Statement of Opportunities

July 2010

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Executive Summary

The Statement of Opportunities Report (SOO) is published annually by the Independent Market Operator (IMO). The SOO provides information to current and potential participants in the Wholesale Electricity Market (WEM) and other industry stakeholders.

The SOO focuses on opportunities for investment in generation capacity and Demand Side Management (DSM) over the medium term. The 2010 SOO places emphasis on the 2012/13 and 2013/14 Capacity Years. The report sets the amount of capacity required to be available from 1 October 2012, a key parameter of the Reserve Capacity Mechanism in the WEM.

Information is also provided on forecast maximum demand and electricity consumption within the South West interconnected system (SWIS) over the Long Term PASA[1] Study Horizon through to October 2021.

The SOO has been expanded this year to improve information for investors and Market Participants. The following information has been added:

- Western Power has published a Generation Connection Capacity Map to inform developers of the ability of the SWIS to accommodate additional mid-sized generation projects with minimal connection cost. This map is included in Appendix 10.
- A detailed commentary on the availability of fuel for generation is presented in Section 7.2.
- Historical trading prices and volumes from the Short Term Energy Market (STEM) are provided in Section 2.6.

Key Results for 2012/13

- The Reserve Capacity Target for 2012/13 is set at 5,501 MW.
- Forecast average annual growth through to 2020/21 is 4.4% for peak demand and 3.7% for energy.
- The IMO anticipates that 5,493 MW of generation and DSM capacity, either existing or committed with Capacity Credits for 2011/12, will continue in service through to 2012/13.
- An additional 8 MW of new capacity, beyond that already in service or committed, will be required to meet the Reserve Capacity Target in 2012/13.

In May 2010 the IMO completed its annual Expression of Interest process to identify new sources of generation and DSM capability for 2012/13.

Sixteen Expressions of Interest were received, covering a total potential Reserve Capacity of 644 MW. The amounts of each type of capacity are shown in Table A.

[1] Long-Term Projected Assessment of System Adequacy

Table A – Summary of 2010 Expressions of Interest

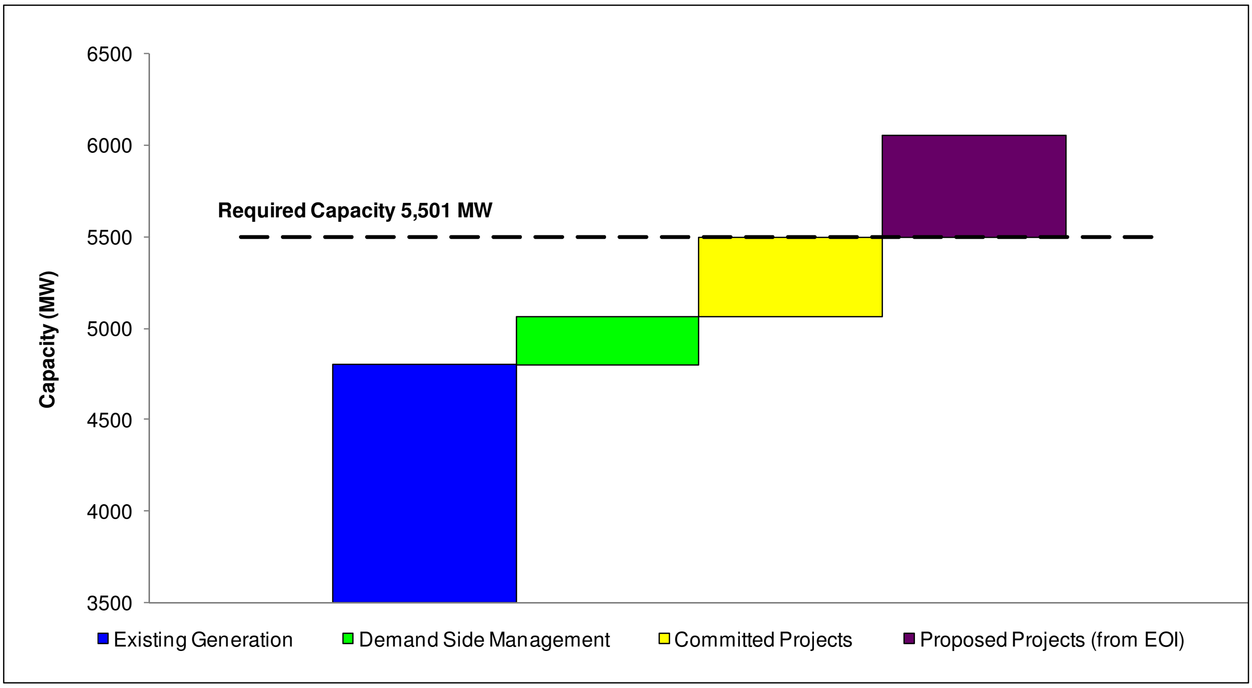
Type of Capacity in the EOI process	Aggregate Potential Reserve Capacity
Thermal	309 MW
Renewable	108 MW
DSM	228 MW
Total	**644 MW**

The IMO estimates that 486 MW of this capacity could potentially be available to meet demand in the 2012/13 year. In addition, 70 MW of capacity was assigned Conditional Certified Reserve Capacity status during the 2009 Certification of Reserve Capacity process.

On this basis, there appears to be more than sufficient potential new generation and DSM to meet the 8 MW identified as additional capacity required for 2012/13.

Figure A illustrates the expected status of capacity in the SWIS in the 2012/13 Reserve Capacity Year.

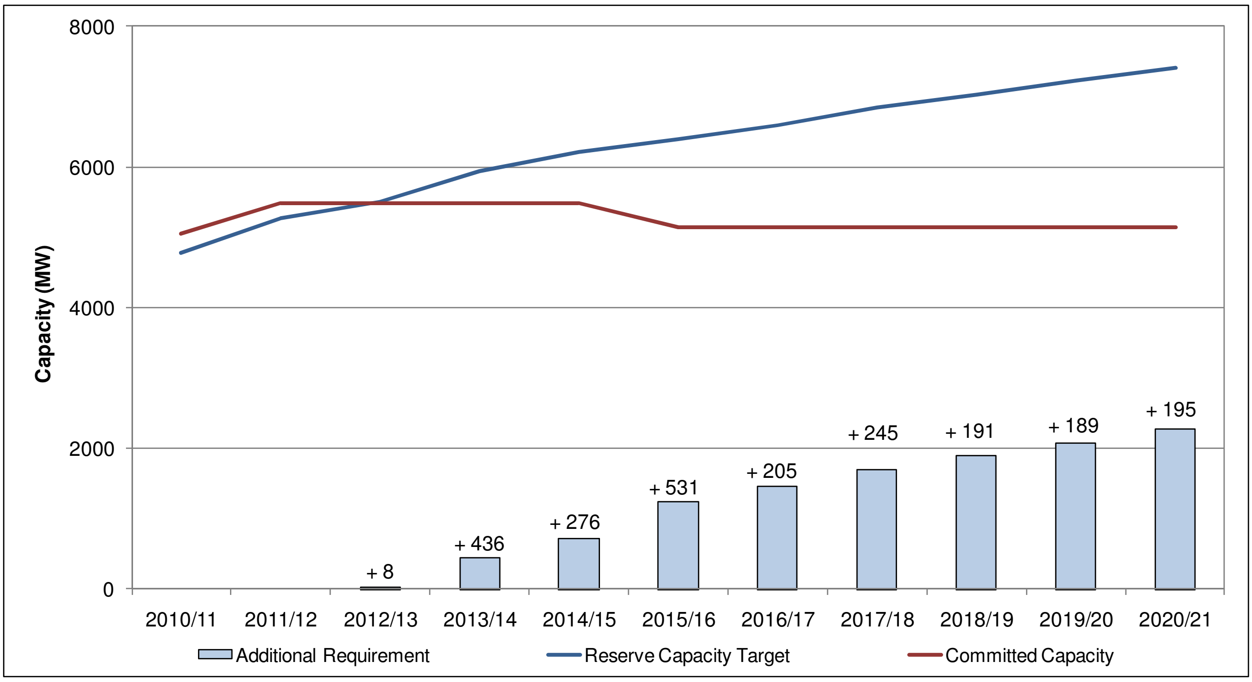
Figure A – Forecast Reserve Capacity Status for 2012/13



Supply-Demand Balance

Figure B shows the supply-demand balance over the period 2010/11 through to 2020/21.

Figure B – Supply-Demand Balance for the period 2010/11 to 2020/21



Key points to note from Figure B are:

- Sufficient Capacity Credits have been procured to meet the Reserve Capacity Requirement during 2010/11 and 2011/12.
- By 2020/21 the total capacity requirement is forecast to be 7,417 MW. Additional capacity of 2,275 MW is forecast to be required to service demand growth and to replace capacity that is likely to be retired at Kwinana Power Station Stage C (forecast for 2015/16).

There are excellent opportunities for new and existing investors to develop new generation and DSM capacity in Western Australia. Over the coming decade, average State economic growth is expected to exceed 4% per year. More than 2,000 MW of new capacity is expected to be required over the coming decade to meet load growth. Given that the Reserve Capacity Mechanism has incentivised the delivery of more than 2,000 MW of new generation and DSM capacity in the last five years, this level of required investment would appear to be achievable.

Importance of New Transmission Works

The timing of new northern and southern transmission works planned by Western Power is of particular importance for the 2012/13 Capacity Year. These works impact on the size and timing of new large block loads and the connection and certification of a number of proposed new generators.

To develop the peak load forecast for 2012/13 the IMO must make a determination on which new loads will gain access to the network and be able to commence operation. New loads are not subject to any certification process and so will have an impact on the supply/demand balance from the time they gain access to the network and commence operation.

Three scenarios are relevant for the impact of the new transmission works:

1. New transmission works are in service prior to 1 October 2012 and this is confirmed in time to allow certification of affected generators.
2. New transmission works come into service after 1 October 2012, but before or during the 2012/13 Hot Season (December – March) so that affected new loads may be in place (and included in peak demand and energy forecasts), but some new generators may not be available, or may not be considered reliable.
3. New transmission works come into service after the 2012/13 Hot Season, so that neither affected generators nor loads will be present during the peak demand. In this case, new loads may be included in energy forecasts for a portion of the year, but will not be included in peak demand forecasts.

The following information has been made available to the IMO and has been used in making its decision about load and generation on the new Mid West Energy Project southern section from Neerabup to Eneabba 330 kV transmission line[2]:

- The Mid West Energy Project southern section will provide a double circuit 330 kV line (initially operated as one 330 kV and one 132 kV circuit) from Neerabup to Eneabba where it will connect to a 330 kV line to supply proposed mining loads. A 330/132 kV terminal station will also be established at Three Springs as part of this proposal.
- While a provision for funding was included in the recently approved State Budget process, this is pending full regulatory approval from the Economic Regulation Authority (ERA) and Government review of the business case for the line.
- Western Power is unable to offer unconstrained transmission access to generators at present.
- Western Power has provided the IMO with indications of the timing schedule for works to this line.
- Western Power has secured the necessary environmental approvals.
- Construction of the line is estimated to require 26 months.
    - Providing unconditional approval has been received by January 2011, the line is estimated to be completed by the end of March 2013.

[2] This project has previously been designated as the North Country Reinforcement (NCR).

On the balance of probabilities, given the status of the various regulatory and funding approvals, ongoing discussions with a foundation mining customer and the timing schedule needed to construct and commission the line, the IMO has concluded that the line is unlikely to be in place prior to the 2012/13 Hot Season (December - March), but that it may be operating during the remainder of the 2012/13 year.

Some additional Mid West load (95 MW) has been allowed for in 2012/13, based on information from Western Power on limited spare capacity in the existing network.

For the 2013/14 forecast demand of 5,370 MW it has been assumed that the new transmission works are in service and the allowance for major loads has been increased by around 200 MW on the assumption that major Mid West mining and associated loads are operational by that time.

The size and timing of these loads is not yet certain. Among other things, this uncertainty relates to the progress of regulatory approvals and the outcome of Government reviews presently underway in relation to transmission works and other support infrastructure.

The Reserve Capacity Target for 2013/14 will be set in the 2011 SOO. By that time, it is expected that much of the present uncertainty will have been resolved, allowing a forecast for 2013/14 to be made on the most up-to-date information available at that time.

Certainty of network access is a prerequisite for certification under the Reserve Capacity Mechanism.

An essential requirement for certification is that a new generator will be in service prior to 1 October 2012. All new generators must provide the IMO with sufficient evidence for it to satisfy itself that this can be achieved, including a transmission access proposal from Western Power.

As a result of this decision, the IMO will not be able to certify new generation plant which is reliant on the new northern transmission works for the 2012/13 Capacity Year.

The Reserve Capacity Mechanism

The SOO is a key element of the Reserve Capacity Mechanism - the mechanism through which the WEM secures capacity to meet peak demand. Retailers of electricity must purchase enough Certified Reserve Capacity to meet their contribution to peak demand plus a contribution to the system-wide reserve margin and excess capacity.

The SOO specifies the future demand needs and the opportunity for parties to invest in and develop new generation and DSM capability.

The Reserve Capacity Mechanism has provided excellent outcomes for the Western Australian market and is attracting interest from investors in generation from across the nation and internationally. Approximately 2,270 MW of new generation plant and DSM have been committed over the last 5 years in the Reserve Capacity Mechanism to enter the market by 2011/12.

This level of investment is an outstanding outcome for Western Australia. Not only is this investment helping to ensure reliability of supply, but the increasing number of Market Participants and range of capacity types is providing greater competition in the market.

In May 2009, the IMO published a Reserve Capacity Mechanism Review Report which provides information about the historic performance of the mechanism. The report can be accessed through the IMO website[3].

Next Steps

Parties offering a generation or a DSM facility as Reserve Capacity must register with the IMO as a Market Participant and must register their facilities for the purposes of Reserve Capacity. Market Participants must then apply for their facilities to be certified and apply to be assigned Capacity Credits.

Certification is required for all new and existing facilities. Applications for Certification of Reserve Capacity of generation and DSM capacity for the 2012/13 Reserve Capacity Year are now open and must be provided to the IMO by 5:00 PM WST on Tuesday, 20 July 2010.

Further information on the Reserve Capacity process is available on the IMO website at http://www.imowa.com.au. Parties planning to participate in these processes should familiarise themselves fully with the requirements of the relevant Market Rules and Market Procedures. Parties intending to participate in the WEM for the first time are strongly encouraged to contact the IMO at an early stage to discuss the market requirements for new entrants.

[3] http://www.imowa.com.au/f875,52032/52032_RCM_ReportV5_PUBLISHED_1_.pdf

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Requirements of the Wholesale Electricity Market Rules

The following table is provided to assist readers wishing to find particular information in this report as required by the Market Rules. Market Rule 4.5.13 specifies the information that must be included in the Statement of Opportunities Report. The table below provides links to the appropriate section of the report for each of these items.

Market Rule	Report section where item is addressed
4.5.13. The Statement of Opportunities Report must include: (a) the input information assembled by the IMO in performing the Long Term PASA study including, for each Capacity Year of the Long Term PASA Study Horizon: i. the demand growth scenarios used;	Section 4 Appendix 3 Appendix 4 Appendix 5
ii. the generation capacities of each generation Registered Facility;	Appendix 9
iii. the generation capacities of each committed generation project;	Appendix 9
iv. the generation capacities of each probable generation project;	Section 5.6
v. the Demand Side Management capability and availability;	Appendix 9
vA. the amount of Reserve Capacity forecast to be required to serve the aggregate Intermittent Load;	Section 5.3
vi. the assumptions about transmission network capacity, losses and network and security constraints that impact on study results; and	Sections 4.2 and 7.1
vii. a summary of the methodology used in determining the values and assumptions specified in (i) to (vi), including methodological changes relative to previous Statement of Opportunities Reports;	Sections 3, 4 and 5
(b) the Reserve Capacity Target for each Capacity Year of the Long Term PASA Study Horizon;	Section 5.3
(c) the amount by which the installed generation capacity plus the Demand Side Management available exceeds or falls short of the Reserve Capacity Target for each Capacity Year and each demand growth scenario considered in the study;	Section 5.5 Appendix 6
(d) the extent to which localised supply restrictions will exist while satisfying the Reserve Capacity Target for each Capacity Year and each demand growth scenario considered in the study;	Sections 4.2 and 7.1
(e) a statement of potential generation, demand side and transmission options that would alleviate capacity shortfalls relative to the Reserve Capacity Target and to capacity requirements in sub-regions of the SWIS; and	Section 5.6
(f) the Availability Curve for the 2nd and 3rd Capacity Years of the Long Term PASA Study Horizon.	Section 5.4

1. Introduction

While Western Australia's growth has recently been suppressed by the global economic downturn, the State economy is forecast to recover significantly in the short to medium-term, driving growth in electricity demand.

Developers are making major investments in power generation capability within the SWIS. In recent years, plans have been announced for further conventional generation in the metropolitan, South West and the Mid West regions. At the same time Commonwealth and State Government measures to encourage renewable generation are stimulating proposals for wind farms and other renewable projects.

This Statement of Opportunities Report (SOO) is published to provide information to parties considering participation in the Reserve Capacity element of the Wholesale Electricity Market (WEM). It also provides electricity demand and consumption information for Market Participants and other interested parties. As such, the SOO is a key element in the Reserve Capacity Mechanism, a series of processes through which the IMO identifies the requirement for future generation and Demand Side Management (DSM) capacity and facilitates the introduction of this capacity onto the South West interconnected system (SWIS).

The 2010 SOO provides updated expectations on the capacity available on the SWIS from that provided in the 2009 SOO and in the 2010 Summary of Expressions of Interest published in May 2010. Forecasts of key economic parameters, along with energy consumption and demand forecasts, are provided for the Long Term PASA Study Horizon, which extends to 2020/21.

The SOO contains a detailed profile of the SWIS, including a current load duration curve, typical load profiles, a thorough analysis of the current generation mix, and forecasts of peak demand and energy consumption through to 2020/21. Analysis on the current economic environment is also provided.

2. Electricity Generation and Consumption in the SWIS

Historically, electrical output from power stations has been measured at two distinct points:

- at the generator terminals (which is a measure of the gross production level); and
- at the point where the electricity is sent out from the power station (the net amount of electricity exported onto the transmission grid).

As the WEM uses sent-out capacity quantities, the information provided in the SOO is presented in terms of sent-out capacity expressed in megawatts (MW), unless otherwise specified. Energy production is also presented in sent-out terms and is measured in gigawatt-hours (GWh).

2.1 2009/10 Summer Weather and Maximum Demands

Electricity demand in the SWIS is strongly correlated with the daily temperature in the Perth metropolitan area. Summer maximum temperatures can range from the mid-twenties to the mid-forties, with consequent daily peak electricity demands from below 2,000 MW to above 3,700 MW.

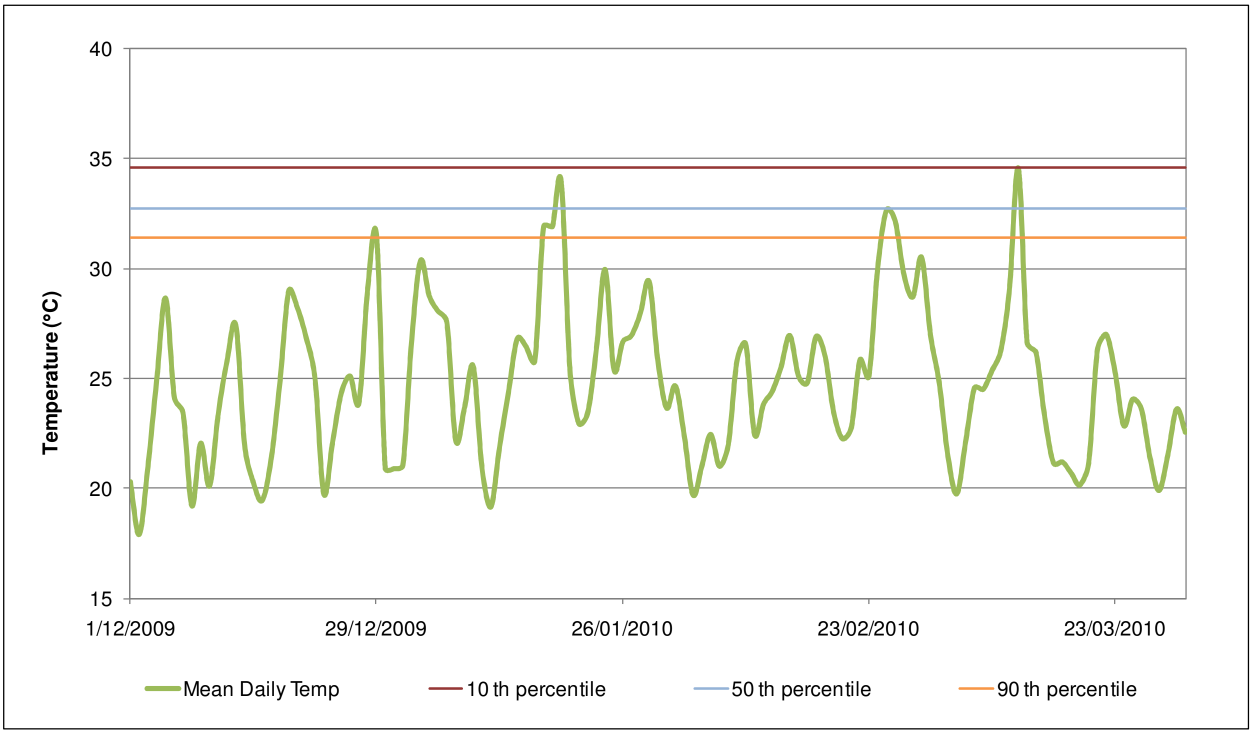
The Hot Season for the SWIS is defined as the period from 1 December to 1 A, with the highest maximum demands expected between mid-January and mid-March. The daily peak demand is higher on business days than on weekends and public holidays.

Typically, the highest maximum demands are recorded when there is a sequence of hot days with high overnight temperatures. The IMO's forecasting is based on the arithmetic mean of the minimum overnight temperature and the maximum temperature for each day. This "mean temperature" is used to predict the likelihood of a maximum demand event occurring.

In 2009/10, Perth experienced summer conditions higher than historic averages. Temperatures were more than 2°C above the historic average in December and January before average conditions returned through February and March.

Figure 1 shows the Perth mean daily temperatures from December 2009 to March 2010, as published by the Bureau of Meteorology, compared with the Probability of Exceedance (POE) levels given by the National Institute of Economic and Industry Research (NIEIR), which prepares the forecasts provided in this document. These levels reflect the probability range for the highest mean daily temperature over the summer period.

Figure 1 – Perth Temperatures December 2009 to March 2010

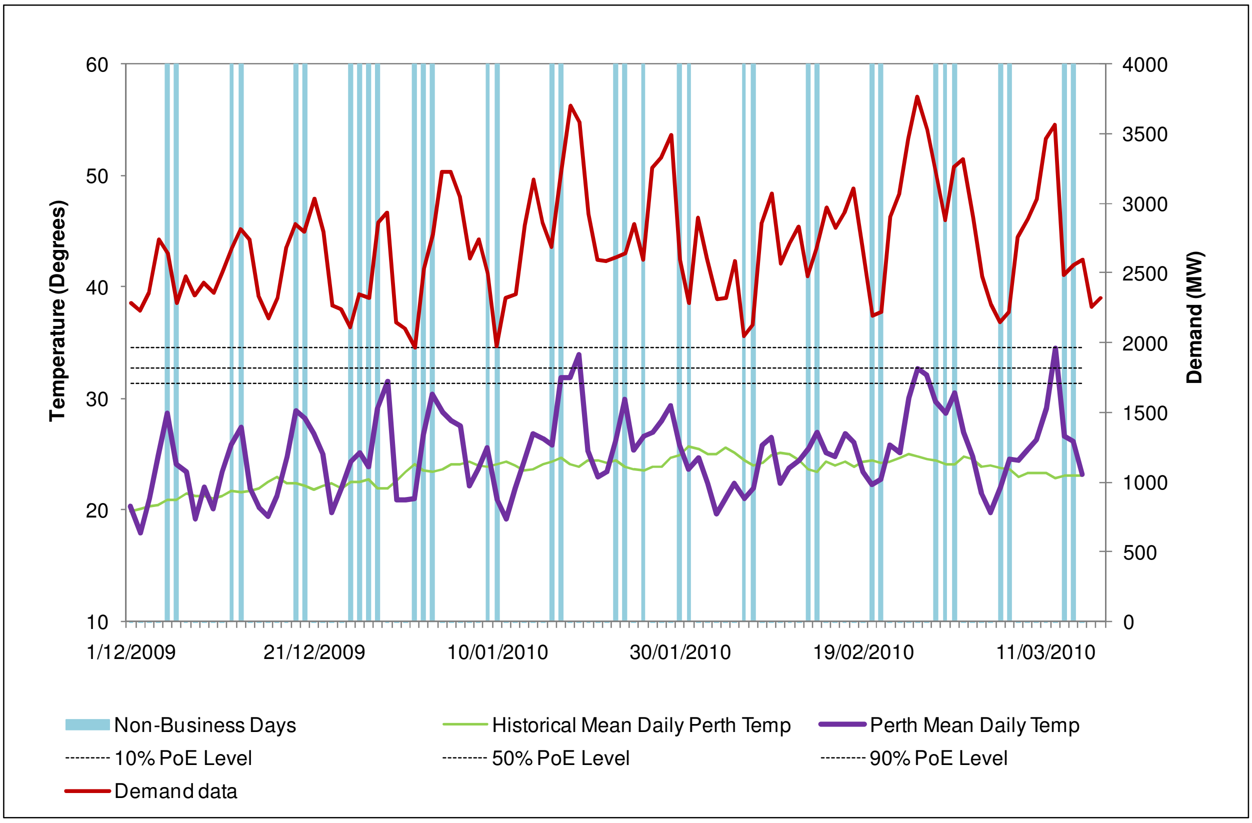


(Source: Bureau of Meteorology)

From Figure 1 it can be seen that the peak mean daily temperature exceeded the 50% POE level on two occasions. There were no days when the mean daily temperature exceeded 10% POE levels. There were seven occasions when the mean daily temperature exceeded the 90% POE level.

The daily peak demand is compared to the mean daily temperatures for the Hot Season in Figure 2.

Figure 2 –Perth Mean Daily Temperature on Business and Non-Business Days



As shown in Figure 2, the SWIS demand peaked at 3,766 MW on 25 February 2010. The mean daily temperature on this day was 32.7°C, making it the third hottest day in the summer, corresponding to a POE level of approximately 50%. This was preceded by a mean daily temperature of 30.0°C on the previous day.

The highest 2009/10 Hot Season mean daily temperature of 34.6°C (minimum of 28.1°C and maximum of 41.0°C) was recorded on 12 March 2010. This was preceded by a mean daily temperature of 29.1°C on 11 March 2010. The maximum demand on 12 March was at just over 3,560 MW.

Table 1 shows the difference between the actual peak demand in 2010 and forecasts provided in the SOOs since 2005. The forecasts have been corrected for the actual temperature conditions on the peak demand day in 2010.

Table 1 – Temperature-Corrected Forecast Accuracy

Maximum demand = 3766 MW		Accuracy (MW)	Accuracy (%)
2005 Temperature-Corrected Forecast	3497	-269	-7.1%
2006 Temperature-Corrected Forecast	3803	37	1.0%
2007 Temperature-Corrected Forecast	3924	158	4.2%
2008 Temperature-Corrected Forecast	3987	221	5.9%
2009 Temperature-Corrected Forecast	3859	93	2.5%

Table 1 shows that the 2009/10 peak demand was 93 MW lower than the forecast provided in the 2009 SOO. Lower load at two major industrial facilities during the peak interval accounts for 70 MW of this variation.

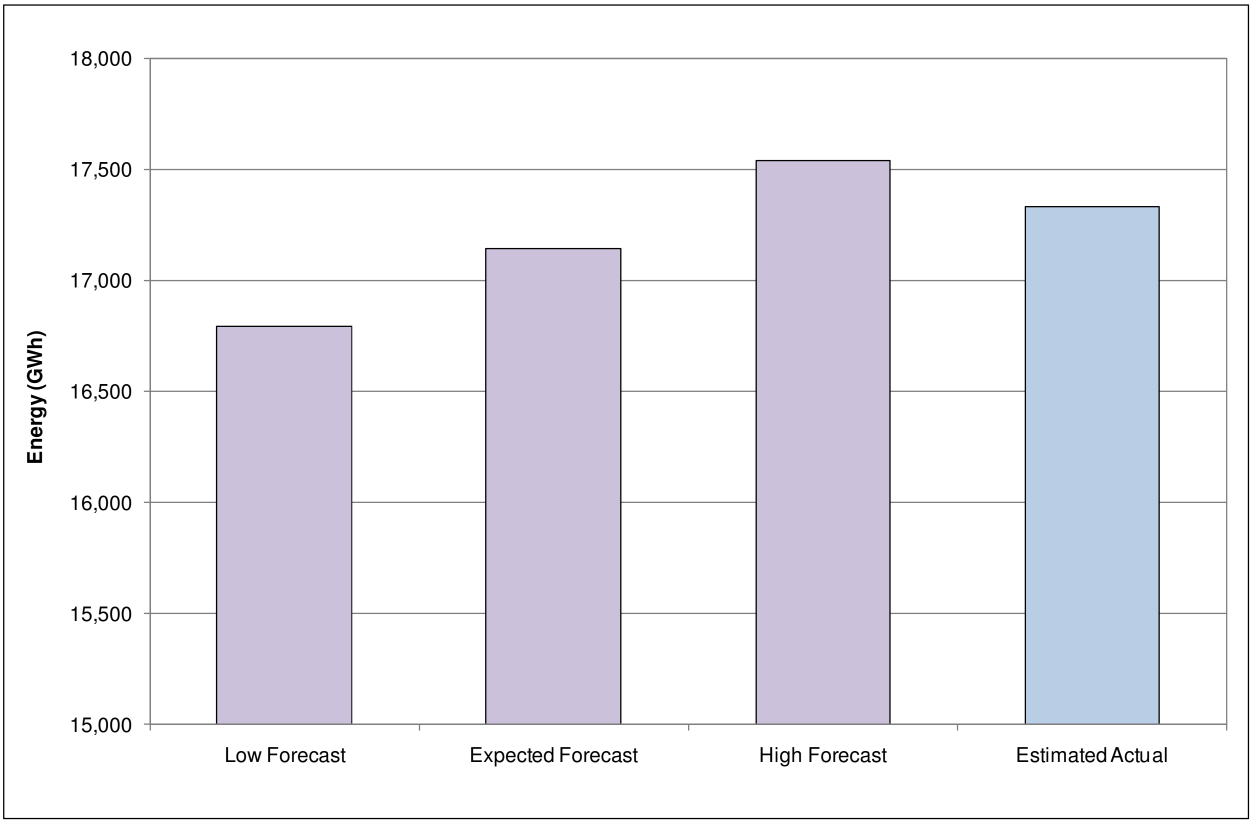
Table 1 also shows that the 2009/10 peak demand is significantly higher than the forecast provided in 2005, but lower than each of the forecasts from 2006 onwards. The considerable year-on-year variation is a reflection of increasing visibility of new large loads, and of the significant difficulties in forecasting in recent years. Factors such as the global financial crisis and the government stimulus packages have had varying but substantial effects on the Australian economy. In general, improved accuracy is expected as the date of forecast becomes closer to the Capacity Year being forecast.

2.2 Actual Sent-Out Energy

Figure 3 compares forecast energy from the 2009 SOO for Expected, Low and High growth cases with the estimated actual energy consumption for the 2009/10 financial year of 17,322 GWh. This estimate comprises nine months of actual data plus three months of estimated energy consumption to the end of June 2010.

The actual energy consumed is above the Expected forecast provided in the 2009 SOO. One of the factors which have led to this difference is the higher level of economic activity than was forecast.

Figure 3 – Comparison of Actual and Forecast Sent-Out Energy for 2009/10



2.3 SWIS Load Duration Curve

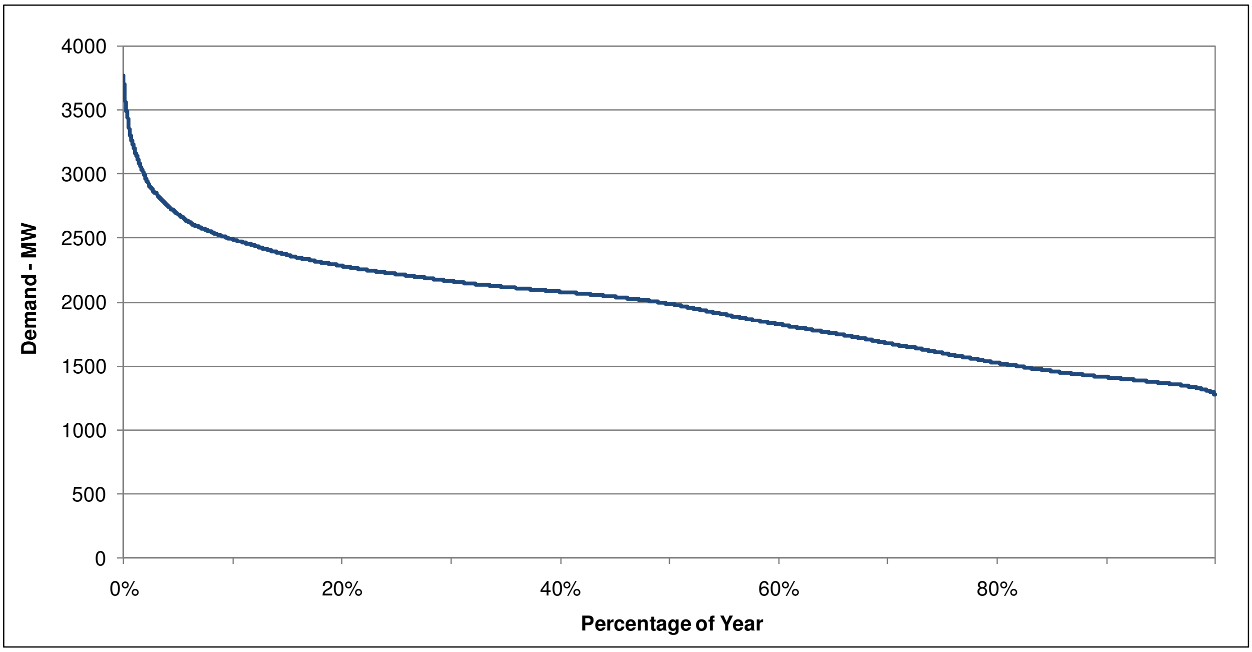
As with any product, the final cost of producing electricity is partly determined by the extent to which production capacity is utilised. If average demand is significantly below peak demand, a higher proportion of peaking plant will be needed to provide capacity during the times of peak demand.

In an electricity system, variation in demand can be examined in a load duration curve. This shows the demand in the system against the percentage of time for which it is reached or exceeded.

The load duration curve provides an insight into the likely optimum mix of generation types. Typically generators with lowest running cost have the highest capital cost and vice versa. Cost is generally minimised if demand levels that only occur for a small part of the year are supplied from generators with low capital cost, even though the running costs of this type of plant (e.g. diesel fuel cost) may be high, or DSM. Conversely, demand that is present most of the time is best supplied from generators with low running cost, even though their capital costs may be high.

Figure 4 shows the load duration curve for the period from April 2009 through to March 2010, which has a similar shape to the load duration curve presented in the 2009 SOO covering the previous year.

Figure 4 – Load Duration Curve April 2009 to March 2010



The most significant factors shown in this figure are that:

- The load exceeded 90% of the annual maximum, i.e. 3,390 MW, for less than 0.5% of the year (78 half-hour trading intervals), compared with 53 trading intervals last year.

- The load exceeded 80% of the annual maximum, i.e. 3,013 MW, for only 1.8% of the year (317 half-hour trading intervals) compared with 303 trading intervals last year.

- The mean load over the year was 1,961 MW, which is 52% of the maximum demand compared with 54% last year.

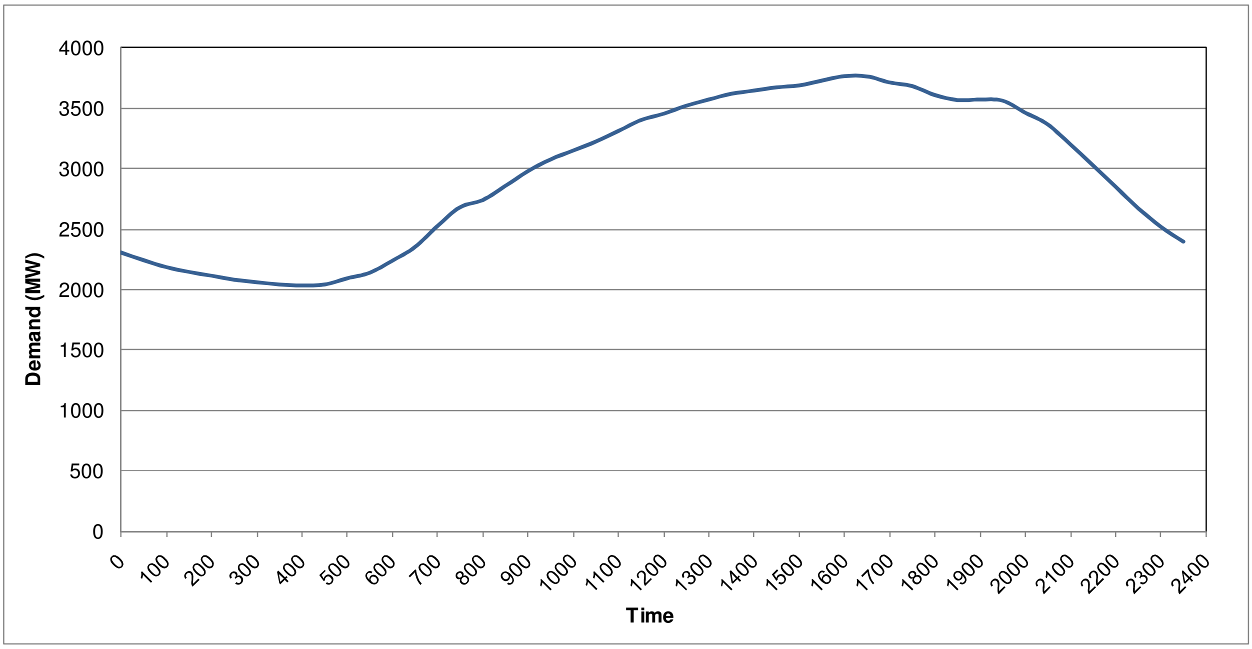
- The minimum load was 1,260 MW at 1:30 AM on 11 May 2009 compared with 1,185 MW last year.

This data suggests the load profile has a similar shape to the load duration curve evident last year.

2.4 Typical SWIS Daily Load Shape

Electricity demand varies substantially through each day with overnight loads being markedly lower than daytime demand. Figure 5 illustrates the level of demand in each trading interval on 25 February 2010, the day of highest maximum demand. Appendix 7 includes further daily load curves covering the winter day with the highest maximum demand and typical autumn and spring days.

Figure 5 – Daily Load Curve 2010 Peak Demand Day (25 February 2010)



2.5 Information on Market Generators

2.5.1 Capacity Credits by Fuel Type

As discussed in section 2.3, a mix of generator types is needed to minimise the overall cost of producing electricity. This is also relevant for the fuel type used by generators.

Highly utilised generators will usually use low-cost fuels such as coal or natural gas. However, low-cost fuels can incur large fixed costs for transport, storage and processing. These high costs can be warranted if utilisation is high.

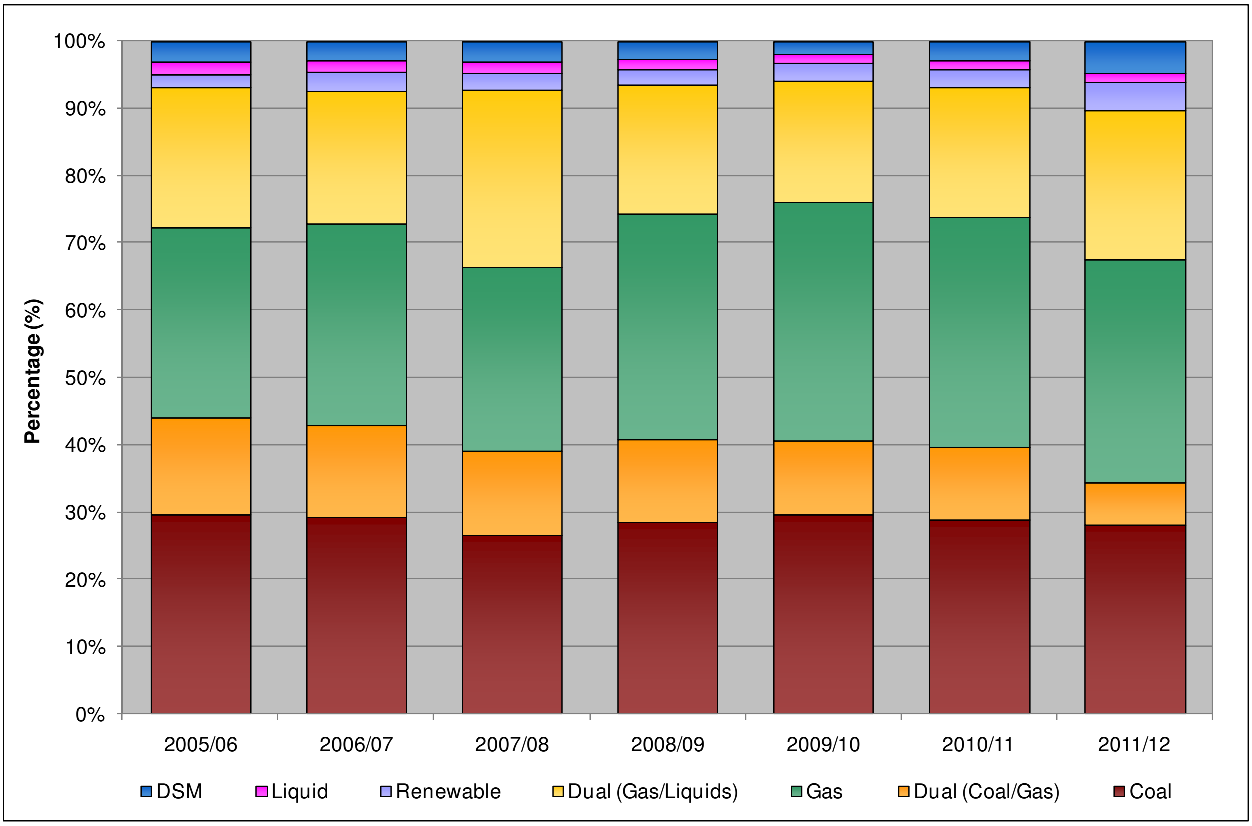
Conversely, plants operating only rarely may have lower total costs if other fuels are used – perhaps with higher unit costs, but lower fixed costs. For example, high-cost distillate fuel can be the best choice for plants which will run only at peak demand times.

Diversity of fuel types can mitigate against failures or restrictions in the supply of a particular fuel type. For instance, access to coal-fired and distillate-fired generation capacity was very important in minimising the impacts of the Varanus Island gas supply disruption in 2008.

Dual-fuel plant also played an important part in maintaining system reliability and security during the Varanus Island incident. The IMO is currently investigating ways to incentivise investment in dual-fuel capability through the Reserve Capacity Mechanism for future Capacity Years.

Figure 6 illustrates the healthy mix of fuel types in the SWIS. This graph shows the composition of the generation capacity based on fuel type, for each year since the 2005/06 Capacity Year. While there have been some changes to the mix of fuel types, the significant diversity of capacity has continued since the introduction of the Reserve Capacity Mechanism.

Figure 6 – Percentage of Capacity Credits by Fuel Type



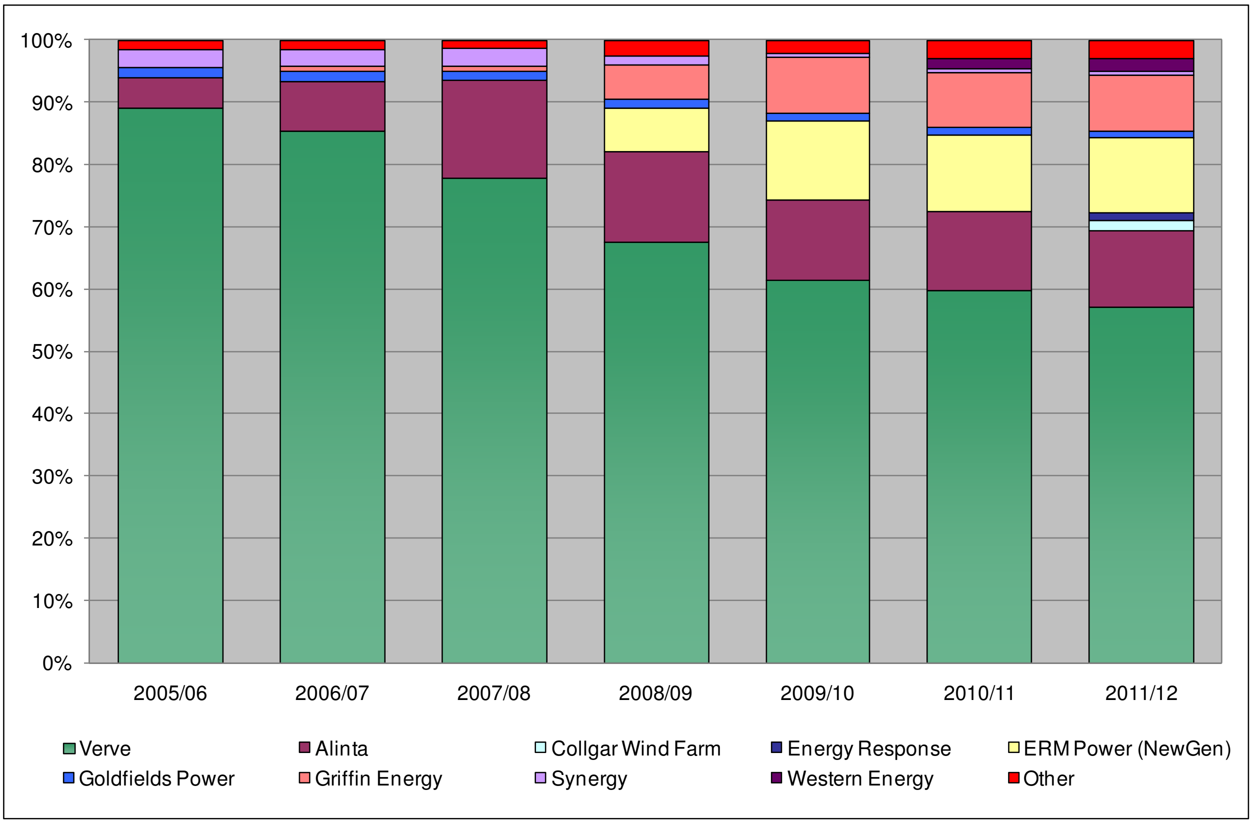
A key observation from this figure is that the vast majority of capacity continues to be coal- or gas-fired. It is evident that the system is gradually becoming more reliant on generation that can only fire on gas and slightly less reliant on coal. Also, the percentage of dual-fuel capacity is decreasing and liquids-only plant shows little change across the period. More recently, the percentage of Capacity Credits assigned to both renewable sources and DSM has increased significantly.

2.5.2 Capacity Credits by Market Participant

Figure 7 shows the Capacity Credits assigned to Market Participants as a percentage of the total number assigned in the SWIS for each year since the 2005/06 Capacity Year.

This illustrates the decrease in the relative share of the capacity market held by Verve Energy as a result of the capacity cap placed on it by Government and the increase in private capacity. In 2011/12, Verve Energy will hold 57% of Capacity Credits.

Figure 7 – Capacity Credits by Market Participant (minimum 1% market share)

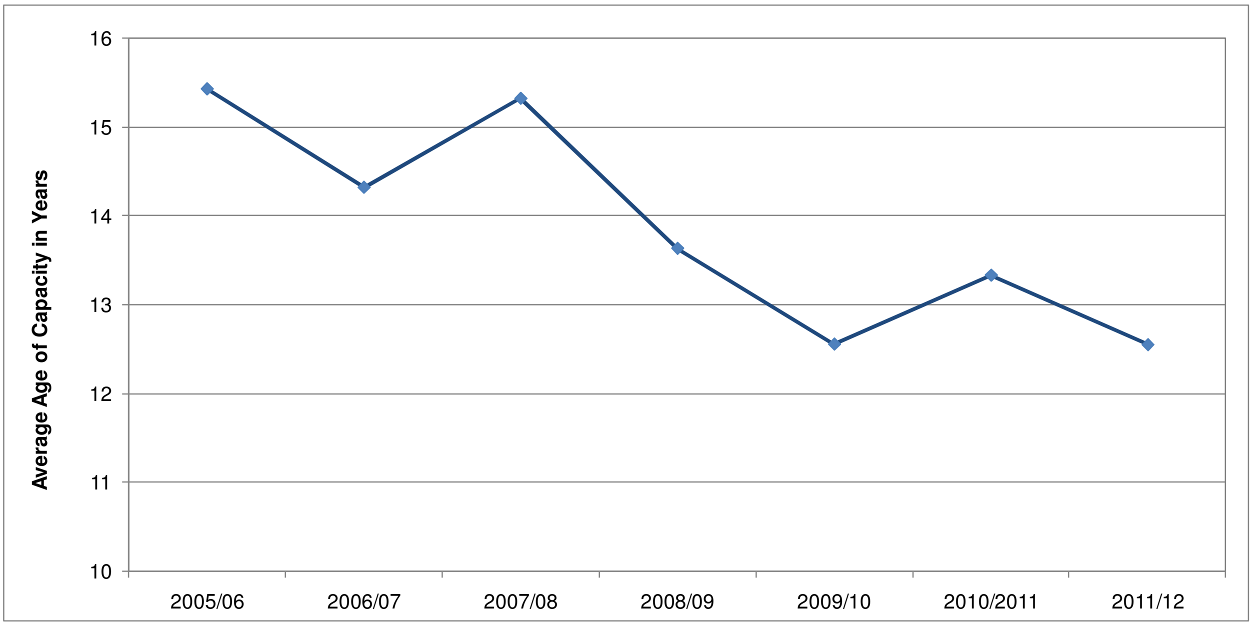


2.5.3 Age and Availability of Generation Plant

The age of generation plant can influence its efficiency, reliability, flexibility and production cost.

As can be seen in Figure 8, the average age of generating capacity on the SWIS has fallen significantly over the years since market start. This reflects the rapid introduction of new capacity over recent years and the retirement of older plant.

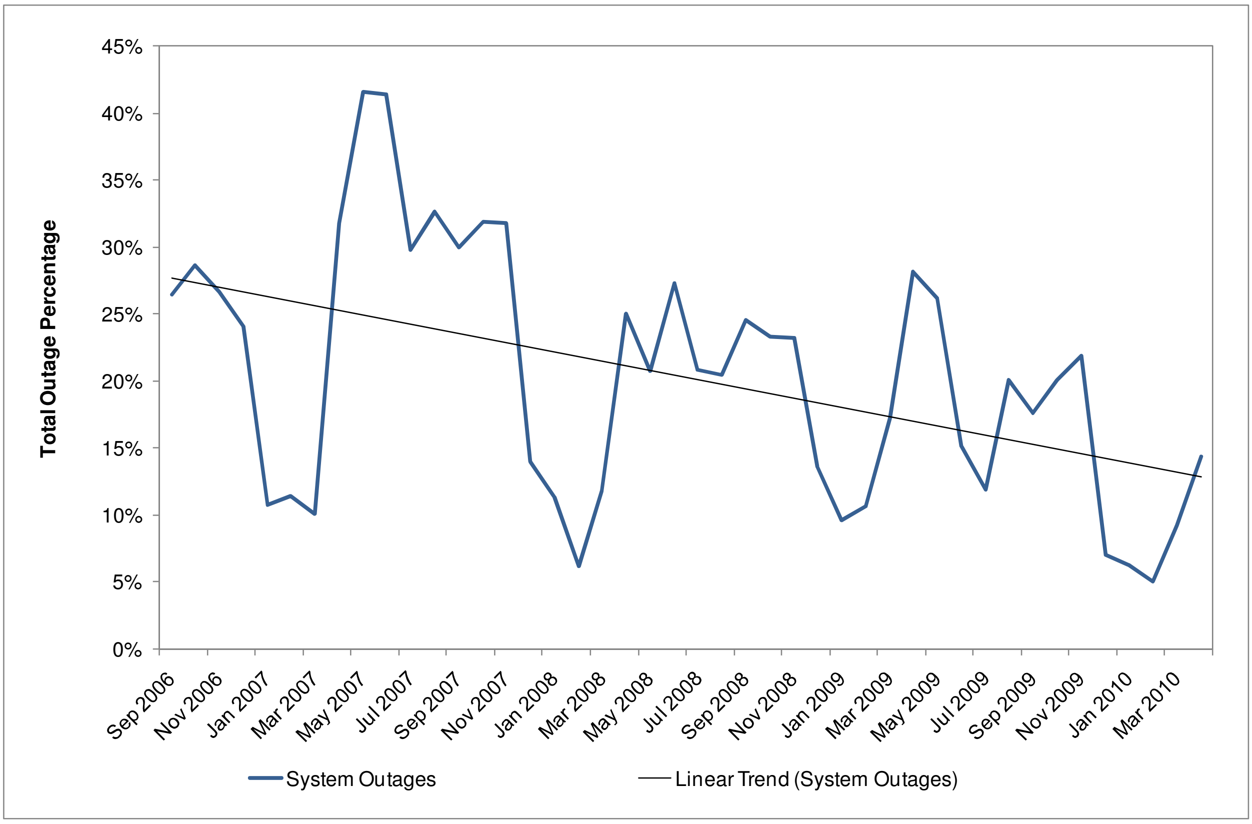
Figure 8 – Average Age of Generation Capacity



Given that the economic life of a power station is typically more than 30 years, the average age of SWIS generation is relatively low. It is expected that the average age will fall further as the market continues to encourage the building of new plant and as Verve Energy retires older, less efficient plant.

Figure 9 shows the total outage rates displayed as a percentage of the allocated Capacity Credits in the market. The linear trend line of reducing facility outage rates is consistent with the reducing plant age. The seasonality of the outage rates is obvious, indicating the scheduling of Planned Outages outside the Hot Season.

Figure 9 – Monthly Average Outage Percentage

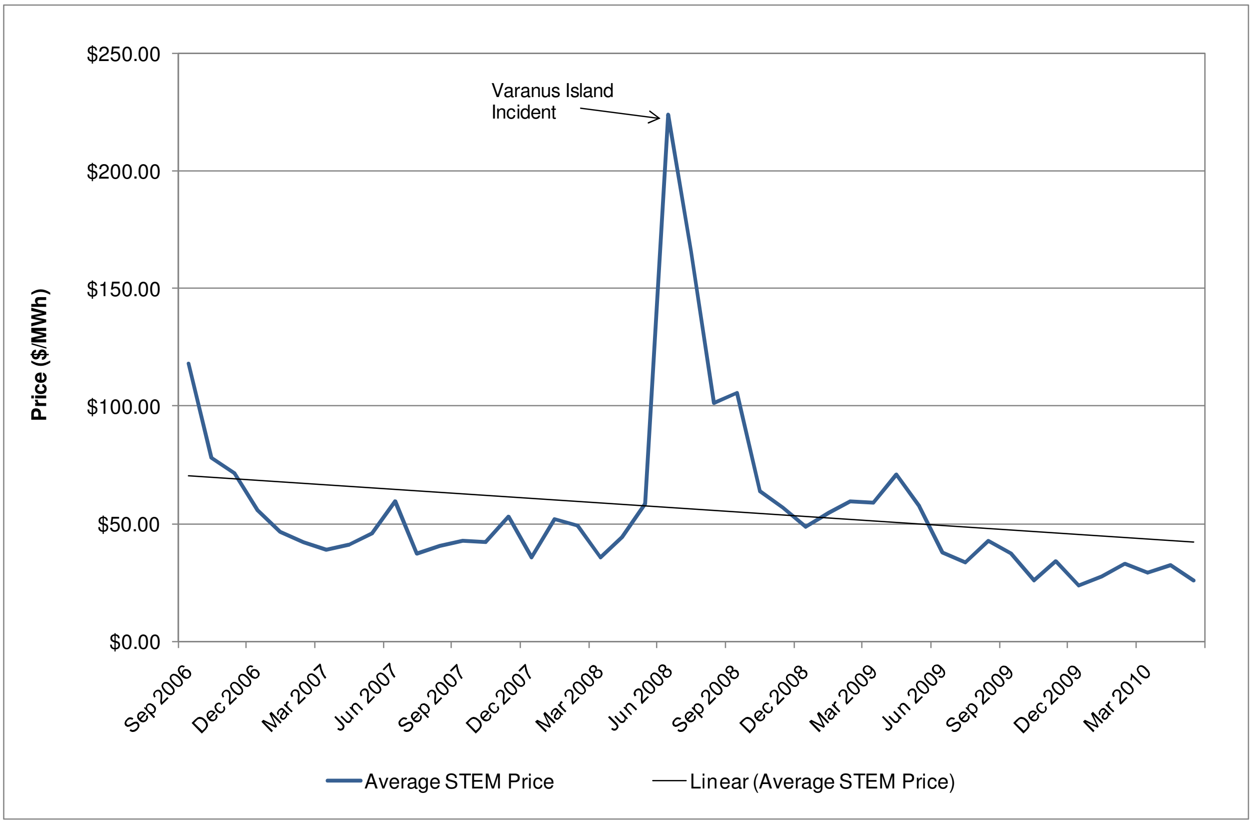


2.6 Energy Pricing in the Wholesale Electricity Market

The energy trading component of the Wholesale Electricity Market (WEM) has been in operation since Energy Market Commencement (EMC) on 21 September 2006. In that time the energy price has proven to be responsive to changes in the supply-demand balance in the SWIS. As the energy trading mechanisms in the WEM have matured, trading quantities have increased. Downward pressure on prices has been observed. These trends indicate increasing competition in the WEM and represent a positive market outcome.

The monthly average price has shown a downward and generally linear trend since EMC as shown in Figure 10. In this plot, the purple line indicates the monthly average price in the Short-Term Energy Market (STEM) and the black line indicates the linear trend for the whole dataset.

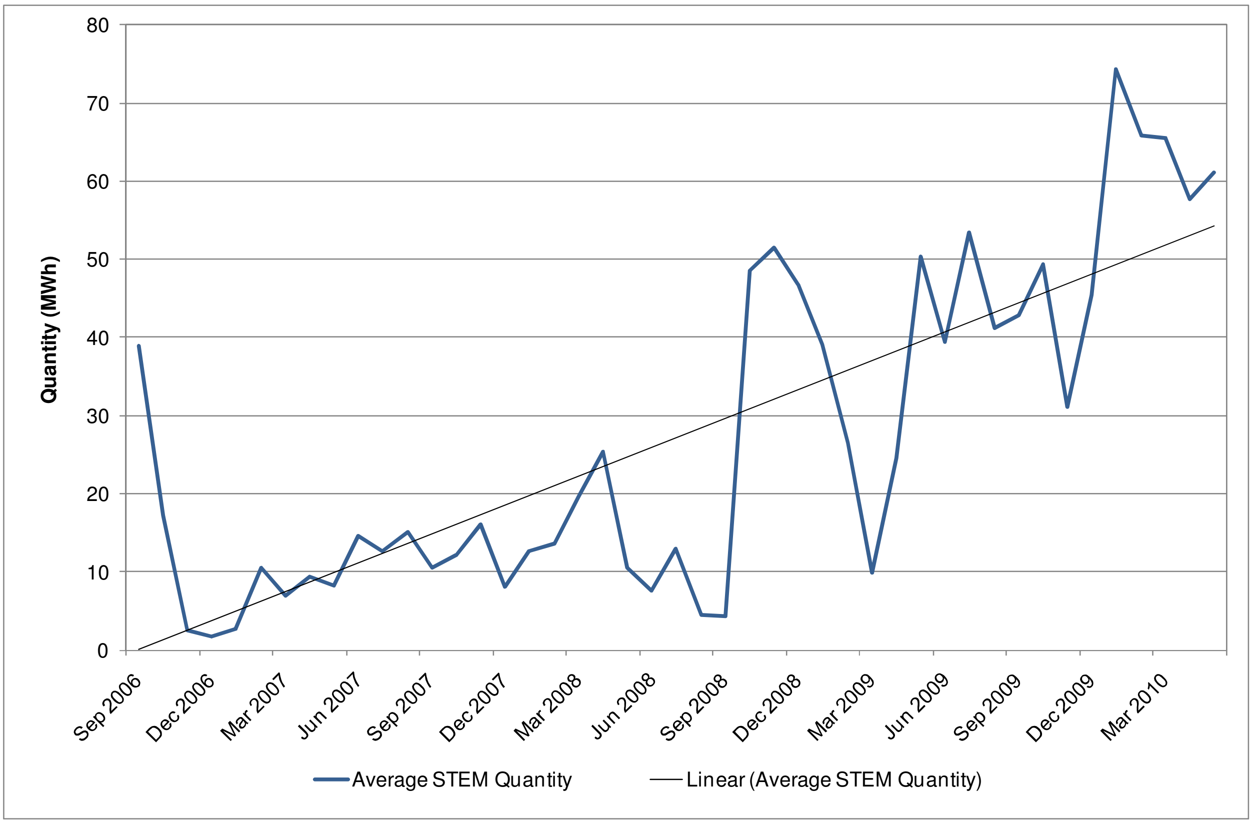
Figure 10 – Average STEM Price



The monthly price can be seen to be high initially at EMC, which suggests an adjustment period reflective of inexperience with the trading mechanisms. After this initial period, the monthly price reduced to the levels reflective of those seen most recently. The Varanus Island gas explosion in 2008 caused severe price spikes in the period between June and August, indicative of the supply restrictions on non-liquid fuels during that time.

The increased competition is evident in the growing quantity traded in the STEM. The green line in Figure 11 shows the increasing trend of the quantity of energy traded per interval. The entry of new independent power producers (IPPs) into the WEM has been a key driver in the increased competition, and this trend is likely to continue with new independent power producers (IPP) due to enter the market in the coming years. Another factor has been a steady rise in the usage of the STEM as a tool for Market Participants to adjust risk around their bilateral contract positions.

Figure 11 – Average STEM Quantity Traded (per interval)



Spikes in the quantity traded in the STEM are evident around the commencement of the 2008/09 and 2009/10 Capacity Years, with the quantity reducing shortly after. These are coincident with the entry of large new facilities into the WEM, and suggest that the owners of these facilities have traded energy in the STEM prior to the commencement of their bilateral contracts.

3. Economic Environment

3.1 Background

Economic forecasts are an important input in electricity forecasting. The electricity forecasts used by the IMO are provided by NIEIR. NIEIR has prepared all demand forecasts for the IMO since the IMO's inception. NIEIR was previously engaged by the then Western Power Corporation for forecasts used in the Generation Status Review from 2003 (a predecessor of the SOO). NIEIR has extensive experience in forecasting in Australia over several decades.

NIEIR's approach includes a top-down consideration of the Australian economy, from which forecasts are developed for Western Australia and the region served by the SWIS. These economic forecasts, combined with historic electricity demand data and projections of air-conditioning demand, are major determinants of the final electricity forecasts. The forecasting methodology is discussed further in section 4 of this report.

The level of economic activity has both a general and specific impact on the maximum demand for, and consumption of, electricity. Buoyant economic conditions encourage the purchase of discretionary items such as air-conditioning systems and plasma televisions. Construction of new dwellings is also strongly correlated with the strength of the economy, and leads directly to the purchase and usage of electrical appliances and demand for basic materials.

Resource extraction, processing and export are significant to the Western Australian economy and to electricity demand growth. Some of these activities have a direct impact on demand in the SWIS. Of particular relevance at present, are proposed iron ore developments that have substantial power needs for mineral processing.

Major developments in regional areas outside of the SWIS can have a significant impact on SWIS electricity demand:

- Much of the design, procurement and management support is provided by personnel based within the Perth metropolitan area.
- Much of the fly-in/fly-out workforce resides in the SWIS.
- Substantial quantities of basic materials and equipment are sourced from within the SWIS.
- This economic activity can boost population growth in Western Australia, particularly through interstate and overseas migration.

The forecasts included in this report show a slight increase in the compound economic growth rate over the next few years, compared with those in the 2009 SOO. This increase flows through to a slight increase in the forecast growth rate for base electricity demand and consumption through to 2012, prior to the consideration of new block loads. However, changes to the assumptions for these block loads has led to the maximum demand and energy forecasts for 2012/13 being lower than the corresponding forecasts last year.

This chapter includes discussion on changes in economic outlook which have occurred since the 2009 SOO. A comparison is also provided between NIEIR's forecasts and a number of other publicly available forecasts.

3.2 Economic Outlook

Figure 12 and Figure 13 show the forecasts of growth, measured by Gross Domestic Product (GDP) and Gross State Product (GSP), through to 2020/21 for the Expected, High and Low growth cases.

NIEIR forecasts that Australia's annual average economic growth over the period to 2020/21 will be approximately 3.0% while the Western Australian economy is expected to grow faster at 4.2% per year over the same period. By comparison, the 2009 SOO reported growth rates through to 2019/20 of 2.6% and 4.0% for GDP and GSP respectively. A detailed comparison of 2009 and 2010 GDP and GSP forecasts for the short term is provided later in this chapter (Figure 16 and Figure 17).

During the last five years, the resources boom has resulted in rapid growth in Western Australia with flow-on effects in the general economy including the Perth region. However, the effect of the global economic slowdown postponed and/or shut down a number of major resource developments. This contributed to a broader slowdown in the local economy, but not to the extent that had been forecast. GSP growth has remained positive, contrary to the forecasts provided in the 2009 SOO.

The Western Australian economy is forecast to recover strongly through to 2012/13 with GSP growth of around 5% per annum in this period. This growth is expected to be driven by increases in private business investment and private consumption expenditure. These increases are predicted to offset reduction in government capital expenditure associated with the completion of stimulus package programmes.

NIEIR forecasts that inflationary pressures and higher interest rates will then combine to slow economic growth, leading to a reduction in GSP growth in 2013/14. GSP growth is forecast to rebound the following year back to average levels for the forecast period.

Figure 12 – Forecast Australian Economic Growth

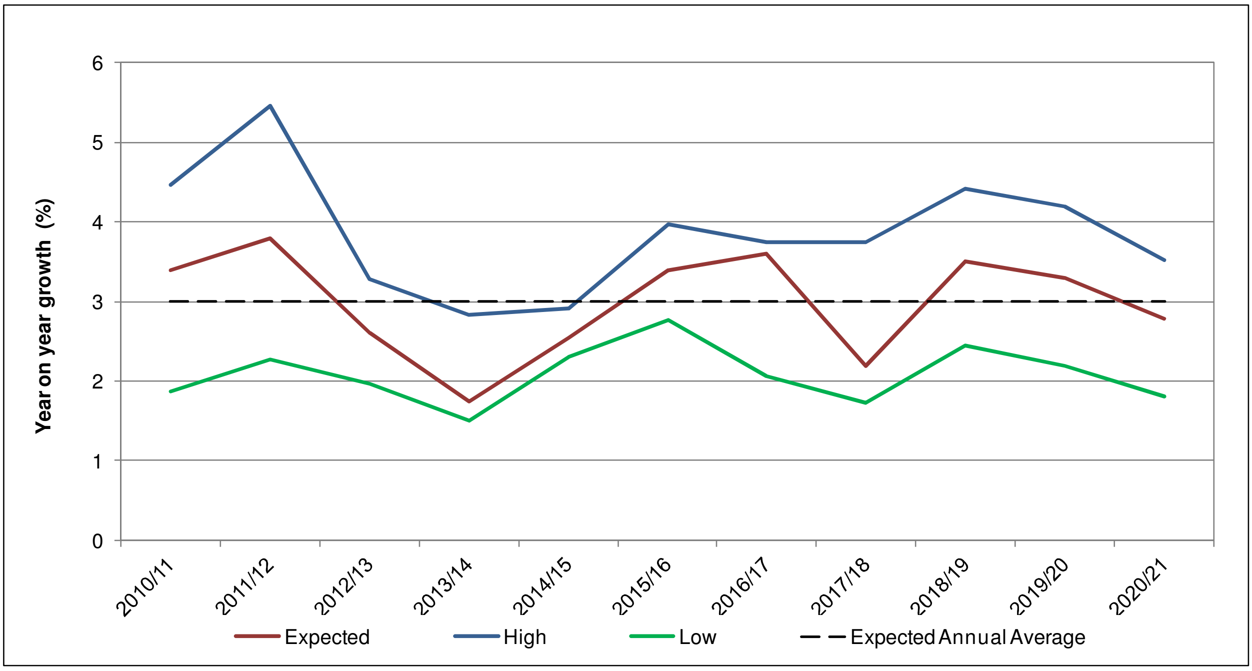


Figure 13 – Forecast Western Australian Economic Growth

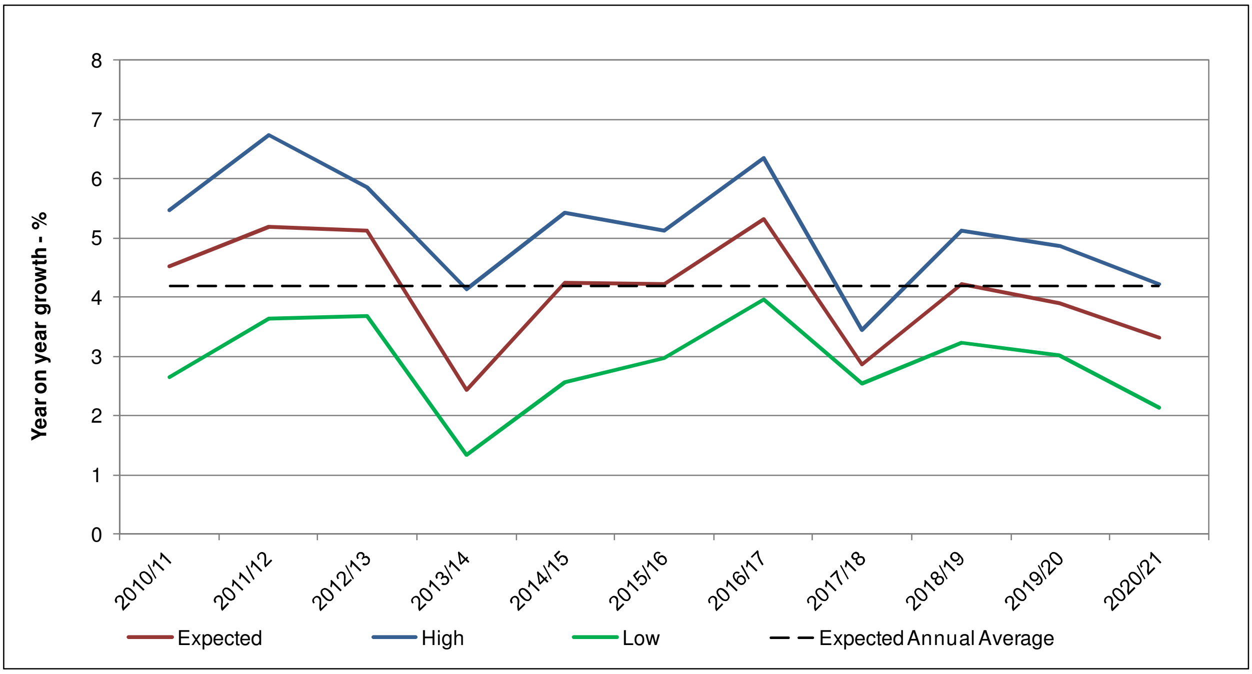


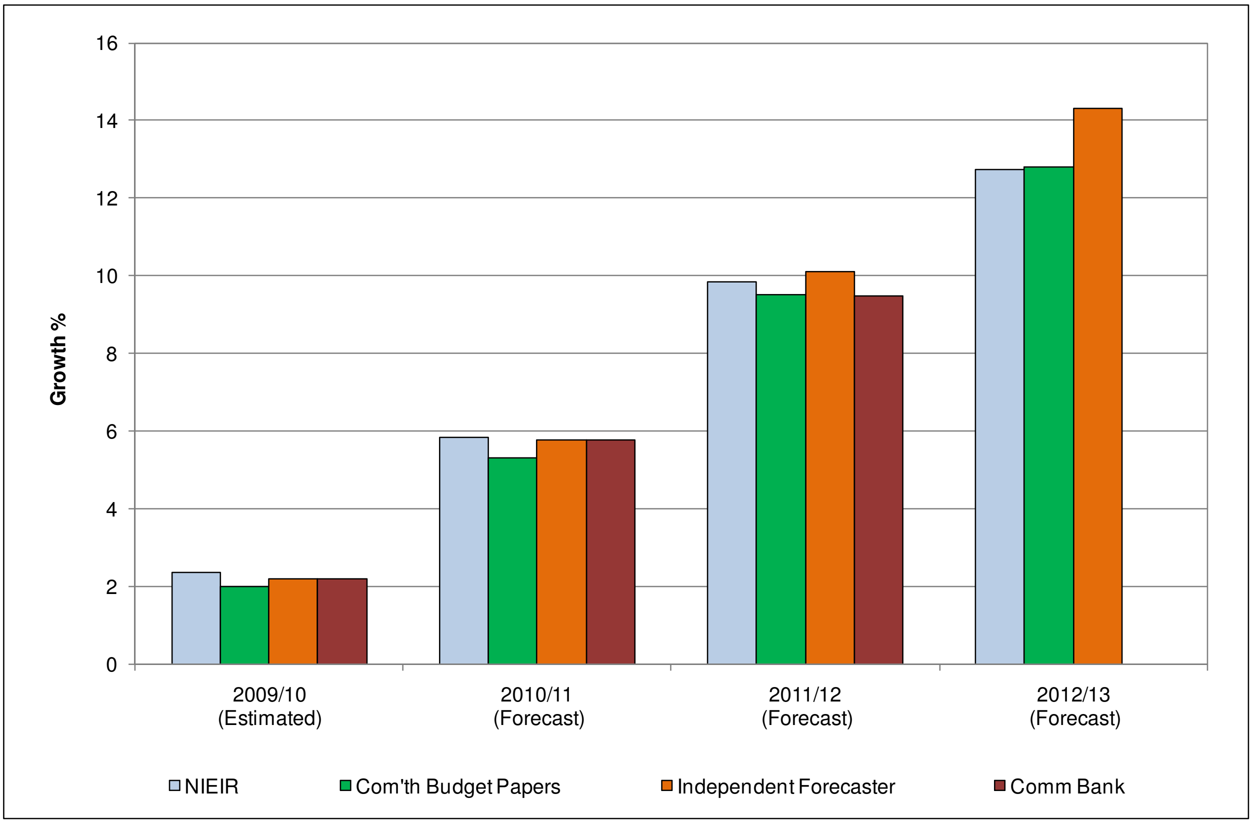
Figure 14 compares NIEIR's forecasts with those of three other organisations:

- the Commonwealth Government Budget Papers (published in May 2010);
- a major independent forecaster (published in February 2010); and
- the Commonwealth Bank Economic Forecast (published May 2010).

The ANZ Economic Outlook was used for comparison with NIEIR's forecasts in the previous SOOs. This publication has been suspended after the September quarter 2009 report, so the Commonwealth Bank Economic Forecast has been introduced as a replacement.

This comparison is presented on a compounded basis to smooth out the variations that occur from year to year. The "Independent Forecaster" included in the graph has requested that it not be named. Note that the Commonwealth Bank forecast extends only to 2011/12, so it is excluded from the 2012/13 comparison.

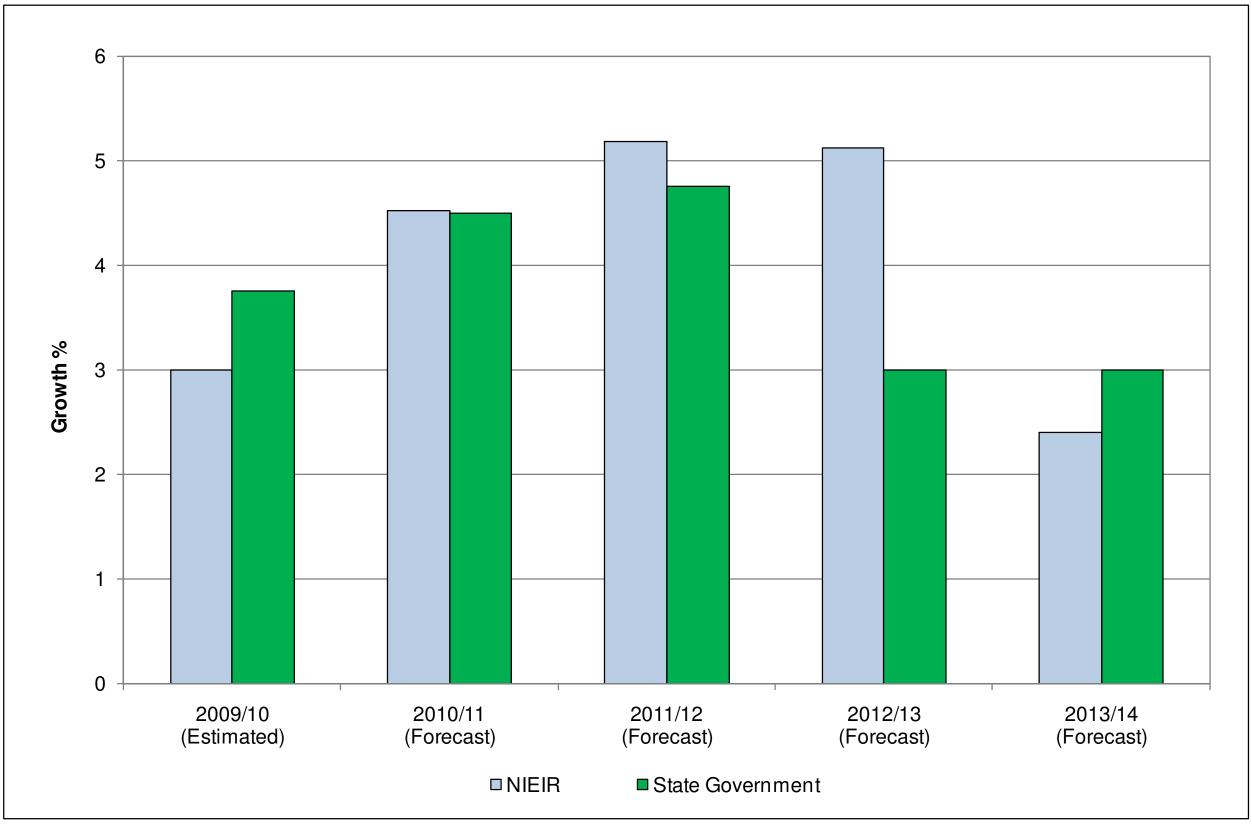
Figure 14 – Compound Australian Economic Growth



Compared with the forecasts presented in the 2009 SOO, there is excellent agreement between the forecasts this year. The only appreciable variation is the timing of the reduction in GDP growth. Both NIEIR and the Commonwealth Government Budget Papers predict a slowing in growth in 2012/13, while the independent forecaster predicts that the slowdown will not occur until 2013/14.

Figure 15 shows that the NIEIR forecasts of Western Australian GSP growth year-on-year for 2009/10 through to 2012/13 are in reasonable agreement with those published by the Western Australian Department of Treasury and Finance (DTF) in the May 2010 budget papers. While NIEIR forecasts that higher GSP growth will continue for 2012/13 and slow in 2013/14, DTF forecasts GSP growth to ease in 2012/13.

Figure 15 – Comparison of WA Economic Growth Forecasts



3.3 Comparison with NIEIR's Previous Economic Forecasts

Figure 16 and Figure 17 show that NIEIR's 2010 short-term forecasts for GDP and GSP have a smoother profile than those provided in 2009. At the time the 2009 SOO was published, NIEIR was forecasting a longer and more severe economic downturn between 2008/09 and 2010/11, followed by a steeper recovery. It is now evident that the Australian and Western Australian economies have grown above 2009 expectations and NIEIR's updated forecasts reflect an earlier and smoother recovery in the short to medium term.

Note that in Figure 16 and Figure 17 the 2008/09 forecast prepared in 2009 is an estimated figure based on nine months of actual data.

Figure 16 – Comparison of 2009 and 2010 Australian Economic Growth Forecasts

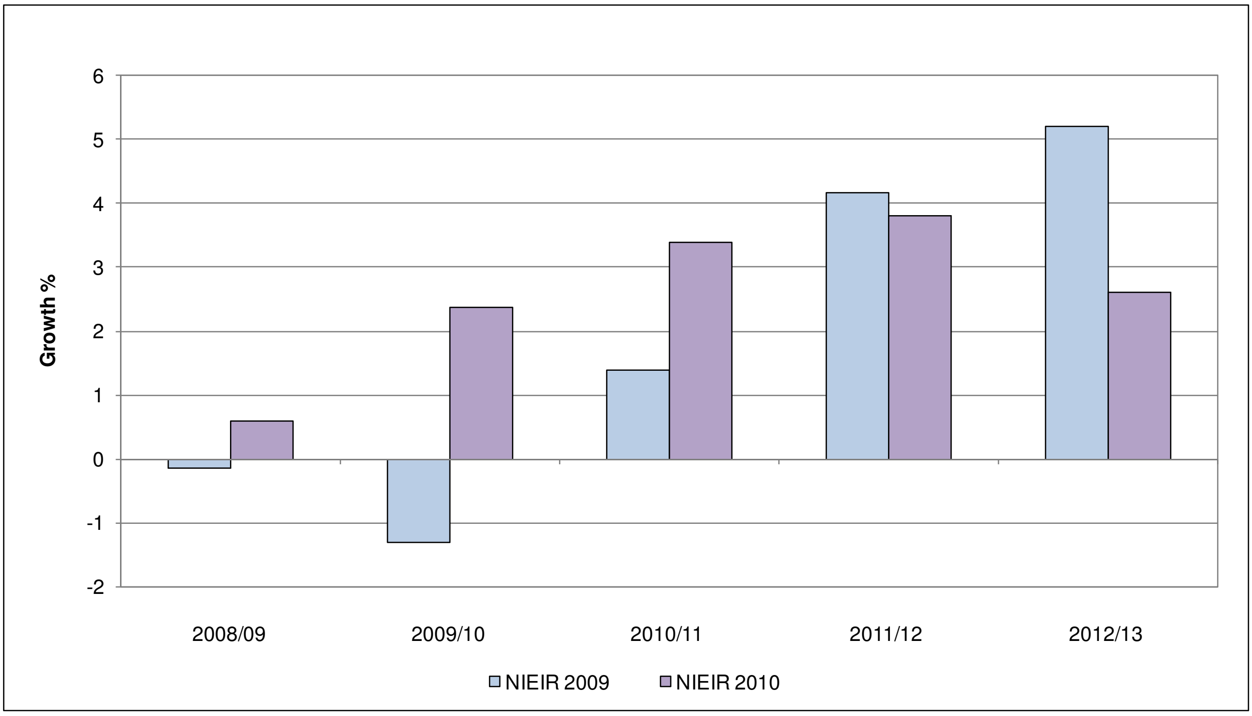
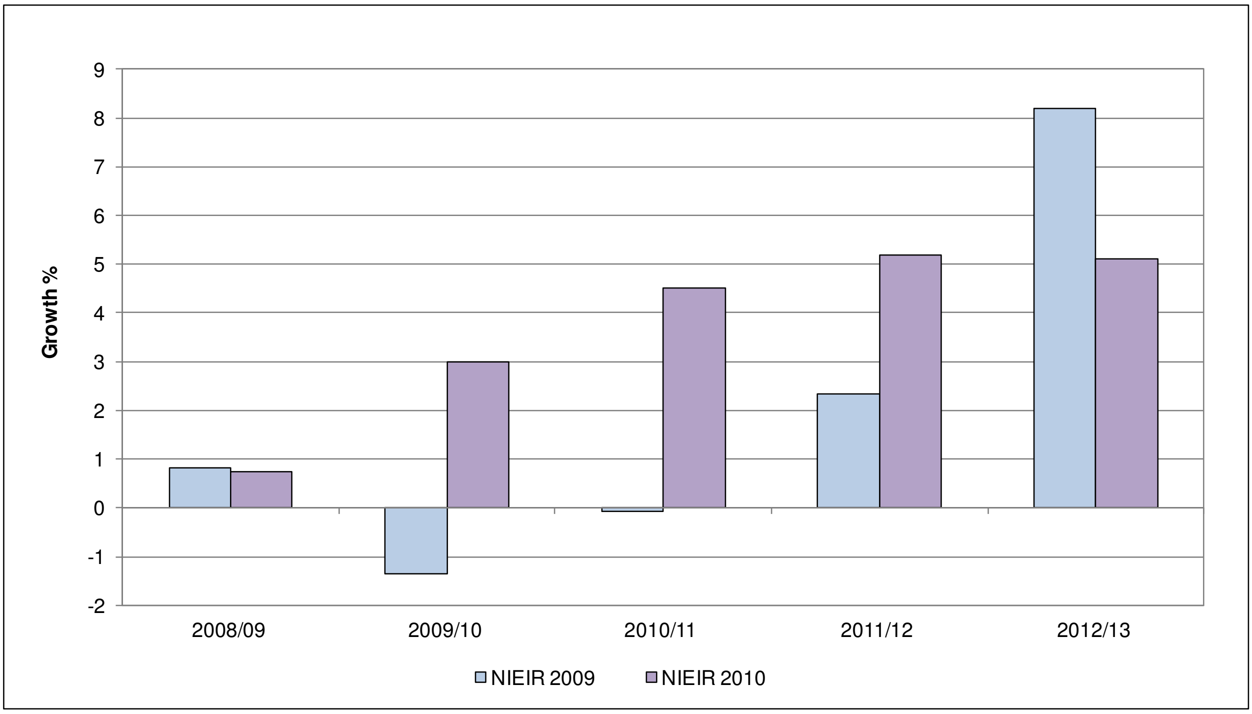


Figure 17 – Comparison of 2009 and 2010 WA Economic Growth Forecasts



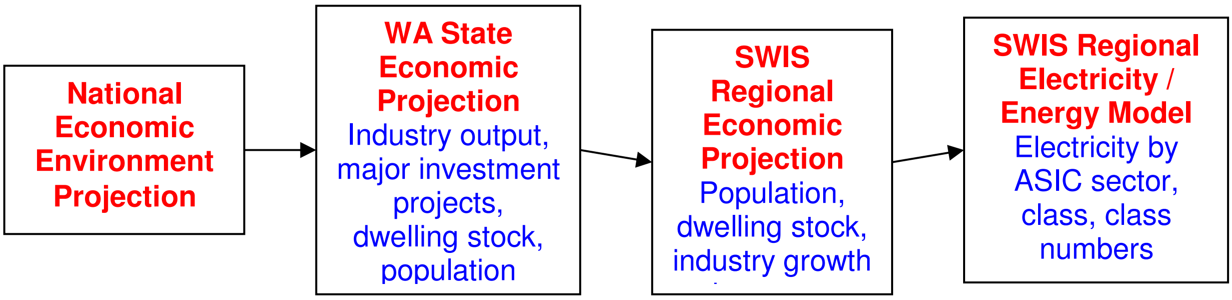
4. Peak Demand and Energy Forecasts, 2010/11 to 2020/21

4.1 Forecasting Methodology

Most of the forecast preparation for this SOO has been undertaken by the NIEIR on behalf of the IMO. NIEIR prepare forecasts of economic activity, electricity consumption and maximum demand for many of the electricity jurisdictions within Australia. For the SWIS, NIEIR has prepared forecasts for the past seven years, initially for Western Power Corporation and subsequently for the IMO's SOO.

The energy forecasting process used by NIEIR is comprised of a number of different econometric forecasting modules. Figure 18 shows the relationships between the major components of NIEIR's integrated energy modelling systems.

Figure 18 – NIEIR Energy and Electricity Forecasting Systems



The core tool used by NIEIR is its national econometric model of the Australian economy. This provides projections of national economic growth using inputs from various statistical sources including the Australian Bureau of Statistics and the Australian Taxation Office.

The national economic projections are used as input into a state economic projection model which provides an estimate of GSP and other indicators. The State model is then further disaggregated into the statistical subdivisions that make up the region served by the SWIS.

The economic forecasts of the SWIS include projections of population growth, dwelling stock composition and industry growth by sector. This portion of the forecasting system then links the SWIS regional economic forecast with electricity use based on assumptions about appliance penetration and efficiency, weather conditions and separate forecasts of major industrial loads.

The IMO publishes two sets of forecasts each year within the SOO. These forecasts cover:

- The maximum demand, which is the measure of the highest level of power consumption at any point in time over the year. This is measured in MW.
- Electricity consumption which is the amount of energy sent-out and consumed within the SWIS over a financial year. This is measured in GWh over the full year.

Electricity consumption is driven, to a large extent, by underlying economic-based drivers. Maximum demand, while also partially dependent on economic growth, is highly correlated with ambient temperatures.

Because summer maximum demands are so strongly influenced by the ambient temperature, a number of forecasts are prepared for the IMO. Each group of forecasts is based on three sets of temperature conditions for the peak day in the summer:

- The 10th percentile temperature condition which is expected to be exceeded only once in every ten years (10% POE).
- The 50th percentile temperature condition which is expected to be exceeded once in every two years (50% POE).
- The 90th percentile temperature condition which is expected to be exceeded nine times in every ten years (90% POE).

The 10%, 50% and 90% POE temperature conditions have been determined by analysis of historic weather data. Mean daily temperatures (the arithmetic mean of the daily maximum and daily minimum temperature) for the Perth metropolitan region are the metrics used. Mean daily temperatures of 34.6°C, 32.7°C and 31.4°C correspond to the 10%, 50% and 90% POE temperature conditions respectively.

The maximum demand and electricity consumption forecasts used to determine the Reserve Capacity Target are based on Expected economic growth conditions. The forecast outcomes associated with High or Low economic growth conditions are provided as a guide to the variability in outcomes that could be expected.

4.2 New Major Loads

The demand forecast developed by NIEIR incorporates several new major loads identified by the IMO through consultation with the industry. Generally, the IMO considers 20 MW to be minimum threshold for new major block loads.

To assess the size and likelihood that various projects will go ahead, the IMO enters into discussions with developers of these major projects. However, there is always some uncertainty in this assessment relating to:

- decisions associated with the actual development of the proposed mining operations; and
- the timing for the provision of support infrastructure; in particular, new transmission lines and associated facilities.

Block loads associated with magnetite iron ore projects in the Mid West are the key potential new major loads important to the 2012/13 year, but the majority of the new load are dependent on planned new transmission works.

The new Mid West Energy Project southern section from Neerabup to Eneabba 330 kV transmission line would need to be completed in order to fully supply major proposed mining loads. For clarity:

- While a provision has been made in the State Budget for expenditure for the Mid West Energy Project southern section this is "subject to final regulatory approvals and Government review of the business case"[4]. These approvals have not yet been granted and would be required before works are started.
- Discussions are progressing with the proposed connection of a foundation mining customer which, on conclusion of a satisfactory commercial arrangement, will trigger the need for the southern section Neerabup to Eneabba 330 kV line. These negotiations also consider an interim agreement for the customer to be supplied on a non-firm basis prior to the Mid West Energy Project southern section being completed.
- The construction of the line is estimated to take 26 months. Providing unconditional approval has been received by January 2011, the line will be completed by the end of March 2013.

The importance of the new transmission works is further discussed in section 7.1 of this report.

In assessing whether new loads will be in place, the IMO has balanced the need to ensure that sufficient capacity is sought to meet demand, against the importance of avoiding unwarranted cost to the market.

- The network connection risks mentioned above are in addition to any timing risks that might be associated with the resource projects.
- If these loads are presumed to be in place and fully supplied, the market will require the corresponding Reserve Capacity to be provided. The potential cost of this additional capacity is significant, in the order of $30 million for the 2012/13 year. This cost would need to be recovered from electricity customers.

Based on the information available, the IMO has decided that the forecast capacity requirements for 2012/13 should presume no additional new large block loads on the northern transmission system beyond the capacity of the existing network. Some additional load (95 MW) has been allowed for in 2012/13 based on information from Western Power on spare capacity in the existing Mid West network.

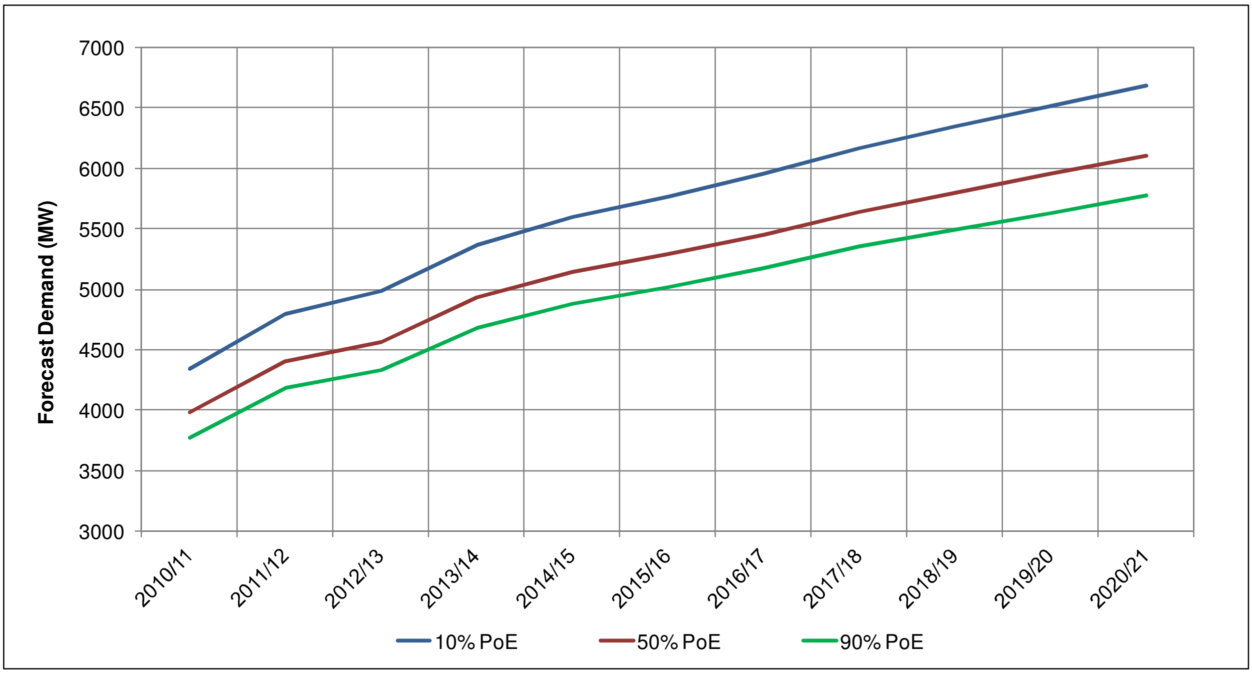
Subject to unconditional approval, it is expected that the new transmission works are in service at the end of March 2013 and the allowance for major loads has been increased to accommodate major Mid West mining loads presumed to be in place by that time.

[4] 2010-11 State Budget, Volume 2, p600. This can be accessed at http://www.ourstatebudget.wa.gov.au/. Please note that the project is referred to as the North Country Reinforcement (NCR) in the Budget Papers.

4.3 Maximum Demand Forecast

Figure 19 shows the forecast SWIS maximum demand for each year in the period to 2020/21. This figure shows the maximum demands for the 10%, 50% and 90% POE cases provided by NIEIR. These forecasts are based on expected economic growth conditions and other new major loads identified by the IMO.

Figure 19 – Forecast Maximum Demand – Expected Economic Growth



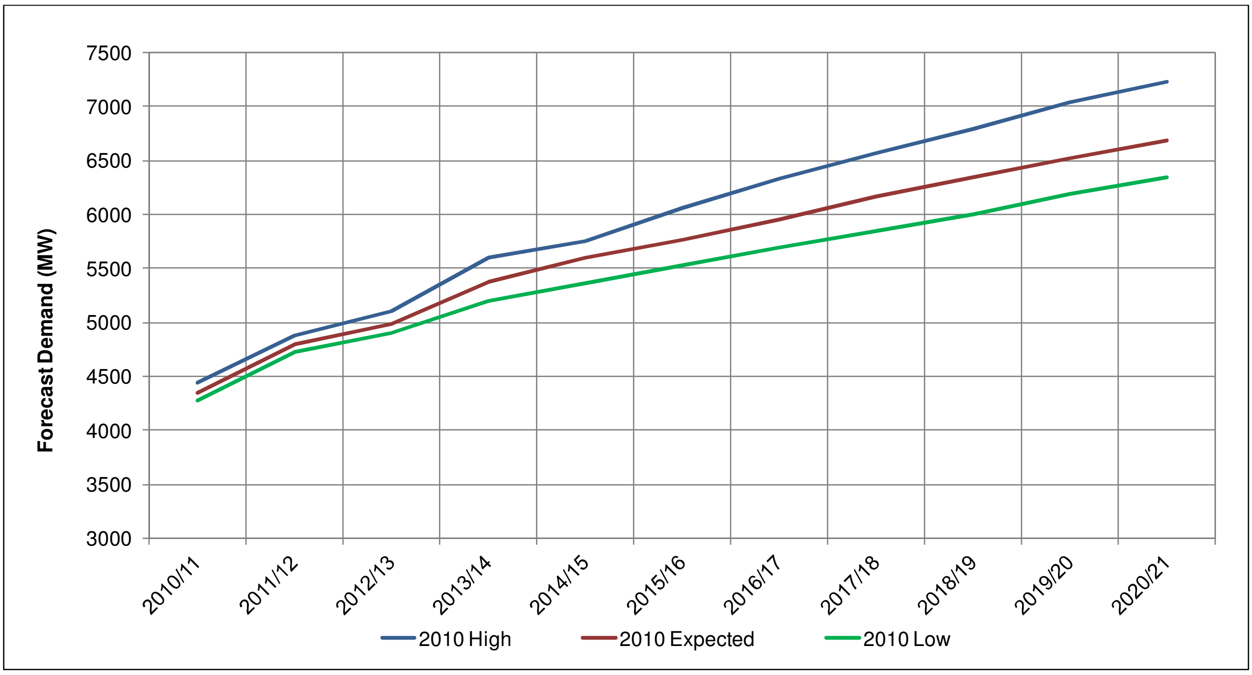
The maximum demand is forecast to increase at an annual compound growth rate of 4.4% over the ten-year period from 2010/11 to 2020/21. In the two years that are the main focus of this report, 2012/13 and 2013/14, the maximum demand is forecast to be 4,986 MW and 5,370 MW respectively. These figures are tabulated in Appendix 2.

New block loads have a strong impact on the rate of growth. Presently the IMO has allowed for approximately 440 MW of additional major block loads through to 2015/16.

The sensitivity of temperature on maximum demand can be seen in the differences between the POE values in Figure 19. For the 2012/13 Reserve Capacity Year, if average (50% POE) temperature conditions are experienced, the maximum demand is forecast to be 8.4% lower (approximately 417 MW) than the 10% POE forecast. Similarly, if the system maximum demand is experienced on a cooler than average day (e.g. 90% POE), the maximum demand is forecast to be approximately 13% lower (650 MW) than the 10% POE scenario.

The effect of the assumptions about state economic growth (as forecast by GSP), which underpin the maximum demand forecasts, is shown in Figure 20. The 10% POE forecasts for the Expected, High and Low economic growth scenarios are shown.

Figure 20 – Impact of Economic Growth on Maximum Demand for the 10% POE Forecast



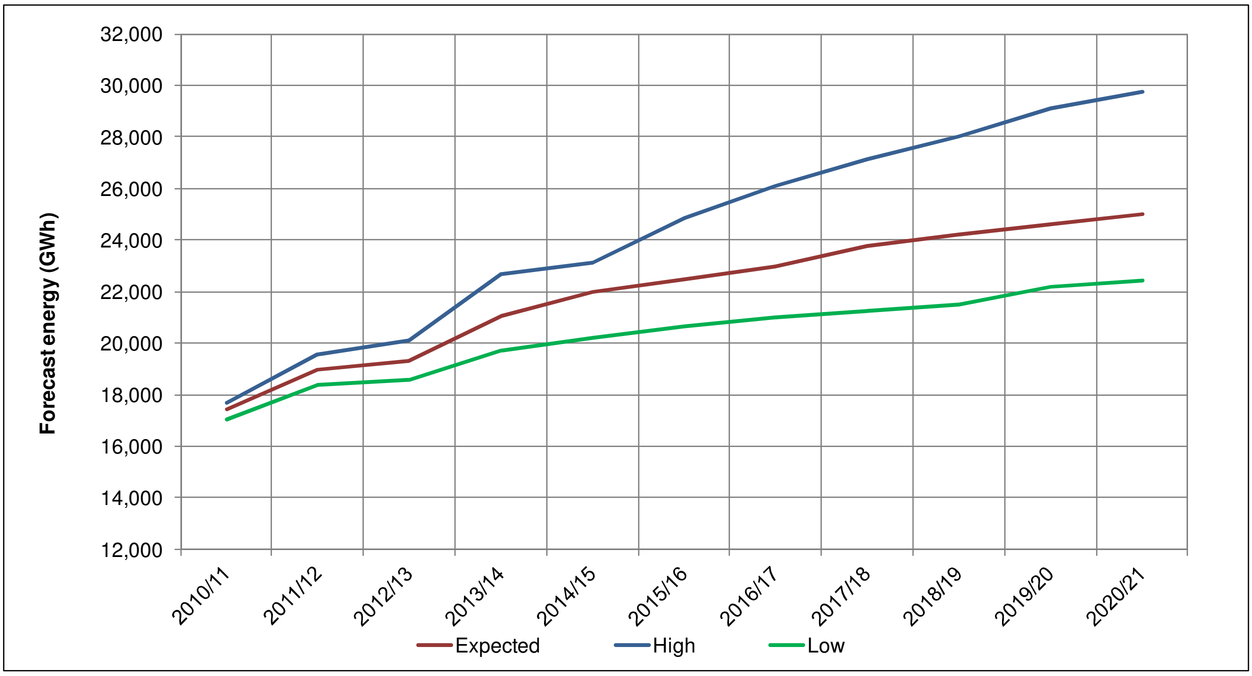
Sensitivity analysis of the economic assumptions on maximum demand shows that if conditions similar to the High economic case are experienced up to 2012/13, the maximum demand is forecast to be approximately 111 MW (2.2%) higher than for the Expected case. Should economic growth be aligned with the Low scenario, the 10% POE maximum demand is forecast to be approximately 89 MW (1.8%) lower than the Expected case.

4.4 Energy Forecast

Figure 21 presents the energy consumption forecasts for the SWIS over the Long Term PASA Study Horizon to 2020/21. Over this period, energy consumption is forecast to grow on average by approximately 3.7% per annum.

Under the High economic growth scenario, the growth in energy consumption is forecast to be 5.4%, while in the Low economic growth scenario energy consumption is forecast to increase at 2.8% per annum on average.

Figure 21 – Forecast Sent-Out Energy



The expected energy requirements of the SWIS in 2012/13 are forecast to be 19,321 GWh. This is approximately 3.2% below the forecast in the 2009 SOO. The reasons for the change are revisions in the economic forecasts and a delay in the start expected date of major new loads due to changed expectations of the timing of transmission network upgrades. The energy forecasts can be found in Appendix 5.

4.5 Differences between the 2009 and 2010 Forecasts

Table 2 shows how the maximum demand forecast has changed from that prepared in 2009.

Table 2 – Change from 2009 to 2010 Demand Forecast

Year	2009 10% POE Forecast (MW)	2010 10% POE Forecast (MW)	Change in 10% POE Demand from 2009 to 2010 Forecast (MW)
2010/11	4,397	4,346	-51
2011/12	4,725	4,793	68
2012/13	5,132	4,986	-146
2013/14	5,452	5,370	-82
2014/15	5,518	5,601	83
2015/16	5,721	5,767	46
2016/17	5,903	5,955	52
2017/18	6,065	6,168	103
2018/19	6,232	6,343	111
2019/20	6,396	6,517	121

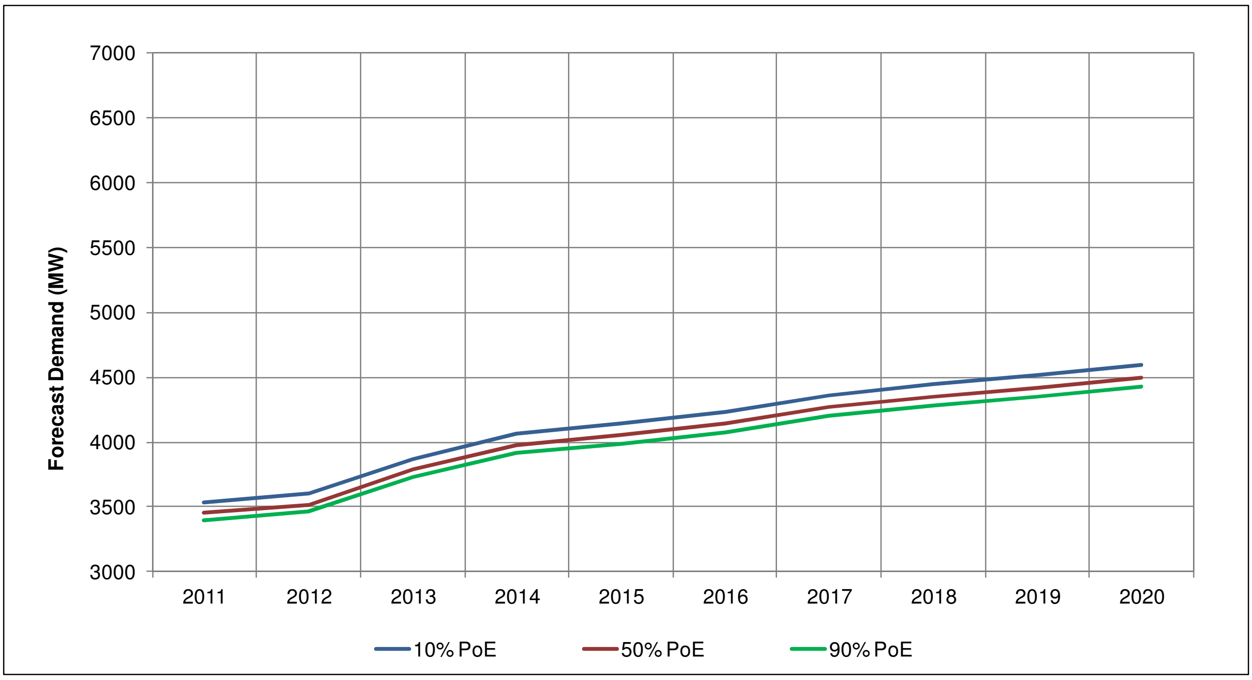
The new forecast shows some change in maximum demand for the 2010/11 year, 51 MW lower than forecast last year, and there are notable reductions for both 2012/13 and 2013/14. This is the result of the delayed introduction of a number of significant block loads which were included for 2012/13 in the 2009 forecasts, but which are not included in the 2010 forecasts until 2013/14 or beyond. The majority of these block loads are reliant on the Mid West Energy project southern section transmission upgrade. As noted above in section 4.2, the IMO has decided to consider this upgrade from 2013/14 onwards.

Forecasts in the outer years of the study period grow at a faster rate than predicted last year. This is a result of higher economic growth rates forecast by NIEIR in the later years and increases in assumptions for block loads associated with mining projects.

4.6 Winter Maximum Demand Forecasts

Figure 22 shows the maximum demands forecast for winter periods during the Long Term PASA Study Horizon for the Expected economic growth scenario.

Figure 22 – Winter Maximum Demands



Winter peak demand is strongly influenced by the requirement for heating. However, electricity competes directly with gas and other energy sources in this sector so only supplies a portion of total peak demand. Electricity demand for winter heating is substantially lower than the demand for summer cooling, which generally does not have alternative fuel sources.

Because the total demand is lower, the contribution from base industrial and commercial loads during the winter is proportionately higher than in summer. This results in lower temperature variability in winter maximum demand.

Residential and commercial lighting is a significant component of the maximum demand. These, coupled with demand for domestic heating and cooking, mean that the winter peak occurs in the evening, around 6:00 PM.

A number of factors will influence the rate of growth in the winter peak demand including:

- the increased use of reverse-cycle air conditioning for domestic heating;
- the decreased use of domestic wood heaters and non-ducted gas heaters; and
- government programs to replace incandescent lights with more energy efficient units.

Currently, the winter peak demand is forecast to grow at an average rate of 3.4% to reach a level of 4,492 MW in 2020. This is 73% of the forecast summer maximum demand, reinforcing that the SWIS is a summer peaking system.

5. Reserve Capacity Requirements

5.1 Planning Criterion

The IMO is required to set a Reserve Capacity Target for each year at a level which ensures that the two elements of the Planning Criterion are met. The first element relates to meeting demand on the day with the highest maximum demand. The second element ensures that adequate levels of energy can be supplied throughout the year.

The Market Rule[5] in respect of the maximum demand criterion requires the Reserve Capacity Target be set so there is sufficient generation and DSM capacity to:

> *"meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus a reserve margin equal to the greater of:*
>
> *i. 8.2% of the forecast peak demand (including transmission losses and allowing for Intermittent Loads); and*
>
> *ii. the maximum capacity, measured at 41°C, of the largest generating unit;*
>
> *while maintaining the Minimum Frequency Keeping Capacity for normal frequency control. The forecast peak demand should be calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten;"*

The second element of the criterion[6] requires that sufficient capacity be provided to:

> *"limit expected energy shortfalls to 0.002% of annual energy consumption (including transmission losses)".*

The Planning Criterion applies to the provision of generation and DSM capability and does not include transmission reliability planning.

The Reserve Capacity Target is set such that the most stringent element of the Planning Criterion is used to determine the Reserve Capacity Target. In each year of the Long Term PASA Study Horizon, 8.2% of the forecast maximum demand is greater than the capacity of the largest generating unit (measured at 41°C). The 8.2% factor therefore sets the level of reserve margin.

The capacity required to meet the first element (peak demand) is shown in Table 3, contained in Section 5.3. The Minimum Frequency Keeping Capacity has been provided by Western Power for the initial years through to 2012/13. For the Capacity Years beyond 2012/13, the IMO has spliced a forecast load following requirement from ROAM Consulting's draft Work Package 3 report for the Renewable Energy Generation Working Group (REGWG)[7]. The ROAM Consulting report includes forecasts for four planting scenarios, with Scenario 4 deemed to be the most

[5] Clause 4.5.9(a) of the Wholesale Electricity Market Rules
[6] Clause 4.5.9(b) of the Wholesale Electricity Market Rules
[7] For further information, please see http://www.imowa.com.au/regwg

likely scenario at this stage based on expectations of a moderate carbon reduction policy regime and higher gas prices.

The Market Rules require the IMO to undertake a review, at least once every five years, of the planning criterion used to assess system reliability. The last such review was completed in November 2007.

5.2 Role of the Second Element of the Planning Criterion

Although the annual peak demand occurs in summer, the availability of capacity is very important for reliability throughout the year. This is because it is necessary for plant to be regularly taken out of service for maintenance to ensure its ongoing reliability. These plant outages are typically scheduled for lower load periods in autumn, spring and, to a lesser extent, in winter. The outage scheduling process is designed to ensure orderly planning of outages so that sufficient capacity is available at all times.

A key role of the second element of the Planning Criterion, relating to energy shortfalls, is to ensure that there is sufficient plant to accommodate this required maintenance throughout the year.

Energy shortfall is tested by modelling the power system in detail across the year. This modelling takes account of the need for plant maintenance and the anticipated level of unplanned (or “forced”) outages. The result is an estimate of the percentage of demand that would not be met due to insufficient supply capacity. The criterion is very stringent, requiring that this “energy shortfall” is less than 0.002% of the annual forecast demand.

For a particular peak demand and generation capacity, the level of energy shortfall across the year would be expected to increase with either:

- an increase in load factor (flatter demand); or
- a deterioration in plant availability.

Load factor could increase with an increase in base load, perhaps through new industrial or mining loads, or with higher domestic winter loads, perhaps through a move to reverse-cycle air conditioning rather than gas heating. Increased forced outage rates or planned maintenance would reduce plant availability.

To date, load factors and plant availability have been such that the Reserve Capacity Target has been set by the first element of the Planning Criterion, relating to annual peak demand.

As indicated above, the present trend suggests that the peak demand forecast will continue to set the Reserve Capacity Target for the immediate future. This is because the load factor appears to be reducing (with increased summer air conditioning) and plant availability is improving, as reported in section 2.5.3.

However, ongoing assessment of the level of unserved energy ensures that changes in plant performance or load shape are being monitored so that the appropriate Reserve Capacity Target is set and reliability of supply is maintained.

The IMO has retained McLennan Magasanik Associates (MMA) to conduct reliability modelling of the SWIS to assess the energy-related element of the Planning Criterion and to develop the Availability Curve, which is given in Section 5.4.

5.3 Forecast Capacity Requirements

Table 3 shows the Reserve Capacity Target for each year of the Long Term PASA Study Horizon, as determined from the maximum demand requirement of the Planning Criterion.

Table 3 – Capacity required to satisfy peak demand criterion

(All figures in MW rounded to nearest integer)

Year	Maximum Demand	Reserve Margin	Load Following	Intermittent Loads	Total
2010/11	4,346	356	60	16	4,778
2011/12	4,793	393	60	15	5,261
2012/13	**4,986**	**409**	**90**	**16**	**5,501**
2013/14	5,370	440	110	17	5,937
2014/15	5,601	459	135	18	6,213
2015/16	5,767	473	135	17	6,392
2016/17	5,955	488	137	17	6,597
2017/18	6,168	506	151	17	6,842
2018/19	6,343	520	152	17	7,032
2019/20	6,517	534	153	17	7,221
2020/21	6,689	548	162	17	7,416

The figure of 5,501 MW, as shown in Table 3, is therefore the Reserve Capacity Requirement for the 2010 Reserve Capacity Cycle.

5.4 Availability Curve

The Market Rules include the concept of Availability Classes, where capacity is assigned to a class that reflects the maximum number of hours per year that the capacity is available. This approach recognises the value of DSM but ensures that the time limitations of DSM are properly considered when assessing system reliability.

Four Availability Classes are defined under the Market Rules:

- Class 1 relating to capacity that is available more than 96 hours every year;
- Class 2 relating to capacity that is available for 72 to 96 hours every year;
- Class 3 relating to capacity that is available for 48 to 72 hours every year; and
- Class 4 relating to capacity that is available for 24 to 48 hours every year.

Class 1 covers generation capacity, while Classes 2 to 4 relate to DSM. Capacity from an Availability Class with higher availability can be used to meet the requirement for an Availability Class with lower availability.

Assuming that the Reserve Capacity Target is just met, the Availability Curve indicates the minimum amount of capacity required to be provided by generation capacity to ensure that the energy requirements of users are satisfied . The remainder of the Reserve Capacity Target can be met by further generation capacity or by DSM.

The Availability Curve does not limit the amount of Capacity Credits assigned to any Availability Class where there is intent to bilaterally trade.

The Availability Curve information for 2012/13 and 2013/14 is shown in Table 4.

Table 4 – Availability Curve

Availability Curve Information	2012/13 (MW)	2013/14 (MW)
Market Rule 4.5.12(a):		
Capacity required for more than 24 Hours	4490	4805
Capacity required for more than 48 Hours	4338	4662
Capacity required for more than 72 Hours	4239	4556
Capacity required for more than 96 Hours	4158	4481
Market Rule 4.5.12(b):		
Minimum Generation Required	4097	4199
Market Rule 4.5.12(c):		
Capacity associated with Availability Class 1	4158	4481
Capacity associated with Availability Class 2	81	75
Capacity associated with Availability Class 3	99	106
Capacity associated with Availability Class 4	1163	1275

Due to the complexity of the Availability Curve determination, the IMO has provided a more detailed explanation in Appendix 8.

5.5 The Supply-Demand Balance

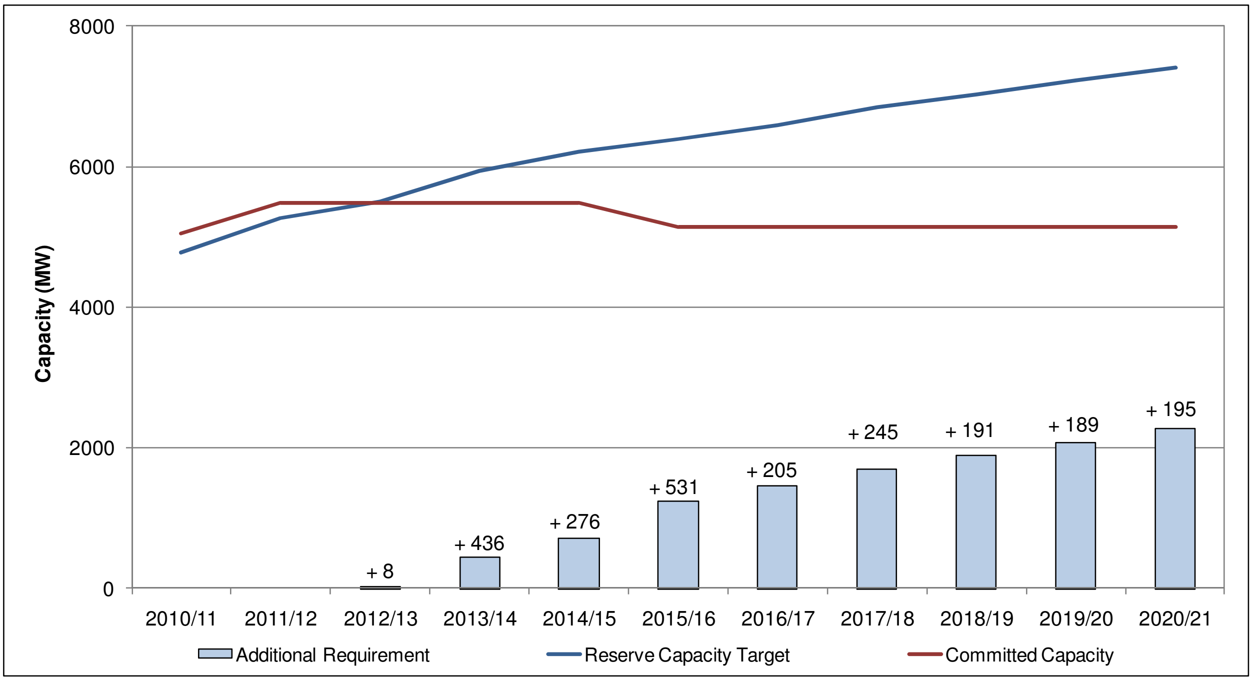
The supply-demand balance for the period to 2020/21 in the SWIS is presented in Figure 23.

- The blue line in this figure shows the Reserve Capacity Target, increasing from 4,779 MW in 2010/11 to 7,417 MW by 2020/21.
- The red line shows the level of generation and DSM capacity which is in place or committed.
    - For the 2010/11 and 2011/12 Capacity Years, the level of capacity is set by the assigned Capacity Credits. The increase in capacity from 2010/11 to 2011/12 demonstrates the significant commitment to new facilities made in the 2009 Reserve Capacity Cycle, particularly given that Kwinana Stage A is scheduled to be decommissioned in 2012 and has no Capacity Credits assigned for 2011/12.

- For subsequent years, the levels of both generation and DSM capacity are assumed to be predominantly constant at the levels shown in Appendix 9. The IMO has forecast a reduction of 351 MW in 2015/16 for the decommissioning of Kwinana Stage C, although the timing of this retirement is subject to a commercial decision by Verve Energy.

- The blue bars, show the cumulative requirement for additional capacity to meet the Reserve Capacity Target over the next ten years.

Figure 23 – Required Generation and DSM Capacity



Key points to note from Figure 23 are:

- Sufficient Capacity Credits have been procured to meet the Reserve Capacity Requirement during 2010/11 and 2011/12.
- Additional Capacity Credits of 8 MW will be needed to meet the Reserve Capacity Target in 2012/13.
- A further 2,275 MW of Capacity Credits will be needed to meet the Reserve Capacity Target from 2012/13 to 2020/21 after accounting for the likely retirement of Kwinana Power Station Stage C.

This figure illustrates the substantial opportunity for investment in generation and DSM capacity in Western Australia. More than 2,000 MW of new capacity is forecast to be required over the coming decade to meet load growth. This represents an excellent opportunity for new and existing investors in the WEM.

Circumstances may change over the period through to 2020/21. Project proponents, investors and developers are advised to make independent assessments of the possible supply and demand conditions.

Graphs of the supply demand balance for High and Low economic forecasts are provided in Appendix 5.

5.6 Opportunity for Investment

A total of 5,501 MW and 5,937 MW of generation and DSM capacity must be available to meet the Reserve Capacity Requirements in 2012/13 and 2013/14 respectively.

This means that 8 MW of new capacity, in addition to that already in place, or under construction, must be secured to meet the requirements for 2012/13. The requirement grows to 444 MW by 2013/14 - an additional 436 MW above the 2012/13 requirement. This is summarised in Table 5.

Table 5 – Opportunity for Investment

	2012/13	2013/14
Existing Generation	4,802 MW	4,802 MW
Existing DSM	99 MW	99 MW
New Generation and DSM Committed for 2012/13	592 MW	592MW
Plant Closures	0 MW	0 MW
Reserve Capacity Requirement	5,501 MW	5,937 MW
Additional Capacity Required (cumulative)	8 MW	436 MW

The most recent Expressions of Interest process identified proposals for 644 MW of new Reserve Capacity for the 2012/13 Capacity Year. It should be noted, however, that the proponents of these developments have not necessarily indicated any level of commitment to proceed.

The IMO has analysed these developments based on its understanding of the status of relevant network access and environmental approvals. From this analysis, the IMO considers that potential developments may represent 486 MW of Capacity Credits.

In addition, 70 MW of capacity was assigned Conditional Certified Reserve Capacity status during the 2009 Certification of Reserve Capacity process.

The IMO has not assessed the probability of each of the potential projects. As with any competitive market, the probability of a proposed project is partly determined by the success of competing projects. Accordingly, for the purposes of this report, the IMO has not determined that any of the potential projects are "probable".

The opportunity for new investment is illustrated in Figure 24 and Figure 25. In these figures "Proposed Projects" relates to the 486 MW of planned projects identified above as "potential".

Figure 24 – Opportunity for Investment – 2012/13

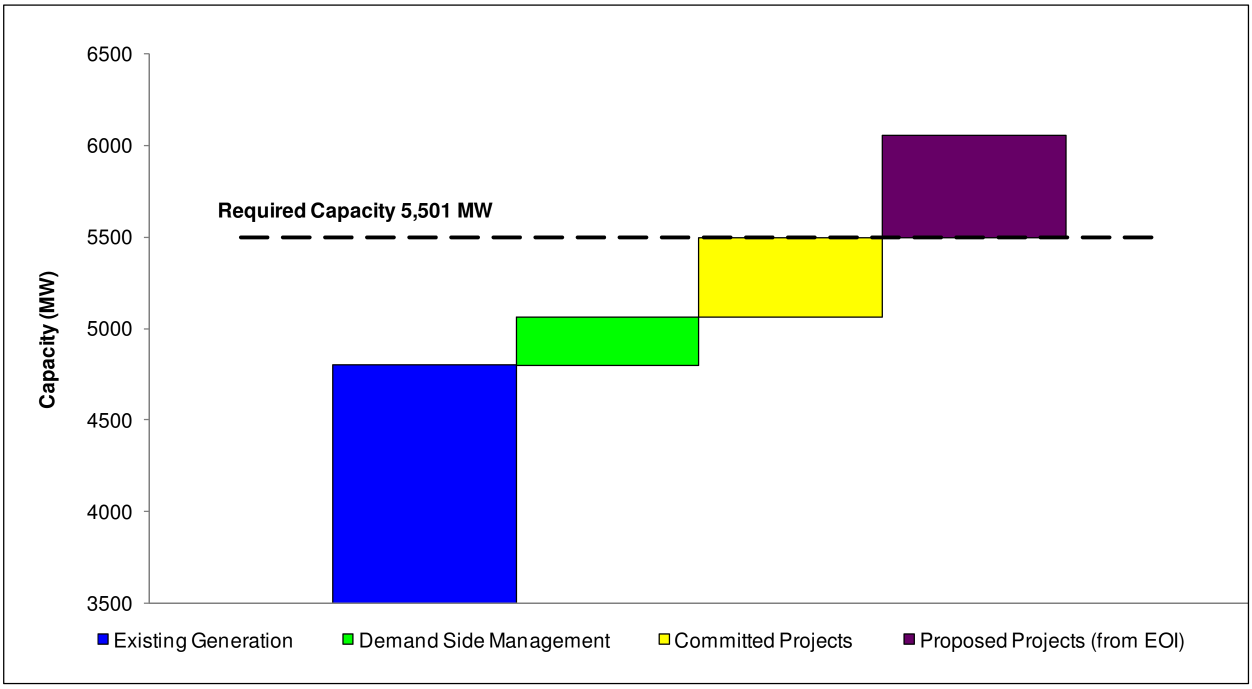
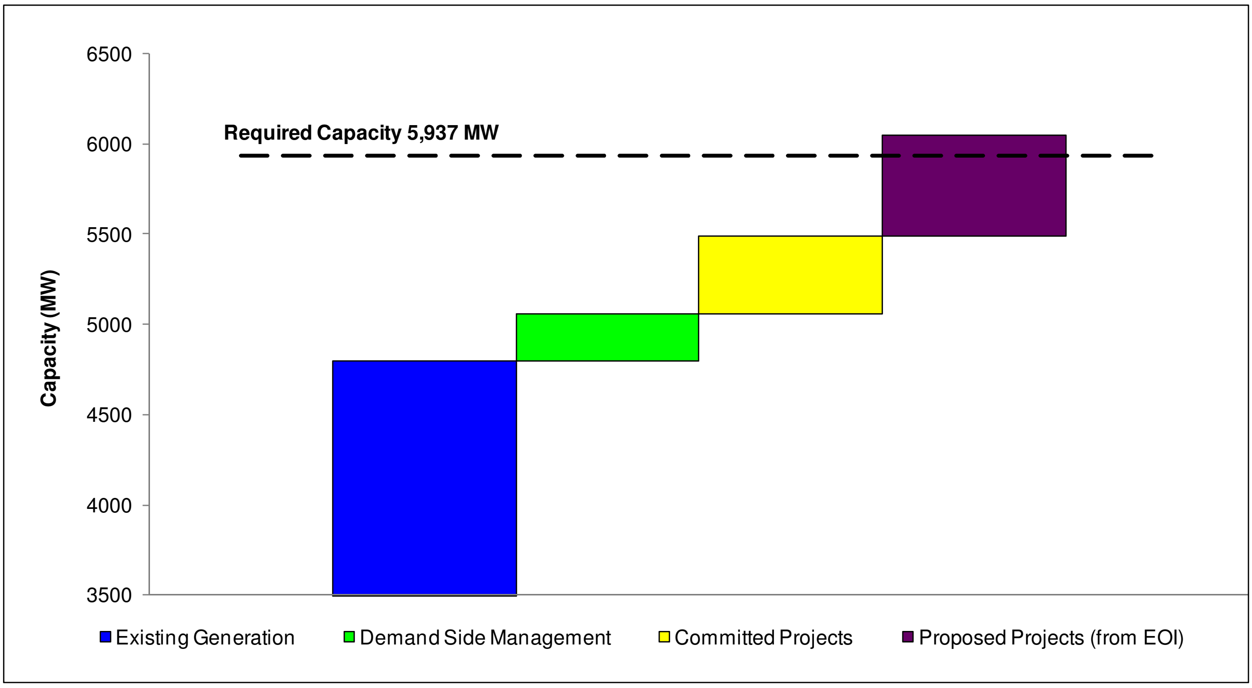


Figure 25 – Opportunity for Investment – 2013/14



6. Next Steps in the Reserve Capacity Process

The next stage in the Reserve Capacity process is for Market Participants to apply for Certified Reserve Capacity and then apply to be assigned Capacity Credits. Certification and Capacity Credits apply only to one year so new applications must be made each year for all existing or planned generation and DSM facilities.

The timetable for the process is:

- Applications for Certification of Reserve Capacity are now open and must be provided to the IMO by 5:00 PM WST on Tuesday, 20 July 2010.
- Market Participants with facilities which are granted Certified Reserve Capacity must then apply for Capacity Credits, indicating whether they intend to trade capacity bilaterally or whether they wish to offer the Certified Reserve Capacity into a Reserve Capacity Auction (if one is required). This process must be completed by 5:00 PM on Tuesday, 10 August 2010.
- On Wednesday 11 August 2010, the IMO will advise Market Participants who have indicated their intention to trade their capacity bilaterally how many Capacity Credits have been assigned to their facilities.
- By 5:00 PM on Wednesday 18 August 2010, the IMO will advise whether sufficient capacity has been secured through bilateral trades. If the Reserve Capacity Requirement has been met, no Reserve Capacity Auction will be held. If sufficient capacity has not been secured through bilateral trades, the IMO will also advise that it will run a Reserve Capacity Auction to secure the outstanding quantity.
- If a Reserve Capacity Auction is required, Market Participants must provide their offers between Friday 20 August and Friday 27 August 2010. The IMO would run the Reserve Capacity Auction on Wednesday 1 September 2010.

Prospective developers should note that for a facility to receive Certified Reserve Capacity, it must fully meet the requirements of Market Rule 4.10.1(c) in respect to network access and environmental approvals. Both of these processes can take a considerable time and potential developers are encouraged to contact Western Power and the Department of Environment at the earliest opportunity.

Disruptions to gas supply in 2008 have focused attention on ensuring that appropriate fuel supply arrangements are in place for all facilities. In seeking certification for generation facilities, Market Participants must provide full details of their fuel supply and transport contract arrangements with appropriate supporting documentation. The IMO acknowledges that fuel supply arrangements are often complex and may comprise a portfolio of supply and transport arrangements. Market Participants should develop a presentation that will address potential questions and assist the IMO in undertaking the certification assessment within the short timeframe provided.

Further information on the Certification of Reserve Capacity process[8], and the procedure for Declaration of Bilateral Trades and the Reserve Capacity Auction[9], are available on the IMO website.

[8] http://www.imowa.com.au/crc

[9] http://www.imowa.com.au/f711,482900/482900_Market_Procedure_for_Declaration_of_Bilateral_Trades_and_the_Reserve_Capacity_Auction.pdf

7. Key Issues for Potential Developers

7.1 Transmission Restrictions on the SWIS

The WEM design is predicated on an unconstrained network. Analysis for the Planning Criterion is based on a consistent assumption of an unconstrained network.

In this model the Reserve Capacity Mechanism does not differentiate generating capacity on the basis of location. Transmission constraints are addressed in other ways.

- Before a new load or generator can connect to the network, it must secure network access. This is provided based on the capacity of the existing network to accommodate the new connection, or subject to the network being upgraded as required.
- Network constraints are taken into account in the forecast for the Reserve Capacity Mechanism. If new loads or generating plant require the completion of new transmission works, then the timing of those works is considered in the assessment process.
- The Reserve Capacity Mechanism is complemented by a mechanism for Network Control Services (NCS). This can be used to arrange for additional generation or DSM to be located to overcome network transfer constraints. The amount and location of any NCS needed is determined by the Network Operator, Western Power, as an alternative to network augmentation. Any required NCS is then procured by the IMO under the current arrangements. At its April 2010 meeting, the MAC agreed that the NCS procurement and contracting functions should be shifted to Western Power. The IMO, in consultation with System Management and Western Power, will be drafting changes to the Market Rules to implement this agreement

In its submission to the Strategic Energy Initiative[10], Western Power indicated its support for a review of the benefits of a transition from an unconstrained to a constrained network, similar to the system used in other electricity markets including the National Electricity Market (NEM), New Zealand, Singapore and PJM (USA). Western Power highlights some of the potential benefits in network utilisation and simplification of the queuing process, while acknowledging the implementation challenges in dispatch management and the Reserve Capacity Mechanism. The submission also supports the development of a framework for “Generation Park” planning. Western Power states that Generation Parks could “offer savings achieved through economies of scale and provide a degree of certainty for potential generators” around many location-related issues (such as land ownership, planning and environmental approvals, transport links and transmission network connection).

Each year, Western Power publishes the Annual Planning Report (APR) to provide advice and guidance on the status of the transmission network and distribution system. The APR presents the results from scenario-based transmission planning activities conducted by Western Power for their long-term planning purposes. The most recent Western Power APR, published in May 2009, can be downloaded from the Western Power website[11]. Western Power is planning to publish the 2010 APR in October 2010.

[10] http://www.westernpower.com.au/documents/sustainability/StrategicEnergyInitiativeOfficeEnergy.pdf
[11] http://www.westernpower.com.au/documents/investmentPlanning/2009_ANNUAL_PLANNING_REPORT.pdf

To assist potential developers, Western Power has recently prepared and published the Generation Connection Capacity Map for the first time, as announced by the Minister for Energy on 28 June 2010. This map provides developers with an indication of the ability of the SWIS to accommodate additional mid-sized generation projects with minimal connection cost. This map is included in Appendix 10.

As shown in the Generation Connection Capacity Map, the transmission system is nearing capacity in several locations. While this is in part due to the strong increase in overall electricity demand, it is also due to the requests for connections for new generators and to accommodate differing energy flows across the system. The changing economics between various fuel types and high levels of interest in renewable energy generation makes it difficult to determine the likely location and size of future power generation projects. Consequently, Western Power is now planning substantial capacity upgrades throughout the transmission system.

The most significant new project under consideration is the proposed Mid West Energy project southern section Neerabup to Eneabba 330 kV double circuit transmission line to provide additional capacity in the Mid West region. This new line could serve a number of planned mineral loads and prospective power generation developments. Discussions are currently progressing with a prospective foundation mining customer. The conclusion of a satisfactory commercial arrangement between Western Power and the foundation customer, together with unconditional regulatory and funding approval, will trigger the need for reinforcement.

Western Power has also identified the need for a series of facility upgrades to increase the power transmission capability from the south west of the state to the metropolitan area. This work includes new 330 kV transmission lines, new switchyards and voltage support equipment. The driver for this project was the connection of generation in the south-west of the SWIS. The project has not progressed to regulatory approval stage due to uncertainty regarding the timeframe for developing new generation in the area. Alternative generation developments in the Perth metropolitan area have deferred the need for this network reinforcement. Western Power is continuing to review the need for this project in light of these revised plans in consultation with key government and industry stakeholders.

It should be noted that when a Market Participant applies for Certified Reserve Capacity in respect of a generation facility that has not yet entered service, the Market Rules require that facility to provide a letter from the relevant Network Operator indicating:

- that it has made a transmission access proposal; and
- that the facility will be entitled to firm access from the nominated service date.

To be certified in the 2010 Reserve Capacity Cycle, a new facility must be capable of fully meeting its reserve capacity obligations by 1 October 2012.

The IMO will be able to consider applications for certification for proposed generators only if Market Participants provide an appropriate transmission access proposal from Western Power[12] advising that firm access will be available from a date prior to 1 October 2012. These letters must be provided by the 20 July 2010 closing date for applications for certification.

[12] Made in accordance with clause 4.10.1(c)(i) of the Market Rules.

Based on advice from Western Power, the IMO understands that a final decision on the northern 330 kV transmission line will not have been made in time to allow certification for the 2012/13 Capacity Year of any proposed new generators which rely on the new transmission line. It is unlikely that Western Power will be in a position to offer access prior to the closing date.

Generation projects reliant on the new transmission works would be able to apply for certification in future years once network access can be secured.

7.2 Availability of Fuel for Generation

SWIS power generation is dominated by more conventional plant types, which burn some form of non-renewable fossil fuel. Much of the balance of the Capacity Credits is allocated to some form of renewable energy and DSM. As was shown in Figure 6, 55% of Capacity Credits for the 2011/12 Capacity Year are allocated to plant fuelled by gas only or gas-liquids dual fuelled plant. Coal and dual fuelled coal-gas/liquids plant accounts for a further 35% of Capacity Credits.

In the SWIS, a mixture of coal plant and some gas-fired plant (particularly cogeneration plants and combined cycle gas turbines) is typically used for base-load capacity. Gas-fired plant and some coal plant are used for mid-merit duty while peak-load plants are dominated by gas, dual-fuelled gas-liquids and liquids plant.

While gas accounted for some 62% of electricity generated on a State-wide basis in 2007-08[13], much of this generation was located outside of the SWIS, predominantly in the Pilbara and Goldfields regions. In 2009, gas accounted for approximately 50% of electricity (energy) in the SWIS from thermal generation, but this proportion is increasing with the commissioning of cogeneration and combined cycle gas turbine power plant in recent years.

This section provides an overview of the main fuel supplies used in SWIS conventional power generation, being coal and gas, with some commentary on liquids (distillate).

7.2.1 Coal

Western Australia's coal supply for power generation is sourced entirely from two operators in the Collie Basin, around 200 km south east of Perth: Wesfarmers Premier Coal and The Griffin Coal Mining Company Pty Ltd (currently in administration). The area also hosts the three major coal-fired power stations in the SWIS, the only other coal-fired plant being located at Kwinana. Additional coal reserves are located near Eneabba in the Mid West. There are several other known but undeveloped coal deposits in the South and Mid West, including the Irwin River and Vasse deposits.

Coal production for calendar year 2009 totalled 6.6 Mt[14] and is expected to increase to about 7.5 Mt during 2010[15]. Around 80% of the coal produced in Western Australia is consumed in power generation[16]. All Western Australian coal-fired power generation is located in the SWIS,

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[13] *Australian Energy Statistics* used in the publication *Energy Update 2009*, ABARE, Table F5.
[14] *Western Australian Mineral and Petroleum Statistics Digest 2009*, Department of Mines and Petroleum.
[15] Wesfarmers Premier Coal submission to Strategic Energy Initiative, March 2010.
[16] http://www.newcolliecoal.com.au/wa_coal_industry/coal_uses.phtml

mostly adjacent to or very close to the producing coal mines. In 2008-09, some 581 kt of coal was exported[17], with the balance used largely for mineral processing and industrial applications.

Table 6 shows the coal reserves held by the two Collie operators.

Table 6 – Collie Coal Reserves

Reserves Category	Coal Reserves (Mt)[18]
Measured (high level of confidence)	690
Indicated (reasonable level of confidence)	575
Total Measured and Indicated	**1,265**

Additional resources, for which there is a lower level of confidence, are inferred.

Some of these reserves will be committed under long term contracts. The Collie operators have advised sufficient reserves are available outside of current commitments to provide long term supply for around 1,000 MW of base load coal-fired power generation.

In addition to the coal resources and production in the traditional Collie area, Aviva Corporation Ltd has reported the presence of at least 75 Mt of proved and probable coal reserves at its Central West Coal Project, sufficient to provide fuel over 30 years for a 450 MW power station[19].

7.2.2 Natural Gas

Gas is used for base load, mid-merit and peaking generation in the SWIS. Gas is also used extensively in Western Australia as an input to the alumina refining and other industrial processes (including other non-ferrous metals, iron and steel, chemicals, glass, ceramics, concrete and cement). For calendar year 2009, Western Australia consumed some 355 PJ (about 973 TJ/d) of domestic gas (domgas)[20], the highest consumption of all Australian states. About 845 PJ of LNG was produced during the same period[21]. Other than small quantities used domestically, all of the LNG was produced by the North West Shelf Venture and exported.

The quantity of gas used in the SWIS for power generation has increased in recent years, with the commissioning of cogeneration units associated with alumina manufacture, two combined cycle gas turbine (CCGT) power plants at Kwinana (Verve Energy's Cockburn CCGT, NewGen Kwinana) and open cycle gas turbine (OCGT) plants (ERM Power's Neerabup Power Station, Alinta Wagerup). Further new gas-fired plant is under construction, including the Western Energy plant at Kwinana and Verve Energy's Kwinana High Efficiency Gas Turbines.

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[17] *Fremantle Port Authority Annual Report, 2008-09.*
[18] *Energy WA Coal Reserves,* fact sheet compiled by Office of Energy, 1 August 2008,
[19] *Public Environmental Review, Central West Coal Mine Project,* and *Public Environmental Review, Coolimba Power Station Project*, Aviva Corporation Ltd, 2009
[20] *Western Australian Mineral and Petroleum Statistics Digest 2009*, Department of Mines and Petroleum. Conversion factor of 38.2 MJ/m^3 used.
[21] *Western Australian Mineral and Petroleum Statistics Digest 2009*, Department of Mines and Petroleum. Conversion factor of 18,040 kt/PJ used.

7.2.2.1 Gas Supply

Natural gas first became available from the Perth Basin areas in the Mid West in 1971. The gas was delivered through the Parmelia pipeline. The commencement of production from the much larger capacity North West Shelf production area in 1984 saw significant growth in the penetration of gas in the Western Australian energy mix. This gas, supplied from the Karratha Gas Plant (KGP), was delivered through the Dampier to Bunbury Natural Gas Pipeline (DBNGP).

Gas supply diversity further increased, along with a further increase in energy market penetration, with the commissioning of the Varanus Island gas processing facilities, operated by an Apache Corporation subsidiary, in 1992.

Domgas consumption in Western Australia has grown significantly from about 100 TJ/d in 1984, when gas from the north west of the state was introduced, to nearly 1,000 TJ/d in 2009. The KGP and Varanus Island facilities are estimated to supply more than 97% of Western Australia's domgas[22].

7.2.2.2 Gas Processing Capacity

Figure 26 summarises the existing, committed and announced potential domgas processing capacity in Western Australia.

Please note that the illustration only shows the capacity of the domgas plants and does not provide a forecast of actual production, nor indicate contractual commitments for gas produced from those plants.

Within the graph, the IMO has split the various projects into "expected" and "speculative". A full explanation of these classifications is shown in Table 7, accompanied by a detailed summary of available information related to current and future domestic gas production and processing capacity.

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[22] *Western Australia Gas Market Study*, Wood Mackenzie Report, 26 March 2010 (from ACCC website), http://www.accc.gov.au/content/trimFile.phtml?trimFileName=D10+3402413.pdf&trimFileTitle=D10+3402413.pdf&trimFileFromVersionId=934594.

Figure 26 – Existing, Committed and Potential WA Domgas Processing Capacity

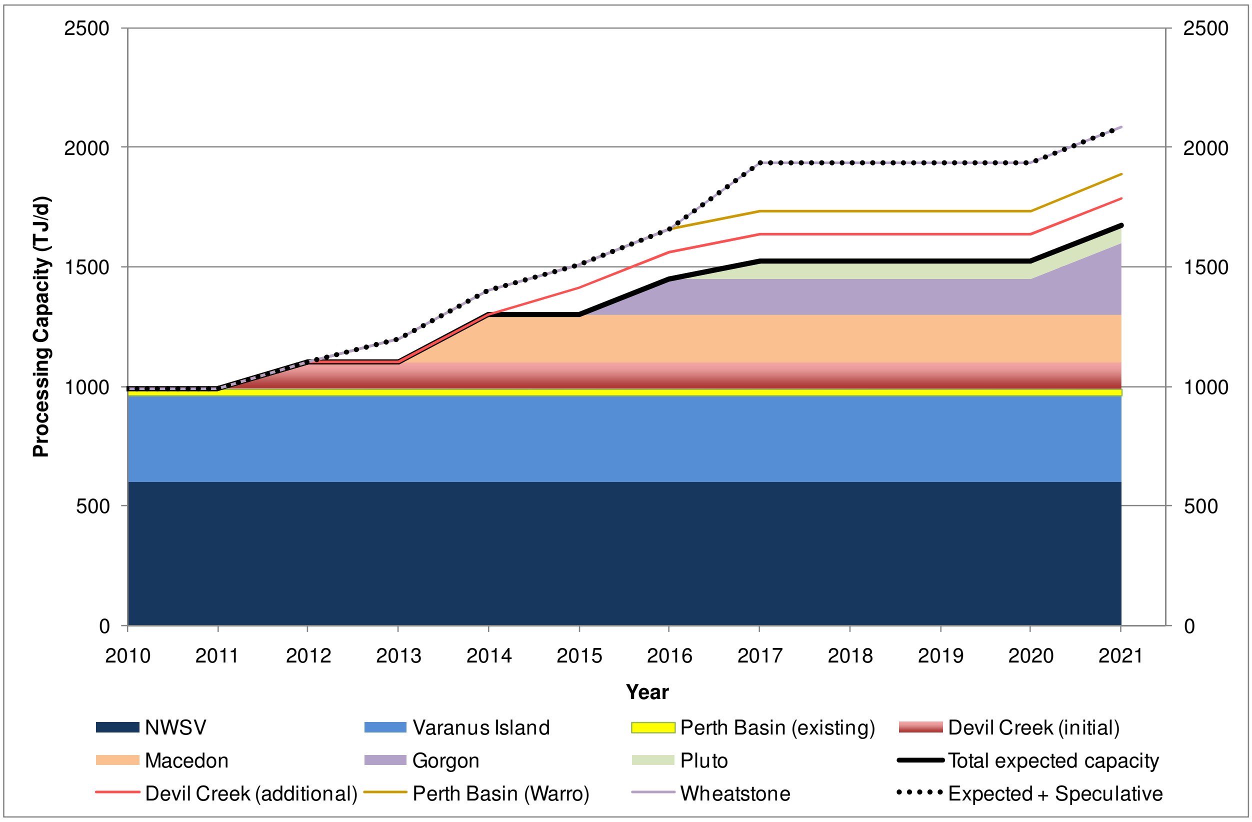

Table 7 – Summary of Available Information Related to Current and Future Domestic Gas Production and Processing Capacity

Information	IMO Comments
North West Shelf Venture (NWSV)	
• LNG project, operated by Woodside.	The IMO expects domgas supply from NWSV to continue at or near current levels for the next 10 years, provided that commercial terms can be reached, in order to maintain
• Current domgas processing capacity around 600 TJ/d, although some sources report capacity as high as 660 TJ/d. *Sources: Woodside submission to Gas Supply and Emergency Management Committee[23]; Speech by Premier Colin Barnett to Baker Institute, 13 Apr 2010[24].*	
• 2009 average output 572 TJ/d. *Source: Wood Mackenzie* "Western Australia Gas Market Study"*, available from ACCC website[25].*	

[23] http://www.energy.wa.gov.au/cproot/1581/2/NWSJV%20Report%20to%20GSEMC.pdf
[24] http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=133337&

<table>
<tr><td>

- The original domgas obligation for the project is likely to be satisfied by around 2014.
Source: ACCC website, 'North West Shelf – Application for authorisation, supporting submission'[26].

</td><td rowspan="2">utilisation of existing facilities.</td></tr>
<tr><td>

- "Redevelopment work at North Rankin and development of the GWF fields is expected to progress to maintain plateau production for over 10 years".
Source: Woodside 2009 Annual Report, page 17.

</td></tr>
<tr><td colspan="2">Varanus Island</td></tr>
<tr><td>

- Operated by Apache, all gas for domestic use.

</td><td rowspan="3">With current output near plant capacity and the Halyard & Spar fields likely to be tied in, the IMO expects Varanus Island production could be maintained at or near current levels for 7-10 years.</td></tr>
<tr><td>

- Current processing capacity around 365 TJ/d, currently producing at this rate.
Sources: Speech by Premier Colin Barnett to Baker Institute, 13 Apr 2010[27]*; Apache Corporation website*[28].

</td></tr>
<tr><td>

- Future development of the Halyard & Spar fields will sustain production in the coming years.
- Halyard scheduled to begin production during 2011.
Source: Apache Corporation 2009 Annual Report Form 10-K.
- Santos and Apache reviewing terms to process gas from the Spar and Halibut fields through Varanus Island.
Source: The West Australian, 20 May 2010.

</td></tr>
<tr><td colspan="2">Devil Creek</td></tr>
<tr><td>

- Operated by Apache, all gas for domestic use.

</td><td rowspan="4">The IMO considers 110 TJ/d could be maintained for at least 7 years. Timing of the increase to 220 TJ/d is uncertain and the IMO has classified this as speculative from 2015.</td></tr>
<tr><td>

- Plant under construction, due online in late 2011.
Source: Apache news release, 15 Sept 2009, "Groundbreaking signals commencement of new WA domestic gas hub".

</td></tr>
<tr><td>

- Plant being built to capacity of 220 TJ/d. Initial output of 110 TJ/d. Remaining plant capacity "will provide for the expected future increase in demand for natural gas in WA".
Source: Devil Creek Development Project website[29].

</td></tr>
<tr><td>

- Little public information about field lifetime. The supply contract with CITIC Pacific's Sino Iron project is for 7 years, commencing in the second half of 2011.

</td></tr>
</table>

[25] http://www.accc.gov.au/content/trimFile.phtml?trimFileName=D10+3402413.pdf&trimFileTitle=D10+3402413.pdf&trimFileFromVersionId=934594

[26] http://www.accc.gov.au/content/trimFile.phtml?trimFileName=D10+3402407.pdf&trimFileTitle=D10+3402407.pdf&trimFileFromVersionId=934594

[27] http://www.mediastatements.wa.gov.au/Pages/default.aspx?ItemId=133337&

[28] http://www.apachecorp.com/Operations/Australia/Production.aspx

[29] http://www.apachedcdp.com.au/index.php?option=com_content&task=view&id=13&Itemid=28

*Source: Santos news release, 7 Jan 2009, "*Santos signs US$585 million Sino Iron gas supply contract*".* • Expected life of the Reindeer field is 10 to 14 years. The joint venture is planning for the ability to tie in prospective gas fields in the future. *Source: "*Devil Creek Development Project, Draft Public Environmental Review, Part A – Onshore*", June 2008.*	
Macedon	
• Project operated by BHP Billiton, all gas to be for domestic use. Includes gas from Macedon field and gas reinjected into the field from the Pyrenees development for future recovery. Incidentally, the Pyrenees development has an estimated production life of 25 years. *Source: BHP Billiton press release, 1 Mar 2010, "*First Oil Production from Pyrenees Development, Offshore Western Australia*".*	The IMO expects the project to be sanctioned and first gas to be produced by the end of 2013. The IMO considers that production of 220 TJ/d could be sustained for 7-10 years.
• Project due for sanction in mid-2010, first gas expected in 2013. • Capacity of 220 TJ/d (200 million cubic feet per day). *Source: BHP Billiton Petroleum Investor and Analyst Briefing, 20 May 2010.*	
• Little public information about project lifetime, but industry speculation of 20-year project life. *Source: Pex Publications, Oil & Gas Radar, 1 Apr 2010[30].*	
Gorgon	
• LNG project, operated by Chevron. LNG contracts have been signed for durations between 15 and 25 years.	The IMO expects that 150 TJ/d will commence in 2015, with an additional 150 TJ/d available in 2021, in line with the listed references.
• 2000 PJ of gas reserved for domestic use. Minimum of 300 TJ/d processing capacity required as part of the State Agreement, unless commercially unviable. First gas expected by end of 2015. *Source: Department of State Development website[31].*	
• Expressions of interest have been sought for the first 150 TJ/d. *Source: Statement by WA Premier, 14 Sept 2009, "*Gorgon set to take Western Australia to new heights in oil and gas industry*".* • "Chevron says it does not expect to be delivering its full quota of 300 tj/day until 2021 because of an expected oversupply in the domestic market". *Source: The West Australian, 16 June 2009, "*Barnett opens door to gas reserve changes*", published in Domgas Alliance submission to Strategic Energy Initiative[32].*	

[30] http://www.pex.com.au/samples/ogr_sample1.pdf
[31] http://www.dsd.wa.gov.au/7599.aspx
[32] (http://www.erawa.com.au/cproot/8515/2/20100503%20D29252%20DBNGP%20-%20Submission%208%20-%20Annexure%205%20-%20Domgas%20Alliance%20WA%20State%20Energy%20Initiative%20-%20Domestic%20Gas%20Action%20Plan%20Submission%20to%20the%20SEI.pdf

Pluto	
• LNG project, operated by Woodside. LNG contracts have been signed for 15 years. • Under the 15% domestic gas reservation policy, Woodside's obligation is for domgas supply to commence 5 years from first LNG production (due early 2011), providing it is commercially viable. *Source: Statement by WA Premier, 8 Dec 2006,* "Woodside commits to domestic gas reservation policy".	The IMO considers that around 75 TJ/d could become available in 2017, assumed on the basis of the 15% reservation policy, with an allowance of 20 TJ/d of dogmas per 1Mtpa of LNG.
Perth Basin	
• Latent Petroleum pursuing development of Warro tight gas field in Perth Basin. Target production from the field is 100 TJ/d, commencing in 2012 or 2013. *Source: PetroleumNews.net, 7 May 2010, "*Latent likes chances of tight gas success*"*[33]. • AWE and Origin continue occasional drilling operations in the Perth Basin.	Due to technological challenges, the IMO has classified the Warro project as speculative at this stage. Existing Perth Basin production is expected to remain relatively constant.
Wheatstone	
• LNG project, operated by Chevron. Heads of Agreement signed with Tokyo Electric Power Company (TEPCO) to supply LNG for 20 years. *Source: Chevron news release, 5 Dec 2009, "*Chevron and TEPCO Sign Major Wheatstone LNG and Equity Deal*".* • Chevron reached agreement with Apache and KUFPEC for Julimar and Brunello gas to be produced through the Wheatstone LNG facility. *Source: Chevron news release, 22 Oct 2009, "Chevron Welcomes New Partners to Wheatstone Project".* • Final investment decision due in 2011. *Source: Apache Corporation 2009 Annual Report Form 10-K*. • First domestic gas estimated in 2017. Estimated capacity of 200 TJ/d. *Source: WA Business News, 4 March 2010, "*Buyer beware as Woodside hails 'new price foundation'*".*	The IMO has conservatively classified this project as speculative at this stage, in the absence of a final investment decision or firm supply contracts.

[33] http://www.petroleumnews.net/storyview.asp?storyid=1135396&sectionsource=s90&highlight=latent

Domgas may also become available from further offshore developments. Onshore exploration is also continuing.

7.2.3 Gas Transportation

Gas is transported into the SWIS via three routes:

- DBNGP, which receives gas from the KGP, Varanus Island and Devil Creek (from late 2011) facilities, and which will receive gas from other new offshore developments when they are commissioned, such as Macedon and Gorgon;

- Parmelia Pipeline from the Perth Basin areas, which is also connected to the DBNGP at Mondarra; and

- The Goldfields Gas Pipeline (GGP), which is connected to the Varanus Island facilities and with the DBNGP at the GGP inlet. The GGP delivers gas to the Goldfields region where some of the power generation is connected to the SWIS via Western Power's 220 kV transmission line.

7.2.3.1 DBNGP

Following a recent expansion, the "full haul" (to the south west) capacity of the DBNGP is 895 TJ/d. Capacity is understood to be fully contracted. DBP Transmission, the operator, advises another 80 TJ/d can be added by completion of the duplication of the pipeline, and that further expansions are possible, subject to agreement on commercial terms.[34]

7.2.3.2 Parmelia Pipeline

This pipeline, owned and operated by APA Group, has a current capacity of about 65 TJ/d, of which approximately 25 TJ/d is presently uncontracted. Pipeline capacity can be expanded to about 120 TJ/d[35]. The Parmelia Pipeline and DBNGP are interconnected at Mondarra. The pipeline extends to Pinjarra, to the south of Perth.

7.2.3.3 GGP

The GGP, majority-owned and operated by APA Group, has a current capacity of around 150 TJ/d, with approximately 98% of this capacity committed. Capacity can be expanded, subject to agreement on commercial terms, to a nominal expanded capacity of 167 TJ/d.[36]

7.2.4 Gas Storage

A commercial underground gas storage facility is operated by APA at Mondarra and which is connected to both the Parmelia Pipeline and the DBNGP. APA has advised it is presently designing for the expansion of the facility to accept around 70 TJ/d of injection and a withdrawal rate of up to 150 TJ/d.

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[34] Data for DBNGP gathered from Gas Supply and Emergency Management Committee Report to Government, Sept 2009 (http://www.energy.wa.gov.au/cproot/1576/2/Mitigation%20Full%20%20Report%20-%20Evans%20_%20Peck.pdf) and discussion with DBP Group

[35] Figures for Parmelia Pipeline gathered from http://www.energy.wa.gov.au/cproot/1575/2/Mitigation%20Report%20Summary%20-%20Evans%20_%20Peck.pdf and discussion with APA Group.

[36] Data for GGP gathered from http://www.ggt.com.au/heretohelp.php and discussion with APA Group.

7.2.5 *Liquid Fuel*

Diesel is the dominant liquid fuel used for power generation in the SWIS. Generators contract directly with the oil companies to supply their requirements. Diesel is typically used in the SWIS for short-term peaking generation. Oil companies tend to maintain only limited stocks of around 10-17 days consumption[37], so prolonged use of diesel for generation of significant quantities of energy may place strains on the supply chain, unless mitigations are put into effect ahead of the requirement. It should be noted that the swift mobilisation of diesel supplies from Singapore following the Varanus Island incident enabled local inventories to be supplemented at short notice.

7.3 Potential Changes for Dual-Fuelled Facilities

As mentioned previously, dual-fuel plant played an important part in maintaining system reliability and security during the Varanus Island incident. However, the IMO recognises that the Market Rules currently provide no incentive for generators that are capable of running on more than one fuel type, while requiring that additional Reserve Capacity tests are performed on such facilities.

Consequently, the IMO Board has requested that the IMO investigate ways to incentivise investment in dual-fuel capability. Market Participants are advised that proposals for changes to the Market Rules are likely to be put forward for stakeholder consultation.

7.4 Incentives for Renewable Generation and Carbon Emission Reduction

The Federal and State Governments have announced numerous mechanisms designed to increase the proportion of energy produced by renewable generation and reduce carbon emissions. Some of these initiatives are listed below. This list is not exhaustive, and the IMO recommends that proponents perform their own research into the schemes below and their eligibility for any associated funding.

- The Federal Government's Renewable Energy Target (RET) Scheme seeks to encourage additional renewable energy generation to meet the Government's commitment for 20% for Australia's energy supply to be supplied by renewable sources by 2020. Renewable energy generators receive incentives in the form of Renewable Energy Certificates (RECs) that can be traded. Further information is available from the Office of the Renewable Energy Regulator[38].
- The Solar Flagships Program forms part of the Federal Government's Clean Energy Initiative and seeks to assist in the establishment of 1,000 MW of solar generation capacity throughout Australia. No projects from Western Australia were among the shortlisted projects for Round 1 of this program, but Round 2 is currently expected to be held in 2013-14. Further information is available from the Department of Resources, Energy and Tourism[39].
- The State Government's Low Emissions Energy Development (LEED) Fund has been established to support the development of low-emission electricity generation

[37] *Maintaining Supply Reliability in Australia*, Australian Institute of Petroleum, April 2008
[38] http://www.orer.gov.au/index.html
[39] http://www.ret.gov.au/energy/energy%20programs/cei/sfp/Pages/default.aspx

technology. Applications for Round 3 funding have closed, but it is anticipated that applications will be called in 2010/11 for Round 4 funding. Further information is available from the Department of Environment and Conservation[40].

7.5 Potential Changes for Intermittent Generators

The Market Advisory Committee (MAC) has convened the REGWG, which has been requested to:

- identify priority issues arising, or that could arise, from increasing penetration of intermittent renewable energy generation in the SWIS;
- determine the appropriate framework for analysis of issues and options for resolving them against the Market Objectives; and
- submit its assessment, analysis and conclusions in a report to the MAC.

To achieve these objectives, the REGWG is undertaking several work streams, some of which may result in proposals for changes to the Market Rules. Each of the work packages below are currently in progress.

- Work Package 1 was commissioned to develop planting scenarios based on a range of future policy, economic growth and technology development scenarios. These scenarios are to be used in subsequent simulation work.
- Work Package 2 explores and compares various methods for valuing the capacity provided by intermittent generators and allocating Capacity Credits to these facilities.
- Work Package 3 analyses the Frequency Control Service requirements for different penetration levels of intermittent generation, and explores the apportionment of the marginal cost of such services.
- Work Package 4 evaluates the appropriateness of the existing Technical Rules and Power System Operating Procedures as applied to intermittent generators, in the context of increasing penetration of intermittent generation.

Parties considering development of wind farms, and other intermittent generation options, should be aware of this review and that proposals for changes to the Market Rules may be put forward for stakeholder consultation. More information on the REGWG can be found on the IMO website[41].

7.6 Potential Changes for Demand Side Management

DSM is voluntary reduction or curtailment of demand, usually in response to external factors. DSM is an integral part of the WEM and can be assigned Capacity Credits.

[40] http://www.dec.wa.gov.au/content/view/3550/2283/
[41] http://www.imowa.com.au/regwg

Experience gained since commencement of the market has identified a number of operational issues with DSM. Consequently, a discussion paper was submitted to the MAC in May 2010, which is likely to lead to changes to the Market Rules within the next twelve months.

Market Participants considering offering DSM into the WEM are encouraged to familiarise themselves with the issues in this discussion paper and to be aware that proposals for changes to the Market Rules may be put forward for stakeholder consultation.

7.7 Review of the Maximum Reserve Capacity Price Determination

The Market Rules require the IMO to undertake a review at least once in every five years of the methodology and process followed to determine the Maximum Reserve Capacity Price (outlined in the Market Procedure for Determination of the Maximum Reserve Capacity Price).

The MAC has convened the Maximum Reserve Capacity Price Working Group (MRCPWG) to undertake this review. The Working Group held its first meeting on 31 May 2010 and will seek to complete its review during 2010. Changes to the Market Rules and the Market Procedure may be proposed at the completion of the review.

Further details can be found on the IMO's website[42].

7.8 Change to the Window of Entry into the Reserve Capacity Market

The four-month window of entry for new entrant generators has been brought forward for the 2012/13 Capacity Year to start on 1 June, with all capacity to be fully available no later than 1 October each year.

Previously, the timeframe for new capacity to enter the Reserve Capacity market was a four-month window from 1 August to 30 November.

The IMO considered that the previous dates for entry of new capacity may have encouraged inappropriate risk taking. For example, a developer may have taken an optimistic view and brought a project forward in order to meet the 30 November deadline. However, minor delays could then have resulted in the capacity then being unavailable for some or all of the Hot Season.

This matter was dealt with under Rule Change Proposal: RC_2009_11[43]. This is expected to have a net benefit to the market by minimising the risk associated with bringing new capacity into service.

7.9 Verve Energy Review

Following the completion of the Verve Energy Review in August 2009, three work streams have commenced to implement the recommendations:

- The Market Rules Design Team has been established to develop rule changes to address shortcomings identified in the review.

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[42] http://www.imowa.com.au/MRCPWG
[43] www.imowa.com.au/RC_2009_11

- The Vesting Contract between Verve Energy and Synergy is being significantly redesigned.
- A Generation Outlook will be developed to "provide an outline of the type, size and timing of future power generation to help ensure the State has adequate, cost-efficient electricity supply"[44].

The Market Rules Design Team is considering changes to the arrangements for capacity incentives and refunds, day-ahead planning and real-time dispatch, competitive balancing and ancillary services. Full details on this work and the status of this review can be found on the IMO's website[45].

[44] Media Release by the Western Australian Minister for Energy; Training and Workforce Development, 23 April 2010
[45] http://www.imowa.com.au/design_review

Appendix 1 Abbreviations

APR - Transmission and Distribution Annual Planning Report (published by Western Power)

CCGT – Combined Cycle Gas Turbine

DBNGP – Dampier to Bunbury Natural Gas Pipeline

DSM - Demand Side Management

DTF - Western Australian Department of Treasury and Finance

EMC – Energy Market Commencement

ERA – Economic Regulation Authority

GDP – Gross Domestic Product (for Australia)

GGP – Goldfields Gas Pipeline

GSP – Gross State Product (for Western Australia)

GWh – Gigawatt-hour

IMO – Independent Market Operator

IPP – Independent Power Producer

KGP – Karratha Gas Plant

kV – kilovolt

LEED – Low Emissions Energy Development (Fund)

LT PASA – Long Term Projected Assessment of System Adequacy

MAC – Market Advisory Committee

MCAP – Marginal Cost Administered Price

MMA – McLennan Magasanik Associates

MRCPWG – Maximum Reserve Capacity Price Working Group

Mt – Megatonne

MW – Megawatt

NCS – Network Control Services

NEM – National Electricity Market

NIEIR – National Institute of Economic and Industry Research

OCGT – Open Cycle Gas Turbine

PJ – Petajoule

POE – Probability of Exceedance

RCM – Reserve Capacity Mechanism

REC – Renewable Energy Certificate

REGWG – Renewable Energy Generation Working Group

RET – Renewable Energy Target

SOO – Statement of Opportunity Report

STEM – Short Term Energy Market

SWIS – South West interconnected system

TJ – Terajoule

WEM – Wholesale Electricity Market

Appendix 2 Forecasts of Economic Growth

Growth in Australian Gross Domestic Product
(% Year on year growth)

Year	Expected	High	Low
2010/11	3.4	4.5	1.9
2011/12	3.8	5.5	2.3
2012/13	2.6	3.3	2.0
2013/14	1.7	2.8	1.5
2014/15	2.5	2.9	2.3
2015/16	3.4	4.0	2.8
2016/17	3.6	3.7	2.1
2017/18	2.2	3.8	1.7
2018/19	3.5	4.4	2.5
2019/20	3.3	4.2	2.2
2020/21	2.8	3.5	1.8
Average Growth %	**3.0**	**3.9**	**2.1**

Growth in Western Australian Gross State Product
(% Year on year growth)

Year	Expected	High	Low
2010/11	4.5	5.5	2.6
2011/12	5.2	6.7	3.6
2012/13	5.1	5.9	3.7
2013/14	2.4	4.1	1.3
2014/15	4.2	5.4	2.6
2015/16	4.2	5.1	3.0
2016/17	5.3	6.3	4.0
2017/18	2.9	3.5	2.5
2018/19	4.2	5.1	3.2
2019/20	3.9	4.9	3.0
2020/21	3.3	4.2	2.1
Average Growth %	**4.2**	**5.2**	**3.0**

Appendix 3 Forecasts of Summer Maximum Demand

Summer Maximum Demand Forecasts with Expected Economic Growth (MW)

Year	10% POE	50% POE	90% POE
2010/11	4,346	3,979	3,774
2011/12	4,793	4,401	4,181
2012/13	4,986	4,569	4,335
2013/14	5,370	4,928	4,681
2014/15	5,601	5,140	4,882
2015/16	5,767	5,288	5,020
2016/17	5,955	5,453	5,173
2017/18	6,168	5,645	5,352
2018/19	6,343	5,799	5,494
2019/20	6,517	5,951	5,634
2020/21	6,689	6,102	5,773
Average Growth %	**4.4**	**4.4**	**4.3**

Summer Maximum Demand Forecasts with High Economic Growth (MW)

Year	10% POE	50% POE	90% POE
2010/11	4,440	4,071	3,864
2011/12	4,883	4,488	4,266
2012/13	5,097	4,676	4,440
2013/14	5,598	5,151	4,900
2014/15	5,745	5,278	5,016
2015/16	6,057	5,570	5,298
2016/17	6,325	5,816	5,531
2017/18	6,567	6,036	5,739
2018/19	6,791	6,238	5,928
2019/20	7,033	6,457	6,135
2020/21	7,230	6,632	6,297
Average Growth %	**5.0**	**5.0**	**5.0**

Summer Maximum Demand Forecasts with Low Economic Growth (MW)

Year	10% POE	50% POE	90% POE
2010/11	4,276	3,911	3,707
2011/12	4,724	4,336	4,119
2012/13	4,897	4,485	4,255
2013/14	5,198	4,763	4,519
2014/15	5,360	4,907	4,653
2015/16	5,529	5,059	4,796
2016/17	5,692	5,201	4,926
2017/18	5,843	5,332	5,046
2018/19	5,996	5,465	5,167
2019/20	6,193	5,642	5,333
2020/21	6,343	5,771	5,451
Average Growth %	**4.0**	**4.0**	**3.9**

Appendix 4 Forecasts of Winter Maximum Demand

Winter Maximum Demand Forecasts with Expected Economic Growth (MW)

Year	10% POE	50% POE	90% POE
2010	3,304	3,226	3,173
2011	3,531	3,451	3,395
2012	3,601	3,518	3,462
2013	3,871	3,786	3,728
2014	4,064	3,976	3,916
2015	4,141	4,051	3,990
2016	4,234	4,141	4,078
2017	4,361	4,265	4,200
2018	4,442	4,345	4,278
2019	4,520	4,420	4,352
2020	4,594	4,492	4,423
Average Growth %	**3.4**	**3.4**	**3.4**

Winter Maximum Demand Forecasts with High Economic Growth (MW)

Year	10% POE	50% POE	90% POE
2010	3,355	3,271	3,223
2011	3,645	3,557	3,506
2012	3,763	3,673	3,620
2013	4,194	4,100	4,044
2014	4,332	4,234	4,176
2015	4,602	4,500	4,439
2016	4,826	4,719	4,656
2017	5,010	4,900	4,834
2018	5,186	5,073	5,004
2019	5,396	5,277	5,206
2020	5,542	5,420	5,346
Average Growth %	**5.1**	**5.2**	**5.2**

Winter Maximum Demand Forecasts with Low Economic Growth (MW)

Year	10% POE	50% POE	90% POE
2010	3,247	3,170	3,122
2011	3,425	3,345	3,296
2012	3,457	3,376	3,326
2013	3,621	3,539	3,488
2014	3,761	3,676	3,624
2015	3,804	3,718	3,665
2016	3,850	3,763	3,708
2017	3,880	3,791	3,736
2018	3,919	3,829	3,773
2019	4,016	3,924	3,867
2020	4,046	3,952	3,894
Average Growth %	**2.2**	**2.2**	**2.2**

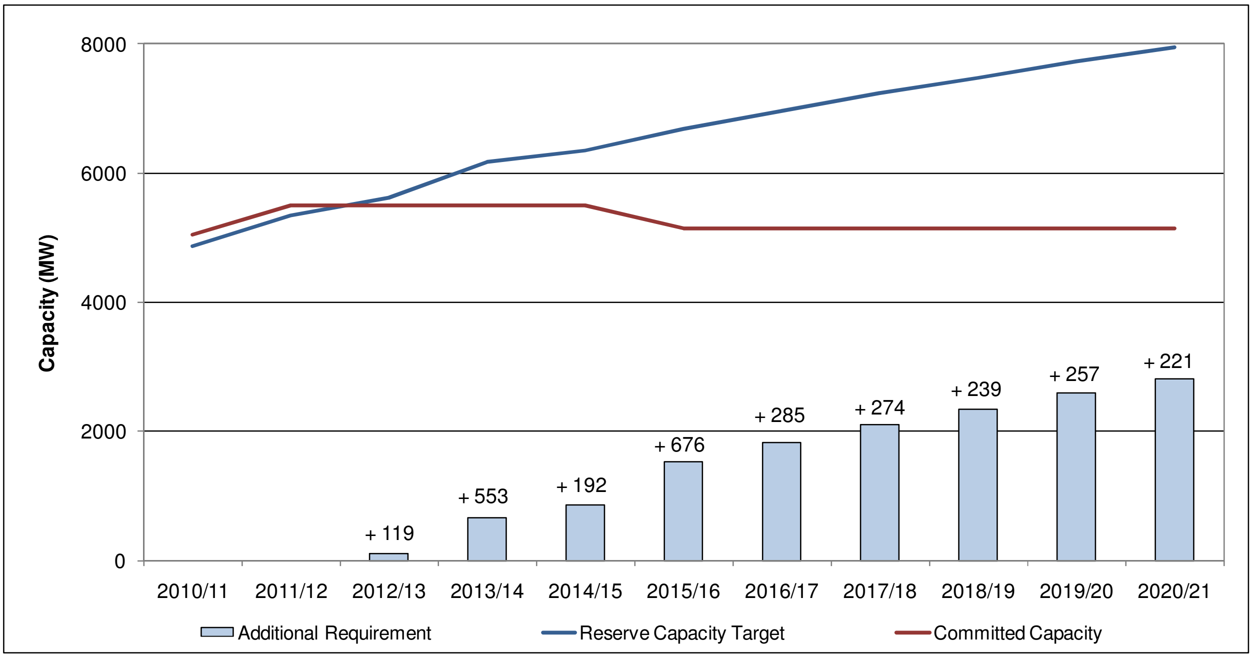
Appendix 5 Forecasts of Energy Sent-Out

Forecasts of Energy Sent-Out for the SWIS (GWh)

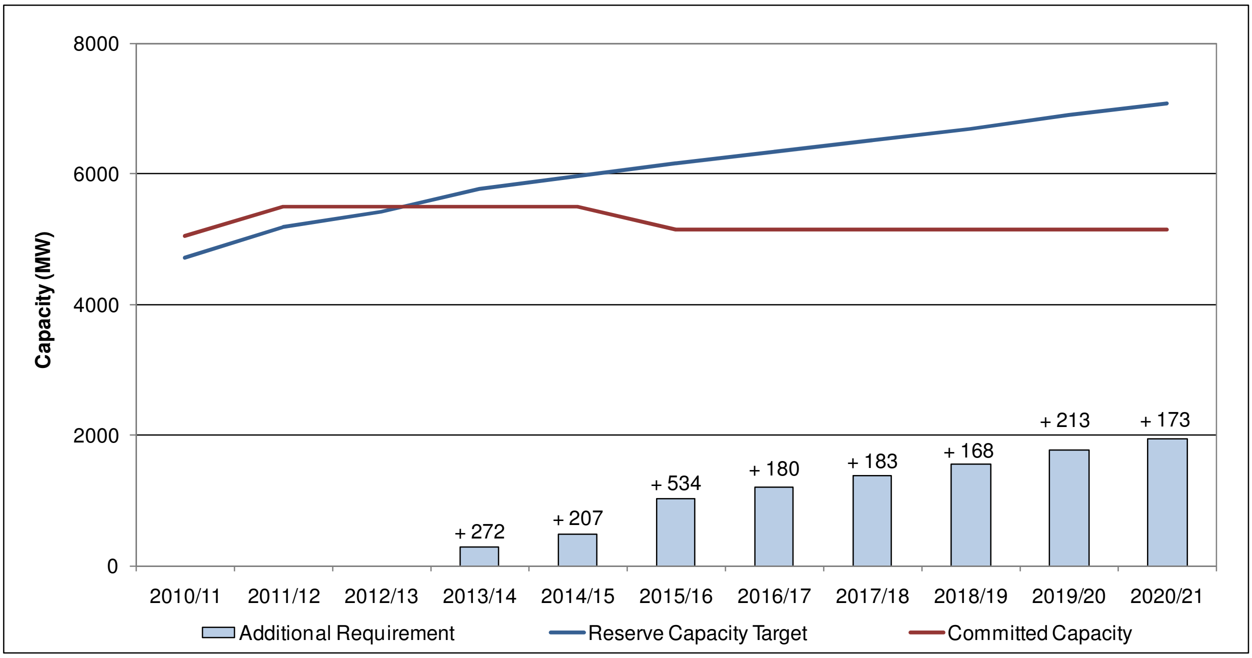
Year	Expected	High	Low
2010/11	17,409	17,656	17,024
2011/12	18,944	19,550	18,347
2012/13	19,321	20,086	18,585
2013/14	21,041	22,701	19,714
2014/15	22,006	23,123	20,228
2015/16	22,478	24,836	20,672
2016/17	22,999	26,082	21,003
2017/18	23,785	27,108	21,244
2018/19	24,219	28,001	21,513
2019/20	24,630	29,090	22,193
2020/21	25,024	29,736	22,408
Average Growth %	**3.7**	**5.4**	**2.8**

Appendix 6 Supply Demand Balance for High and Low Economic Forecasts

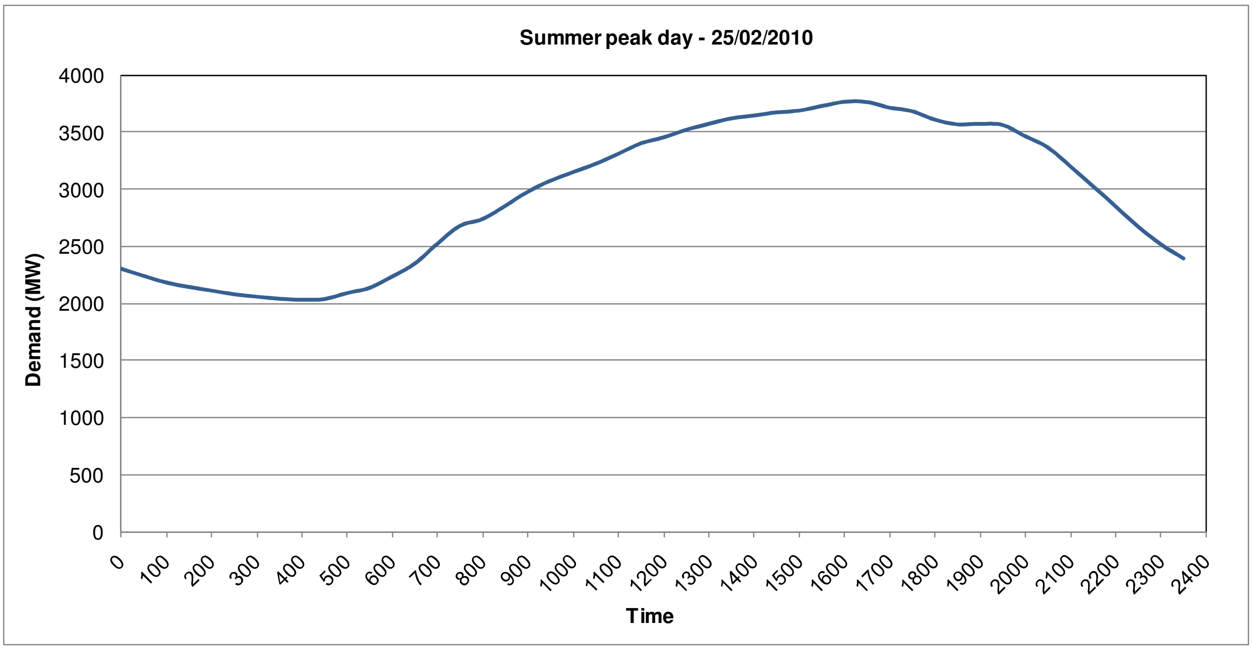
Required Generation and DSM Capacity in High Economic Growth Scenario

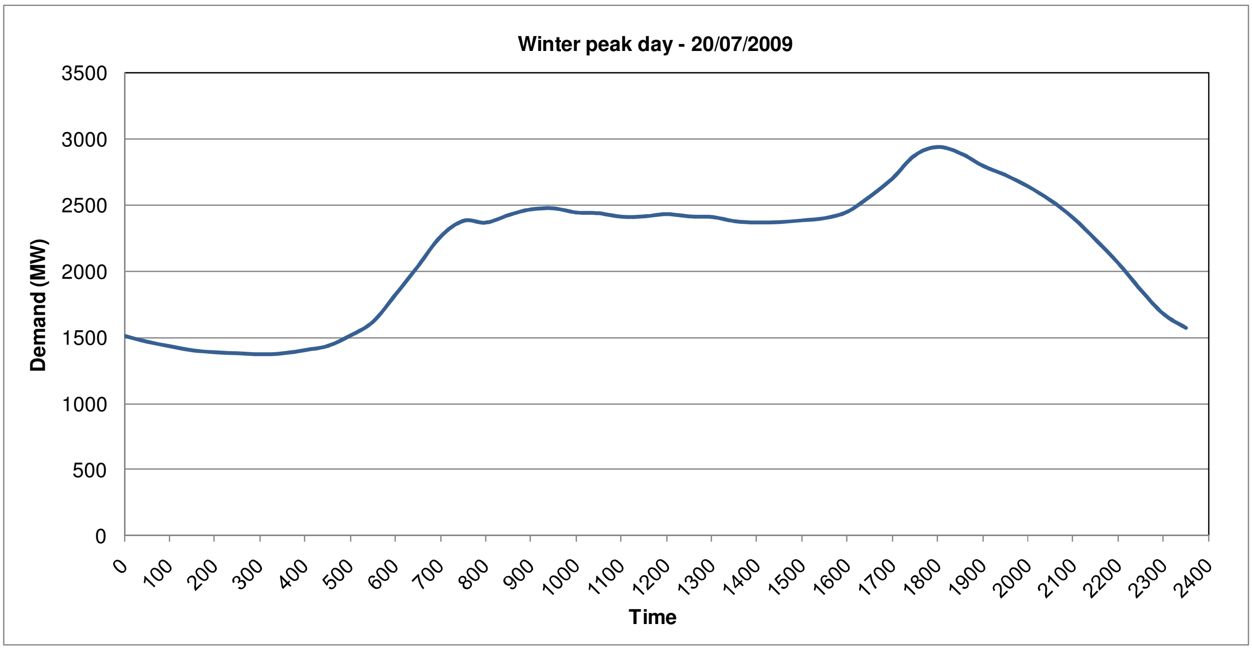


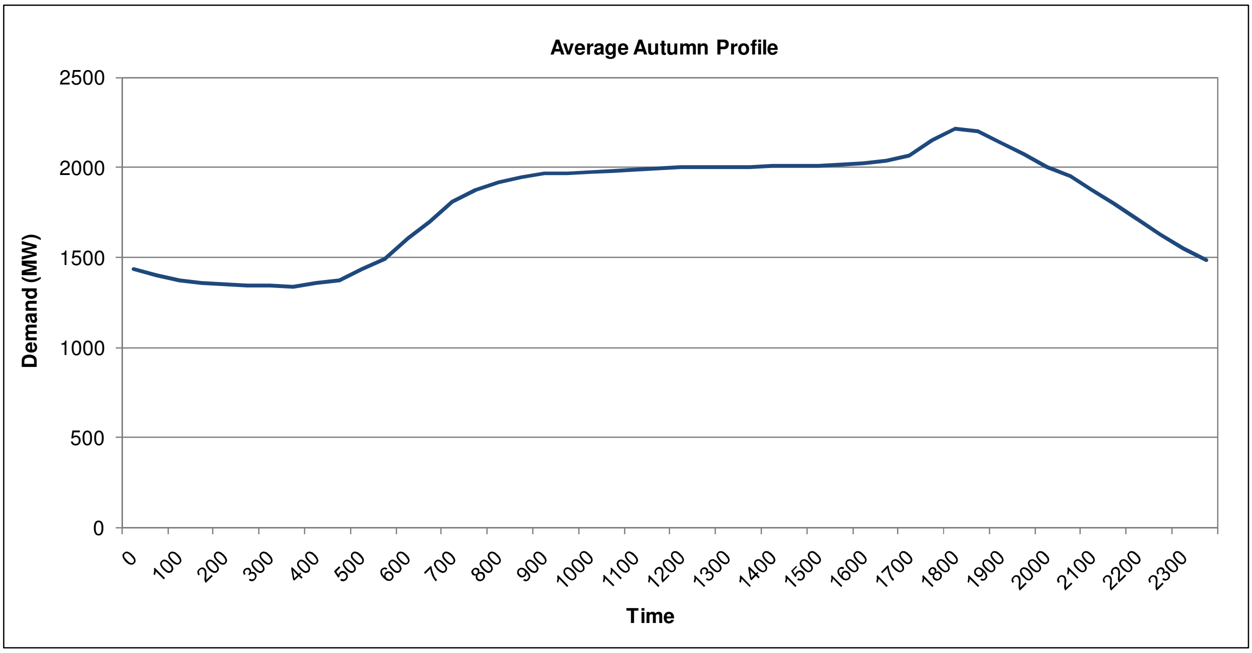
Required Generation and DSM Capacity in Low Economic Growth Scenario

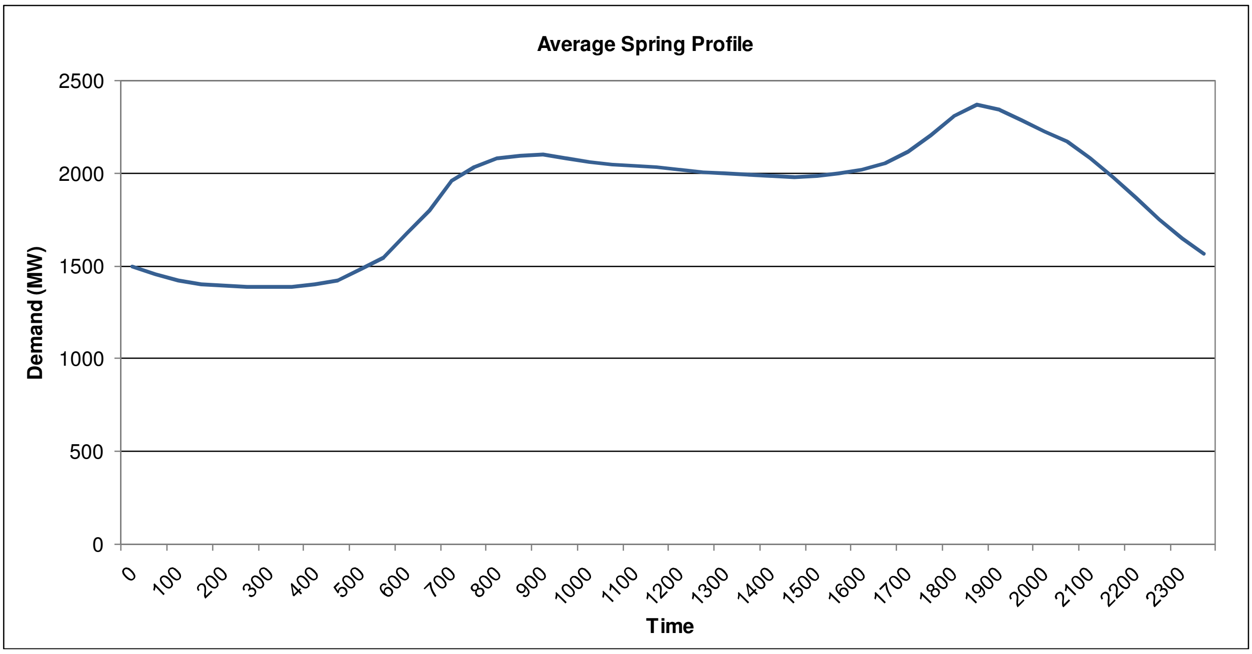


Appendix 7 Typical Daily Load Curves






Average Autumn Profile
2500
2000
1500
1000
500
0
Demand (MW)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
Time


Average Spring Profile
2500
2000
1500
1000
500
0
Demand (MW)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
1900
2000
2100
2200
2300
Time

Appendix 8 Determination of Availability Curve

The Availability Curve determination is a complex process from the Market Rules. In recognition of this complexity, the IMO offers a more detailed explanation below.

In essence:

- Availability Class 1 ensures that there is sufficient generation capacity to cover all but the highest 96 hours of demand;
- Availability Class 2 ensures that there is sufficient generation and DSM capacity to cover all but the highest 72 hours of demand;
- Availability Class 3 ensures that there is sufficient generation and DSM capacity to cover all but the highest 48 hours of demand; and
- Availability Class 4 ensures that there is sufficient generation and DSM capacity to cover the highest 48 hours of demand. This Class also includes all additional capacity to cover the reserve margin and the difference between expected and 10% POE forecasts.

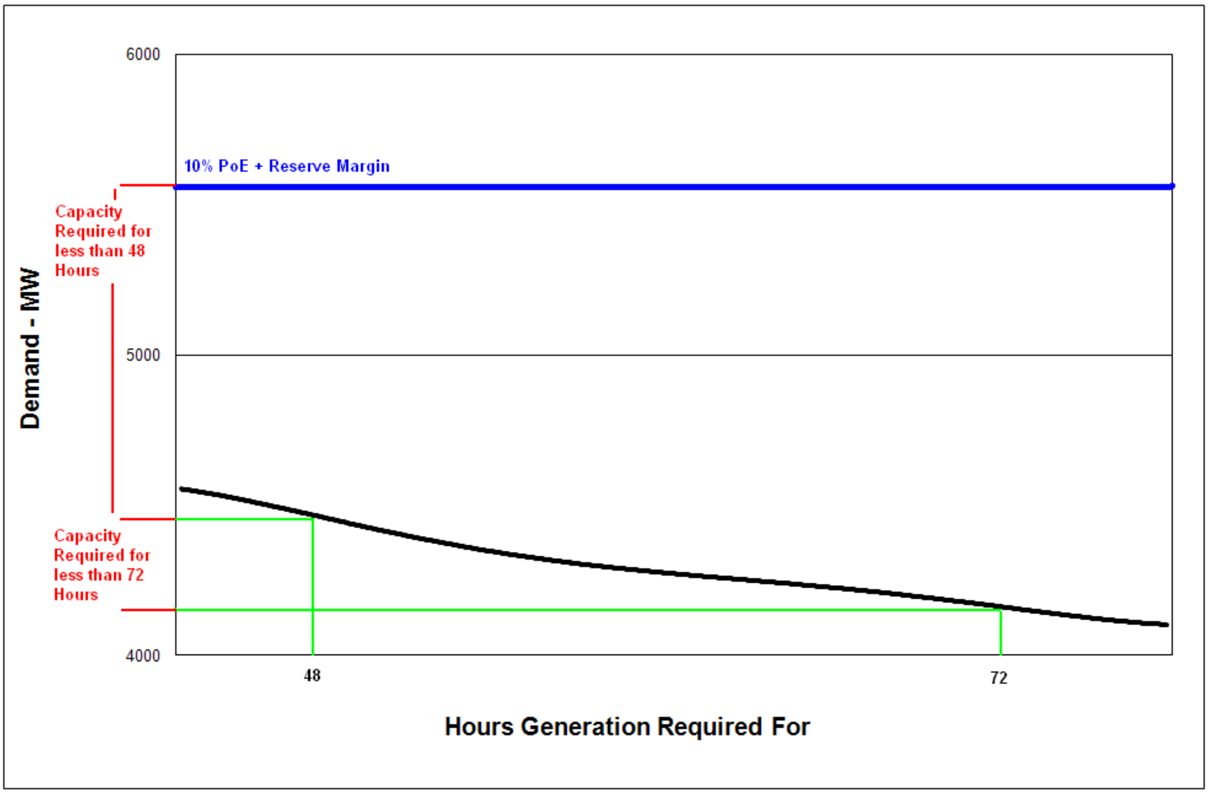
Please read below for more information on the application of both elements of the Planning Criterion in determining the Availability Curve.

The Availability Curve ensures that there is sufficient capacity at all times to satisfy both elements of the Planning Criterion (10% PoE + Margin and 0.002% Unserved Energy). This is done by assessing the capacity required for more than 96 hours, 72 hours, 48 hours and 24 hours based on a Load duration curve which has been scaled up to be equivalent to the expected maximum demand [**MR 4.5.12(a)**]. This level of "Required Capacity" is then compared to the "Minimum Generation Required", where the Minimum Generation Required is calculated by assuming that the 96 hours of highest demand were reduced through the activation of DSM and then calculating the generation required (including an allowance for expected outages) to ensure that the 0.002% Unserved Energy (USE) criterion could be satisfied for this reduced load profile [**MR 4.5.12(b)**].

The Availability Curve (or "the capacity associated with each availability class" as it is referred to in table 4) is then calculated by comparing the Minimum Generation Required to the Required Capacity for each of the Availability Classes, with the greater of the two numbers setting the requirement for each Availability Class. [**MR 4.5.12(c)**]. As the Minimum Generation Required is less than the capacity needed for more than 96 hours, the level of capacity required for Availability Class 1 is set by the capacity required for more than 96 hours. In turn:

- Availability Class 2 is defined as the difference between the Capacity Required for less than 96 hours and the Capacity Required for more less 72 hours;
- Availability Class 3 is defined as the difference between the Capacity Required for less than 72 hours and the Capacity Required for less than 48 hours(The difference between the two green lines in the graph below); and
- Availability Class 4 is defined as the difference between the Capacity Required for less than 48 hours and the Reserve Capacity Requirement(between the top green line and the solid blue line in the figure below).

The Capacity associated with Availability Class 4 is much higher than that associated with both Availability Class 2 and 3 because it incorporates both the difference between the Required Capacity for less than 48 hours and the 10% PoE + Reserve Capacity Margin Requirement.



Appendix 9 Facility Capacities

Registered Generation Facilities - Existing and Committed

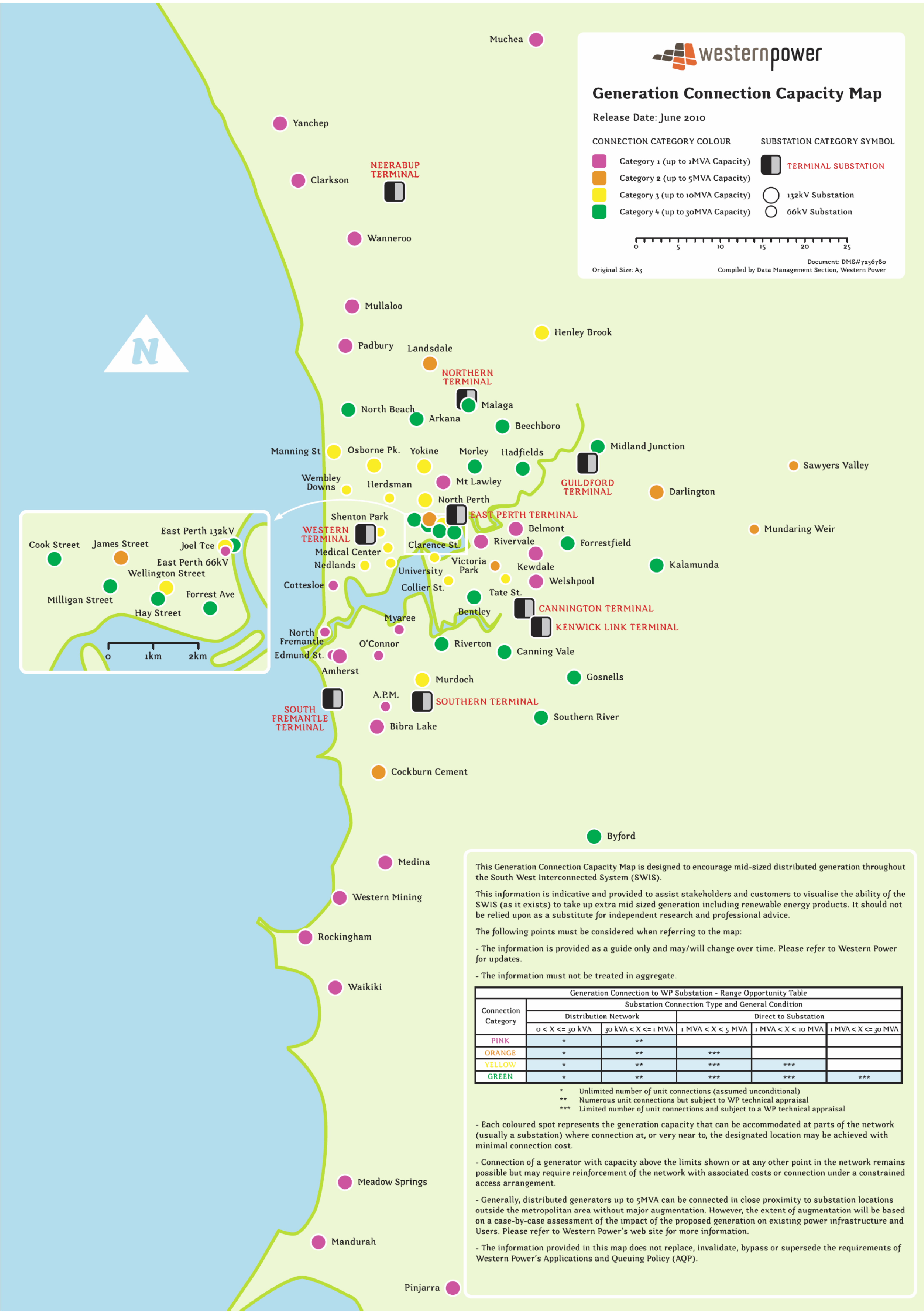
Participant Name	Facility Name	Capacity Credits (2011/12)
Alcoa of Australia	ALCOA_WGP	24
Alinta Sales Pty Ltd	ALINTA_PNJ_U1	129
Alinta Sales Pty Ltd	ALINTA_PNJ_U2	132
Alinta Sales Pty Ltd	ALINTA_WGP_GT	176
Alinta Sales Pty Ltd	ALINTA_WGP_GT2	176
Alinta Sales Pty Ltd	ALINTA_WWF	39.313
Collgar Wind Farm	INVESTEC_COLLGAR_WF1	90
EDWF Manager Pty Ltd	EDWFMAN_WF1	29.867
Goldfields Power Pty Ltd	PRK_AG	61.4
Griffin Power Pty Ltd	BW1_BLUEWATERS_G2	215.9
Griffin Power 2 Pty Ltd	BW2_BLUEWATERS_G1	215.9
Landfill Gas And Power Pty Ltd	CANNING_MELVILLE	1.188
Landfill Gas And Power Pty Ltd	KALAMUNDA_SG	1.3
Landfill Gas And Power Pty Ltd	RED_HILL	2.399
Landfill Gas And Power Pty Ltd	TAMALA_PARK	3.386
Mount Herron Engineering Pty Ltd	MHPS	0.223
NewGen Neerabup Partnership	NEWGEN_NEERABUP_GT1	330.6
NewGen Power Kwinana Pty Ltd	NEWGEN_KWINANA_CCG1	320
Perth Energy Pty Ltd	ATLAS	0.934
Perth Energy Pty Ltd	GOSNELLS	0.656
Perth Energy Pty Ltd	ROCKINGHAM	1.607
Perth Energy Pty Ltd	SOUTH_CARDUP	2.839
SkyFarming Pty Ltd	SKYFRM_MTBARKER_WF1	0.935
Southern Cross Energy	STHRNCRS_EG	11.995
Tesla Corporation Pty Ltd	TESLA_PICTON_G1	9.9
Verve Energy	ALBANY_WF1	7.085
Verve Energy	BREMER_BAY_WF1	0.195
Verve Energy	COCKBURN_CCG1	231.8
Verve Energy	COLLIE_G1	318
Verve Energy	GERALDTON_GT1	15.516
Verve Energy	KALBARRI_WF1	0.624
Verve Energy	KEMERTON_GT11	143
Verve Energy	KEMERTON_GT12	141.7
Verve Energy	KWINANA_G1	*

Participant Name	Facility Name	Capacity Credits (2011/12)
Verve Energy	KWINANA_G2	*
Verve Energy	KWINANA_G5	174
Verve Energy	KWINANA_G6	177
Verve Energy	KWINANA_GT1	16.925
Verve Energy	KWINANA_GT2	92.156
Verve Energy	KWINANA_GT3	92.156
Verve Energy	MUJA_G5	185
Verve Energy	MUJA_G6	185
Verve Energy	MUJA_G7	211
Verve Energy	MUJA_G8	211
Verve Energy	MUNGARRA_GT1	32.15
Verve Energy	MUNGARRA_GT2	32.15
Verve Energy	MUNGARRA_GT3	31.999
Verve Energy	PINJAR_GT1	32.15
Verve Energy	PINJAR_GT10	107
Verve Energy	PINJAR_GT11	115
Verve Energy	PINJAR_GT2	31.703
Verve Energy	PINJAR_GT3	37
Verve Energy	PINJAR_GT4	37
Verve Energy	PINJAR_GT5	37
Verve Energy	PINJAR_GT7	37
Verve Energy	PINJAR_GT9	107
Verve Energy	PPP_KCP_EG1	76.9
Verve Energy	SWCJV_WORSLEY_COGEN_COG1	106
Verve Energy	TIWEST_COG1	33
Verve Energy	WEST_KALGOORLIE_GT2	34.175
Verve Energy	WEST_KALGOORLIE_GT3	19
Waste Gas Resources Pty Ltd	HENDERSON_RENEWABLE_IG1	2.66
Western Australia Biomass Pty Ltd	BRIDGETOWN_BIOMASS_PLANT	40
Western Energy Pty Ltd	PERTHENERGY_KWINANA_GT1	105

Registered DSM Facilities - Existing and Committed

Participant Name	Facility Name	Capacity Credits (2011/12)	Availability (hr / year)
Alinta Sales Pty Ltd	ALINTA_DSM_1	17	24
Barrick (Kanowna) Ltd	KANOWNA_CL1	9	24
DMT Energy	DMTENERGY_CL1 block 1	7	24
DMT Energy	DMTENERGY_CL1 block 2	10	24
Energy Response	ERESPONS_CL1 block 1	13	48
Energy Response	ERESPONS_CL1 block 2	10	48
Energy Response	ERESPONS_CL2 block 1	25	48
Energy Response	ERESPONS_CL2 block 2	20	48
Energy Response	ERESPONS_CL2 block 3	5	24
Griffin Power Pty Ltd	DSM_BODDINGTON_CL1	20	48
Premier Power Sales Pty Ltd	PREMPWR_DSM_CL1	10	24
Premier Power Sales Pty Ltd	PREMPWR_DSM_CL2	1.6	24
Premier Power Sales Pty Ltd	PREMPWR_DSM_CL3	20	48
Synergy	SYNERGY_PDS142_CL41	40	48
Water Corporation	WATERCORP_CL1 block 1	14	24
Water Corporation	WATERCORP_CL1 block 2	1	24
Water Corporation	WATERCORP_CL2	17.5	24
Water Corporation	WATERCORP_CL3 block 1	14	24
Water Corporation	WATERCORP_CL3 block 2	6	24

Appendix 10 Generation Connection Capacity Map



This Generation Connection Capacity Map is designed to encourage mid-sized distributed generation throughout the South West Interconnected System (SWIS).

This information is indicative and provided to assist stakeholders and customers to visualise the ability of the SWIS (as it exists) to take up extra mid sized generation including renewable energy products. It should not be relied upon as a substitute for independent research and professional advice.

The following points must be considered when referring to the map:

- The information is provided as a guide only and may/will change over time. Please refer to Western Power for updates.

- The information must not be treated in aggregate.

Generation Connection to WP Substation - Range Opportunity Table					
Connection Category	Substation Connection Type and General Condition				
	Distribution Network		Direct to Substation		
	0 < X <= 30 kVA	30 kVA < X <= 1 MVA	1 MVA < X < 5 MVA	1 MVA < X < 10 MVA	1 MVA < X <= 30 MVA
PINK	*	**			
ORANGE	*	**	***		
YELLOW	*	**	***	***	
GREEN	*	**	***	***	***

* Unlimited number of unit connections (assumed unconditional)
** Numerous unit connections but subject to WP technical appraisal
*** Limited number of unit connections and subject to a WP technical appraisal

- Each coloured spot represents the generation capacity that can be accommodated at parts of the network (usually a substation) where connection at, or very near to, the designated location may be achieved with minimal connection cost.

- Connection of a generator with capacity above the limits shown or at any other point in the network remains possible but may require reinforcement of the network with associated costs or connection under a constrained access arrangement.

- Generally, distributed generators up to 5MVA can be connected in close proximity to substation locations outside the metropolitan area without major augmentation. However, the extent of augmentation will be based on a case-by-case assessment of the impact of the proposed generation on existing power infrastructure and Users. Please refer to Western Power's web site for more information.

- The information provided in this map does not replace, invalidate, bypass or supersede the requirements of Western Power's Applications and Queuing Policy (AQP).