imo Independent Market Operator

Your ref:
Our ref: MAD147
Enquiries: Troy Forward

Mr Robert Pullella
Executive Director
Economic Regulation Authority
Level 6, Governor Stirling Tower
197 St Georges Terrace
PERTH WA 6000

Dear Rob,

SUBMISSION UNDER CLAUSE 3.13.3A(a)

In accordance with clause 3.13.3A(a) of the Wholesale Electricity Market Rules (Market Rules), the Independent Market Operator (IMO) is pleased to provide the Economic Regulation Authority (ERA) with its proposal for the values of the parameters Margin Peak and Margin Off-Peak (margin values) to apply during the Financial Year commencing 1 July 2011 (2011/12 Financial Year).

The IMO engaged Sinclair Knight Merz / McLennan Magasanik Associates (SKM MMA) to provide an independent assessment of the margin values for the 2011/12 Financial Year. SKM MMA's Final Report to the IMO is attached for your consideration. In accordance with the recommendations of this report, the IMO proposes the margin values for the 2011/12 Financial Year to be:

Margin Values	Current	Proposed
Margin Peak	30%	44%
Margin Off-Peak	103%	53%

In its review, SKM MMA has re-applied the methodology it used for the 2009 review of margin values for the Review Period commencing 1 July 2010. In general, the sources of the modelling assumptions used in the study are unchanged from the sources used for 2009 review. However, assumptions relating to natural gas prices and the impact of the implementation of the Collgar wind farm on load following requirements have been brought into alignment with the assumptions used in the ROAM Consulting report "Assessment of FCS and Technical Rules". This report was prepared by ROAM Consulting to address Work Package 3 (Frequency Control Services) of the Renewable Energy Generation Working Group, and has been subject to extensive review by industry participants. An indicative commissioning profile provided by Collgar Wind Farm has also been incorporated into the study assumptions.

The key modelling assumptions used for the study were reviewed by the IMO, System Management and the ERA. In addition, Verve Energy was requested to confirm the assumptions made with regard to its facilities. The IMO considered that given the limitations of confidentiality requirements a wider consultation process would be of limited benefit.

If you have any queries please do not hesitate to contact me.

Yours sincerely

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

30 November 2010

2010 Margin _Peak and Margin_Offpeak Review

FINAL REPORT TO IMO

- 17 November 2010

2010 Margin _Peak and Margin_Offpeak Review

FINAL REPORT TO IMO

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SKM MMA
ABN 37 001 024 095
590 Orrong Road, Armadale 3143
PO Box 2500
Malvern VIC 3144 Australia
Tel: +61 3 9508 6090
Fax: +61 3 9500 1182
Web: www.skmmma.com

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Executive summary

The Wholesale Electricity Market Rules (Market Rules) require the Economic Regulation Authority (ERA) to determine Margin_Peak and Margin_Off-Peak values for each financial year in accordance with the methodology set out in clause 3.13.3A (a) of the Market Rules. Under clause 3.13.3A(a) the Independent Market Operator (IMO) must submit a proposal for these values to the ERA by 30 November each year for the following financial year.

In determining these margin values, the Market Rules require IMO to take into account the energy sales foregone and the generation efficiency losses that could reasonably be expected to be incurred by Verve Energy as a consequence of providing Spinning Reserve (SR). These energy sales foregone and generation efficiency losses (reserve availability costs) may be incurred through:

- movement to a less efficient point on a unit's heat rate curve
- an increase in either production from higher cost Verve Energy plant or Short Term Energy Market (STEM) purchases, to counteract lower cost generation backed off to provide reserve
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not have been required.

Accordingly, the IMO engaged SKM MMA to undertake market modelling of the Wholesale Electricity Market (WEM) to assess the reserve availability cost and hence determine margin values for the financial year commencing July 2011.

The market modelling was undertaken using PLEXOS simulation software, which co-optimised energy and reserve provision to determine least-cost dispatch, treating the WEM as a gross pool market. Although bilateral trades, the STEM and Balancing Mechanism were not modelled explicitly, the dispatch outcomes from simulation of the gross pool assuming short run marginal cost (SRMC) bidding should be equivalent to economically efficient WEM outcomes.

To assess the reserve availability cost that could reasonably be expected to be incurred by Verve Energy for the financial year starting 1 July 2011, revenue and generation cost outcomes were compared from two market simulations with and without SR and Load Following Reserve (LFR) provision. That is:

$$\boxed{\textit{Availability cost} = GenCost\_Res - GenCost\_NRP + (GenQ\_NRP - GenQ\_Res)*SMP}$$

where

GenCost_Res = Verve Energy's total generation costs, including start-up costs, with reserve provision

GenCost_NRP = Verve Energy's total generation costs, including start-up costs, without any reserve provision

GenQ_Res = Verve Energy's total generation volume, with reserve provision

GenQ_NRP = Verve Energy's total generation volume, without any reserve provision

SMP = system marginal price with reserve provision

Having determined the reserve availability cost and System Marginal Price (SMP) through market simulations, the margin values were calculated by re-arranging the formula in clause 9.9.2(a) of the Market Rules.

The resulting margin values proposed for the financial year commencing July 2011 are 44% for Margin_Peak and 53% for Margin_Off-Peak. Table 1 summarises the availability cost, peak and off-peak SMPs, that form the basis for this assessment, averaged over 10 random outage samples.

Table 1 Parameter estimates for 2011/12 financial year

	Average value
Margin_Off-Peak	53%
Margin_Peak	44%
Availability cost ($M)	35.42
Off-peak price ($/MWh)	28.19
Peak price ($/MWh)	73.2

In assessing these margin values, the following key assumptions were made:

- price of cogeneration, Verve, and IPP contracts gas were assumed to be $2/GJ, $3/GJ, and $4/GJ respectively for the 2011/12 financial year,
- the price for new gas contracts was assumed to be $6/GJ for the 2011/12 financial year,
- no Carbon Pollution Reduction Scheme (CPRS) was implemented within the 2011/12 financial year,
- Collgar wind farm was commissioned in stages starting July 2011, resulting in an increase in LFR requirement from +/- 72 MW to +/- 100.75 MW by the end of the financial year,

- Kwinana_GT2 and Kwinana_GT3, two LMS 100 high efficiency gas turbine units, were available for all of the 2011/12 financial year and these units could provide reserve,
- Kwinana G1, Kwinana G2, Muja A, and Muja B were assumed to be offline for the entirety of the 2011/12 financial year,
- no Ancillary Service contracts for SR or LFR were assumed,
- start-up costs incurred due to provision of reserve were included as part of the reserve availability cost.

1. Introduction

The Independent Market Operator of Western Australia (IMO) engaged SKM MMA to assist in determining the appropriate margin values to be used for the financial year starting 1 July 2011.

In assessing the Margin_Peak and Margin_Off-Peak values, market modelling and analysis was conducted taking into account the factors for determining the margin values as prescribed in clause 3.13.3A (a) of the Market Rules.

This report summarises the results of this analysis and outlines the key assumptions and methodology adopted in developing the proposed margin values.

All prices in this report are given in real June 2010 dollars.

2. Methodology for calculating margin values

Ancillary services for the Western Australian Wholesale Electricity Market (WEM) are currently all provided by Verve Energy. The IMO pays Verve Energy for these services in accordance with the formula prescribed in clause 9.9.2(a) of the Wholesale Electricity Market Rules (Market Rules).

Two of the key parameters of the formula in 9.9.2(a) are the Margin_Peak and Margin_Off-Peak, which are to be proposed by the IMO to the ERA each financial year. These parameters are intended to reflect the payment margin (i.e. as a percentage of the Marginal Cost Administrative Price (MCAP) in either the peak or off-peak periods) that, when multiplied by the volume of reserve provided and the MCAP, will compensate Verve Energy for energy sales foregone and losses in generator efficiency resulting from backing off generation to provide Spinning Reserve (SR). Clause 3.13.3A(a) stipulates that:

(a) by 30 November prior to the start of the Financial Year, the IMO must submit a proposal for the Financial Year to the Economic Regulation Authority:

i. for the reserve availability payment margin applying for Peak Trading Intervals, Margin_Peak, the IMO must take account of:

1. the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Peak Trading Intervals;

2. the loss in efficiency of the Electricity Generation Corporation Registered Facilities that System Management has scheduled to provide Spinning Reserve during Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves;

ii for the reserve availability payment margin applying for Off-Peak Trading Intervals, Margin_Off-Peak, the IMO must take account of:

1. the margin the Electricity Generation Corporation could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Off-Peak Trading Intervals;

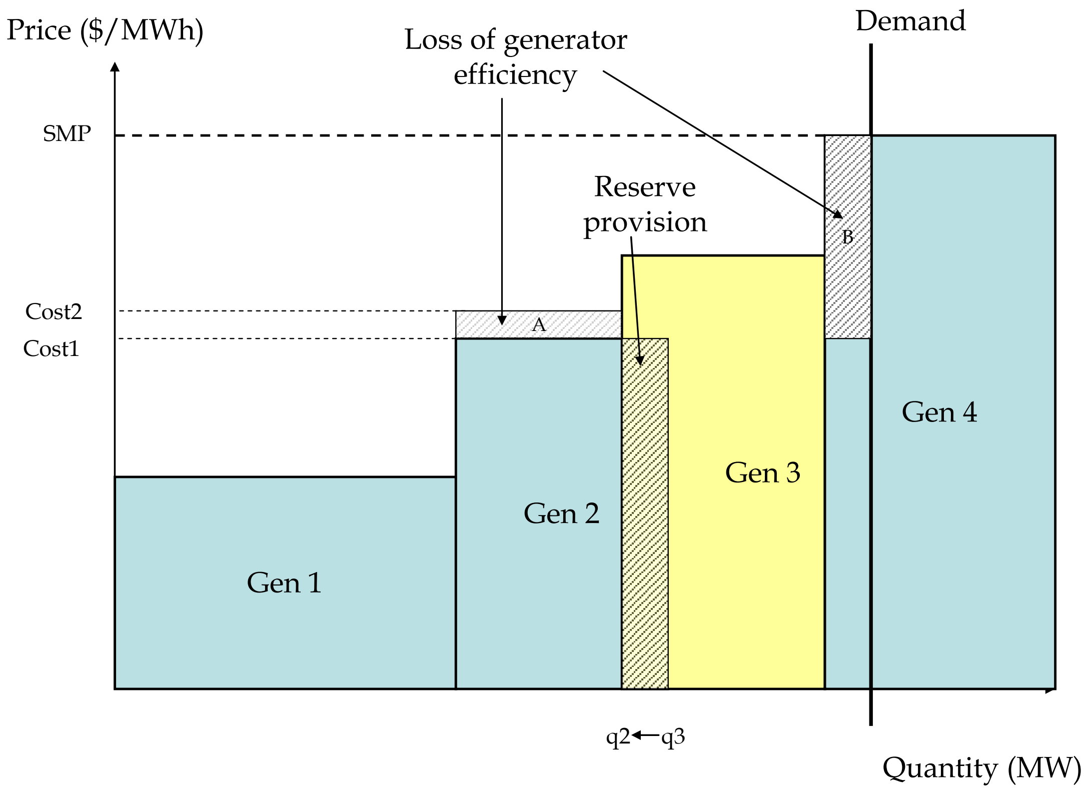
2. the loss in efficiency of the Electricity Generation Corporation Registered Facilities that System Management has scheduled to provide Spinning Reserve during Off-Peak Trading Intervals that could reasonably be expected due to the scheduling of those reserves;

If only Verve Energy provides Ancillary Services, the reserve availability cost is equal to the sum of generator efficiency losses and energy sales foregone, which may be incurred through:

- movement to a less efficient point on a unit's heat rate curve
- an increase in either production from higher cost Verve Energy plant or Short Term Energy Market (STEM) purchases, to counteract lower cost generation backed off to provide reserve
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not have been required.

By way of example, consider a simple system consisting of four generators, three of which are owned by the Market Generator (Gen 1, Gen 2 and Gen 4), and one which is owned by an Independent Power Producer (IPP) (Gen 3). In this example, summarised diagrammatically in Figure 2-1, only the Market Generator can provide reserve and, in this period, SR is provided by backing off generation from Gen 2 (quantity q3 – q2). By reducing output, Gen 2's average generation cost has increased from Cost 1 to Cost 2, as it is generating less efficiently. Additionally, energy production costs have increased due to the commitment of Gen 4. Consequently, the reserve availability cost incurred by the Market Generator is equivalent to the sum of the shaded areas A and B plus the cost of starting up Gen 4. If Gen 4 had been an IPP, Area B would represent the margin the Market Generator could have earned on energy sales foregone due to reserve provision.

■ **Figure 2-1 Example of generator efficiency losses resulting from reserve provision**



Through market simulations, this availability cost was calculated for peak and off-peak periods by comparing Verve Energy's total generation costs and generation quantities, with and without providing reserve. That is:

Availability cost = GenCost_Res – GenCost_NRP + (GenQ_NRP – GenQ_Res)*SMP

where:

GenCost_Res = Verve Energy's total generation costs, including start-up costs, with reserve provision

GenCost_NRP = Verve Energy's total generation costs, including start-up costs, without any reserve provision

GenQ_Res = Verve Energy's total generation volume, with reserve provision

GenQ_NRP = Verve Energy's total generation volume, without any reserve provision

SMP = system marginal price with reserve provision

For calculating losses in generator efficiency resulting from reducing output to provide SR, heat rate curves were considered within SKM MMA's WEM database.

2.1. Constraining units on to provide reserve

During the off-peak, some units may be constrained on at minimum stable level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the SMP.

To illustrate this situation, consider again the simple four generator example introduced earlier although, this time, assume that all generators are owned by the same Market Generator. In the original example, Gen 2 was backed off to provide reserve, and Gen 4 was committed to meet demand (Figure 2-1). Gen 4's dispatch was equal to the level of reserve provided (q3 – q2) and the reserve availability cost was equal to area A + area B.

Now, consider the situation whereby Gen 4 has a minimum stable level greater than (q3 – q2). In order to meet the reserve requirement, Gen 2 must still back off generation from q3 to q2, but Gen 4 is now constrained on to its minimum stable level. Consequently, Gen 3's output is reduced as there is insufficient demand for Gen 3 to operate at maximum capacity and for Gen 4 to operate at minimum stable level (Figure 2-2). At the margin, any variations in demand will be met by Gen 3. Therefore, Gen 3 is the marginal generator setting the price, not Gen 4. The reserve availability cost is the sum of areas A, B and C, representing the increase in generation costs incurred by Market Generator as a consequence of providing reserve.

If Gen 4's generation costs are significantly larger than the cost of the marginal generator, and if Gen 4's minimum stable level is greater than the level of reserve provision required, then it is possible that this availability cost may result in relatively high margin value (greater than 100%, as we observed in last year's review). In the WEM, this situation may arise if Cockburn is constrained on, as SKM MMA understands that this unit has a relatively high minimum stable level.

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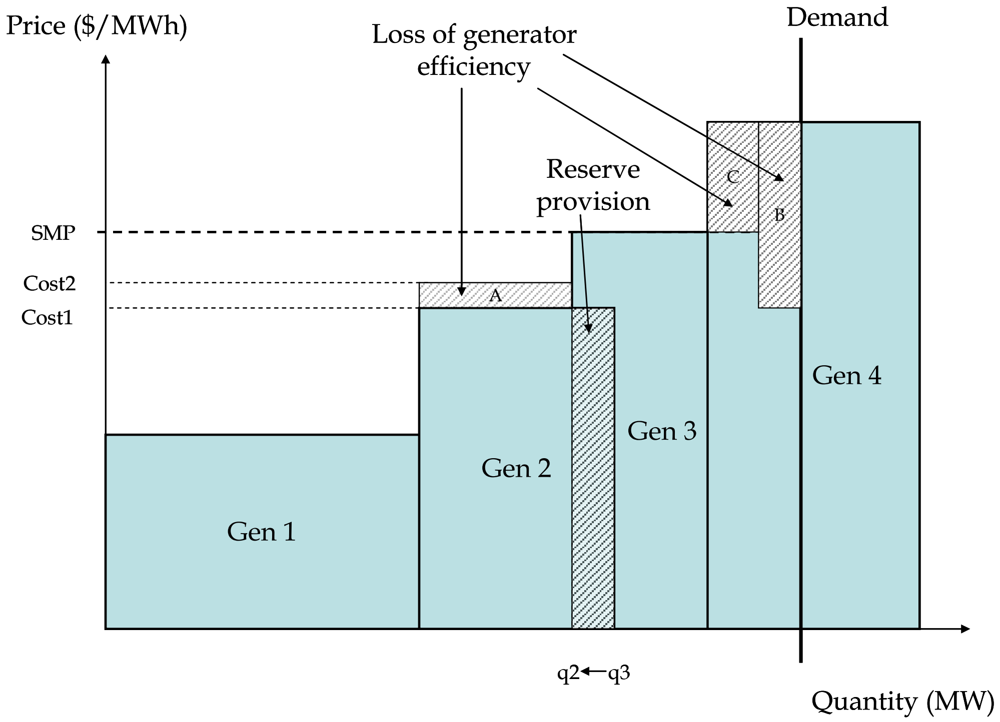
- **Figure 2-2 Example of availability cost with Gen 4 constrained on**



It is also possible to have more than one Verve Energy unit constrained on to provide reserve if demand is low and the level of generation from IPP's is relatively high, since Verve Energy is assumed to be the sole provider of SR.

3. Modelling the wholesale electricity market

The WEM for the South West interconnected system (SWIS) commenced operation on 21 September 2006. This market consists of three components:

- an energy market, which is an extension of the previous bilateral contract arrangements, with a residual day-ahead energy market
- a services component, to balance supply and demand, dispatch SR and ensure supply reliability and quality
- a Reserve Capacity Mechanism (RCM), to ensure that there is adequate capacity to meet demand each year.

The energy market and the RCM are operated by the IMO. Other services are controlled by System Management.

The WEM is relatively small, and a large proportion of the electricity demand is for mining and industrial use, which is supplied under long-term contracts. Over 90% of energy sales in the SWIS are traded through bilateral contracts that closely follow the individual customer's load.

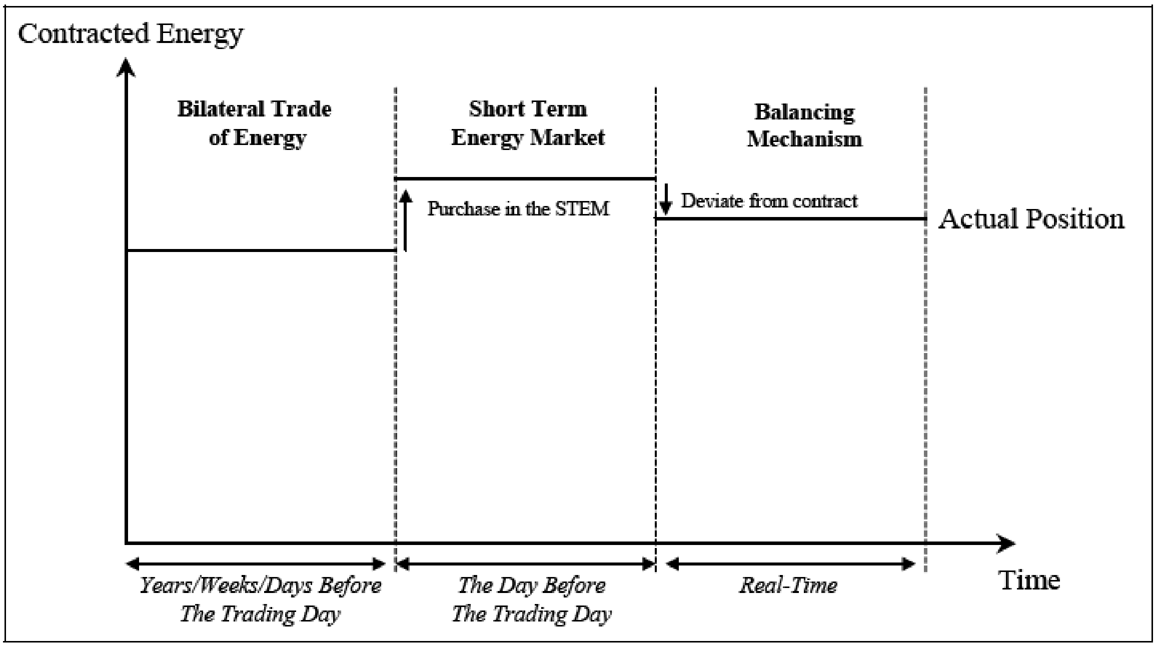
The STEM is a residual, day-ahead trading market which allows contract participants to trade out any imbalances. Market Participants (both Market Generators and Market Customers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, the generator may wish to sell energy in excess of its bilateral contract into the STEM. Similarly, Market Customers may use the STEM to trade out imbalances between the bilateral contract position and expected demand.

The IMO is responsible for clearing the offers and bids in the STEM. The STEM price is set at the point where the marginal offer price and marginal bid price are equal.

There will inevitably be slight differences between the day-ahead net contract volumes and the real time demand. Under the balancing mechanism, System Management may instruct Verve Energy to alter its scheduled dispatch in real time to accommodate these deviations and maintain system security. If necessary, IPPs may also be instructed to vary generation volumes. The MCAP is the price determined after supply and demand have been balanced in real time, and is calculated in accordance with Section 6.14 of the Market Rules.

Figure 3-1 shows the relationship between bilateral trades, the STEM and the balancing mechanism.

- **Figure 3-1 Components of the Energy Trading Market**



SOURCE: IMO. 2006. *The South West Interconnected System Wholesale Electricity Market: An Overview*

3.1. PLEXOS simulation software

For this analysis the WEM was simulated using PLEXOS, commercially available software developed in Australia by Energy Exemplar. PLEXOS is a Monte Carlo mathematical program that co-optimises both the energy and reserve markets in the WEM, using the same techniques that are used to clear the NEM, New Zealand and Singaporean electricity markets.

In the PLEXOS model, SKM MMA did not explicitly model the bilateral trades, STEM and balancing market separately. Instead, a gross pool was modelled, assuming economically efficient short-run marginal cost dispatch. In theory, the same economically efficient dispatch outcomes should be achievable from the STEM as from a gross pool, with lowest cost resources scheduled first.

In PLEXOS, dispatch is optimised to meet load and ancillary service requirements at minimum cost subject to a number of operating constraints. In our WEM model, these operating constraints include:

- generation constraints – availability (planned and unplanned outages), unit commitment and other technical constraints
- transmission constraints –linearised DC optimal power flow (OPF) equations and line ratings
- fuel constraints – for example, daily fuel limits
- ancillary service constraints – maximum unit response, calculation of dynamic risk.

Requirements for LFR and SR are modelled as two different services in the PLEXOS model, with the same MW of reserve contributing to both services.

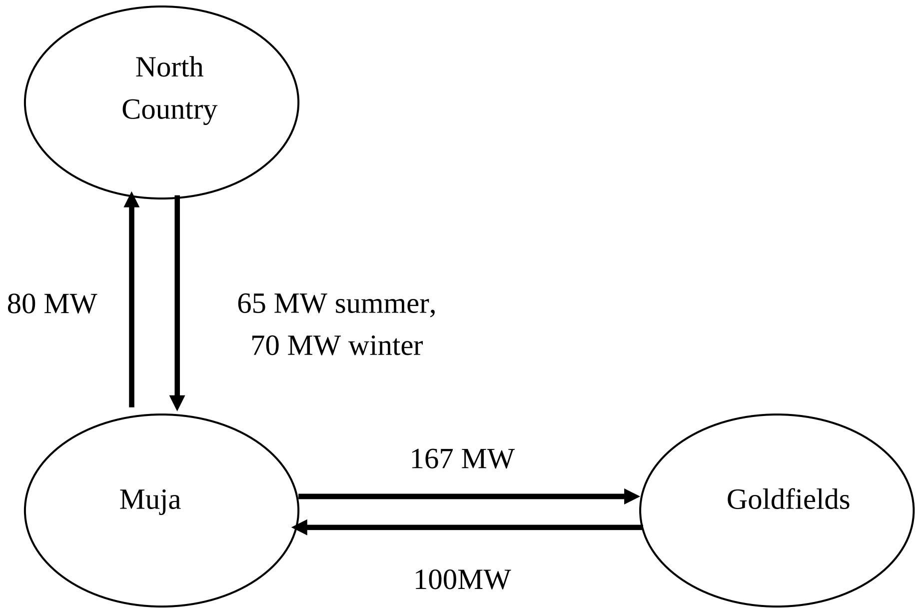
4. Key modelling assumptions

This section outlines the key modelling assumptions used in the PLEXOS market simulations. These assumptions have been reviewed by the IMO, System Management and the ERA. In addition, Verve Energy was requested to confirm the assumptions made with regard to its facilities.

4.1. Network topography

The SWIS was modelled as a three-node system with a single uniform price. Interconnectors between the three nodes: Muja, Goldfields and North Country, allowed us to represent the major congestion points in the system. Figure 4-1 shows the network configuration modelled in PLEXOS and the maximum flow limits assumed in each direction. The transmission upgrade from North Country to Muja (330kV line from Geraldton to Perth), was assumed to lie outside of the horizon of this study.

- **Figure 4-1 3-node model of SWIS model**



The Mungarra units, Geraldton GT and Alinta, Emu Downs and Kalbarri wind farms were located in the North Country, the West Kalgoorlie, Southern Cross and Parkeston units were located in the Goldfields region, and all other units were assumed to be located at the Muja node.

4.2. Demand assumptions

Table 4-1 shows our assumptions for sent-out energy and summer and winter maximum demand across the 3 nodes. These values are based on the 2010 Statement of Opportunities (SOO) load forecasts (medium growth scenario, 50% PoE), distributed among the three regions in accordance with the 2002/03 actual loads plus the trends in relative regional growth. Intermittent non-scheduled load information was provided by the IMO.

- **Table 4-1 2011/12 load assumptions**

Parameter	*Muja (Perth)*	*Goldfields*	*North Country*	*Total SWIS*
Energy (GWh)	16,792	886	1,266	18,944
Summer Peak Demand 50% PoE (MW)	4,143	157	223	4,401
Winter Peak Demand 50% PoE (MW)	3,189	149	185	3518
Intermittent non-scheduled load (MW)	110.3	46	0	156.3

In Table 4-1, as the regional peaks are not coincident (i.e. they happen at different dates), the sum of the individual peak demands is slightly higher than the total SWIS demand.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the 3 nodes (based on 2002/03 historical data), which are then grown to match the energy and peak demand values in Table 4-1. The regional growth is split based on the parameters in Table 4-2.

- **Table 4-2 Load growth parameters**

Parameter	*Muja (Perth)*	*Goldfields*	*North Country*
Energy growth	2.30%	0.71%	3.64%
Summer peak demand growth	2.42%	0.72%	3.70%
Winter peak demand growth	0.75%	0.22%	1.15%

The growth rates specified in Table 4-2 were derived from growth rates extrapolated from trends observed in regional growth rates up to 2002/03. These regional growth rates are then scaled in each year to ensure that the total system energy and peak are consistent with the values in Table 4-1. More recent data has not been available but we do not expect the use of more recent data to be material for this study as intraregional flows are not a major factor in the provision of ancillary services in the WEM. Coincidence factors are calculated based on one year of historical data (FY ending 2003), to calculate the total system peak as a function of the individual region peaks. This is because total energy growth is the weighted average of all individual regions' growth, but total peak demand growth is not since the region peaks are non-coincident peaks.

4.3. Fuel assumptions

We are representing the following fuels in our modelling:

- Coal: used by Muja, Collie and the Bluewaters units,
- Cogeneration contract gas: gas for Alcoa and Alinta cogeneration plants,
- Verve Contract gas: gas under existing Verve Energy contracts,
- IPP contract gas: gas under contract for existing IPP plants,
- New gas: reflects the estimated price for new gas contracts, and as a secondary fuel for some of the other units if they have used up their contract gas supply,
- Distillate: used as a primary fuel by Geraldton and the West Kalgoorlie units, and as a secondary fuel for some of the other units if they have used up their gas supply.

Multi-fuelled units are modelled as able to use more than one fuel. Kwinana G5 and Kwinana G6 are modelled as burning a mix of 50% gas and 50% coal (on a fuel energy basis). The units using contract gas can use new gas if the contracted gas for the portfolio is insufficient. The Kemerton units, Pinjar GT1-5 and 7, Kwinana GT1-3, and Alinta Wagerup units can operate on either gas or distillate, but will only use distillate if the supply of gas for the respective portfolio is insufficient.

4.3.1. Fuel costs

Table 4-3 shows our assumptions on fuel prices:

- **Table 4-3 Fuel prices (real June 10 dollars)**

Name	*Price ($/GJ) 2011/12*
Coal	2.0
Cogeneration contract gas	2.0
Verve contract gas	3.0
IPP contract gas	4.0
New gas	6.0
Landfill gas	2.18
Distillate	18.35

The coal price is converted from $/tonne, assuming an energy content of 19.5 GJ/tonne.

Natural gas prices have been aligned with contract gas prices used in the ROAM Consulting report "Assessment of FCS and Technical Rules" (REGWG Work Package 3)[1]. Cogeneration contract gas and landfill gas prices are assumed to be $2.00/GJ and $2.18/GJ respectively; these values have been estimated by MMA and were used in last year's margin value review.

Distillate prices come from MMA's Electricity Price Limits 2010 study[2], which estimated a price of $18.35/GJ applying a calorific value of 38.6 MJ/litre. The additional transport cost to the Goldfields is estimated to be 72c/GJ.

Gas transport charges come from ACIL Tasman "Gas prices in Western Australia" report[3], $1.74/GJ for units in the South-West and $4.06/GJ for units in Goldfields[4]. Based on the new tariffs structure, we estimate gas transport charges to Mungarra to be $1.24/GJ.

4.3.2. Fuel constraints

Based on our understanding of the market and historical data, we have included gas constraints limiting the contract gas daily availability. It is assumed that any gas used by Verve Energy or Alinta cogeneration plant in excess of the corresponding daily contract limit is purchased at the new gas price. These constraints are estimated from historical dispatch data and liquid fuel usage for 2008, and have been fine-tuned in our PLEXOS model during previous SWIS back-casting exercises.

4.4. Generation assumptions

4.4.1. Existing generators

The modelling of the existing generation system includes the larger private power stations owned by Alcoa and the Goldfields miners. Table 4-4 shows the existing generators in the model, and some of their key properties driving marginal costs and unit commitment. Some of the objects listed may represent the aggregation of one or more actual facilities. Most of the properties were obtained from publicly available information (SOO, planning reviews, IMO website, and companies' websites). Missing parameters were estimated by SKM MMA based on the nature and known characteristics of the facilities, or based on actual half-hourly dispatch information.

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1 http://www.imowa.com.au/f139,754290/Report_Imo00016_to_IMO_2010-11-03a_FINAL.pdf (last accessed, 16/11/10)
2 http://www.imowa.com.au/f2354,718308/MMA_Final_Report_2010.pdf (last accessed, 16/11/10)
3 http://www.imowa.com.au/f2138,484255/ACIL_Tasman_Final_Report_-_Updated.pdf (last accessed, 16/11/10)
4 Prices in the ACIL Tasman "Gas Prices in Western Australia" report are nominal for the capacity year 2010/11. In order to convert them to real June 2010 dollars, we used the same approach used for the distillate prices.

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Although we are only reporting marginal heat rates at maximum capacity, our model actually includes polynomial heat rate functions. SRMC values in the table are estimated for 2011/12, based on the primary fuel only and considering the heat rate at maximum capacity.

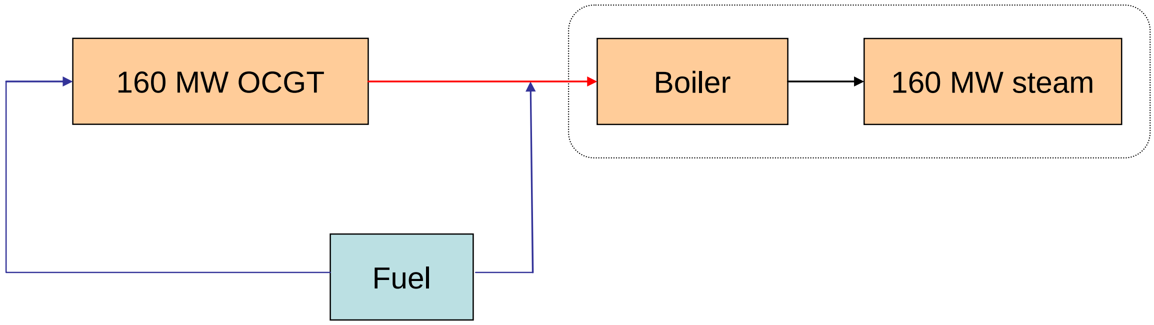
Fuel transport charges reflecting variable gas pipeline costs have been estimated for some of the generating units to reflect geographical differences in estimated fuel prices.

For the wind farms and landfill gas plants the assumed value of renewable energy certificates (REC) has been subtracted from the variable operating and maintenance costs, resulting in a negative SRMC. Even with an MCAP of $0/MWh, renewable generators would be foregoing REC revenue if they were shut down.

4.4.1.1. Kwinana NewGen

The Kwinana NewGen CCGT consists of a 160 MW open cycle gas turbine, and a 160 MW steam turbine. In base load operation, 240 MW of power may be provided, with an additional 80MW available from the steam unit during peak periods through auxiliary duct firing. This configuration is modelled explicitly in PLEXOS, as shown in Figure 4-2.

- **Figure 4-2 Kwinana NewGen CCGT model in PLEXOS**



The steam turbine cannot operate without the gas turbine. Therefore, the contingency risk that this unit imposes on the system is equal to the combined output from the power station. An additional constraint is imposed in the PLEXOS model to ensure that this risk is appropriately considered in determining the spinning reserve requirement.

4.4.2. Future generators

Table 4-5 shows the properties of future generators assumed to become operational within the 2011/12 financial year. In summary, we have considered the following units for commissioning/retirement:

- Perth Energy: OCGT to be located in Muja region, 4 units available for the 2011/12 financial year (limited to 110MW, as the network ETAC for the 2011/12 financial year is restricted to 110 MW),
- Collgar: wind farm to be located in Muja region, with staged commissioning as per an indicative commissioning forecast provided by Collgar,
- Muja A and B recommissioning: expected to be available on August 2012, so they are outside the horizon under consideration,
- Kwinana GT2 and Kwinana GT3: 2 x 100 MW LMS100 units to be located at the existing Kwinana B site, and assumed to be available for the whole financial year 2011/12,
- Tesla Picton: small diesel unit (9.9MW) located close to Bunbury and assumed to be available for the whole financial year 2011/12,
- Kalamunda: small diesel unit (1.3MW) located close to Perth and assumed to be available for the whole financial year 2011/12,
- Kwinana G1 and Kwinana G2 are assumed to be retired for all the financial year 2011/12,
- Bremer Bay wind farm will not be considered as its effect is considered to be negligible.
- Bridgewater Biomass: Due to the uncertainty about whether this plant will be available, it has been excluded from our analysis following advice from IMO.

4.4.3. Unit commitment

Unit commitment assumptions are critical to the assessment of margin values, particularly overnight when a number of units may prefer to stay on and generate at minimum stable level, rather than be decommissioned and incur high start-up costs in subsequent periods. In the PLEXOS simulations, unit commitment decisions were optimised within the model based on start-up costs and minimum stable level assumptions provided by the IMO in last year's review. In reality, this portion of a generator's output may be bid into the STEM below SRMC, or even at negative cost.

Table 4-4 Properties of existing generators

Generator	*Units*	*Supply intermittent load?*	*Marginal HR at max (GJ/MWh)*	*Primary fuel*	*Primary Fuel Price 2011/12 ($/GJ)*	*Transport charge ($/GJ)*	*VO&M ($/MWh)*	*SRMC 2011/12 ($/MWh)*
BW1_BLUEWATERS_G2	1	No	8.9	Coal	2		2.18	19.98
BW2_BLUEWATERS_G1	1	No	8.9	Coal	2		2.18	19.98
COLLIE_G1	1	No	7.94	Coal	2		1.09	16.97
MUJA_G5	1, retires 2020	No	11.04	Coal	2		4.37	26.45
MUJA_G6	1, retires 2021	No	11.04	Coal	2		4.37	26.45
MUJA_G7	1	No	9.24	Coal	2		4.1	22.58
MUJA_G8	1	No	9.24	Coal	2		4.1	22.58
ALINTA_PNJ_U1	1	No	6.52	Cogen gas	2	1.74	2.33	26.71
ALINTA_PNJ_U2	1	No	6.52	Cogen gas	2	1.74	2.33	26.71
ALCOA_WGP	4	Yes	6.51	Cogen gas	2	1.74	5.53	29.88
PPP_KCP_EG1	1	Yes	7.77	Verve gas	3	1.74	4.42	41.25
SWCJV_WORSLEY_COGEN_COG1	1, retires Feb 2014	No	7.93	Verve gas	3	1.74	3.99	41.58
TIWEST_COG1	1	No	10.09	Verve gas	3	1.74	0.6	48.43

Generator	Units	Supply intermittent load?	Marginal HR at max (GJ/MWh)	Primary fuel	Primary Fuel Price 2011/12 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh)	SRMC 2011/12 ($/MWh)
COCKBURN_CCG1	1	No	9.27	Verve gas	3	1.74	3.77	47.71
KWINANA_G5	1, retires 2016	No	11.69	Mix 50% Verve gas and 50% Verve coal	2.5	1.74	4.2	43.60
KWINANA_G6	1, retires 2016	No	11.69	Mix 50% Verve gas and 50% Verve coal	2.5	1.74	4.2	43.60
KWINANA_GT1	1	No	11.03	Verve gas	3	1.74	22.02	74.30
MUNGARRA_GT1	1	No	12.69	Verve gas	3	1.24	4.48	58.29
MUNGARRA_GT2	1	No	12.69	Verve gas	3	1.24	4.48	58.29
MUNGARRA_GT3	1	No	12.89	Verve gas	3	1.24	4.48	59.13
PINJAR_GT01	1	No	12.69	Verve gas	3	1.74	10.05	70.20
PINJAR_GT02	1	No	12.69	Verve gas	3	1.74	10.05	70.20
PINJAR_GT03	1	No	10.02	Verve gas	3	1.74	6.01	53.50
PINJAR_GT04	1	No	10.02	Verve gas	3	1.74	6.01	53.50
PINJAR_GT05	1	No	10.02	Verve gas	3	1.74	6.01	53.50
PINJAR_GT07	1	No	10.02	Verve gas	3	1.74	6.01	53.50

Generator	*Units*	*Supply intermittent load?*	*Marginal HR at max (GJ/MWh)*	*Primary fuel*	*Primary Fuel Price 2011/12 ($/GJ)*	*Transport charge ($/GJ)*	*VO&M ($/MWh)*	*SRMC 2011/12 ($/MWh)*
PINJAR_GT09	1	No	11.29	Verve gas	3	1.74	4.37	57.88
PINJAR_GT10	1	No	11.29	Verve gas	3	1.74	4.37	57.88
PINJAR_GT11	1	No	9.97	Verve gas	3	1.74	5.08	52.34
NEWGEN_KWINANA GT	1	No	11.45	IPP gas	4	1.74	2.18	67.90
NEWGEN_KWINANA ST	1	No	9.12	Waste heat/IPP gas	4	1.74	2.18	54.53
STHRNCRS_EG_1-2	2	Yes	12.66	IPP gas	4	4.06	4.42	106.46
STHRNCRS_EG_3-4	2	Yes	11.58	IPP gas	4	4.06	4.42	97.75
KEMERTON_GT11	1	No	11.13	Verve gas	3	1.74	2.33	55.09
KEMERTON_GT12	1	No	11.13	Verve gas	3	1.74	2.33	55.09
ALINTA_WGP_GT	1	No	16.2	IPP gas	4	1.74	2.33	95.32
ALINTA_WGP_GT2	1	No	16.2	IPP gas	4	1.74	2.33	95.32
NEWGEN_NEERABUP	2	No	11.63	IPP gas	4	1.74	2.33	69.09

Generator	***Units***	***Supply intermittent load?***	***Marginal HR at max (GJ/MWh)***	***Primary fuel***	***Primary Fuel Price 2011/12 ($/GJ)***	***Transport charge ($/GJ)***	***VO&M ($/MWh)***	***SRMC 2011/12 ($/MWh)***
PRK_AG	3	Yes	8.03	IPP gas	4	4.06	4.42	69.14
GERALDTON_GT1	1	No	15.27	Distillate	18.35		2.51	282.70
WEST_KALGOORLIE_GT 2	1	No	14.75	Distillate	18.35	0.72	32.78	314.04
WEST_KALGOORLIE_GT 3	1	No	14.75	Distillate	18.35	0.72	32.78	314.04
GENERIC LANDFILL GAS	1	No	11.3	Landfill Gas	2.18		-24.52	0.11
ALBANY_WF1	12	No		Wind			-38.4	-38.40
ALINTA_WWF	54	No		Wind			-38.4	-38.40
SKYFRM_MTBARKER_W F1	1	No		Wind			-38.4	-38.40
KALBARRI_WF1	2	No		Wind			-38.4	-38.40
EDWFMAN_WF1	48	No		Wind			-38.4	-38.40

* The numbers in the table are based on information derived from the SOO and other publically available data.

▪ Table 4-5 Properties of future generators

Generator	Units	Marginal HR at max (GJ/MWh)	Primary fuel	Primary Fuel Price 2010/11 ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh)	SRMC 2010/11 ($/MWh)
COLLGAR	127		Wind			-38.4	-38.40
PERTH_ENERGY_GT1	4	11.6	New gas	6	1.74	4.39	94.17
KWINANA_GT2	1	8.44	Verve gas*/ distillate	3	1.74	6.21	46.22
KWINANA_GT3	1	8.44	Verve gas*/ distillate	3	1.74	6.21	46.22
TESLA_PICTON	1	15.27	Distillate	18.35		2.51	282.70
KALAMUNDA	1	15.27	Distillate	18.35		2.51	282.70

*Assuming that the high efficiency GT has access to the gas freed up by the shutdown of Kwinana B.

4.5. Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both spinning reserve (SR) and load following reserve (LFR) will be modelled in PLEXOS.

4.5.1. Spinning reserve

The spinning reserve requirement in the WEM is equivalent to 70% of the generating unit producing the largest total output in that period. Spare capacity on other generating units and/or interruptible load is made available to support system frequency in the event of a contingency.

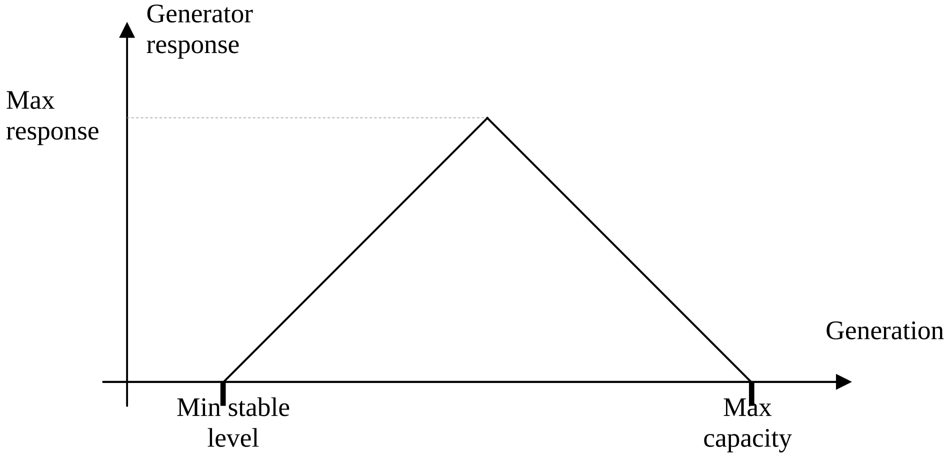
In PLEXOS, reserve and energy are co-optimised. Therefore, the model will reduce the output from the largest generating unit if, in doing so, less reserve needs to be carried on the system and total system costs are reduced. In the WEM, this results in Collie being de-rated overnight in the PLEXOS simulations to reduce the level of SR requirement.

4.5.2. Load following reserve

Load following reserve is required to meet fluctuations in supply and demand in real time. The current load following requirement is ± 60 MW and is a component of the spinning reserve. Therefore, the same MW of reserve may be used to meet both the load following and spinning reserve requirements.

The generators providing load following reserve must be able to raise or lower their generation in response to AGC signals. For example, a generator with 170 MW maximum capacity and 50 MW of minimum stable level will be able to offer up to ± 60 MW of load following reserve by generating 110 MW. The concept is further illustrated in Figure 4-3.

▪ **Figure 4-3 Generator response for load following reserve**



While the dispatch of a load following generator can vary from minute to minute to meet generation and demand fluctuations, for modelling purposes it is assumed that, on average across the half hour period, a load following generator is not providing any load following. That is, intra-half-hour load following fluctuations in their generation average out.

Based on the report "Assessment of FCS and Technical Rules" by Roam Consulting[5], we have assumed an initial load following requirement of ± 72 MW for the 2011/12 year. As Collgar units become commissioned, the load following requirement will increase by 14% of Collgar's installed capacity. Once the 250 MW of the Collgar wind farm become operational, it is expected that the load following requirement will increase by ± 35 MW.

4.5.3. Reserve provision

PLEXOS requires the user to specify which generators can provide a particular type of reserve. Some may be better suited for providing SR than LFR, and some may not be suitable for providing reserve at all, depending on their operational flexibility and the commercial objectives of their owners.

For all generators specified as being able to provide reserve, PLEXOS is set up to assume that, if a unit is generating, all spare capacity could contribute to providing reserve. This is not always possible, so PLEXOS allows users to specify a *Reserve.Generator.Max response* for each generator that can provide reserve. If used, this property limits the reserve provided by a generator in a given period to the minimum of the *Max response* and the spare capacity on the generating unit.

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[5] Op. Cit.

The maximum responses currently assumed are based on information provided by System Management. For some units, all spare capacity is assumed to be available for providing spinning reserve and load following reserve.

For load following reserve, the maximum response represents a unit's ability to increase or decrease output within a 5 minute period, based on the ramp rates provided by System Management. For spinning reserve, additional restrictions are imposed on some units, as suggested by System Management.

4.5.4. Interruptible load

Some reserve may be provided by reducing load through interruptible load arrangements. Consistent with Market Rule 3.11.11 Report [6], 50 MW of interruptible load is assumed to be available for the 2011/12 finanical year and can be used at all times to provide Spinning Reserve.

4.5.5. Ancillary service contracts

No Ancillary Service contracts for Spinning Reserve or Load Following is assumed for the purposes of this study.

4.5.6. Value of reserve shortage

Clause 3.10.2 (d) of the Market Rules states that the SR requirement may be relaxed if:

"…all reserves are exhausted and to maintain reserves would require involuntary load shedding".

To ensure that reserve levels are relaxed prior to involuntary load shedding, a value of reserve shortage (VoRS) is defined representing the cost per MWh of not meeting the reserve requirement. In PLEXOS, a VoRS of $1,000/MWh is assumed for the WEM.

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[6] *http://www.imowa.com.au/f161,48013/48013_2009AncillaryServiceReport.pdf*

5. Results

In each half-hour trading period, the availability cost was calculated using the methodology described in Section 2 and a margin value was determined by rearranging the formula specified in clause 9.9.2 (a) of the Market Rules. The average margin values, availability cost and system marginal prices are presented in Table 5-1 over 10 random outage samples. The Margin_Off-Peak value remained relatively stable between random samples, while the Margin_Peak value showed more variability.

Table 5-1 Parameter estimates

Sample	*Average*	*Standard Error*
Margin_Off-Peak	53%	1.1%
Margin_Peak	44%	1.4%
Availability cost ($M)	35.42	0.99
Off-peak price ($/MWh)	28.19	0.17
Peak price ($/MWh)	73.2	0.69

On average, a Margin_Off-Peak value of 53% is recommended, based on system marginal off-peak prices around $28.2/MWh. For Margin_Peak, an average value of 44% has been estimated, based on system marginal prices around $73.2/MWh. In some instances during peak periods, IPP generation was backed off and total Verve Energy output was increased in order to meet the SR and LFR requirements. If the resulting increase in sales revenue was greater than the increase in cost, the net benefit reduced the reserve availability cost.

In last year's simulations we obtained a Margin_Peak value of 38% and a Margin_Off-Peak value of 152% for the base case in the financial year 2011/12. While the Margin_Peak value obtained this year (44%) is relatively close to the one obtained last year (38%), the Margin_Off-Peak value experienced a significant reduction from 152% to 53%. There are several changes with respect to our previous modelling causing the differences between last year's and this year's simulations:

- We are considering a LFR min provision requirement lower than in last year's Review: while last year's simulations had a LFR requirement of 150 MW, this year's simulations considered a LFR requirement starting at 72 MW and increasing only to about 100 MW at the end of the financial year. With a lower LFR requirement, less Verve Energy units may be constrained on overnight decreasing the Margin-Off-Peak values;
- While all 250 MW of Collgar capacity was available for the whole financial year in last year's Review, in this year's Review we modelled a staged commissioning that reached 200 MW

installed by the end of the financial year, lowering the reserve requirements with respect to last year's Review and also the instances with units constrained on at times when the wind farm was generating at high levels,

- Cheaper fuel for Kwinana G5 and G6 with respect to last year's runs increases their dispatch and their availability to provide reserve.

6. Conclusions

Based on our market modelling, SKM MMA recommends the following margin values for the financial year commencing July 2011:

- Margin_Off-Peak 53%
- Margin_Peak 44%

These values are sensitive to a number of factors including:

- the price and volume assumptions relating to existing gas contracts
- the overnight unit commitment decisions, which are based on start-up costs, minimum stable level assumptions and the maximum reserve provision for each unit
- the LFR requirement once the Collgar wind farm is commissioned.

Moreover, these margin values have been developed assuming that no Ancillary Service contracts for SR or LFR are negotiated for the 2011/12 financial year.

If any of these assumptions were to change, the margin values may need to be reviewed.