otherwise be assigned Certified Reserve Capacity and potentially allocated capacity credits significantly below its true contribution, without diminishing other facilities or technologies. LGP perceives the Rule Change Proposal to be an essential upgrade of the Market Rules to facilitate utilization of Western Australia's abundant solar resource and thereby enhanced participation in the revised federal Mandatory Renewable Energy Target.*

The results found here indicate that LGP's assumptions are accurate in that an alternative capacity credit allocation method which is based on peak load intervals or periods would better represent the contribution that SGF can make to system capacity. Furthermore, given the appropriate calculation methodology is selected the impact of other technologies selecting the new Rule 4.11.3 B or the existing Rule 4.11.3 A should be negligible as assumed by LGP.

8.3 Submission by Perth Energy

The submission from Landfill Gas and Power (LGP) as reported on the IMO's website (http://www.imowa.com.au/Attachments/RuleChange/RuleChange_2008_31.html) is as follows.

> This change would allow developers to nominate that the IMO assess the certification level of a facility as the amount of generation available during peak demand periods with 90% certainty.
>
> Perth Energy agrees with the comments that the present method of certification, based on average output, is not appropriate for solar generators. Some mechanism is required which recognizes that a solar plant provides capacity that closely matches the SWIS demand profile. Perth Energy considers that the approach put forward provides a reasonable mechanism and therefore supports the proposed rule change.
>
> The Draft Rule Change Report notes that the proposed method of calculation could potentially be applied to other generation types and it has been suggested that the rule be specifically limited to solar power plants. Perth Energy does not favour such a limitation. There are other technologies that could potentially utilize this rule, for example pumped storage plants or other peaking plants that can only provide capacity for a limited period. These plants can materially assist the power system reliability during very high demand periods but are not technically capable of covering the full 14 hour peak period.
>
> Perth Energy supports the proposed Rule Change as set out by the IMO.

See the above comments on the Alinta submission.

9 Conclusions

This work has considered calculation options for the allocation of the relevant levels of reserve capacity for SGF operating in Western Australia's South West Interconnected System. In doing so reserve capacity allocations have been determined based on modelled Photovoltaic generators in the 1-2MW capacity range along with Solar Thermal generators which can utilise thermal storage options in capacities above 50MW.

Calculations have been based on publicly available solar resource data from the Bureau of Meteorology and generator models have been developed in MATLAB. In the modelling peak load intervals have been selected across various time frames and the corresponding modelled generation at these peak times has been extracted and analysed for the results.

The instigation for this work was the proposed Rule Change 31 as put forward the IMO by Synergy. The results here indicate that, while the alternative reserve capacity calculation methodology proposed by Rule Change 31 is intuitively correct, the limitations of a restricted data set which only considers a single year of data are clear. Should a Rule Change to the present Rule 4.11.3 focus on SGF an alternative method should be proposed to that of Rule Change 31.

The results of the study show that calculation methodologies which derive small data sets based on limited numbers of peak load intervals are not desirable for SGF due to the inherent variability of the solar resource. Correspondingly, calculation methodologies which consider night time hours are also not desirable as they effectively penalise SGF through the nature of the primary resource and fail to satisfy the Wholesale Market Objectives as a result.

Generally, the outcomes indicate that averages or means will provide similar results when considering peak load intervals or periods, which implies that interval selections over these time frames produce well distributed data sets. Furthermore, a larger data set that does not include night time load intervals will generally produce a consistent result.

While the results here report on an option based on the weighted average method of the Reserve Capacity Refund Mechanism, this option has been found to misrepresent the contribution from SGF when considering all load intervals, and to over-allocate when considering peak intervals only. However, the use of a weighted average method has been found to be effective in its capacity to deliver consistent results. Thus, a more effective weighting system could be derived and effectively applied under the consideration of alternative generation technologies.

10 References

[1] Wholesale Electricity Market Amending Rules, Electricity Industry Act, 1 February 2009.

[2] Rule Change Notice: Capacity Credits for Solar Facilities, IMO, Ref: RC_2008_31, 18 December 2008.

[3] Email to Tom Butler (SEA) from William Street (IMO) dated 6/3/2009.

[4] Wholesale Electricity Market Amending Rules, 2005.

[5] IMO Rule Change Notice: Capacity Credits for Solar Facilities. Ref: RC_2008_31.

[6] IMO Draft Rule Change Report: Capacity Credits for Solar Facilities. Ref: RC_2008_31.

[7] Mills, D.R., Morgan, R.G., "Solar Thermal Electricity as the Primary Replacement for Coal and Oil in the U.S. Generation and Transportation", Ausra, Inc., available: www.ausra.com.au accessed: 10/02/09.

[8] Haberle, A., Et al., "The Solarmondo Line Focussing Fresnel Collector. Optical and Thermal Performance and Cost Calculations", available: www.solarpaces.org, accessed: 19/02/09.

[9] Whenham, S. R., Green, M. A., ET. Al., 2007, "*Applied Photovoltaics*", Earthscan, United Kingdom.

[10] Prior, T., 2007, "*Lecture Notes: ENG307, Resources for Renewable Energy*", Department of Engineering and Energy, Murdoch University, Western Australia.

[11] Butler, T. R., Et al., Econnect Australia Project No. 2175, 2009, "*The Impacts and Benefits of Highly Distributed Embedded Generation in Australian Distribution Networks*", Produced for the CSIRO and retained by Senergy Econnect Australia.

[12] AREVA, 2008, "*Submission to the Garnot Climate Change Review*", Available: www.garnautreview.org.au, Accessed: 10/4/09.

[13] Report Prepared for the New South Whales and Victorian Governments by Wyld Group Pty. Ltd., 2008, "*High Temperature Solar Thermal Technology Roadmap*", Available: www.coag.gov.au, Accessed: 10/2/09.

11 Appendix A: Nomenclature and Abbreviations

11.1 Appendix A1: Nomenclature

H	Daily Global irradiation on the horizontal plane
H_D	Daily Diffuse irradiation on the horizontal plane
H_B	Daily Direct (Beam) irradiation on the horizontal plane
I	Half-hourly Global irradiation on the horizontal plane
I_D	Half-hourly Diffuse irradiation on the horizontal plane
I_B	Half-hourly Direct (Beam) irradiation on the horizontal plane
POA	Subscript: Plane of Array irradiation
G_{SC}	Global Solar Constant: 1367W/m^2
H_0	Daily Global Extraterrestrial irradiation on the horizontal plane
I_0	Half-hourly Global Extraterrestrial irradiation on the horizontal plane
K_T	Daily Average Clearness Index
ω	Hour angle
ω_s	Sunrise hour angle
δ	Solar declination
α	Solar altitude angle
β	Slope angle of *POA* from the horizontal plane
γ	PV array azimuth angle
ϕ	Site latitude
ρ	Site longitude
n	Day of the year (Jan-1 = 1 etc.)

11.2 Appendix A2: Abbreviations

PV	Photovoltaic Generator
ST	Solar Thermal Generator
SGF	Solar Generating Facility
DSG	Direct Steam Generation
BOM	Australian Bureau of Meteorology
SEA	Senergy Econnect Australia

12 Appendix B: Results

The complete sets of results of the study are displayed below. For simplicity and space saving, an arbitrarily selected set of graphical results for both PV and Solar Thermal have been displayed initially followed by the full tabulated results from the study. Tabulated results are listed in order of site in the same format as that of Table 2 which is repeated below for convenience.

Calcualtion Methodology	Load Intervals Selected for Reserve Capacity Calculation Methodologies				
	All	Top 250 (Summer)	Top 250 (Intermediate)	12 Peak	2-5pm (Jan. - Mar.)
Average	Current	X	X	X	PJM
10th Percentile	X	Proposed / Original	Original	X	X
Median	X	X	X	IRCR	X
Weighted Average	RCRM	X	X	X	X

Table 15: Analysis conducted for each site and year group.

All years and groups of years are listed in accordance with the tabulated results as summarised in Table 16. Graphical results are displayed by comparison of calculation technique in respect of interval selection while tabulated results are provided in Summary Tables by site and grouped by single year results and multiple year results. All graphical results are as discussed in Section 6.

Bureau of Meteorology Weather Station Sites and Utilised Data for Results of Reserve Capacity Calculations								
Site	Abbreviation	Technology	BOM Station #	Site Latitude (Degrees)	Site Longitude (Degrees)	Data Utilised	Capacity Years Utilised	Year Groups
Kalgoorlie	KPV	Photovoltaic	12038	-30.5	121.3	Half-hourly Global and Direct	2001 - 2006	All years, 4 x 3 years 2001-2006
Geraldton	GPV	Photovoltaic	8051	-28.5	114.5	Half-hourly Global and Direct	2002 - 2006	All years, 3 x 3 years 2002-2006
Perth	PER	Photovoltaic	9225	-31.6	115.5	Daily Irradiation	2001 - 2008	All years, 6 x 3 years 2001-2008
Badgingarra	BDG	Photovoltaic	9037	-30.4	115.5	Daily Irradiation	2001 - 2008	All years, 6 x 3 years 2001-2008
Hopetoun	HPT	Photovoltaic	9961	-34.0	120.1	Daily Irradiation	2001 - 2008	All years, 6 x 3 years 2001-2008
Walpole	WLP	Photovoltaic	9998	-35.0	116.7	Daily Irradiation	2001 - 2008	All years, 6 x 3 years 2001-2008
Kalgoorlie	KST0	Solar Thermal (0 hours storage)	12038	-30.5	121.3	Half-hourly Direct	2001 - 2006	All years, 4 x 3 years 2001-2006
Kalgoorlie	KST4	Solar Thermal (4 hours storage)	12038	-30.5	121.3	Half-hourly Direct	2001 - 2006	All years, 4 x 3 years 2001-2006
Kalgoorlie	KST10	Solar Thermal (10 hours storage)	12038	-30.5	121.3	Half-hourly Direct	2001 - 2006	All years, 4 x 3 years 2001-2006
Kalgoorlie	KST16	Solar Thermal (16 hours storage)	12038	-30.5	121.3	Half-hourly Direct	2001 - 2006	All years, 4 x 3 years 2001-2006
Geraldton	GST0	Solar Thermal (0 hours storage)	8051	-28.5	114.5	Half-hourly Direct	2002 - 2006	All years, 3 x 3 years 2002-2006
Geraldton	GST4	Solar Thermal (4 hours storage)	8051	-28.5	114.5	Half-hourly Direct	2002 - 2006	All years, 3 x 3 years 2002-2006
Geraldton	GST10	Solar Thermal (10 hours storage)	8051	-28.5	114.5	Half-hourly Direct	2002 - 2006	All years, 3 x 3 years 2002-2006
Geraldton	GST16	Solar Thermal (16 hours storage)	8051	-28.5	114.5	Half-hourly Direct	2002 - 2006	All years, 3 x 3 years 2002-2006

Table 16: Summary table of the sites, generation technologies, years and year groups utilised in the study as reported by results here.

12.1 Appendix B1: Graphical Results for Selected Sites

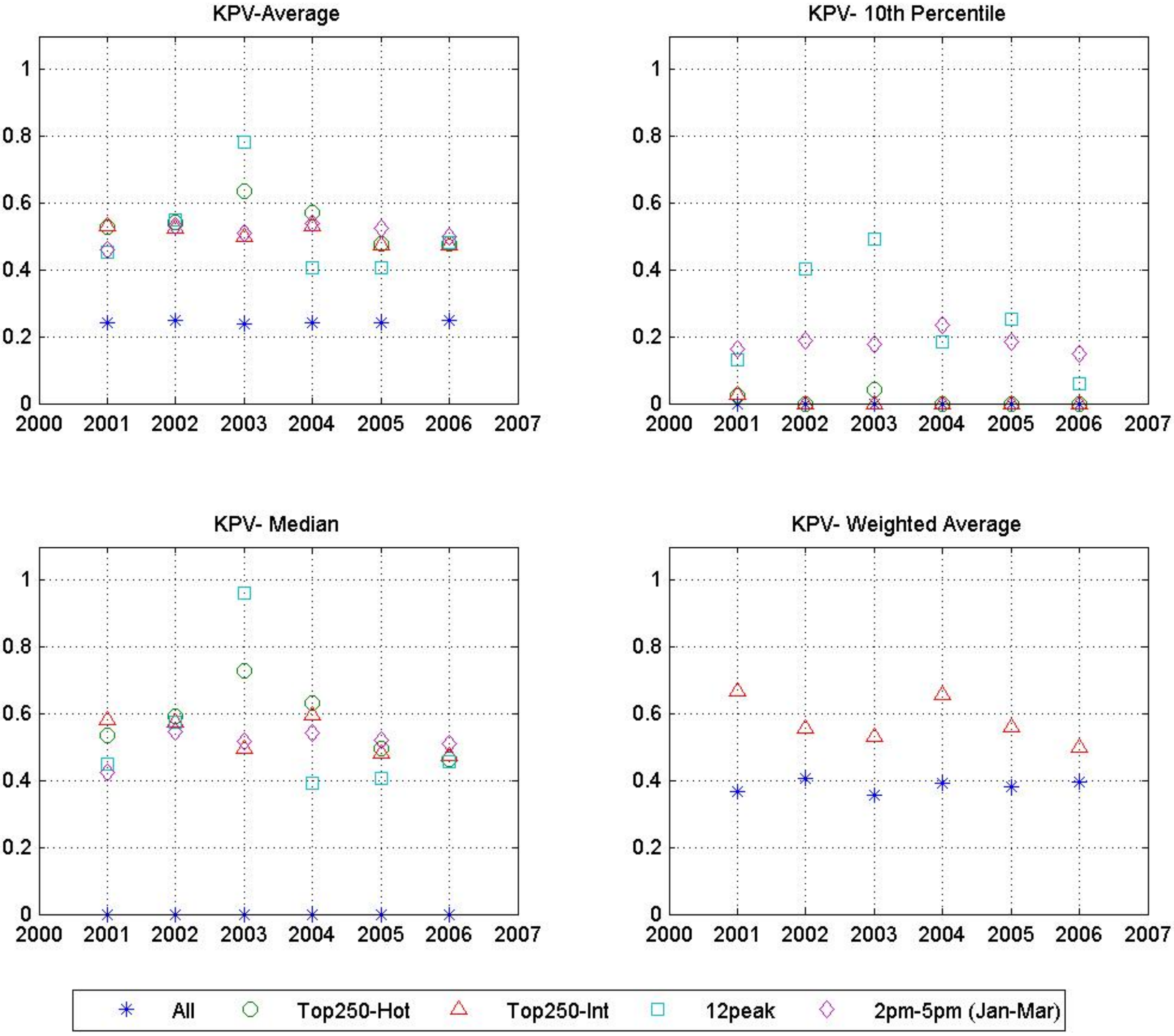


Figure 15: Comparison of results found when calculating reserve capacity based on all methodologies for Kalgoorlie PV generation over single year time frames.

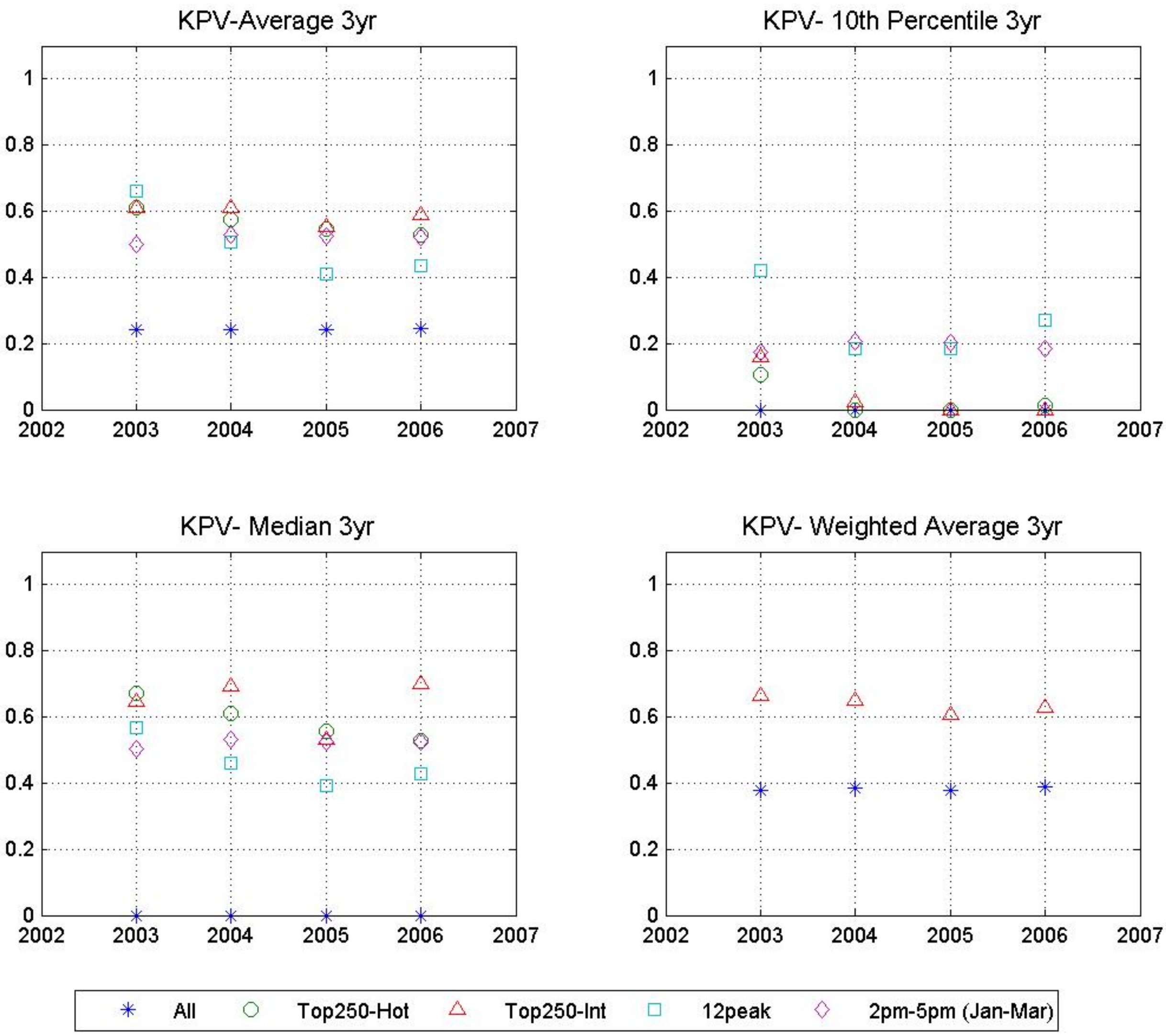


Figure 16: Comparison of results found when calculating reserve capacity based on all methodologies for Kalgoorlie PV generation over three year time frames.

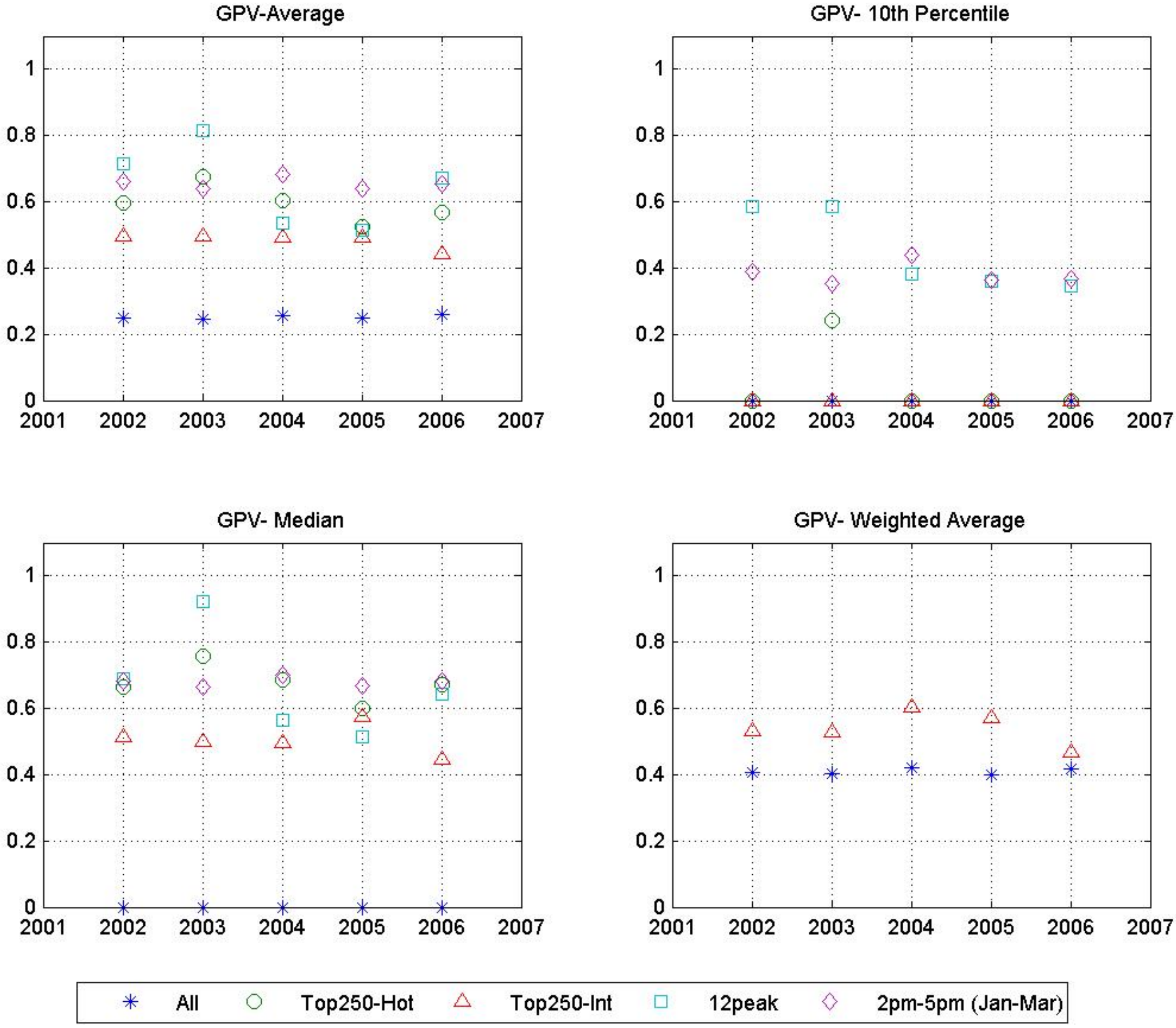


Figure 17: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton PV generation over single year time frames.

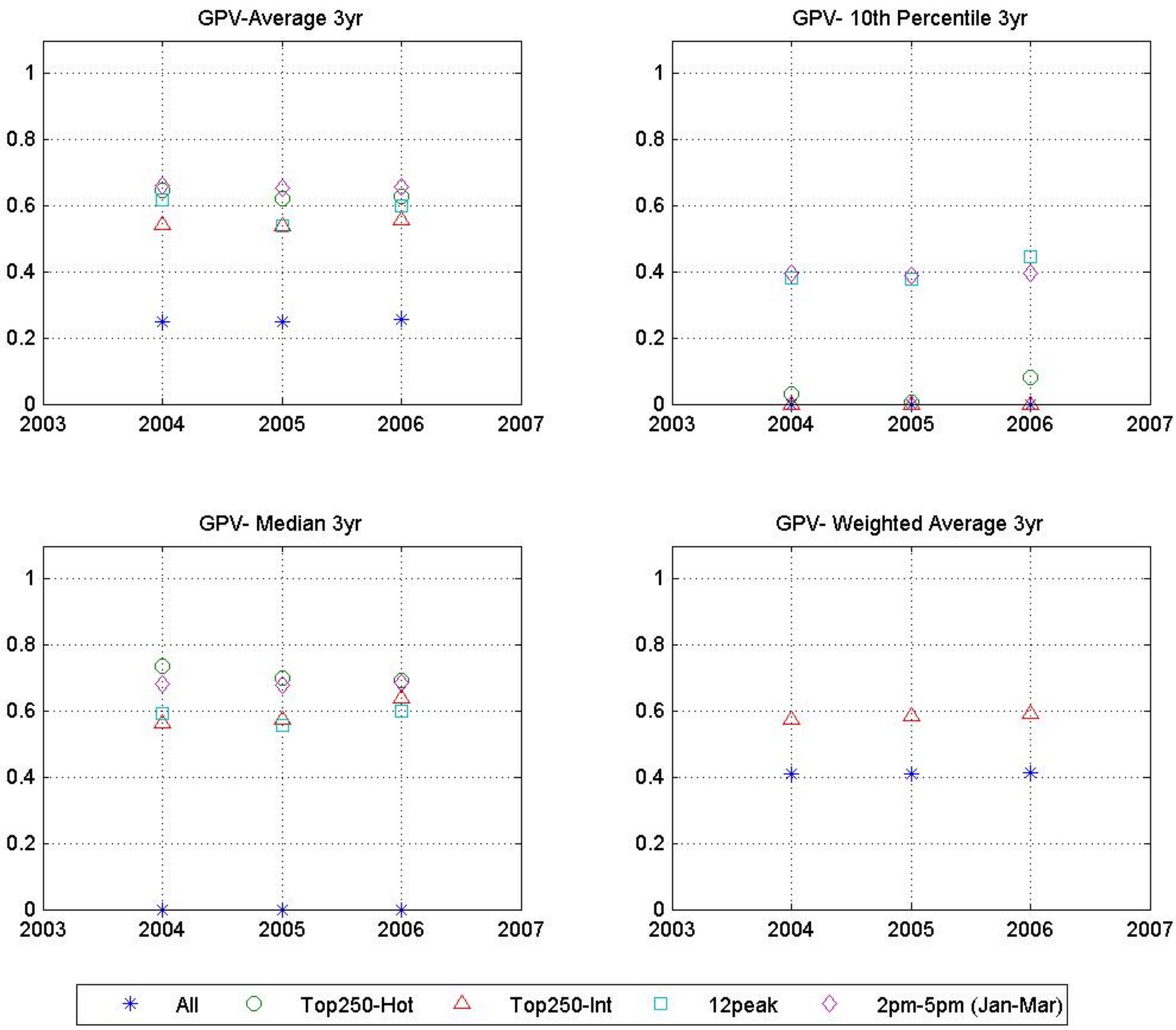


Figure 18: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton PV generation over three year time frames.

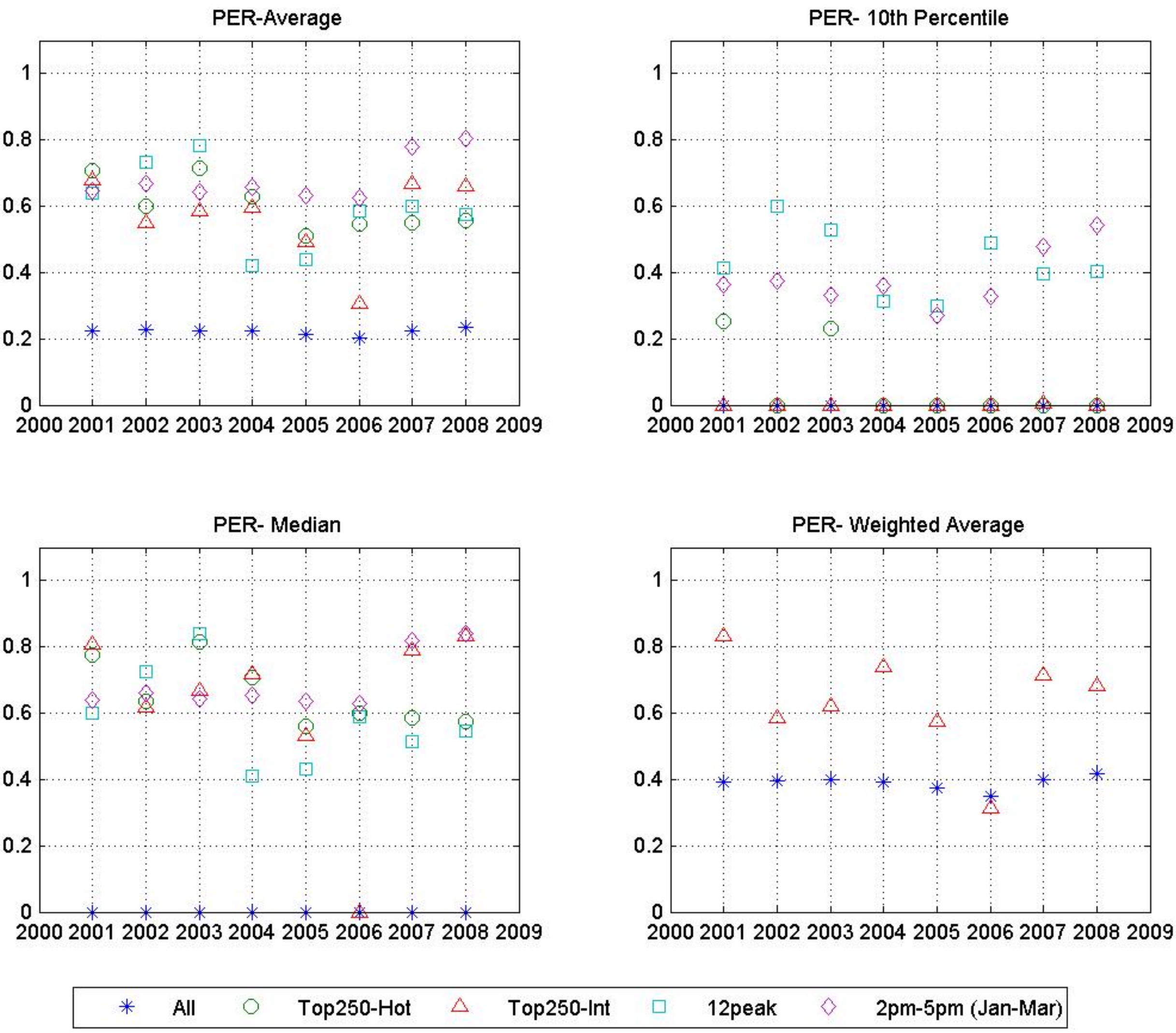


Figure 19: Comparison of results found when calculating reserve capacity based on all methodologies for Perth PV generation over single year time frames.

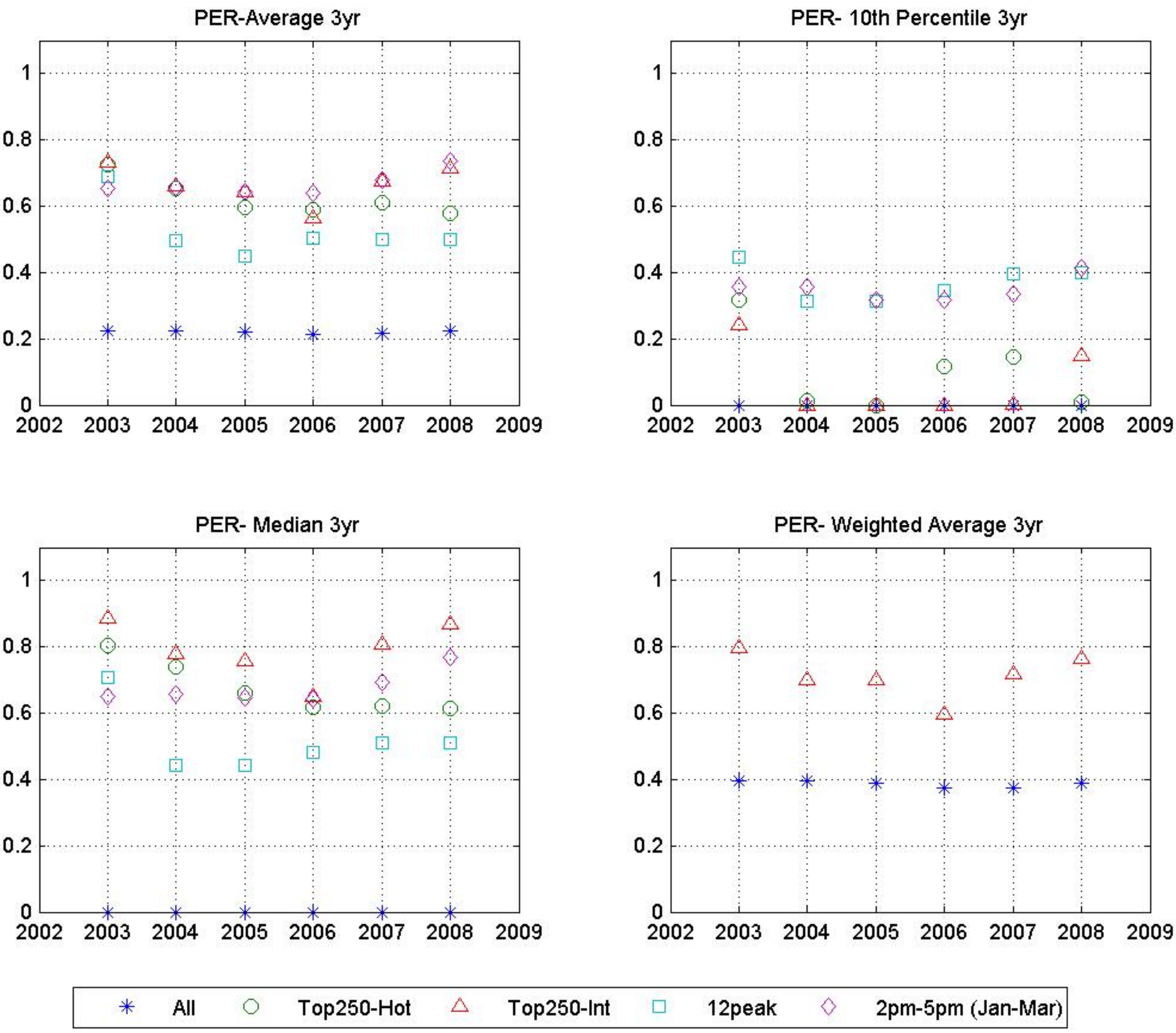


Figure 20: Comparison of results found when calculating reserve capacity based on all methodologies for Perth PV generation over three year time frames.

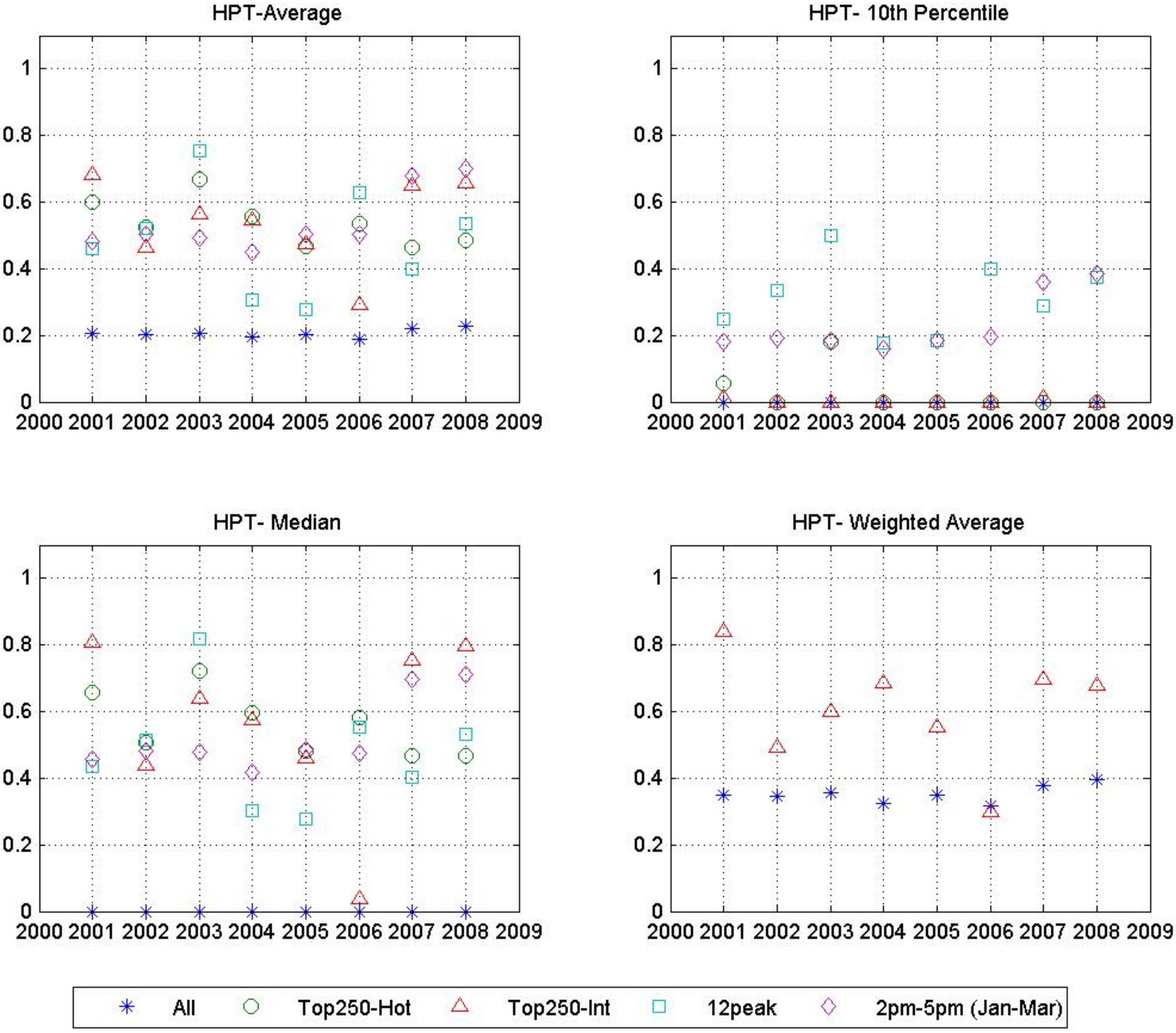


Figure 21: Comparison of results found when calculating reserve capacity based on all methodologies for Hopetoun PV generation over single year time frames.

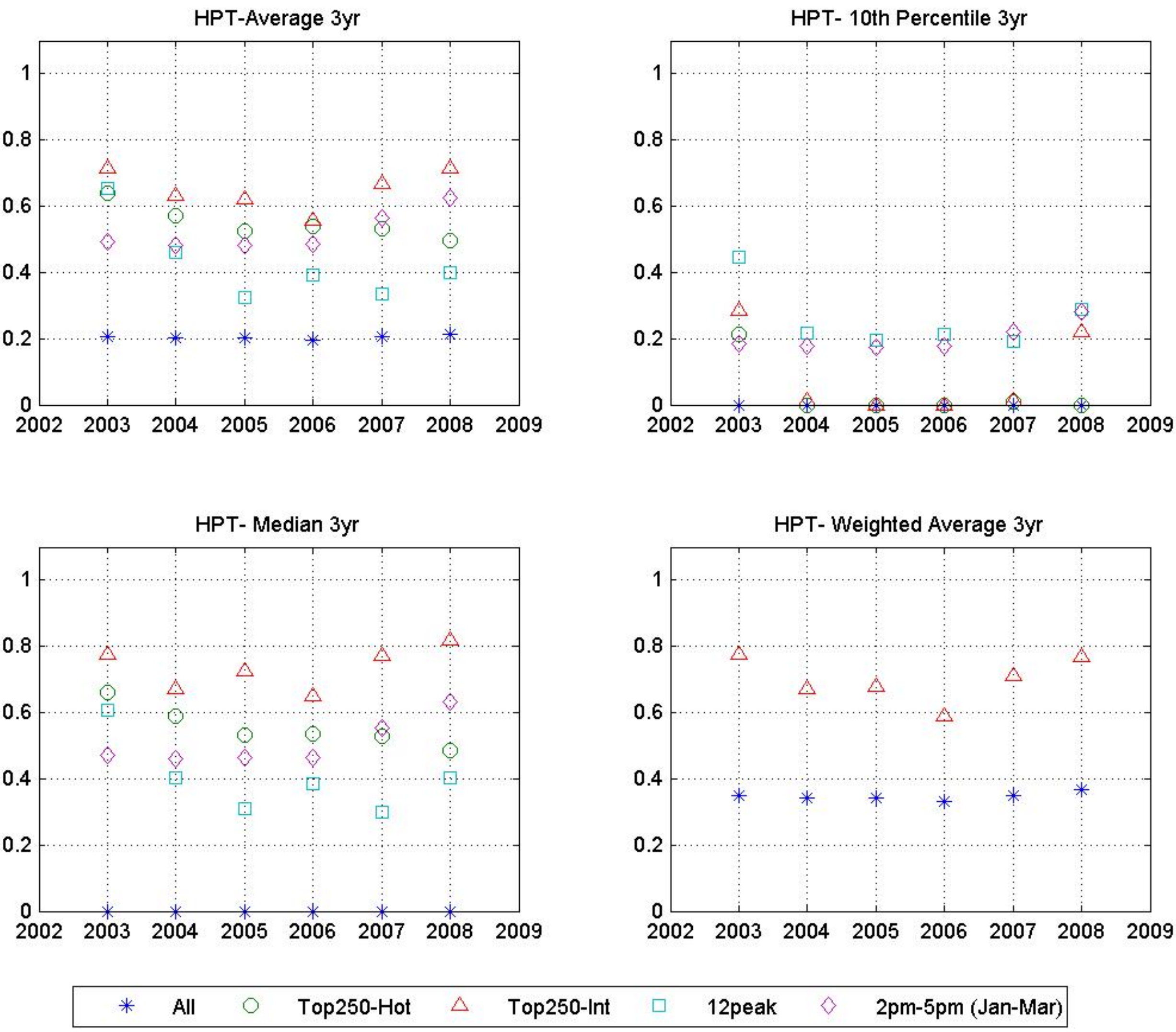


Figure 22: Comparison of results found when calculating reserve capacity based on all methodologies for Hopetoun PV generation over three year time frames.

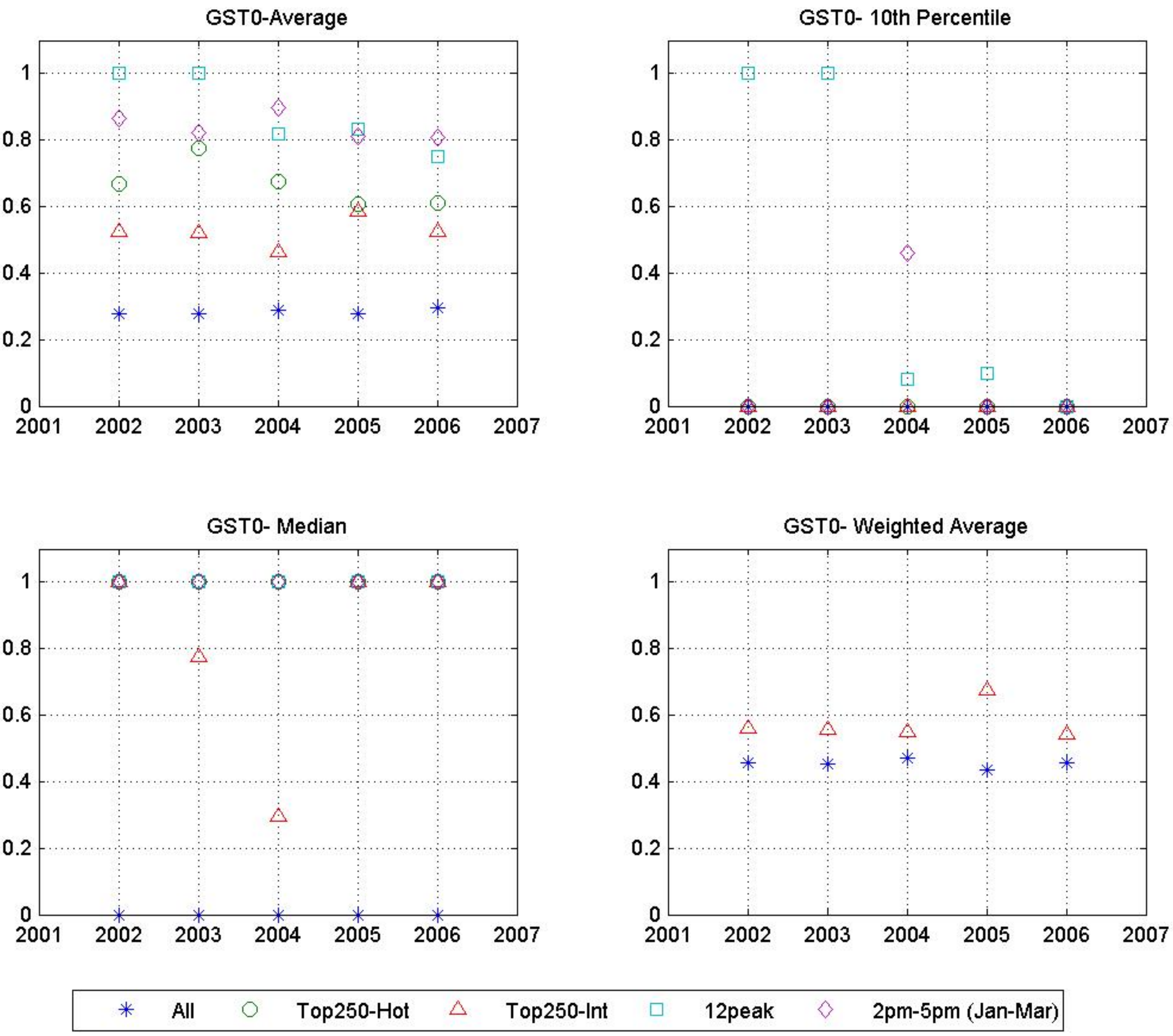


Figure 23: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation excluding storage over single year time frames.

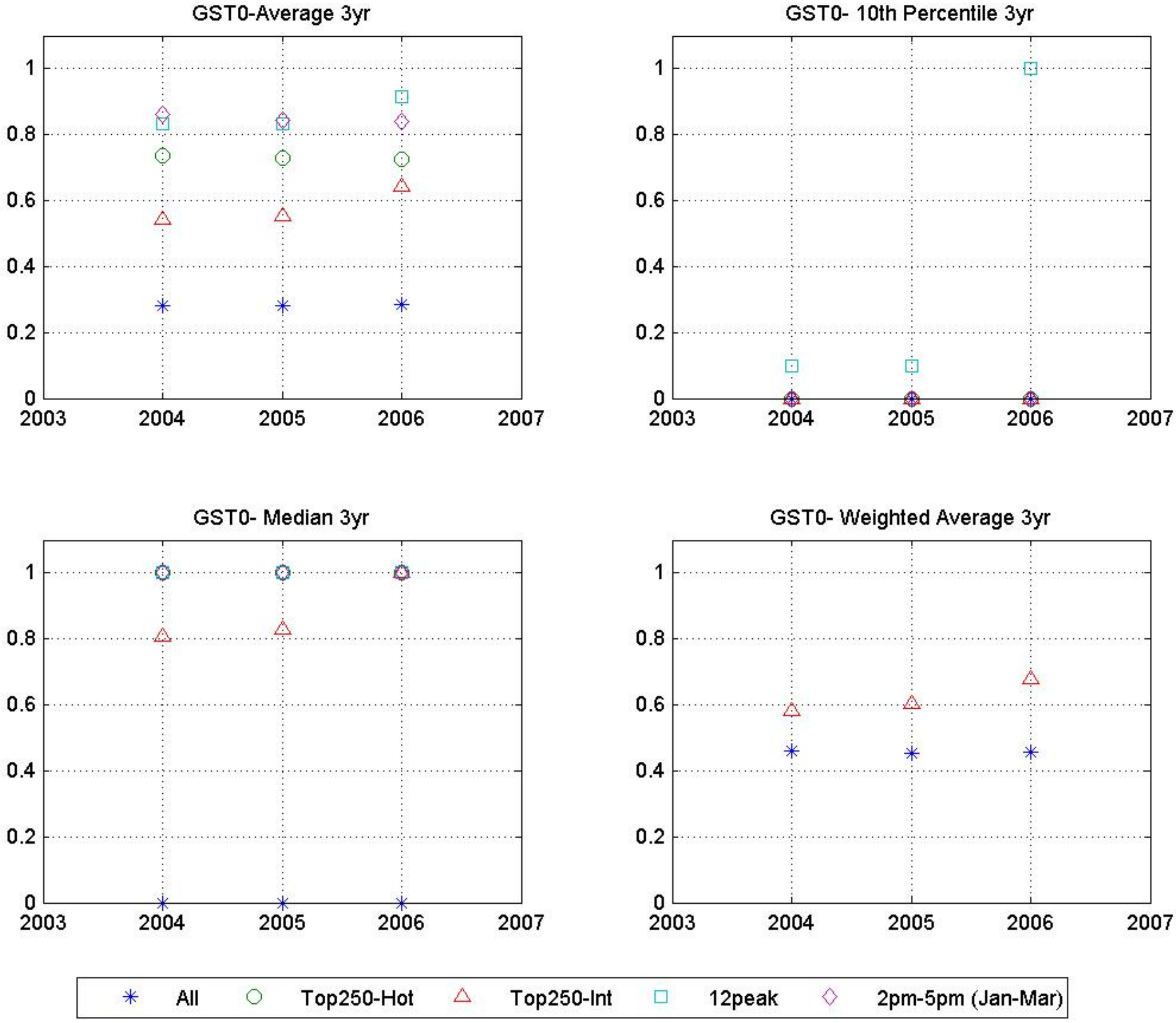


Figure 24: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation excluding storage over three year time frames.

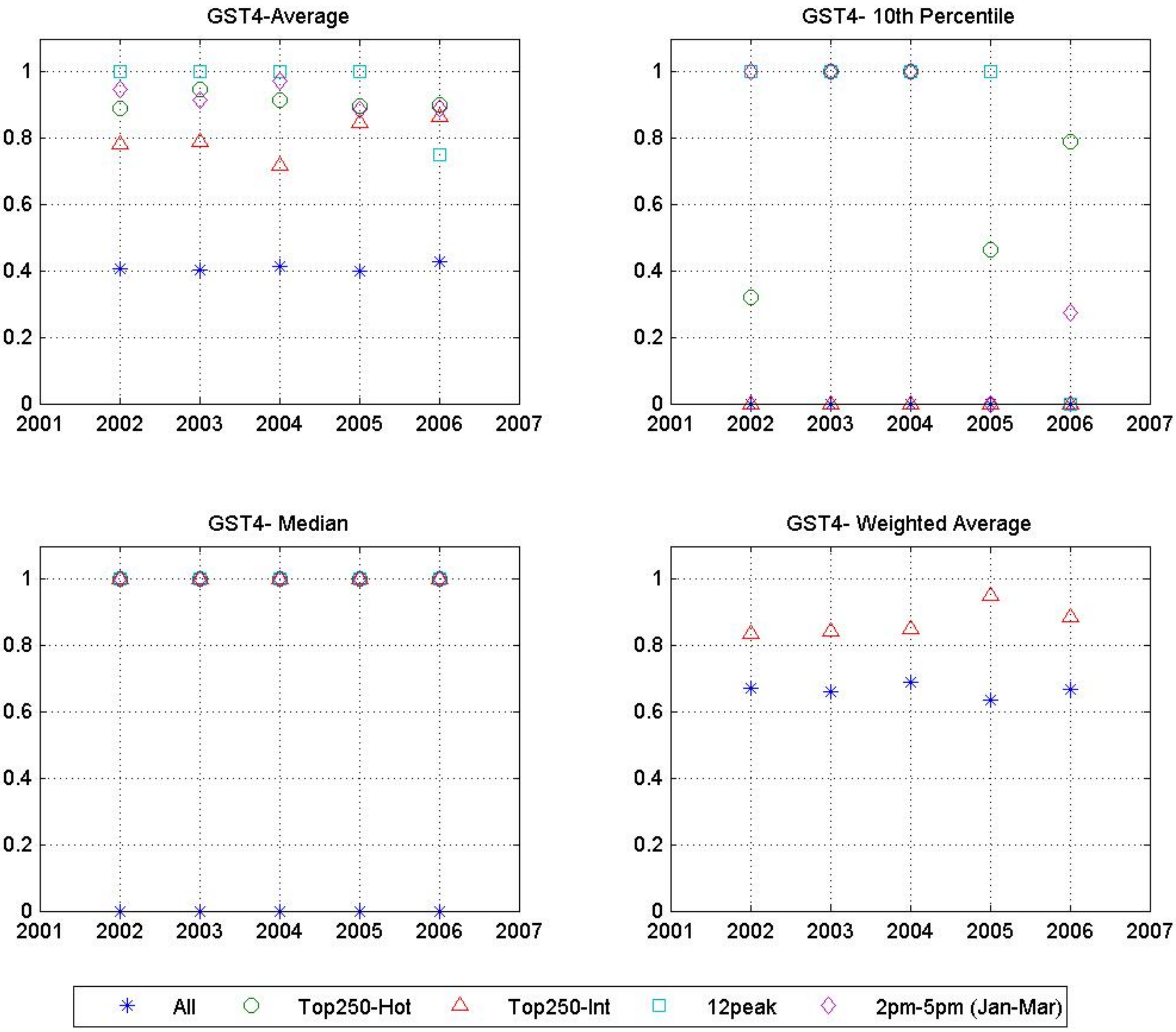


Figure 25: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation including four hours of thermal storage over one year time frames.

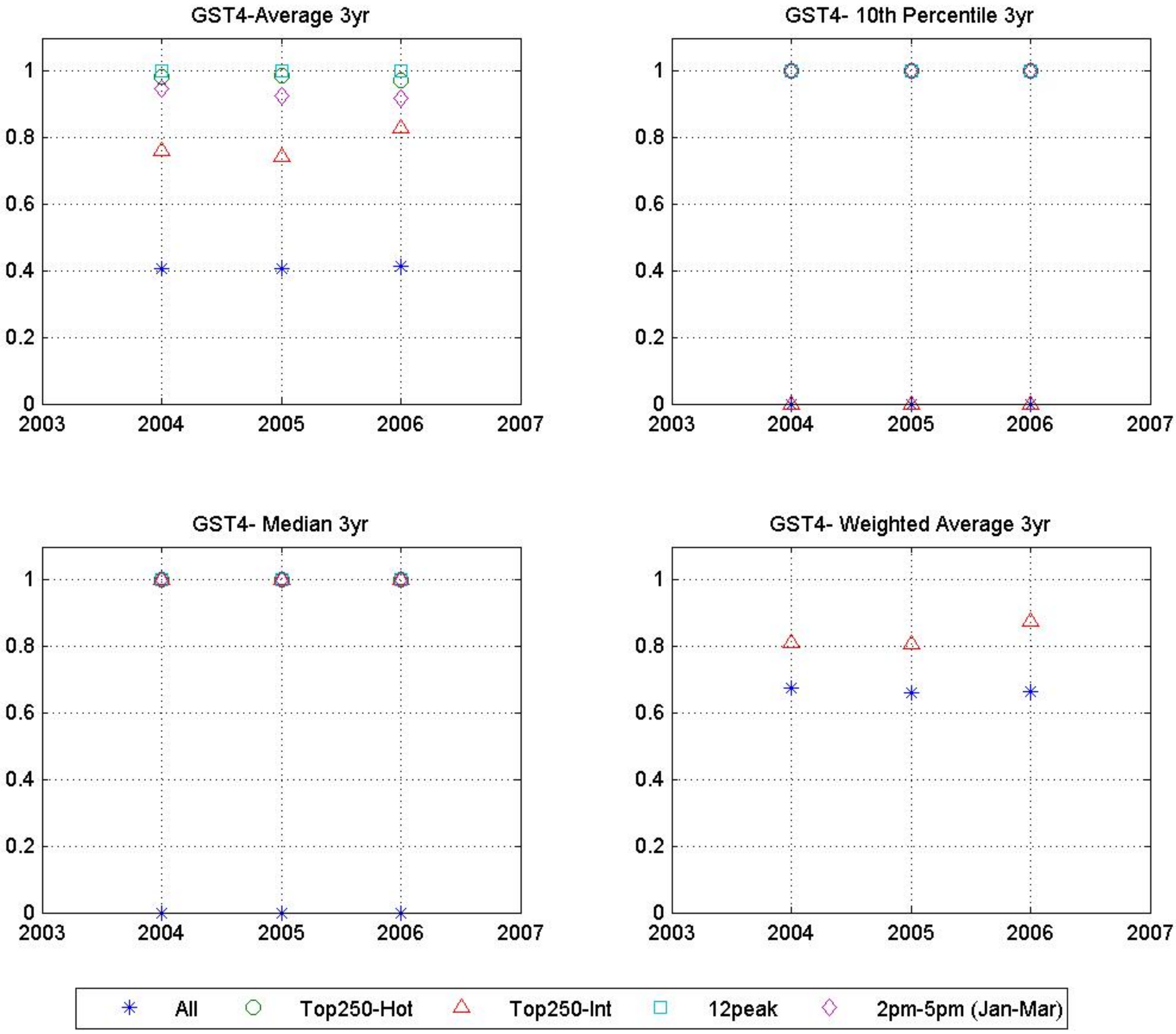


Figure 26: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation including four hours of thermal storage over three year time frames.

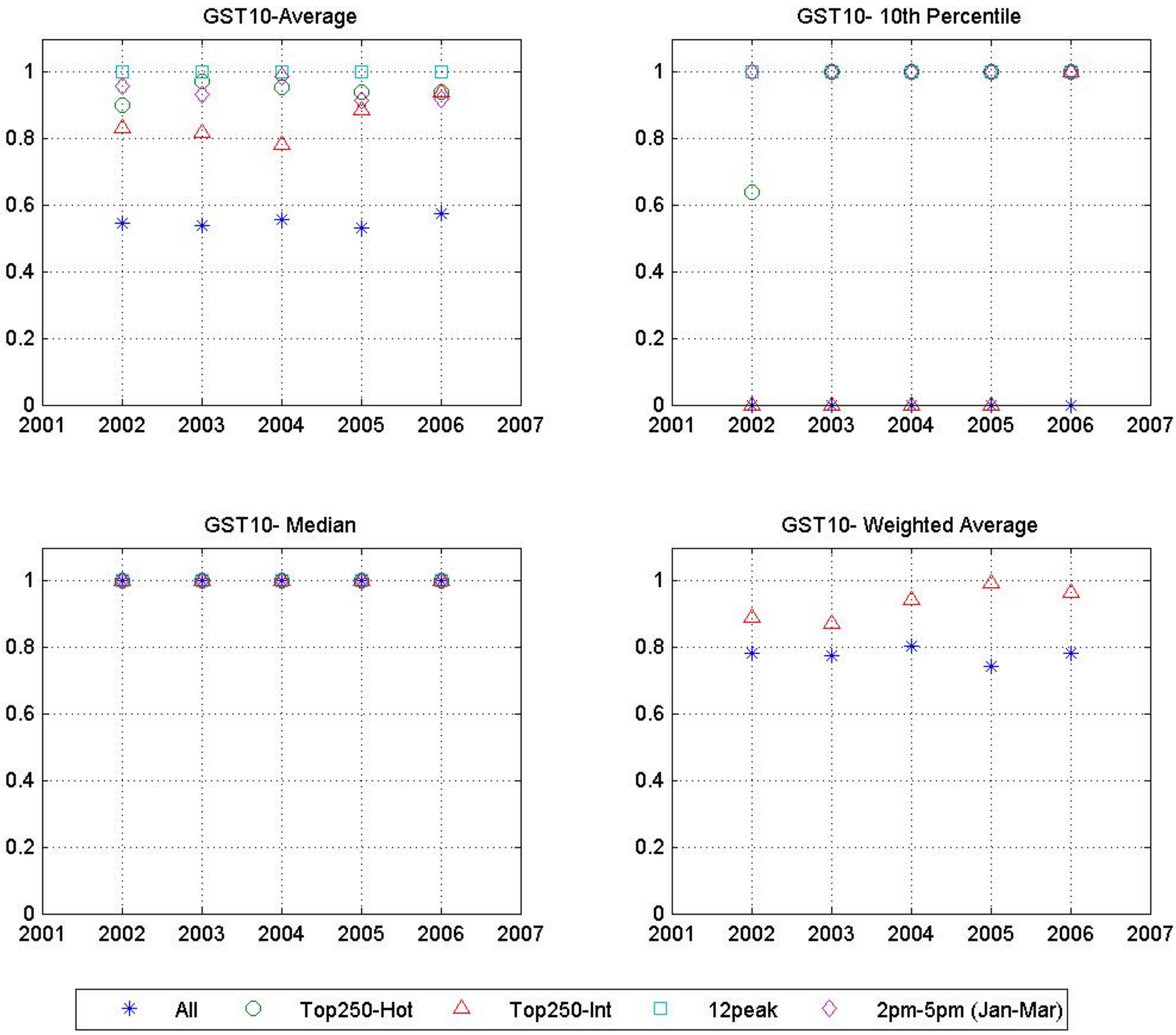


Figure 27: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation including ten hours of thermal storage over one year time frames.

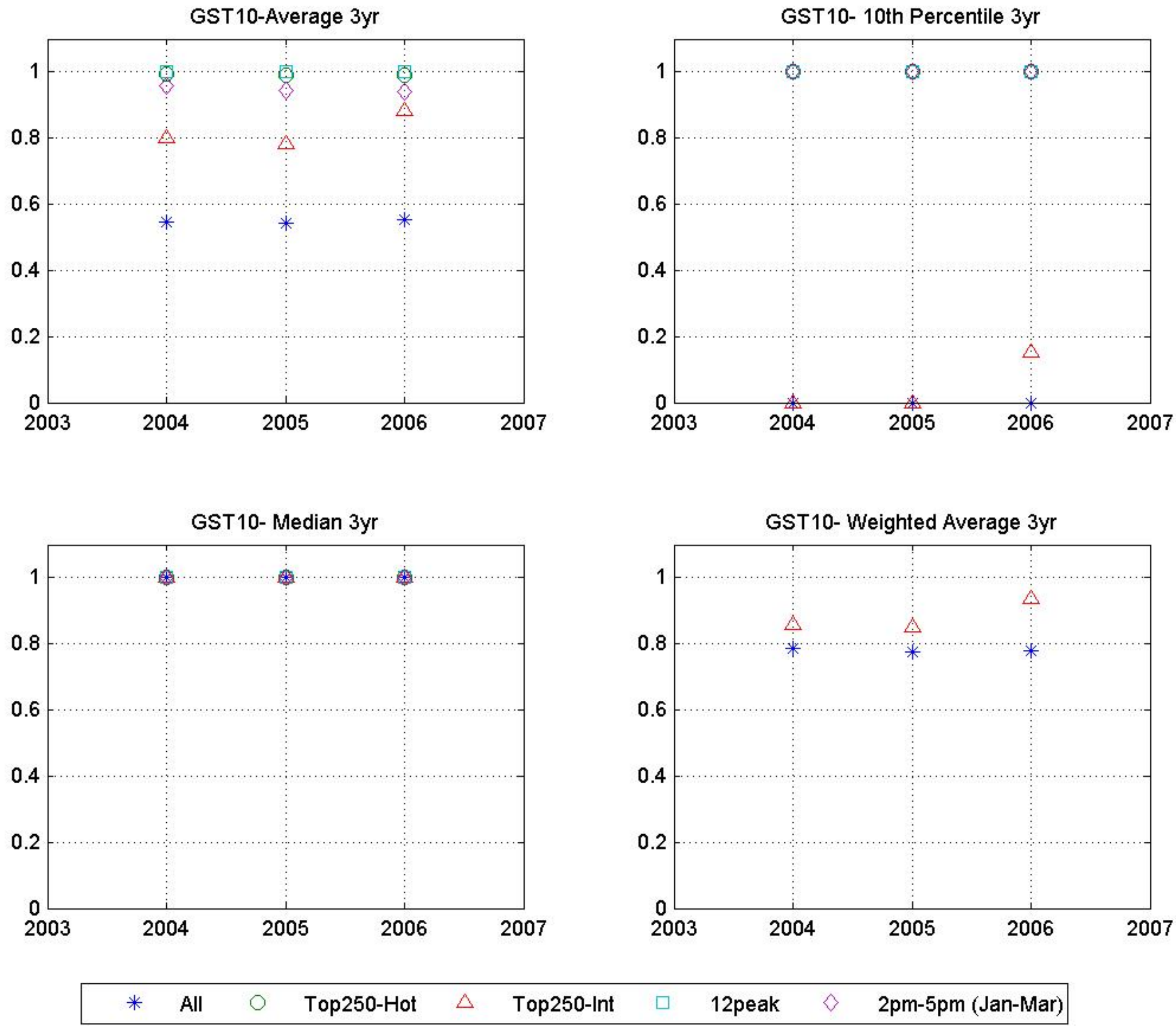


Figure 28: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation including ten hours of thermal storage over three year time frames.

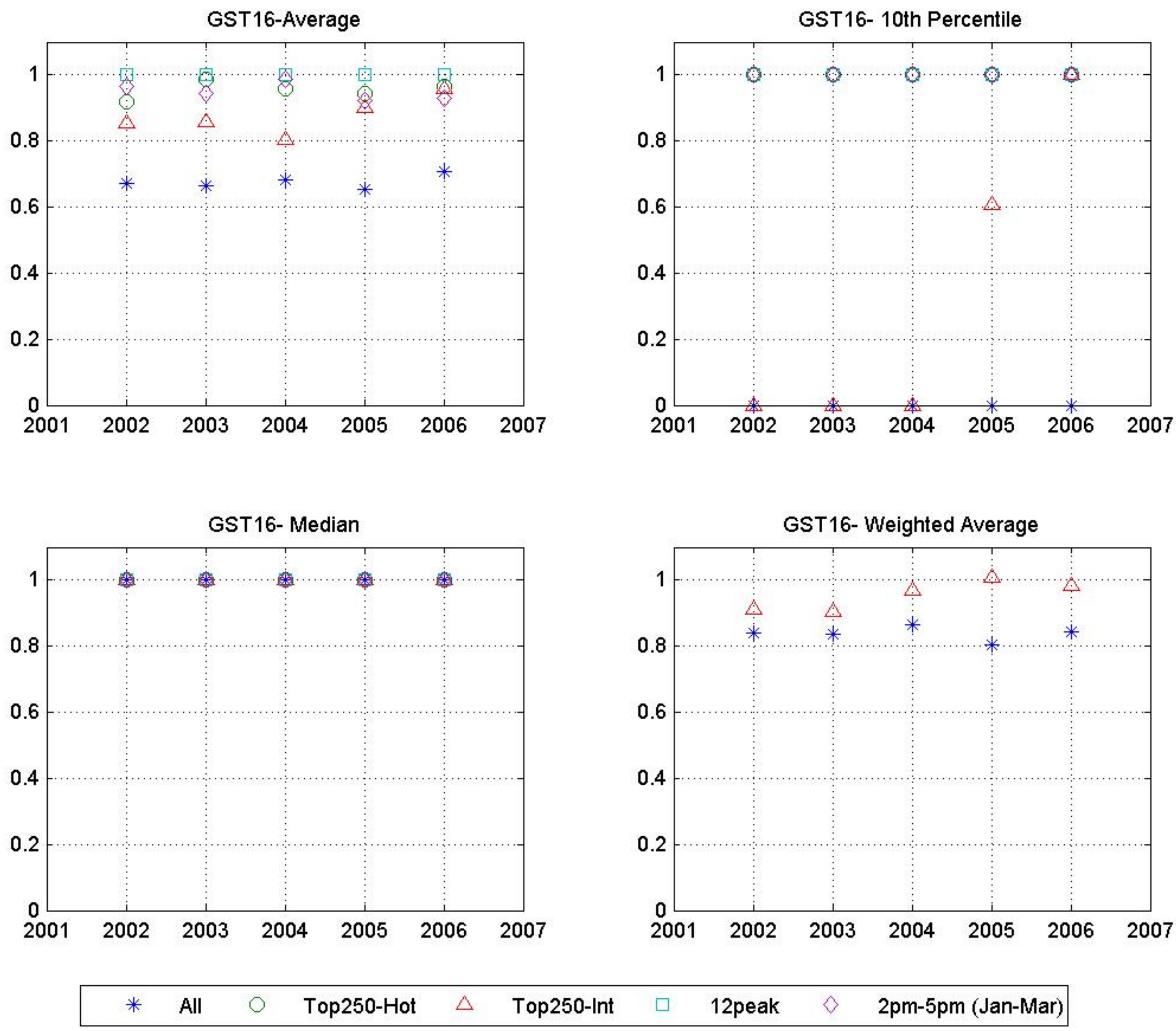


Figure 29: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation including sixteen hours of thermal storage over one year time frames.

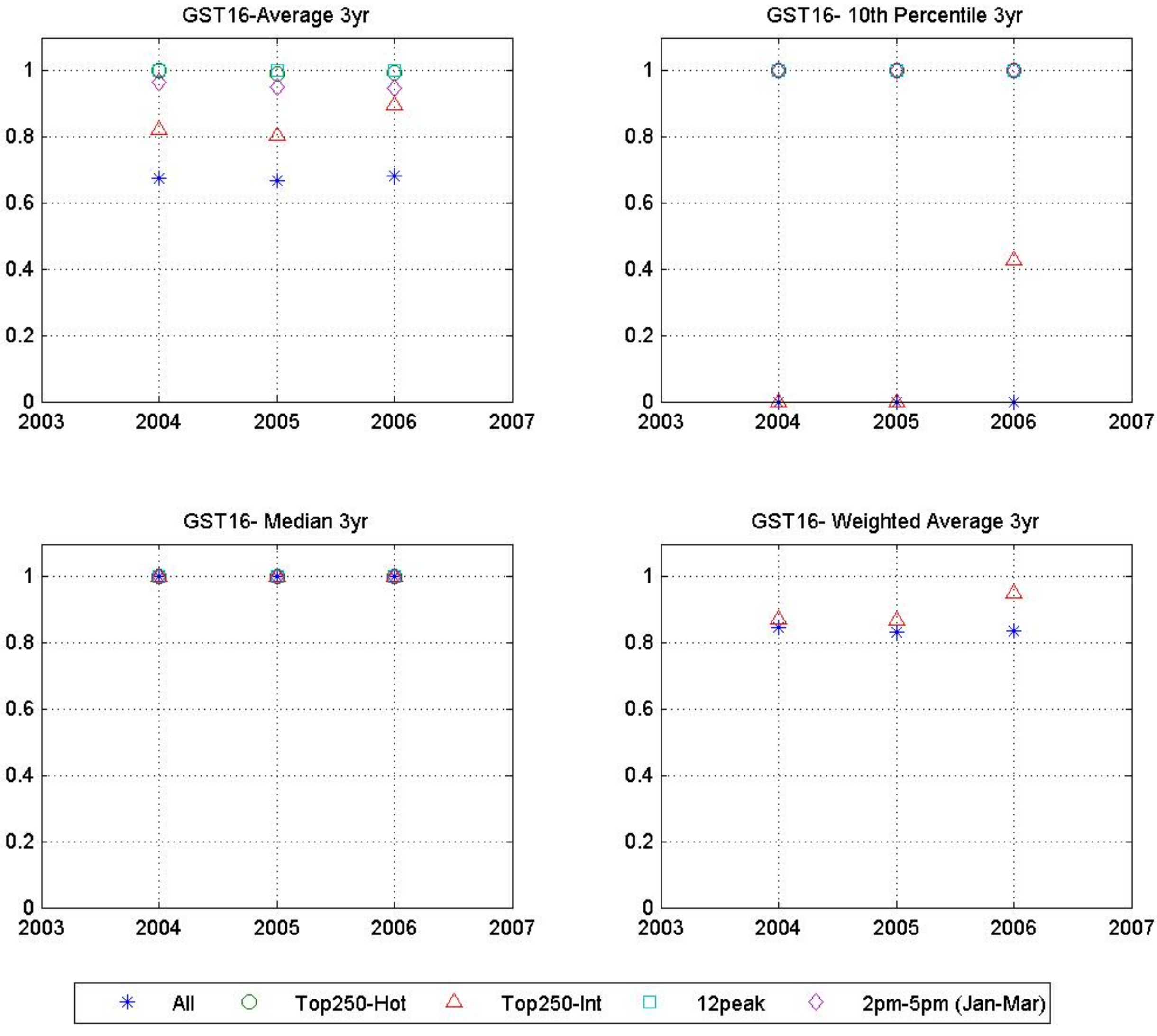


Figure 30: Comparison of results found when calculating reserve capacity based on all methodologies for Geraldton Solar Thermal generation including sixteen hours of thermal storage over three year time frames.

12.2 Appendix B2: Results for Single Year Studies

Summary Results Table for Calculation Methods From Kalgoorlie: KAL

Method	Interval Selections				
2001					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.1%	53.0%	53.1%	45.4%	46.1%
10th Percentile	0.0%	2.3%	2.5%	13.1%	16.3%
Median	0.0%	53.6%	58.3%	44.8%	42.4%
Weighted Average	36.8%	177.3%	66.9%	188.1%	146.0%
2002					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.9%	54.2%	52.4%	55.1%	53.2%
10th Percentile	0.0%	0.0%	0.0%	40.4%	18.8%
Median	0.0%	59.2%	57.5%	57.6%	54.6%
Weighted Average	40.8%	200.7%	55.8%	198.0%	162.8%
2003					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	23.8%	63.5%	49.9%	78.1%	51.2%
10th Percentile	0.0%	4.2%	0.0%	49.4%	17.7%
Median	0.0%	72.9%	49.5%	96.4%	51.6%
Weighted Average	35.7%	214.8%	53.1%	310.1%	164.6%
2004					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.3%	57.0%	53.3%	40.6%	53.9%
10th Percentile	0.0%	0.0%	0.0%	18.6%	23.5%
Median	0.0%	63.2%	59.6%	39.3%	54.1%
Weighted Average	39.1%	201.3%	65.8%	174.0%	164.7%
2005					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.1%	48.0%	47.6%	40.5%	52.3%
10th Percentile	0.0%	0.0%	0.0%	25.4%	18.4%
Median	0.0%	49.7%	48.3%	40.8%	52.1%
Weighted Average	38.3%	177.9%	56.2%	173.6%	158.2%
2006					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	25.1%	47.9%	47.4%	48.2%	49.9%
10th Percentile	0.0%	0.0%	0.0%	5.8%	15.0%
Median	0.0%	46.5%	47.4%	45.6%	51.0%
Weighted Average	39.5%	199.5%	50.0%	206.5%	155.3%

Summary Results Table for Calculation Methods From Geraldton: GER					
2002					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	24.9%	59.5%	49.8%	71.4%	66.0%
10th Percentile	0.0%	0.0%	0.0%	58.7%	38.9%
Median	0.0%	66.5%	51.4%	69.1%	68.2%
Weighted Average	40.8%	218.7%	53.2%	250.1%	201.6%
2003					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	24.7%	67.4%	49.7%	81.4%	64.1%
10th Percentile	0.0%	24.2%	0.0%	58.4%	35.3%
Median	0.0%	75.7%	50.1%	92.2%	66.4%
Weighted Average	40.3%	231.1%	53.0%	328.1%	196.7%
2004					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	25.5%	60.5%	49.4%	53.6%	68.2%
10th Percentile	0.0%	0.0%	0.0%	38.0%	43.9%
Median	0.0%	68.7%	49.7%	56.5%	69.9%
Weighted Average	42.2%	223.1%	60.2%	229.6%	210.1%
2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	24.9%	52.5%	49.2%	51.3%	64.1%
10th Percentile	0.0%	0.0%	0.0%	36.2%	36.3%
Median	0.0%	60.1%	57.4%	51.6%	67.0%
Weighted Average	40.1%	196.2%	57.1%	219.7%	191.2%
2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	26.1%	56.8%	44.4%	67.3%	65.3%
10th Percentile	0.0%	0.0%	0.0%	34.4%	36.8%
Median	0.0%	67.1%	44.4%	64.4%	68.3%
Weighted Average	41.7%	237.4%	46.7%	288.3%	198.5%

Summary Results Table for Calculation Methods From Perth: PER

2001

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.4%	70.7%	67.9%	64.1%	64.8%
10th Percentile	0.0%	25.1%	0.0%	41.5%	36.2%
Median	0.0%	77.4%	80.7%	60.0%	64.0%
Weighted Average	39.1%	225.2%	83.5%	223.7%	196.9%

2002

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.6%	59.8%	55.1%	73.2%	66.8%
10th Percentile	0.0%	0.0%	0.0%	60.2%	37.5%
Median	0.0%	63.7%	61.9%	72.7%	66.2%
Weighted Average	39.7%	217.1%	58.7%	258.1%	199.6%

2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.6%	71.4%	58.6%	78.1%	64.4%
10th Percentile	0.0%	22.9%	0.0%	52.8%	33.1%
Median	0.0%	81.5%	66.7%	84.0%	64.5%
Weighted Average	40.1%	242.6%	62.2%	313.7%	197.3%

2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.4%	62.7%	59.6%	42.0%	65.8%
10th Percentile	0.0%	0.0%	0.0%	31.2%	36.1%
Median	0.0%	70.8%	71.7%	41.1%	65.5%
Weighted Average	39.1%	222.7%	74.1%	179.7%	196.4%

2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	21.5%	50.9%	49.2%	43.9%	63.1%
10th Percentile	0.0%	0.0%	0.0%	30.0%	27.0%
Median	0.0%	56.0%	53.1%	43.2%	63.7%
Weighted Average	37.6%	185.4%	57.5%	187.8%	188.3%

2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.4%	54.5%	30.8%	58.4%	62.7%
10th Percentile	0.0%	0.0%	0.0%	49.0%	32.9%
Median	0.0%	59.9%	0.0%	59.0%	63.0%
Weighted Average	34.9%	226.5%	31.4%	250.1%	188.4%

2007

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.6%	54.9%	66.7%	59.9%	78.0%
10th Percentile	0.0%	0.0%	0.4%	39.6%	47.7%
Median	0.0%	58.6%	78.9%	51.3%	81.8%
Weighted Average	40.0%	189.1%	71.4%	221.6%	237.0%

2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	23.6%	55.6%	66.1%	57.6%	80.4%
10th Percentile	0.0%	0.0%	0.0%	40.4%	54.2%
Median	0.0%	57.6%	83.4%	54.6%	84.2%
Weighted Average	41.6%	210.6%	68.1%	218.5%	242.3%

Summary Results Table for Calculation Methods From Badgingarra: BDG

Method	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
2001					
	Interval Selections				
Average	22.7%	68.3%	69.2%	59.5%	62.1%
10th Percentile	0.0%	23.5%	0.0%	43.9%	33.1%
Median	0.0%	75.3%	85.4%	56.8%	61.1%
Weighted Average	38.8%	219.7%	84.8%	212.5%	189.7%
2002					
	Interval Selections				
Average	22.6%	54.8%	51.0%	64.2%	65.5%
10th Percentile	0.0%	0.0%	0.0%	49.6%	36.8%
Median	0.0%	57.8%	55.1%	63.6%	65.3%
Weighted Average	39.5%	200.2%	54.4%	231.1%	196.3%
2003					
	Interval Selections				
Average	23.5%	72.6%	57.9%	79.0%	64.5%
10th Percentile	0.0%	24.6%	0.0%	53.2%	36.5%
Median	0.0%	82.8%	65.0%	89.1%	63.9%
Weighted Average	40.8%	246.2%	61.5%	319.2%	195.7%
2004					
	Interval Selections				
Average	23.0%	62.9%	58.2%	44.7%	66.3%
10th Percentile	0.0%	0.0%	0.0%	29.4%	38.2%
Median	0.0%	72.0%	68.3%	45.1%	66.0%
Weighted Average	40.2%	226.0%	72.5%	191.5%	200.2%
2005					
	Interval Selections				
Average	22.3%	51.2%	51.4%	47.9%	63.7%
10th Percentile	0.0%	0.0%	0.0%	33.1%	30.3%
Median	0.0%	56.4%	56.9%	48.0%	64.3%
Weighted Average	38.4%	189.0%	59.8%	204.9%	189.6%
2006					
	Interval Selections				
Average	20.6%	54.1%	30.7%	60.4%	60.3%
10th Percentile	0.0%	0.0%	0.0%	40.2%	30.0%
Median	0.0%	61.6%	0.0%	55.0%	58.8%
Weighted Average	34.6%	225.2%	31.3%	258.4%	181.0%
2007					
	Interval Selections				
Average	23.3%	53.8%	67.9%	57.4%	79.2%
10th Percentile	0.0%	0.0%	0.4%	38.9%	50.1%
Median	0.0%	56.0%	85.9%	50.7%	82.5%
Weighted Average	40.8%	184.6%	72.7%	213.8%	240.7%
2008					
	Interval Selections				
Average	24.0%	51.4%	64.8%	51.5%	79.8%
10th Percentile	0.0%	0.0%	0.0%	30.2%	49.9%
Median	0.0%	51.8%	80.0%	49.3%	83.4%
Weighted Average	41.6%	193.8%	66.8%	192.7%	238.5%

Summary Results Table for Calculation Methods From Hopetoun: HPT

Method	Interval Selections				
2001					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.7%	60.1%	68.3%	46.0%	48.0%
10th Percentile	0.0%	5.5%	1.3%	25.0%	18.0%
Median	0.0%	65.9%	80.7%	43.7%	45.7%
Weighted Average	34.8%	193.5%	83.9%	172.7%	148.2%
2002					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.3%	52.3%	46.4%	52.0%	50.4%
10th Percentile	0.0%	0.0%	0.0%	33.4%	19.3%
Median	0.0%	50.7%	44.0%	51.6%	48.4%
Weighted Average	34.5%	189.4%	49.4%	190.6%	148.2%
2003					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.7%	66.7%	56.5%	75.5%	49.1%
10th Percentile	0.0%	18.0%	0.0%	49.9%	18.5%
Median	0.0%	72.2%	64.0%	82.0%	47.8%
Weighted Average	35.7%	226.1%	60.1%	303.5%	148.3%
2004					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	19.7%	55.8%	54.5%	30.5%	44.9%
10th Percentile	0.0%	0.0%	0.0%	17.7%	15.9%
Median	0.0%	59.5%	57.6%	30.3%	41.7%
Weighted Average	32.6%	194.8%	68.5%	130.7%	130.0%
2005					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.4%	46.6%	47.4%	27.8%	50.5%
10th Percentile	0.0%	0.0%	0.0%	18.6%	18.4%
Median	0.0%	48.1%	45.9%	27.7%	48.6%
Weighted Average	34.8%	166.5%	55.5%	119.0%	148.3%
2006					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.8%	53.4%	29.2%	62.9%	50.2%
10th Percentile	0.0%	0.0%	0.0%	39.9%	19.4%
Median	0.0%	58.3%	3.8%	55.3%	47.6%
Weighted Average	31.9%	222.1%	29.8%	269.4%	151.9%
2007					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	21.9%	46.3%	65.2%	39.9%	68.0%
10th Percentile	0.0%	0.0%	1.4%	28.9%	35.9%
Median	0.0%	46.6%	75.3%	40.4%	69.8%
Weighted Average	37.9%	158.5%	69.7%	152.9%	203.9%
2008					
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.9%	48.7%	65.9%	53.5%	70.0%
10th Percentile	0.0%	0.0%	0.0%	37.4%	38.3%
Median	0.0%	46.9%	79.9%	53.2%	71.2%
Weighted Average	39.7%	182.0%	67.7%	203.8%	209.5%

Summary Results Table for Calculation Methods From Walpole: WLP					
2001					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.2%	58.5%	65.3%	60.8%	50.0%
10th Percentile	0.0%	13.0%	0.0%	36.9%	20.5%
Median	0.0%	56.9%	72.6%	57.7%	46.5%
Weighted Average	31.7%	182.4%	80.7%	205.5%	152.4%
2002					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.3%	55.3%	48.1%	66.9%	55.5%
10th Percentile	0.0%	0.0%	0.0%	43.3%	23.0%
Median	0.0%	56.3%	48.6%	65.4%	54.5%
Weighted Average	32.9%	202.4%	51.2%	242.7%	167.6%
2003					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.7%	63.8%	51.5%	69.0%	52.3%
10th Percentile	0.0%	9.6%	0.0%	42.6%	17.8%
Median	0.0%	72.2%	51.1%	66.9%	50.9%
Weighted Average	32.8%	211.4%	54.8%	276.8%	153.8%
2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	17.4%	54.0%	50.7%	34.7%	48.2%
10th Percentile	0.0%	0.0%	0.0%	8.1%	17.6%
Median	0.0%	57.2%	48.2%	38.5%	44.9%
Weighted Average	30.4%	188.5%	62.2%	148.6%	144.4%
2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.5%	45.4%	48.5%	28.8%	54.9%
10th Percentile	0.0%	0.0%	0.0%	4.3%	17.8%
Median	0.0%	44.4%	52.4%	32.8%	54.1%
Weighted Average	32.3%	160.5%	56.4%	123.5%	159.8%
2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	17.0%	55.8%	27.6%	70.1%	57.1%
10th Percentile	0.0%	0.0%	0.0%	51.7%	26.5%
Median	0.0%	62.6%	0.1%	68.2%	56.1%
Weighted Average	30.5%	231.9%	28.4%	299.9%	172.1%
2007					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	19.7%	52.0%	61.1%	52.8%	69.0%
10th Percentile	0.0%	0.0%	1.2%	32.2%	34.4%
Median	0.0%	56.9%	67.4%	49.9%	71.2%
Weighted Average	34.9%	178.6%	65.4%	197.5%	205.5%
2008					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.6%	52.0%	61.5%	53.4%	69.5%
10th Percentile	0.0%	0.0%	0.0%	22.4%	36.7%
Median	0.0%	50.6%	69.9%	52.0%	70.1%
Weighted Average	36.6%	194.5%	63.4%	198.6%	213.1%

Summary Results Table for Calculation Methods From Kalgoorlie: KST0					
2001					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	26.5%	52.8%	54.6%	66.7%	52.7%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	91.7%	95.5%	100.0%	75.2%
Weighted Average	38.5%	180.0%	69.5%	285.4%	167.9%
2002					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.2%	56.8%	56.7%	75.0%	66.1%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	43.1%	212.5%	60.3%	285.4%	200.3%
2003					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	26.6%	75.4%	54.2%	100.0%	65.8%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	97.9%	100.0%	100.0%
Weighted Average	39.1%	256.7%	57.5%	380.5%	210.4%
2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.1%	65.9%	58.5%	58.3%	73.6%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	42.9%	230.6%	73.2%	249.7%	225.1%
2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.0%	51.3%	49.8%	50.0%	68.2%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	99.8%	44.4%	50.0%	100.0%
Weighted Average	41.4%	191.2%	59.7%	214.0%	203.9%
2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.6%	50.7%	58.7%	61.7%	65.2%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	64.3%	100.0%	100.0%	100.0%
Weighted Average	42.9%	211.1%	61.1%	264.1%	201.9%

Summary Results Table for Calculation Methods From Kalgoorlie: KST4

2001					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	38.3%	69.2%	68.5%	69.5%	73.1%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	56.3%	235.4%	84.7%	293.5%	234.1%
2002					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.5%	78.2%	78.2%	75.0%	83.9%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	63.8%	291.4%	83.4%	285.4%	253.6%
2003					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	38.8%	94.0%	81.8%	100.0%	87.2%
10th Percentile	0.0%	100.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	58.1%	321.9%	86.5%	380.5%	285.8%
2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.5%	88.8%	85.1%	100.0%	88.0%
10th Percentile	0.0%	23.8%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	63.6%	317.8%	102.3%	428.0%	274.0%
2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.3%	76.5%	77.4%	91.7%	85.6%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	61.2%	276.6%	88.6%	392.4%	256.6%
2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	40.0%	78.1%	90.3%	75.0%	84.5%
10th Percentile	0.0%	0.0%	63.8%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	63.2%	319.1%	92.9%	321.0%	264.2%

Summary Results Table for Calculation Methods From Kalgoorlie: KST10					
2001					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	50.7%	72.1%	72.7%	71.9%	75.0%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	76.7%	100.0%	100.0%	100.0%	100.0%
Weighted Average	67.6%	243.8%	89.2%	300.2%	240.3%
2002					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	53.1%	80.2%	83.1%	82.7%	85.8%
10th Percentile	0.0%	0.0%	0.0%	42.4%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	76.2%	295.5%	88.5%	307.4%	260.2%
2003					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	51.9%	94.4%	85.8%	100.0%	88.0%
10th Percentile	0.0%	100.0%	0.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	70.3%	322.9%	90.4%	380.5%	287.4%
2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	53.2%	95.4%	88.7%	100.0%	88.9%
10th Percentile	0.0%	100.0%	0.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	76.3%	345.7%	105.2%	428.0%	276.6%
2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	52.9%	82.8%	86.2%	100.0%	88.3%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	73.1%	291.5%	97.9%	428.0%	263.9%
2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	54.0%	84.9%	94.4%	75.0%	86.5%
10th Percentile	0.0%	0.0%	100.0%	0.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	75.6%	338.8%	97.3%	321.0%	270.1%

Summary Results Table for Calculation Methods From Kalgoorlie: KST16

2001

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	62.3%	75.9%	75.6%	75.2%	76.1%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	73.5%	253.0%	92.3%	309.8%	243.2%

2002

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	65.2%	82.3%	84.8%	86.9%	87.5%
10th Percentile	0.0%	0.0%	0.0%	49.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	82.0%	299.9%	90.4%	319.4%	265.9%

2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	64.2%	94.5%	91.1%	100.0%	88.4%
10th Percentile	0.0%	100.0%	98.6%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	76.2%	323.3%	96.0%	380.5%	288.3%

2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	65.6%	96.7%	90.4%	100.0%	90.0%
10th Percentile	0.0%	100.0%	86.4%	100.0%	63.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	81.9%	350.2%	106.5%	428.0%	278.3%

2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	65.3%	86.8%	91.8%	100.0%	89.7%
10th Percentile	0.0%	0.0%	93.8%	100.0%	35.7%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	79.2%	300.2%	103.1%	428.0%	266.2%

2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	66.5%	87.4%	95.4%	75.0%	88.1%
10th Percentile	0.0%	0.0%	100.0%	0.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	81.4%	346.1%	98.2%	321.0%	274.7%

Summary Results Table for Calculation Methods From Geraldton: GST0

2002

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.9%	66.7%	52.5%	100.0%	86.6%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	45.7%	248.3%	56.2%	356.7%	266.6%

2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.8%	77.5%	52.0%	100.0%	82.4%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	77.6%	100.0%	100.0%
Weighted Average	45.3%	269.7%	55.7%	392.4%	256.5%

2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	28.7%	67.6%	46.4%	81.9%	89.7%
10th Percentile	0.0%	0.0%	0.0%	8.2%	45.9%
Median	0.0%	100.0%	29.6%	100.0%	100.0%
Weighted Average	47.3%	254.2%	55.0%	350.4%	275.1%

2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	27.7%	60.7%	58.5%	83.3%	81.3%
10th Percentile	0.0%	0.0%	0.0%	10.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	43.7%	226.7%	67.4%	356.7%	238.3%

2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	29.4%	61.1%	52.4%	75.0%	80.8%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	45.8%	255.1%	54.3%	321.0%	242.7%

Summary Results Table for Calculation Methods From Geraldton: GST4					
2002					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	40.5%	89.1%	78.2%	100.0%	94.7%
10th Percentile	0.0%	32.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	67.0%	329.2%	83.6%	356.7%	290.5%
2003					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	40.3%	94.7%	79.1%	100.0%	91.7%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	66.3%	326.6%	84.5%	392.4%	284.6%
2004					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	41.4%	91.4%	71.7%	100.0%	97.4%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	68.8%	346.2%	85.2%	428.0%	302.5%
2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	39.9%	89.6%	84.6%	100.0%	88.6%
10th Percentile	0.0%	46.5%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	63.6%	317.8%	95.2%	428.0%	265.4%
2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	42.7%	90.0%	86.7%	75.0%	89.2%
10th Percentile	0.0%	78.9%	0.0%	0.0%	27.3%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	66.8%	362.4%	88.8%	321.0%	272.7%

Summary Results Table for Calculation Methods From Geraldton: GST10

2002

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	54.6%	90.3%	83.3%	100.0%	95.8%
10th Percentile	0.0%	63.9%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	78.1%	331.5%	89.2%	356.7%	294.0%

2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	53.9%	97.3%	81.8%	100.0%	93.4%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	77.5%	335.5%	87.3%	392.4%	290.2%

2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	55.6%	95.4%	78.2%	100.0%	98.7%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	80.5%	357.5%	94.4%	428.0%	305.6%

2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	53.2%	93.9%	88.6%	100.0%	91.4%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	74.5%	325.8%	99.4%	428.0%	274.4%

2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	57.3%	93.9%	94.0%	100.0%	92.1%
10th Percentile	0.0%	100.0%	100.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	78.4%	379.0%	96.7%	428.0%	283.4%

Summary Results Table for Calculation Methods From Geraldton: GST16

2002

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	67.3%	91.9%	85.6%	100.0%	96.4%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	83.9%	333.3%	91.3%	356.7%	296.8%

2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	66.5%	98.8%	85.7%	100.0%	94.5%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	83.5%	339.6%	90.6%	392.4%	293.6%

2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	68.4%	95.9%	80.4%	100.0%	98.8%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	86.4%	358.0%	96.8%	428.0%	305.8%

2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	65.2%	94.6%	90.0%	100.0%	92.3%
10th Percentile	0.0%	100.0%	60.8%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	80.4%	326.9%	101.0%	428.0%	277.4%

2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	70.8%	96.6%	96.0%	100.0%	93.0%
10th Percentile	0.0%	100.0%	100.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	84.5%	388.0%	98.4%	428.0%	286.0%

12.3 Appendix B3: Results for Multiple Years Studies

Summary Results Table for Calcualtion Methods From Kalgoorlie: KPV					
2001-2003					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.2%	61.2%	61.0%	66.2%	50.1%
10th Percentile	0.0%	10.7%	15.9%	42.1%	17.4%
Median	0.0%	67.1%	64.8%	56.8%	50.2%
Weighted Average	37.7%	217.7%	66.6%	259.1%	157.3%
2002-2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.3%	57.6%	61.0%	50.6%	53.0%
10th Percentile	0.0%	0.0%	2.4%	18.6%	20.7%
Median	0.0%	61.2%	69.2%	45.9%	53.2%
Weighted Average	38.6%	214.6%	64.9%	216.5%	164.0%
2003-2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.1%	54.8%	55.3%	41.0%	52.6%
10th Percentile	0.0%	0.0%	0.0%	18.6%	20.2%
Median	0.0%	55.7%	53.3%	39.3%	52.5%
Weighted Average	37.7%	219.7%	60.7%	175.7%	162.3%
2004-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.5%	52.7%	59.1%	43.7%	52.1%
10th Percentile	0.0%	1.3%	0.0%	26.9%	18.6%
Median	0.0%	52.9%	70.1%	43.0%	52.4%
Weighted Average	39.0%	216.7%	62.8%	186.9%	159.4%
2001-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	24.4%	55.6%	63.6%	43.7%	51.2%
10th Percentile	0.0%	5.1%	11.6%	26.9%	17.8%
Median	0.0%	55.6%	70.9%	43.0%	51.6%
Weighted Average	38.4%	230.3%	68.0%	186.9%	158.4%

Summary Results Table for Calcualtion Methods From Geraldton: GPV					
2002-2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	25.0%	64.6%	54.2%	62.0%	66.1%
10th Percentile	0.0%	3.0%	0.0%	38.0%	39.4%
Median	0.0%	73.8%	56.5%	59.2%	68.1%
Weighted Average	41.1%	245.1%	57.6%	265.3%	202.8%
2003-2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	25.0%	62.0%	53.8%	54.0%	65.5%
10th Percentile	0.0%	0.4%	0.0%	37.9%	38.8%
Median	0.0%	70.2%	57.7%	55.8%	67.9%
Weighted Average	40.9%	250.3%	58.7%	231.3%	199.4%
2004-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	25.5%	62.9%	55.8%	59.9%	65.9%
10th Percentile	0.0%	8.2%	0.0%	44.7%	39.4%
Median	0.0%	69.5%	63.8%	59.9%	68.5%
Weighted Average	41.3%	259.6%	59.2%	256.5%	200.1%
2002-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	25.2%	64.4%	57.0%	59.9%	65.6%
10th Percentile	0.0%	11.0%	0.0%	44.7%	38.5%
Median	0.0%	70.0%	60.5%	59.9%	68.1%
Weighted Average	41.0%	266.2%	60.7%	256.5%	199.7%

Summary Results Table for Calcualtion Methods From Perth: PER					
2001-2003					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	22.5%	72.7%	73.4%	69.1%	65.3%
10th Percentile	0.0%	31.8%	24.3%	44.5%	35.7%
Median	0.0%	80.5%	88.5%	70.8%	65.0%
Weighted Average	39.7%	250.9%	79.8%	274.8%	197.9%
2002-2004					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	22.5%	65.5%	66.1%	49.5%	65.7%
10th Percentile	0.0%	1.3%	0.0%	31.2%	35.6%
Median	0.0%	73.9%	78.0%	44.4%	65.6%
Weighted Average	39.6%	245.3%	70.2%	211.7%	197.7%
2003-2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	22.2%	59.8%	64.2%	45.0%	64.4%
10th Percentile	0.0%	0.0%	0.0%	31.2%	31.8%
Median	0.0%	65.9%	75.7%	44.2%	64.6%
Weighted Average	38.9%	239.4%	70.1%	192.6%	194.0%
2004-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	21.5%	58.9%	56.5%	50.5%	63.9%
10th Percentile	0.0%	11.8%	0.0%	34.6%	31.7%
Median	0.0%	61.7%	65.2%	48.2%	64.2%
Weighted Average	37.3%	241.9%	59.7%	216.0%	191.0%
2005-2007					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	21.5%	61.1%	67.4%	50.2%	67.9%
10th Percentile	0.0%	14.7%	0.4%	39.6%	33.5%
Median	0.0%	62.1%	80.6%	51.0%	69.3%
Weighted Average	37.6%	237.1%	72.0%	214.7%	204.5%
2006-2008					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	22.3%	57.8%	71.4%	49.9%	73.6%
10th Percentile	0.0%	1.0%	14.9%	39.9%	41.5%
Median	0.0%	61.6%	86.8%	51.0%	77.0%
Weighted Average	39.0%	224.6%	76.4%	213.6%	222.4%
2001-2008					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	22.3%	55.5%	69.0%	45.7%	68.2%
10th Percentile	0.0%	0.4%	20.9%	34.7%	36.1%
Median	0.0%	58.6%	76.3%	44.2%	69.0%
Weighted Average	39.1%	217.9%	73.8%	195.6%	205.6%

Summary Results Table for Calcualtion Methods From Badgingarra: BDG

2001-2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.9%	71.6%	72.5%	70.8%	64.0%
10th Percentile	0.0%	33.5%	16.8%	43.1%	34.5%
Median	0.0%	77.1%	87.2%	66.0%	63.5%
Weighted Average	39.7%	249.1%	78.8%	284.1%	193.9%

2002-2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	23.0%	65.3%	62.2%	52.6%	65.5%
10th Percentile	0.0%	1.2%	0.0%	29.4%	37.2%
Median	0.0%	73.5%	72.4%	47.0%	64.9%
Weighted Average	40.2%	247.0%	66.0%	225.1%	197.4%

2003-2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.9%	60.6%	63.0%	46.7%	64.9%
10th Percentile	0.0%	0.0%	0.0%	29.4%	34.3%
Median	0.0%	66.9%	72.6%	46.6%	64.5%
Weighted Average	39.8%	245.1%	68.7%	200.0%	195.2%

2004-2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.0%	59.9%	55.2%	51.9%	63.5%
10th Percentile	0.0%	10.5%	0.0%	39.0%	32.8%
Median	0.0%	63.7%	63.5%	51.4%	63.4%
Weighted Average	37.8%	247.5%	58.3%	222.1%	190.3%

2005-2007

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.1%	60.3%	67.7%	49.5%	67.8%
10th Percentile	0.0%	13.0%	0.3%	38.9%	34.0%
Median	0.0%	62.3%	81.8%	50.2%	68.8%
Weighted Average	38.0%	234.8%	72.3%	212.1%	203.8%

2006-2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.7%	53.7%	70.2%	47.1%	73.1%
10th Percentile	0.0%	0.5%	12.2%	39.1%	40.2%
Median	0.0%	54.1%	86.0%	49.3%	76.2%
Weighted Average	39.1%	208.2%	75.1%	201.7%	219.9%

2001-2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	22.8%	52.6%	67.3%	48.9%	67.7%
10th Percentile	0.0%	0.4%	19.1%	39.3%	35.9%
Median	0.0%	51.5%	74.3%	50.2%	68.0%
Weighted Average	39.4%	206.4%	72.0%	209.5%	203.9%

senergy
alternative energy
econnect

Summary Results Table for Calcualtion Methods From Hopetoun: HPT

2001-2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.6%	63.9%	71.4%	65.5%	49.2%
10th Percentile	0.0%	21.4%	28.3%	44.5%	18.5%
Median	0.0%	66.1%	77.7%	60.6%	47.3%
Weighted Average	35.0%	225.7%	77.7%	260.8%	148.2%

2002-2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.2%	57.2%	63.3%	46.1%	48.1%
10th Percentile	0.0%	0.0%	1.4%	21.7%	17.7%
Median	0.0%	59.0%	67.2%	40.2%	46.2%
Weighted Average	34.2%	215.6%	67.3%	197.2%	142.1%

2004-2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.3%	52.4%	62.2%	32.3%	48.2%
10th Percentile	0.0%	0.0%	0.0%	19.5%	17.4%
Median	0.0%	53.2%	72.5%	31.0%	46.4%
Weighted Average	34.3%	208.4%	67.9%	138.2%	142.2%

2004-2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	19.7%	54.0%	55.7%	39.2%	48.5%
10th Percentile	0.0%	0.0%	0.0%	21.3%	17.8%
Median	0.0%	53.4%	65.2%	38.6%	46.3%
Weighted Average	33.1%	220.9%	58.8%	168.0%	143.3%

2005-2007

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.4%	53.3%	66.7%	33.5%	56.3%
10th Percentile	0.0%	0.9%	1.4%	19.0%	22.1%
Median	0.0%	52.8%	77.3%	29.8%	55.4%
Weighted Average	35.0%	208.6%	71.2%	143.4%	168.0%

2006-2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	21.3%	49.7%	71.7%	39.9%	62.7%
10th Percentile	0.0%	0.0%	22.0%	28.9%	27.9%
Median	0.0%	48.7%	82.0%	40.3%	63.1%
Weighted Average	36.7%	194.0%	76.7%	170.6%	188.3%

2001-2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	20.7%	46.5%	73.8%	38.8%	53.8%
10th Percentile	0.0%	0.0%	30.1%	28.9%	20.5%
Median	0.0%	43.6%	84.5%	40.3%	52.3%
Weighted Average	35.3%	182.9%	78.9%	166.2%	160.9%

senergy alternative energy econnect

Summary Results Table for Calcualtion Methods From Walpole: WLP

2001-2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.4%	66.0%	67.2%	58.3%	52.6%
10th Percentile	0.0%	17.7%	17.5%	34.1%	20.4%
Median	0.0%	70.1%	77.1%	56.3%	50.7%
Weighted Average	32.5%	226.5%	73.2%	231.3%	158.0%

2002-2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.1%	57.8%	59.4%	33.5%	52.0%
10th Percentile	0.0%	0.5%	0.0%	8.1%	19.0%
Median	0.0%	60.9%	68.2%	35.1%	50.4%
Weighted Average	32.0%	215.5%	63.0%	143.3%	155.2%

2003-2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.2%	52.1%	62.1%	30.4%	51.8%
10th Percentile	0.0%	0.0%	0.0%	8.1%	17.8%
Median	0.0%	54.6%	71.9%	33.5%	49.9%
Weighted Average	31.8%	205.3%	67.3%	130.0%	152.6%

2004-2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	17.7%	56.6%	60.1%	38.0%	53.4%
10th Percentile	0.0%	3.0%	0.0%	8.1%	19.4%
Median	0.0%	61.1%	74.7%	38.5%	51.8%
Weighted Average	31.1%	230.8%	63.4%	162.8%	158.7%

2005-2007

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.5%	59.5%	64.9%	42.0%	60.3%
10th Percentile	0.0%	4.6%	1.0%	29.6%	25.0%
Median	0.0%	63.0%	74.1%	40.3%	59.9%
Weighted Average	32.7%	232.6%	69.3%	179.6%	179.1%

2006-2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	19.2%	55.2%	65.2%	38.9%	65.2%
10th Percentile	0.0%	1.4%	8.2%	22.4%	32.0%
Median	0.0%	56.5%	71.7%	40.3%	65.1%
Weighted Average	34.1%	214.1%	69.8%	166.7%	196.8%

2001-2008

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	18.6%	50.1%	68.8%	30.4%	57.0%
10th Percentile	0.0%	1.3%	20.6%	8.1%	22.3%
Median	0.0%	50.2%	77.7%	27.7%	56.1%
Weighted Average	32.8%	195.3%	73.7%	129.9%	171.0%

Summary Results Table for Calcualtion Methods From Kalgoorlie: KST0					
2001-2003					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	26.7%	66.4%	62.5%	100.0%	61.2%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	40.2%	240.4%	67.9%	380.5%	191.5%
2002-2004					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	27.0%	64.8%	67.3%	66.7%	68.8%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	41.7%	242.1%	71.0%	285.4%	212.2%
2003-2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	26.9%	60.3%	56.9%	58.3%	69.5%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	41.2%	241.7%	61.2%	249.7%	213.4%
2004-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	27.2%	58.5%	66.0%	61.7%	69.0%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	42.4%	239.3%	69.2%	264.1%	210.3%
2001-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	27.0%	63.1%	68.7%	61.7%	65.3%
10th Percentile	0.0%	0.0%	0.0%	0.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	41.3%	259.8%	73.1%	264.1%	201.5%

Summary Results Table for Calcualtion Methods From Kalgoorlie: KST4					
2001-2003					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	38.9%	84.1%	76.7%	100.0%	80.9%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	59.3%	304.7%	83.1%	380.5%	255.5%
2002-2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.3%	89.8%	86.9%	100.0%	86.3%
10th Percentile	0.0%	52.8%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	61.9%	342.8%	92.0%	428.0%	269.8%
2003-2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.2%	86.9%	78.8%	100.0%	86.9%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	61.0%	349.5%	84.6%	428.0%	270.8%
2004-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.6%	86.3%	88.2%	100.0%	86.0%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	62.7%	357.1%	93.0%	428.0%	264.9%
2001-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	39.2%	89.1%	88.2%	100.0%	83.6%
10th Percentile	0.0%	26.4%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	61.0%	370.3%	94.1%	428.0%	260.5%

Summary Results Table for Calcualtion Methods From Kalgoorlie: KST10

2001-2003

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	51.9%	84.9%	81.4%	100.0%	82.5%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	71.3%	306.8%	88.2%	380.5%	260.5%

2002-2004

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	52.7%	95.5%	89.3%	100.0%	87.5%
10th Percentile	0.0%	100.0%	33.5%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	74.3%	366.1%	94.5%	428.0%	273.6%

2003-2005

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	52.7%	93.1%	85.8%	100.0%	88.4%
10th Percentile	0.0%	100.0%	0.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	73.3%	374.5%	92.2%	428.0%	274.8%

2004-2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	53.3%	90.5%	94.0%	100.0%	87.9%
10th Percentile	0.0%	93.5%	100.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	75.0%	375.2%	99.2%	428.0%	270.2%

2001-2006

Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	52.6%	92.1%	92.0%	100.0%	85.4%
10th Percentile	0.0%	100.0%	99.5%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	73.2%	383.2%	98.1%	428.0%	265.7%

Summary Results Table for Calcualtion Methods From Kalgoorlie: KST16					
2001-2003					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	63.9%	85.9%	87.5%	100.0%	83.6%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	77.1%	309.7%	94.7%	380.5%	263.9%
2002-2004					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	65.0%	96.6%	95.0%	100.0%	88.7%
10th Percentile	0.0%	100.0%	100.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	80.0%	369.7%	100.6%	428.0%	276.6%
2003-2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	65.0%	95.4%	93.3%	100.0%	89.5%
10th Percentile	0.0%	100.0%	100.0%	100.0%	26.9%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	79.2%	381.8%	100.2%	428.0%	276.6%
2004-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	65.8%	93.9%	97.2%	100.0%	89.3%
10th Percentile	0.0%	100.0%	100.0%	100.0%	10.1%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	80.8%	387.7%	102.6%	428.0%	273.1%
2001-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	64.8%	95.1%	94.9%	100.0%	86.6%
10th Percentile	0.0%	100.0%	100.0%	100.0%	0.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	79.0%	394.5%	101.2%	428.0%	268.8%

Summary Results Table for Calcualtion Methods From Geraldton: GST0

Method	Interval Selections				
2002-2004					
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	28.1%	73.5%	54.4%	83.3%	86.2%
10th Percentile	0.0%	0.0%	0.0%	10.0%	0.0%
Median	0.0%	100.0%	80.9%	100.0%	100.0%
Weighted Average	46.1%	280.2%	58.2%	356.7%	266.1%
2003-2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	28.0%	73.0%	55.4%	83.3%	84.5%
10th Percentile	0.0%	0.0%	0.0%	10.0%	0.0%
Median	0.0%	100.0%	82.9%	100.0%	100.0%
Weighted Average	45.4%	292.6%	60.3%	356.7%	256.7%
2004-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	28.6%	72.5%	64.2%	91.7%	84.0%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	45.6%	297.1%	67.9%	392.4%	252.2%
2002-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	28.3%	74.5%	63.2%	91.7%	84.2%
10th Percentile	0.0%	0.0%	0.0%	100.0%	0.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	45.5%	306.2%	67.2%	392.4%	256.0%

Summary Results Table for Calcualtion Methods From Geraldton: GST4

Method	Interval Selections				
2002-2004					
Method	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	40.7%	98.3%	76.1%	100.0%	94.6%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	67.4%	378.3%	81.3%	428.0%	292.6%
2003-2005					
Method	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	40.5%	98.8%	74.3%	100.0%	92.6%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	66.2%	398.8%	80.8%	428.0%	284.3%
2004-2006					
Method	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	41.3%	97.3%	82.8%	100.0%	91.8%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	66.4%	403.3%	87.7%	428.0%	280.3%
2002-2006					
Method	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	41.0%	97.3%	82.7%	100.0%	92.3%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	0.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	66.5%	403.9%	88.0%	428.0%	283.2%

Summary Results Table for Calcualtion Methods From Geraldton: GST10					
2002-2004					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	54.7%	99.6%	80.2%	100.0%	96.0%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	78.7%	383.0%	85.8%	428.0%	296.6%
2003-2005					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	54.2%	99.2%	78.3%	100.0%	94.5%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	77.5%	400.5%	85.1%	428.0%	290.1%
2004-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	55.4%	99.2%	88.3%	100.0%	94.1%
10th Percentile	0.0%	100.0%	15.3%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	77.8%	411.3%	93.7%	428.0%	287.9%
2002-2006					
Method	**Interval Selections**				
	All	**Top 250 (hot)**	**Top 250 (int.)**	**12 Peak**	**2-5pm Jan.-Mar.**
Average	54.9%	99.2%	86.8%	100.0%	94.3%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	77.8%	411.9%	92.4%	428.0%	289.6%

Summary Results Table for Calcualtion Methods From Geraldton: GST16					
2002-2004					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	67.4%	100.0%	82.1%	100.0%	96.6%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	84.6%	383.4%	87.4%	428.0%	298.8%
2003-2005					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	66.7%	99.2%	80.5%	100.0%	95.2%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	83.5%	400.5%	87.0%	428.0%	292.3%
2004-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	68.1%	99.6%	89.8%	100.0%	94.7%
10th Percentile	0.0%	100.0%	42.9%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	83.8%	413.1%	95.2%	428.0%	289.8%
2002-2006					
Method	Interval Selections				
	All	Top 250 (hot)	Top 250 (int.)	12 Peak	2-5pm Jan.-Mar.
Average	67.6%	99.6%	88.4%	100.0%	95.0%
10th Percentile	0.0%	100.0%	0.0%	100.0%	100.0%
Median	100.0%	100.0%	100.0%	100.0%	100.0%
Weighted Average	83.8%	413.7%	94.1%	428.0%	292.0%