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Dear Rajat

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 2013 (2013/14 Financial Year).

The IMO engaged Sinclair Knight Merz / McLennan Magasanik Associates (SKM MMA) to provide an independent assessment of the margin values for the 2013/14 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 2013/14 Financial Year to be:

Margin Values	Proposed (FY 2013/14)	Current (FY 2012/13)
Margin Off-Peak	27%	31%
Margin Peak	17%	32%
Average Annual Spinning Reserve Capacity_Off-Peak (MW)	197.18	205.78
Average Annual Spinning Reserve Capacity_Peak (MW)	220.16	221.49
Estimated Annual Availability Cost ($M)	7.22	12.51
System Marginal Price_Off-Peak($/MWh)	47.01	52.57
System Marginal Price_ Peak ($/MWh)	50.81	55.93

In its review, SKM MMA has reapplied the methodology it used in 2011 to determine margin values to apply under the new Balancing and Load Following Ancillary Service (LFAS) Markets during the 2012/13 Financial Year.

In general, the modelling assumptions used in the study were based on the assumptions used for the 2011 review, updated as appropriate from relevant sources (such as the 2012 Statement of Opportunities). The IMO and SKM MMA undertook the following measures to improve the quality of the input assumptions.

- The IMO and SKM MMA consulted directly with System Management regarding assumptions on network topography and Load Following response.
- SKM MMA prepared a draft Assumptions Report outlining the methodology and assumptions proposed for the review. The full (confidential) version of this report was reviewed by System Management, the ERA and the IMO.
- A public version of the draft Assumptions report, which excluded confidential Market Generator details, was published by the IMO on 11 September 2012. The IMO invited interested stakeholders to either request a meeting to consult directly with the IMO and SKM MMA or to provide written submissions on the report. No formal submissions or requests for direct consultation were received during the consultation period which closed on 27 September 2012.
- The IMO also requested feedback from eight large Market Generators on full extracts of the key assumptions for their Facilities. The IMO received feedback from five Market Generators on Facility assumptions. The IMO also consulted with the ERA on the updated Facility assumptions received from Market Generators.
- SKM MMA used the feedback provided by stakeholders to update input assumptions.

Review of SKM MMA's methodology for determining margin values

During previous reviews the ERA raised a number of concerns about the methodology used by SKM MMA to calculate the margin values. In particular, the ERA noted concerns that the formula used by SKM MMA to calculate the Availability Cost for Verve Energy only takes into account the differential in Verve Energy's generation costs and generation volumes in providing Spinning Reserve, but not the differential in the system marginal price (SMP).

In response to these concerns, the IMO has conducted a review of the Availability Cost formula as part of its 2012 review of the margin values. The review involved discussions with the ERA and SKM MMA and a comparison of:

- the current formula, which uses the SMP calculated under the "with Spinning Reserve provision" scenario to calculate Verve Energy's revenue under both the "with Spinning Reserve provision" scenario and the "without Spinning Reserve provision" scenario; and
- an alternative formula, in which the SMP calculated under the "without Spinning Reserve provision" scenario is used to calculate Verve Energy's revenue under that scenario.

The only difference between the two formulas is that the alternative formula contains an additional term, consisting of the difference between the SMPs under the two modelled scenarios, multiplied by Verve Energy's total modelled generation volume under the "without Spinning Reserve provision" scenario. This term has been omitted intentionally by SKM MMA. In SKM MMA's methodology, no change in SMP is assumed in determining the level of compensation required for Verve Energy to provide Spinning Reserve. The IMO notes that the inclusion of this term could either increase or decrease the Availability Cost in a given Trading Interval, depending on which SMP was the larger in that Trading Interval.

The IMO shares SKM MMA's concern that the additional term does not reflect the "real world" impact of SMP variations on Verve Energy's revenue. This is for two reasons. Firstly, the "without Spinning Reserve provision" scenario is not a real world scenario, since a system such as the South West interconnected system would never be operated without Spinning Reserve. This means that while the scenario provides a useful estimation of Verve Energy's costs, its SMP results are based on unrealistic assumptions and so are unlikely to be reflective of real market prices.

Secondly, most of the energy generated by Verve Energy is sold under bilateral contracts, and so the IMO considers that changes in the SMP would only be expected to have an impact over the comparatively small quantities generated above or below Verve Energy's Net Contract Position. Including the additional term would apply any price difference to all of Verve Energy's modelled generation output.

Even in a gross pool energy market, generators are typically covered by hedging arrangements for much of their output, which would greatly limit the impact of SMP variations on their actual revenue. The IMO is not convinced that the provision of Spinning Reserve by Verve Energy has an impact on its energy revenue under bilateral contracts that could be approximated by the additional term contained in the alternative Availability Cost formula. Although Balancing Price changes will have some impact on Verve Energy's revenue around its Net Contract Position, the IMO has concluded that the additional term could grossly overestimate the extent of the impact.

For these reasons, the IMO is not satisfied a change to the alternative formula is justified, and has therefore retained the current methodology in the preparation of this proposal.

Please call me on 9254 4333 if you have any queries or would like to discuss further.

Yours sincerely

ALLAN DAWSON
CHIEF EXECUTIVE OFFICER

30 November 2012

Margin Peak and Margin Off-Peak Review 2013/14

FINAL REPORT TO IMO

- V3.2
- 27 November 2012

FINAL REPORT TO IMO

- V3.2
- 27 November 2012

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V2.1	8th November	N.Falcon			Draft report incorporating changes from IMO
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Executive Summary

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 2013.

In determining these margin values, the Market Rules require the IMO and the Economic Regulation Authority (ERA) 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. 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) or Balancing Market 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.

To determine appropriate Margin_Peak and Margin_Off-peak parameters, we calculated the availability cost for spinning reserve in peak and off-peak periods, based on market simulations, and then re-arrange the equation in clause 9.9.2(f) of the Market Rules to calculate the required parameters.

The market simulations were 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 Market were not modelled explicitly, the dispatch outcomes from simulation of a gross pool assuming short run marginal cost (SRMC) bidding should be equivalent to economically efficient WEM outcomes.

In previous modelling, extensive consultation and comparison of modelled outcomes against actual were conducted. For this review, assumptions on prices and costs have generally been escalated by Perth CPI unless a submission from relevant stakeholder was received suggesting otherwise.

To assess the reserve availability cost that could reasonably be expected to be incurred by Verve Energy for the 2013/14 financial year, revenue and generation cost outcomes were compared from two market simulations with and without spinning reserve provision. 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 spinning reserve provision
GenCost_NRP	= Verve Energy's total generation costs, including start-up costs, without any spinning reserve provision
GenQ_Res	= Verve Energy's total generation volume, with spinning reserve provision
GenQ_NRP	= Verve Energy's total generation volume, without any spinning reserve provision
SMP	= system marginal price with spinning reserve provision

In each of the simulations, load following was provided by Verve Energy and Independent Power Producers on a competitive basis.

Having determined the reserve availability cost, average annual SR_Capacity_Peak and SR_Capacity_Off-Peak and System Marginal Price (SMP) through market simulations, the margin values were calculated by re-arranging the formula in clause 9.9.2(f).

The resulting margin values proposed for the Financial Year commencing July 2013 are 27% for Margin_Off-Peak and 17% for Margin_Peak. Table 0-1 summarises the availability cost, SR_Capacity_Peak and SR_Capacity_Off-Peak, and peak and off-peak SMPs that form the basis for this assessment, averaged over 12 random outage samples (refer to Table 5-2).

- **Table 0-1 Parameter estimates for 2013/14 financial year**

Parameter	Average	Standard Error
Margin_Off-Peak	27%	0.9%
Margin_Peak	17%	1.0%
SR_Capacity_Off-Peak (MW)	197.18	0.18
SR_Capacity_Peak (MW)	220.16	0.04
Availability cost ($M)	7.22	0.32
Off-peak price ($/MWh)	47.01	0.07
Peak price ($/MWh)	50.81	0.09

1. Introduction

The Wholesale Electricity Market Rules (Market Rules) require the Independent Market Operator (IMO) to submit proposed values for Margin_Peak and Margin_Off-Peak (margin values) to the Economic Regulation Authority (ERA) for every Financial Year, in accordance with clause 3.13.3A of the Market Rules. Clause 3.13.3A requires the ERA to determine the margin values proposed by the IMO, subject to a public consultation process which must include publishing an issues paper and issuing an invitation for public submissions.

For the 2013/14 Financial Year, the Market Rules require the IMO to conduct a review of the margin values and submit its proposal by 30 November 2012. The ERA must conduct the public consultation process and determine the margin values by 31 March 2013. The Independent Market Operator of Western Australia (IMO) engaged SKM MMA to assist in reviewing the appropriate margin values to be used for the financial year starting 1 July 2013.

To determine appropriate Margin_Peak and Margin_Off-peak parameters, the availability cost for spinning reserve has been calculated in peak and off-peak periods, based on market simulations, and then the equation in clause 9.9.2(f) of the Market Rules has been rearranged to calculate the required parameters.

SKM MMA simulated the Wholesale Electricity Market (WEM) for the South West interconnected system (SWIS) 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 requirements in the WEM.

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 –line ratings and other generic constraints
- fuel constraints – for example, daily fuel limits
- ancillary service constraints – maximum unit response, calculation of dynamic risk

The availability cost resulting from backing-off generation to provide spinning reserve will depend on both the marginal costs of the generators providing the reserve, and the market clearing price set by the marginal generator.

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 2012 dollars. Many of the cost assumptions used are the same as those assumed for the 2012/13 Financial Year review, escalated by Perth CPI to convert from June 2011 dollars to June 2012 dollars[1].

[1] Perth CPI index in June 2011 was 178.4 and in June 2012 was 180.4, so the CPI adjustment factor was 180.4 / 178.4 = 1.0112

2. Methodology for calculating margin values

Spinning reserve ancillary services for the WEM are currently provided by Verve Energy[2]. The IMO pays Verve Energy for these services in accordance with the formula prescribed in clause 9.9.2(f) of the Market Rules.

Two of the key parameters of the formula in clause 9.9.2(f) 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 Balancing Price in either the peak or off-peak periods) that, when multiplied by the volume of Spinning Reserve (SR) provided and the Balancing Price, will compensate Verve Energy for energy sales foregone and losses in generator efficiency resulting from backing off generation to provide 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 Verve Energy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Peak Trading Intervals; and

2. the loss in efficiency of Verve Energy 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 Verve Energy could reasonably have been expected to earn on energy sales forgone due to the supply of Spinning Reserve during Off-Peak Trading Intervals; and

2. the loss in efficiency of Verve Energy Registered Facilities that System Management has scheduled to provide Spinning Reserve during Off-Peak

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[2] With the exception of a small quantity of spinning reserve provided by Interruptible Load under Ancillary Service Contracts.

Trading Intervals that could reasonably be expected due to the scheduling of those reserves;

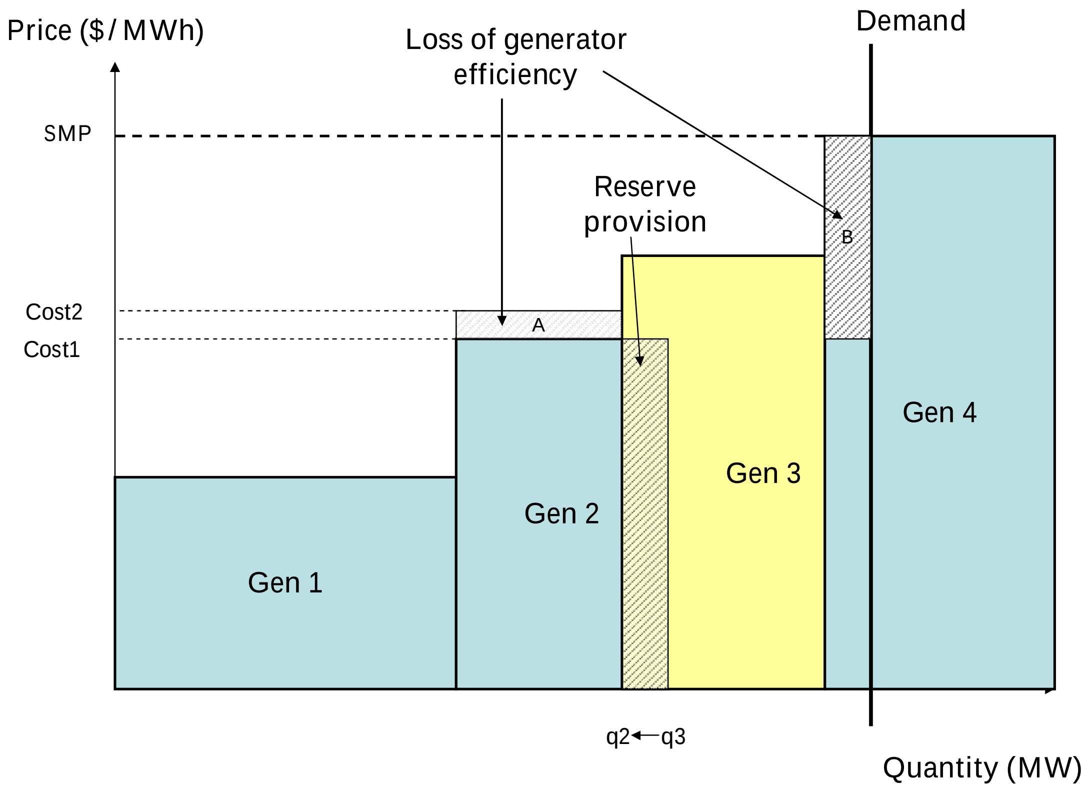
The reserve availability payment to Verve Energy should be equal to the sum of generator efficiency losses and energy sales foregone, which may be incurred through:

- 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) or Balancing Market 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.

2.1. Constraining units off to provide reserve

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 SR 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**



2.2. Constraining units on to provide reserve

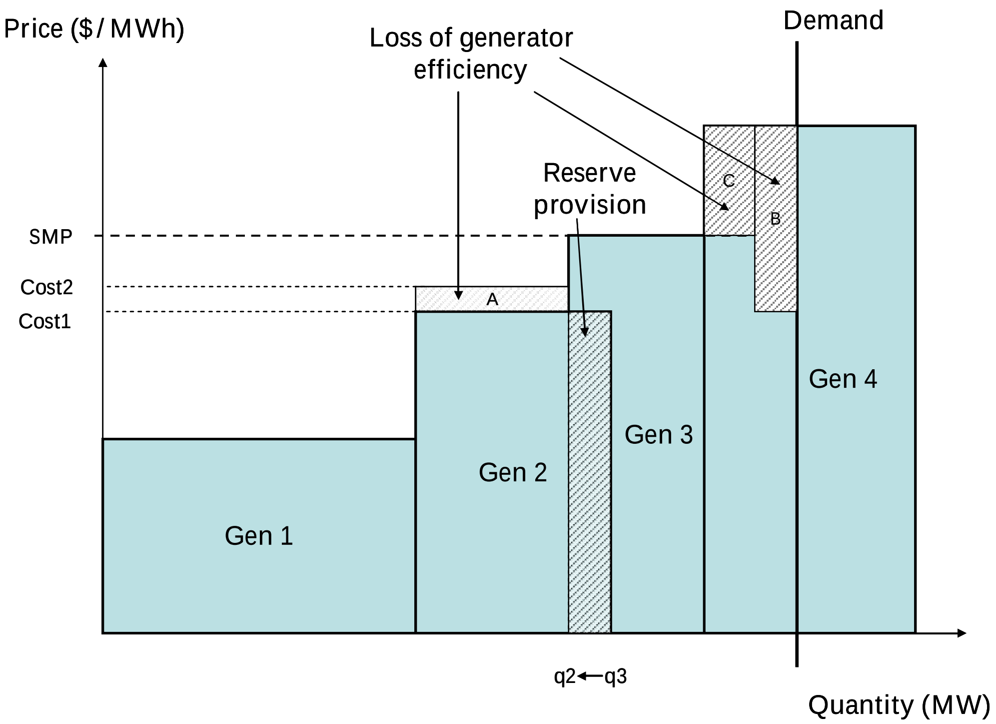
During the off-peak, some units may be constrained on at minimum generation level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the SMP.

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 generation 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 generation 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 generation 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 generation 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 the 2009 review). In the WEM, this situation may arise if Cockburn is constrained on to provide reserve, as this unit has a relatively high minimum generation level.

- **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 (apart from Interruptible Load (IL)).

2.3. Calculating availability cost

Through market simulations, the availability cost is calculated for peak and off-peak periods by comparing Verve Energy's total generation costs and generation quantities, with and without providing SR but with load following reserve provided in both simulations. 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 SR provision

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

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

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

SMP = system marginal price with SR provision

For calculating losses in generator efficiency resulting from reducing output to provide SR, heat rate curves are considered within SKM MMA's WEM database, as discussed in Section 4.5.7.

2.4. Calculating Margin Values

Clause 9.9.2(f) of the Market Rules provides a formula for calculating the total availability cost in each Trading Interval as a function of the Margin value, SR_Capacity, load following raise provision (LFR) and Balancing Price in the period.

In essence, if SR ancillary services are only provided by Verve Energy generators and IL, the availability cost defined by clause 9.9.2(f) is as follows:

Availability cost =

Margin Peak * ∑BalancingPrice_Peak * {SR_Capacity_Peak – LFR_Peak - IL} +

Margin OffPeak * ∑BalancingPrice_Offpeak * {SR_Capacity_Offpeak – LFR_Off-Peak - IL}

Margin values can therefore be calculated by rearranging this formula and using key outputs from the market simulations[3].

The SR_Capacity(t) parameter represents the capacity necessary to cover Ancillary Service Requirement for Spinning Reserve in the Trading Interval as specified by IMO under clause 3.22.1(e) and (f). These clauses define the Ancillary Service Requirement for SR as being equal to the requirement assumed in calculating the Margin values, with a different value used for peak and off-peak trading periods (SR_Capacity_Peak and SR_Capacity_Off-Peak). Therefore, the SR_Capacity_Peak and SR_Capacity_Off-Peak are key parameters to extract from the market

[3] Note that LF reserve is a component of SR

simulations. In PLEXOS, the spinning reserve requirement varies dynamically from period to period. These values are therefore averaged over the year in order to determine a single SR_Capacity_Peak and SR_Capacity_Off-Peak value for use in the formula in clause 9.9.2(f).

The LFR parameter represents the amount of load following raise ancillary service required in the Trading Interval. Assumptions regarding this requirement are discussed in Section 4.6.2.

3. Modelling the wholesale electricity market

The Wholesale Electricity Market (WEM) for the South West interconnected system (SWIS) commenced operation on 21 September 2006. Currently 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
- Balancing services, including a Balancing Market and Load Following Ancillary Service (LFAS) Market to balance supply and demand, dispatch spinning reserve and ensure supply reliability and quality
- A reserve capacity mechanism, to ensure that there is adequate capacity to meet demand each year.

The energy market, Balancing Market, LFAS Market and the reserve capacity mechanism are operated by the Independent Market Operator (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. Up to 90% of energy sales in the SWIS are traded through bilateral contracts that closely follow the individual customer's load.

The Short Term Energy Market (STEM) is a residual day ahead trading market which allows contract participants to trade out any imbalances.

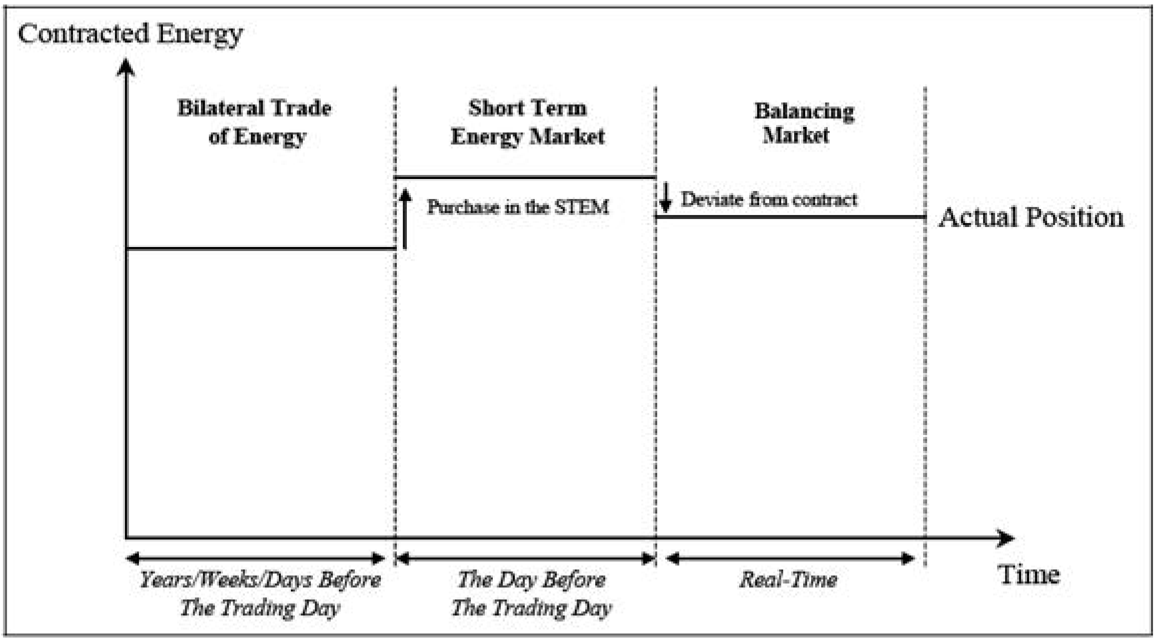
Market participants (both generators and retailers) can submit offers to sell energy to the STEM, or bids to buy energy from the STEM. Market generators may wish to buy energy from the market if the STEM price is lower than its marginal cost of generation. Alternatively, the generator may wish to sell energy in excess of its bilateral contract into the STEM. Similarly, retailers 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. From July 2012, all Balancing Facilities (Verve Energy and IPPs) are required to compete in a Balancing Market to accommodate these deviations and maintain system security. Balancing Facilities are required to participate in the Balancing Market through price-based submissions, using multiple price-volume bands to represent the facility's willingness to generate at different levels of output. The Balancing Price is the price determined in the Balancing Market after supply and demand have been balanced in real time, and is calculated in accordance with clause 7A.3.10 of the Market Rules.

Figure 3-1 shows the relationship between bilateral trades, the STEM and the balancing market over time.

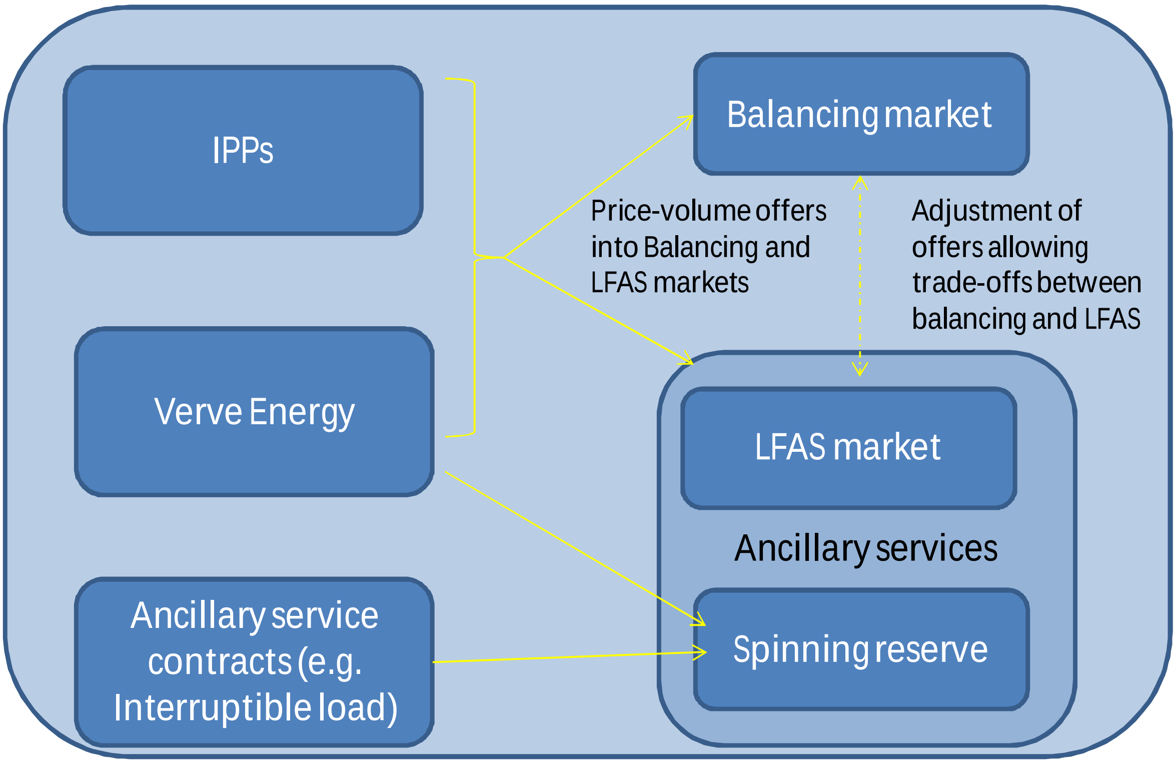
- **Figure 3-1 Components of the Energy Trading Market**



SOURCE: IMO (2006) *The South West Interconnected System Wholesale Electricity Market: An Overview, adapted for MEP*

Verve Energy is the default provider of all ancillary services. However, in the LFAS Market, IPPs can compete with Verve Energy for the provision of LFAS. Payment for LFAS is determined based on the market price for this service (excluding payments made for any emergency backup LFAS provided by Verve Energy on a "pay as bid" basis). SR can only be provided by Verve Energy or through Ancillary Service Contracts such as IL contracts. Figure 3-2 summarises participation by Verve Energy and IPPs in the Balancing Market, LFAS Market and provision of SR.

■ **Figure 3-2 Balancing Market and Ancillary Service Provision**



In the PLEXOS model we do not explicitly model the bilateral trades, STEM and Balancing Market separately. Instead, a gross pool is modelled; assuming economically efficient dispatch, and energy and ancillary services are co-optimised. The Market Evolution Project (MEP) was responsible for the development of both the Balancing Market and the LFAS Market, with the objective being to encourage more efficient dispatch outcomes in the WEM. With the implementation of these markets from July 2012, any discrepancies between the WEM and PLEXOS market model outcomes are expected to be smaller as the new market more closely approximates a gross pool market.

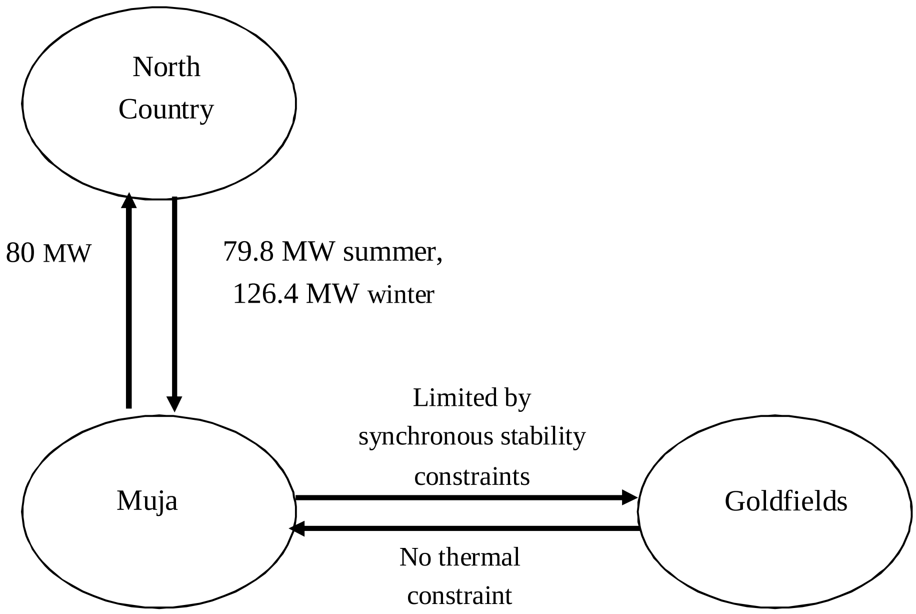
4. Key modelling assumptions

This section outlines the key modelling assumptions used in the PLEXOS market simulations. Most of these assumptions were provided for public review during the consultation period[4], with the exception of a few corrections detected prior to modelling being undertaken. These corrections are outlined in the Errata, provided in Appendix A of this report.

4.1. Network topography

We model the SWIS as a 3-node system with a single uniform price. Interconnectors between the 3 nodes: Muja, Goldfields and North Country, allow 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.

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



The Mungarra units, Verve Geraldton GT, Tesla Geraldton, Greenough Solar Farm and the Walkaway, Mumbida and Kalbarri wind farms are located in the North Country, the West Kalgoorlie, Southern Cross and Parkeston units are located in the Goldfields region, and all other units, including Emu Downs and Collgar wind farms and Merredin Energy diesel unit, are assumed to be located at Muja.

[4] 2012 Margin Peak and Margin Off-peak Review, Assumptions and Methodology Report (Public) V3.0, 10th September 2012

Voltage stability constraints in the North Country influence unit commitment decisions for the Mungarra units. On advice from System Management, when North Country load exceeds 65 MW, one Mungarra unit must be in operation, increasing to two units in operation when load exceeds 95 MW.

From North Country back to Muja, thermal limits constrain flow to 84 MVA in summer and 133 MVA in winter. While the MW equivalent rating changes throughout the day, System Management has suggested a power factor of 0.95 be used for both seasons. The resulting constraint limits flow south to 79.8MW in summer and 126.4 MW in winter.

Additionally, synchronous stability constraints constrain levels of generation in the Goldfields region. The Goldfield's load cannot exceed 130 MW, and the combined export (generated less self load of approximately 110 MW) of Parkeston and Southern Cross is limited to 85 MW.

Commissioning of the Mid West Energy Project (MWEP) (Southern Section) is expected for June 2014, although there are risks of further delays to this project schedule. Given that, at best, the augmentation would only impact one month of the 2013/14 financial year, we do not propose modelling the impact of MWEP for this current review. Doing so would require reassessment of voltage stability constraints and congestion boundaries to be modelled but would be unlikely to materially affect the margin value recommendations.

4.2. Demand assumptions

4.2.1. Regional demand forecasts

Table 4-1 shows the assumptions for sent-out energy and summer and winter maximum demand across the 3 nodes. These values are based on the 2012 Statement of Opportunities (SOO) load forecasts (medium growth scenario, 50% PoE), distributed among the three regions in accordance with the 2009/10 actual loads after separately accounting for the Boddington and Karara mining developments. Intermittent non-scheduled load information was provided by the IMO.

Table 4-1 2013/14 load assumptions

Financial year	Parameter	Muja (Perth)	Goldfields	North Country	Total SWIS
2013/14	Energy (GWh)	16,983	627	648	18,258
	Summer Peak Demand 50% PoE (MW)	4,144	152	145	4,344
	Winter Peak Demand 50% PoE (MW)	3,088	142	107	3,269
	Intermittent non-scheduled load (MW)	98.3	36	0	134.3

In Table 4-1, the regional peaks are not coincident (i.e. they occur at different times), therefore the sum of the individual peak demands is slightly higher than the total SWIS demand. Coincidence factors are derived from the 2009/10 profiles, to calculate the individual region peaks at time of system peak for the 2013/14 financial year.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the 3 nodes (based on 2009/10 historical data including losses), which are then grown to match the energy and peak demand values in Table 4-1. The energy and peak demand forecasts provided in Table 4-1 are net of IMO assumptions on small-scale solar PV uptake. For the 2013/14 financial year, IMO estimated that small-scale solar PV would contribute 72 MW during the summer peak demand. As this will change the daily shape of the load profiles, we have grown the loads by adding back the small-scale solar PV peak and energy demand, and then subtracting an assumed solar PV daily shape based on Bureau of Meteorological data collected from 1975 to 1981 for the Perth Airport site.

4.2.2. Intermittent loads

Generators servicing Intermittent Loads are also modelled in PLEXOS. In case one of these generators is offline as a result of an outage, the system will need to supply their nominated capacity. These generators may also be dispatched in the SWIS up to their maximum scheduled generation level.

4.3. Fuel assumptions

The following fuels are represented in the model:

- Coal: used by Muja G5-G8, Collie and the Bluewaters units,
- Vinalco Coal: used by Muja G1-G4
- Cogeneration contract gas: gas for Alcoa Wagerup and one of the two Alinta cogeneration units
- Verve Contract gas: gas under existing Verve Energy contracts,
- NewGen contract gas: gas for NewGen Kwinana plant
- 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 and may also include some proportion of spot gas purchases,
- Spot gas: a specific gas price proposed by one Market Generator during the consultation period

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- Distillate: used as a primary fuel by the Geraldton, West Kalgoorlie, Tesla, Merredin Energy and Kalamunda 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, Alinta Wagerup units, Parkeston and Perth Energy's Kwinana facility 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 4-2 shows our assumptions on fuel prices. For most coal, gas and landfill gas facilities the prices used are the same as the prices used in the calculation of the FY2012/13 margin values for the new Balancing Market that were determined by the ERA on 22 June 2012, adjusted by Perth CPI to convert from June 2011 dollars to June 2012 dollars. The new gas price of $6.25/GJ falls within the range of prices reported from industry sources in the Western Australian, November 2011[5] of $6 to $8/GJ for gas, albeit at the lower end of this range. Feedback on the appropriateness of this price was sought during the submission period. One Market Participant provided a response on gas price and provided an estimate for its generator(s). Through consultation with the ERA and other stakeholders, it was decided that the gas price for this participant would be changed to this value. To preserve confidentiality this change has not been reflected in Table 4-5. For other generators using new gas the price of $6.25/GJ continues to be used as it represents a combination of new contracts and spot gas.

During the stakeholder consultation period, Vinalco provided the IMO with information about the coal price for Muja G1-G4 units. We have used this in the model.

Distillate prices come from SKM MMA's Electricity Price Limits 2012 study[6], which estimated a price of $23.62/GJ applying a calorific value of 38.6 MJ/litre. The additional nominal financial year 2012/13 transport cost to the Goldfields is estimated to be 94c/GJ.[7]

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[5] http://au.news.yahoo.com/thewest/a/-/wa/12171777/gorgon-gas-deal-to-put-the-heat-on-power-bills/ last cited 31st August 2012

[6] http://www.imowa.com.au/f5789,2360899/SKM_MMA_Final_Report_2012_EPL_Review.pdf

[7] Prices in the SKM MMA "Energy Price Limits for the Wholesale Electricity Market in Western Australia from July 2012" report are nominal for the financial year 2012/13. In order to convert them to real June 2012 dollars, we assumed they are from December 2012 (mid-point of the 2012-13 financial year) and then scaled them back to June 2012 dollars assuming a Perth annual out-year inflation rate of 3%).

Table 4-2 Fuel prices (real June 12 dollars)

Name	Price ($/GJ)
Coal	2.08
Vinalco Coal	Confidential
Cogeneration contract gas	2.67
Verve contract gas	3.12
NewGen contract gas	3.12
IPP contract gas	4.17
New gas	6.25
Spot gas	7.50
Landfill gas	2.28
Distillate	23.27

Gas transport charges, reflecting variable gas pipeline costs, vary based on the generator's geographic location. The gas transport charges assumed for each unit are presented in Table 4-5. In this review, one market participant provided a transport charge of $1.50/GJ for its facility and we have used it in the modelling. To preserve confidentiality the transport charge for this participant in Table 4-5 has not been updated.

The fixed component of the gas transport charge was converted to a variable cost per GJ assuming a load factor of 75%. For gas from the Dampier to Bunbury Pipeline (DBPNG), applying the same load factor, the resulting fixed cost component of the gas transport cost is approximately $1.58/GJ in real June 2012 dollars[8]. Given that many of the gas-fired generators will have take-or-pay contracts, much of this fixed cost component may be considered a sunk cost which does not appear to be fully included within the bid price for gas-fired generators. Adopting the same approach that was applied for the FY2012/13 margin value review, SKM MMA has conservatively assumed that only 50% of the fixed cost component should be included in formulating the marginal costs for gas-fired generators.

4.3.2. Fuel constraints

Constraints limiting the daily availability of contract gas have been included in the modelling, based on understanding of the market and historical data. Constraints on the total gas available in different locations have also been included. These figures correspond to estimations from historical

[8] This price does not include any carbon price pass through. The carbon price pass through is captured by explicitly modelling the transport emission intensity as discussed in Section 4.4.2.

dispatch data and liquid fuel usage for 2008, and have been fine-tuned in the PLEXOS model during previous SWIS backcasting exercises.

4.4. Carbon price and emission intensities

The Federal Government has introduced a price on carbon through the Clean Energy Future scheme, which commenced on 1 July 2012. The price will be set at $24.15/t CO_2-e for the 2013/14 financial year (23.27/t CO_2-e in real June 2012 dollars assuming Australian CPI of 2.5%[9]).

The introduction of a carbon price impacts on the marginal cost of supply and Balancing Prices in the market simulations. For a given carbon price, PLEXOS calculates the short-run marginal cost for each generator including the marginal emission cost, adjusting the merit order accordingly. Key assumptions for this calculation include the carbon price, the emission production rate for each fuel type, and the heat rate of each generator. The CO_2-e emission production rates assumed for each fuel are listed in Table 4-3 and the basis for these assumptions are described in detail below. These emission production rates include both combustion and fugitive emissions as the delivered fuel price excludes the upstream component of fugitive emissions. The heat rates are summarised in Table 4-5. The resulting CO_2-e emission production rate for an individual generator is the product of the heat rate and the fuel emission production rate. The SRMC for the generator is then adjusted by multiplying this generation CO_2-e emission production by the $23.27/t CO_2-e carbon price. The resulting emission intensities for individual power stations, at maximum output, are included in Table 4-5.

■ **Table 4-3 CO2 emission production rate assumed for each fuel (kg/GJ)**

Fuel type	CO_2-e Production Rate (kg/GJ)
Coal	93.1
Vinalco coal	Confidential
Cogen gas	52.3
Verve gas	52.3
NewGen gas	52.3
IPP gas	52.3
New gas	52.3
Spot gas	52.3
Distillate	74.8

[9] Australian CPI growth of 2.5% is assumed as this falls in the middle of the Reserve Bank target range of 2 – 3 %.

4.4.1. Coal fired generation

In Table 1 of the National Greenhouse Accounts (NGA) Factors[10] the emission intensity for black coal is assessed as 88.43 kg CO_2-e /GJ. However, this emission intensity is not location specific. WA's coal typically has a higher moisture and carbon content than black coal in other regions of Australia. Therefore, SKM MMA used an emission intensity of 93.1 kg CO_2-e /GJ, consistent with assumptions in Griffin Power's *Greenhouse Gas Abatement Programme, Bluewaters Project,* 2008[11]. It is assumed that this emission intensity includes fugitive emissions from mining that is not reflected in the delivered fuel price in the model assumptions.

Vinalco provided specific assumptions about heat rates at maximum capacity and the average emission intensity at maximum output.

4.4.2. Gas fired generation

The combustion of natural gas is assessed as 51.33 kg CO_2-e GJ from Table 2 of the NGA Factors.

The transport of natural gas depends on pipeline distance. The relevant transmission factor is 8.72 t CO_2-e /km of pipeline[12]. The total emission of the Dampier to Bunbury Pipeline is published in the NGERS Greenhouse and Energy Information for 2010/11[13] as 264,234 t CO_2-e. The average throughput of the pipeline is approximately 757[14] TJ/day which gives an annual value of 276 PJ. Dividing the published emissions into the throughput gives a transport emission of 0.956 kg CO_2-e/GJ.

For the Gas to Goldfields Pipeline, there is no separately published level of emissions. Assuming maximum gas consumption for compressors of 490 TJ per year and applying the assumed gas combustion figure of 51.33 kg CO_2-e/GJ, we obtain a total pipeline emission combustion figure of 25,151.7 t CO_2-e. The pipeline is 1,378 km from Yarraloola to Kalgoorlie[15]. Based on the transmission factor of 8.72 t CO_2-e/km, the standard emission for the pipeline would be 12,016 t CO_2-e, resulting in a total emissions of 37,168 t CO_2-e. Dividing this quantity into the estimated

10 http://www.climatechange.gov.au/~/media/publications/greenhouse-acctg/national-greenhouse-factors-july-2010-pdf.pdf

11 Greenhouse Gas Abatement Programme for Bluewaters Power Station, cited http://www.griffinenergy.com.au/default.aspx?MenuID=76

12 Table 15: Natural gas transmission emission factors, NGA Factors.

13 http://www.cleanenergyregulator.gov.au/National-Greenhouse-and-Energy-Reporting/Publication-of-NGER-data/greenhouse-and-energy-information/greenhouse-and-energy-information-2010-2011/Pages/default.aspx

14 Revised Access Arrangement Model, ERA website http://www.erawa.com.au/3/1086/48/dampier_to_bunbury_natural_gas_pipeline__revised_a.pm

15 http://www.apa.com.au/media/176981/ggt%20approved%20proposed%20revised%20access%20arrangement%20information%20for%20ggp.pdf

contract capacity of 105.64 TJ/day[16], gives a transport emission intensity of 0.964 kg CO_2-e /GJ delivered. These calculations are summarised in Table 4-4.

The total emission factor for gas is therefore considered to be:

52.29 kg CO_2-e /GJ for Muja and North Country

52.29 kg CO_2-e /GJ for the Goldfields.

Table 4-4 Analysis of gas transport emissions

	Units	DBNGP	GGP
Energy Consumption	TJ	4,910	490
Gas Combustion	t CO_2-e	252,035	25,152
Pipeline	t CO_2-e	12,199	12,016
Total	t CO_2-e	264,234	37,168
NGER Emissions	t CO_2-e	264,234	N/A
Transported	TJ	276,305	38,559
	TJ/day	757	106
Emissions	t CO_2-e /GJ	0.956	0.964

4.4.3. Distillate fired generation

The combustion of distillate (described as diesel oil for stationary energy purposes) is assessed as 69.5 kg CO_2-e /GJ from Table 3 of the NGA Factors.

For distillate supplied to these peaking plants, the notional allowance for transport of distillate is 5.3 kg CO_2-e /GJ from Table 39 of the NGA Factors. There is no distinction by location. We therefore apply a total emission of 74.8 kg CO_2-e /GJ to represent the likely emission of distillate delivered to peaking generators.

4.5. Generation assumptions

4.5.1. Existing generators

Table 4-5 shows some of the key properties of existing generators in the model[17], including the larger private power stations owned by Alcoa and the Goldfields miners.

16 http://www.apa.com.au/media/176981/ggt%20approved%20proposed%20revised%20access%20arrangement%20information%20for%20ggp.pdf

17 Note that Bremer Bay wind farm and Blair Fox (Karakin) wind farm has been excluded as their effect is considered to be negligible. Mt Herron has also been excluded following advice from the IMO that the facility is not expected to generate during the 2013/14 financial year.

Capacity obligations for Southern Cross cut out on 1st October 2013. Given the infrequency with which it would impact on the SWIS within the first three months of the 2013/14 financial year, this power station was not modelled for the 2013/14 financial year. This is not expected to be material to the margin value review outcomes.

Some of the power stations listed may represent the aggregation of one or more actual facilities.

4.5.2. 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. 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.

4.5.3. Unit commitment

Unit commitment is determined within the PLEXOS simulations to minimise total system costs taking cognisance of unit start-up costs. Start-up costs for Pinjar units 1 – 7 and the Perth Energy facility were derived from assumptions provided in SKM MMA's 2012 Energy Price Limits report[18]. Through consultation, some market participants provided updated start-up costs and these confidential values have been used in the modelling. For the remaining facilities, start-up costs were based on Perth CPI escalation of the values used in the FY2012/13 margin value review, which were provided by the IMO.

For some units that typically operate as "must-run", unit commitment is imposed on the model. Specifically, the Bluewaters units, Alinta Pinjarra, Muja 7 and 8, Collie, cogeneration units and other generators meeting private loads are treated as units that must generate whenever they are available.

[18] http://www.imowa.com.au/f5789,2360899/SKM_MMA_Final_Report_2012_EPL_Review.pdf

Table 4-5 Properties of existing generators

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
BW1_BLUEWATERS_G2	9.75	10.79	Coal	2.08		2.27	908	21.12	43.70	1.00
BW2_BLUEWATERS_G1	9.75	10.79	Coal	2.08		2.27	908	21.12	43.70	1.00
COLLIE_G1	9.5	10.38	Coal	2.08		1.14	884	20.58	41.51	1.00
MUJA_G5	11.04	14.06	Coal	2.08		4.55	1028	23.92	51.47	1.00
MUJA_G6	11.04	14.06	Coal	2.08		4.55	1028	23.92	51.47	1.00
MUJA_G7	9.85	11.37	Coal	2.08		4.27	917	21.34	46.13	1.00
MUJA_G8	9.85	11.37	Coal	2.08		4.27	917	21.34	46.13	1.00
ALINTA_PNJ_U1	12	12	Cogen gas	2.67	1.09	-27.69	627	14.60	31.94	0.99
ALINTA_PNJ_U2	12	12	New gas	6.25	1.09	-27.69	627	14.60	74.94	1.01
ALCOA_WGP	12	12.62	Cogen gas	2.67	1.09	-24.36	627	14.60	35.27	0.99
PPP_KCP_EG1	8	10.48	Verve gas	3.12	1.09	-25.51	418	9.73	17.91	1.02
SWCJV_WORSLEY_COGEN_COG1	12	12.02	Verve gas	3.12	1.09	-25.96	627	14.60	39.17	0.99
TIWEST_COG1	13	21.33	Verve gas	3.12	1.09	-29.49	680	15.82	41.06	1.02
COCKBURN_CCG1	8	8.43	Verve gas	3.12	1.09	3.93	418	9.73	47.35	1.01
KWINANA_G5	11.7	14.42	Verve gas/Coal	2.60	1.09	4.37	851	19.79	67.34	1.01
KWINANA_G6	11.7	14.42	Verve gas/Coal	2.60	1.09	4.37	851	19.79	67.34	1.01
KWINANA_GT1	14.6	25.99	Verve gas	3.12	1.09	22.94	763	17.76	102.18	1.01
MUNGARRA_GT1	13.5	21.85	Verve gas	3.12	0.79	4.67	706	16.43	73.96	1.02
MUNGARRA_GT2	13.5	21.85	Verve gas	3.12	0.79	4.67	706	16.43	73.96	1.02
MUNGARRA_GT3	13.2	21.56	Verve gas	3.12	0.79	4.67	690	16.06	72.42	1.02

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
PINJAR_GT01	13.5	21.85	Verve gas	3.12	1.09	confidential	706	16.43	confidential	1.03
PINJAR_GT02	13.5	21.85	Verve gas	3.12	1.09	confidential	706	16.43	confidential	1.03
PINJAR_GT03	13.2	22.46	Verve gas	3.12	1.09	confidential	690	16.06	confidential	1.03
PINJAR_GT04	13.2	22.46	Verve gas	3.12	1.09	confidential	690	16.06	confidential	1.03
PINJAR_GT05	13.2	22.46	Verve gas	3.12	1.09	confidential	690	16.06	confidential	1.03
PINJAR_GT07	13.2	22.46	Verve gas	3.12	1.09	confidential	690	16.06	confidential	1.03
PINJAR_GT09	12.08	19.28	Verve gas	3.12	1.09	4.55	654	15.21	72.39	1.03
PINJAR_GT10	12.08	19.28	Verve gas	3.12	1.09	4.55	654	15.21	72.39	1.03
PINJAR_GT11	12.01	21.74	Verve gas	3.12	1.09	5.29	638	14.84	71.51	1.03
NEWGEN_KWINANA_CCGT	confidential	confidential	NewGen gas	3.12	1.09	2.27	confidential	confidential	confidential	1.02
KEMERTON_GT11	12.2	13.25	Verve gas/distillate	3.12	1.09	2.43	638	14.84	68.64	1.01
KEMERTON_GT12	12.2	13.25	Verve gas/distillate	3.12	1.09	2.43	638	14.84	68.64	1.01
ALINTA_WGP_GT	11.5	16.2	New gas/distillate	6.25	1.09	2.43	601	13.99	100.78	1.01
ALINTA_WGP_GT2	11.5	16.2	New gas/distillate	6.25	1.09	2.43	601	13.99	100.78	1.01
NEWGEN_NEERABUP	confidential	confidential	New gas	6.25	1.09	2.43	confidential	confidential	confidential	1.03
PRK_AG	confidential	confidential	IPP gas	4.17	3.83	4.60	confidential	confidential	confidential	1.24
GERALDTON_GT1	15.25	15.95	Distillate	23.27		2.61	1141	26.54	384.04	1.04
WEST_KALGOORLIE_GT2	13.5	13.5	Distillate	23.27	0.93	34.14	1010	23.50	384.30	1.08
WEST_KALGOORLIE_GT3	14.75	14.75	Distillate	23.27	0.93	34.14	1103	25.67	416.72	1.08

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary Fuel	Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
GENERIC LANDFILL GAS	11.3	11.3	Landfill Gas	2.27		-25.54			0.12	1.02
ALBANY_WF1			Wind			-39.11			-39.11	1.07
ALINTA_WWF			Wind			-39.11			-39.11	0.95
EDWFMAN_WF1			Wind			-39.11			-39.11	1.00
SKYFRM_MTBARKER_WF1			Wind			-39.11			-39.11	1.11
KALBARRI_WF1			Wind			-39.11			-39.11	1.28
COLLGAR			Wind			-39.11			-39.11	1.04
PERTH_ENERGY_GT1	10.7	16.06	New gas	6.25	1.09	21	559	13.02	112.56	1.02
KWINANA_GT2	9.35	15.23	Verve gas/distillate	3.12	1.09	6.47	486	11.32	56.94	1.02
KWINANA_GT3	9.35	15.23	Verve gas/distillate	3.12	1.09	6.47	486	11.32	56.94	1.02
TESLA_PICTON	14.44	14.44	Distillate	23.27		2.61	1080	25.13	363.78	1.02
KALAMUNDA	15.27	18.7	Distillate	23.27		2.61	1142	26.58	384.54	1.04
TESLA_GERALDTON_G1	14.44	14.44	Distillate	23.27	-	$2.61	1080	25.13	363.78	1.03
GRASMERE_WF			Wind		-	-39.11			-39.11	1.08
NAMKKN_MERR_SG1	12.58	12.58	Distillate	23.27	-	$4.67	941	21.90	319.31	1.04
MUJA_G1	confidential	confidential	Vinalco coal	confidential	-	$4.55	confidential	confidential	confidential	1.00
MUJA_G2	confidential	confidential	Vinalco coal	confidential	-	$4.55	confidential	confidential	confidential	1.00
MUJA_G3	confidential	confidential	Vinalco coal	confidential	-	$4.55	confidential	confidential	confidential	1.00
MUJA_G4	confidential	confidential	Vinalco coal	confidential	-	$4.55	confidential	confidential	confidential	1.00
Greenough Solar Farm (PV)			Solar		-	-39.11			-39.11	1.02

* Negative VOM attempts to approximate the impact of the value of steam on economic dispatch of these cogeneration units

4.5.4. Planned maintenance and forced outages

Planned maintenance is modelled in PLEXOS in one of two ways: either explicitly with users specifying the period over which the unit will not be available, or via maintenance rates. If maintenance rates are used, PLEXOS schedules the maintenance to occur in periods of high reserve, where possible, by allocating maintenance in such a way that the minimum reserve level across the year is maximised.

Forced outages are unplanned, and can occur at any time. These are randomly determined in PLEXOS and differ in each Monte Carlo simulation. Twelve Monte Carlo simulations were conducted for this analysis. In each simulation, the frequency with which forced outages occur is determined by the forced outage rate and mean-time-to-repair parameters in the model. The outage rates have been sourced from SKM MMA's *Assessment of Reliability of the South West Interconnected System 2012 – 2022*, prepared for the IMO in 2011. The forced outage rates are derived from outage data provided over the period from 2008 to 2010. The maintenance requirements are based on the requirements assumed for 2013/14 in that study, provided by the IMO for nominated plant. The maintenance rates referred to outages of more than 2 weeks duration. These are relatively large maintenance events which are expected to occur in maintenance cycles. Where no major maintenance is assumed for a unit in the 2013/14 year, 4 days of maintenance is still assumed to cover general wear and tear. Accordingly, a maintenance rate of 1.1% is assigned to all units that are not assumed to undergo major maintenance in the year. No outage rates are included for wind farms since the historical generation profiles of these units will already include outages.

4.5.5. Short run marginal cost calculations

Within the PLEXOS software, the SRMC is calculated as follows:

*SRMC = marginal heat rate * (fuel price + variable transport charge) + VOM cost + carbon cost*

This SRMC is then divided by the marginal loss factor prior to determining the merit order of dispatch. The assumed marginal loss factors for 2013/14 were provided by IMO and are listed for each facility in Table 4-5. Because heat rate curves are used for each facility, the SRMC will vary depending on the level of dispatch (see Section 4.5.7 for more discussion on heat rate curves).

The SRMC values in Table 4-5 are estimated for 2013/14, based on the primary fuel only and considering the average heat rate and carbon cost at maximum capacity. Most of the input values were obtained from publicly available information (SOO, planning reviews, IMO website, and companies' websites). In some cases, Market Participants have provided more accurate details on a confidential basis.

Missing parameters such as variable operating and maintenance (VOM) costs were estimated by SKM MMA, considering the nature and known characteristics of the facilities, or based on actual half-hourly dispatch information. The high VOM cost for Perth Energy was derived from the Energy Price Limits report 2011[19], taking the reported VOM cost of $270 per hour in March 2012 dollars adjusted to real June 2012 dollars, multiplying by an estimate of hours operating based on 2010/11 actual data, and then dividing by an estimate of annual generation also based on the 2010/11 actual data. The 2012 Energy Price Limits report did not include any update to these assumptions so instead, the assumptions used in the FY12/13 margin value review have been escalated by Perth CPI.

For the wind farms and landfill gas plants, the assumed value of Large-scale Generation Certificates (LGCs) has been subtracted from the variable operating and maintenance costs, resulting in a negative SRMC. Even with a Balancing Price of $0/MWh, renewable generators would be foregoing LGCs revenue if they were shut down. The LGC price assumed in this study is $39.11/MWh based on 2013 and 2014 prices currently being traded adjusted to June 2012 dollars. Generation profiles for Albany, Emu Downs, and Alinta wind farms use historical data so that they are properly correlated to the load profile. Historical 2009/10 wind farm data for Collgar wind farm is not available, so it is not possible to correlate the output of this wind farm with the 50% POE load profile used. Instead, the availability of this wind farm is randomly varied around its average capacity factor.

4.5.6. Future generators

Table 4-6 show the properties of future generators expected to be operational over the entire 2013/14 review period. In summary, SKM MMA has considered the following units for commissioning:

- Tesla Kemerton 9.9 MW of diesel units in Muja region
- Tesla Northam 9.9 MW of diesel units in Muja region
- Mumbida Wind Farm 55 MW in North Country.

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[19] http://www.imowa.com.au/f5789,2360899/SKM_MMA_Final_Report_2012_EPL_Review.pdf;

Table 4-6 Properties of future generators

Generator	Average Electrical HR (GJ/MWh sent out HHV) at max	Average Electrical HR (GJ/MWh sent out HHV) at min	Primary fuel	Primary Fuel Price ($/GJ)	Transport charge ($/GJ)	VO&M ($/MWh sent out)	Average CO2-e emission intensity at max (kg/MWh sent out)	Carbon cost ($/MWh sent out)	SRMC 2012/13 ($/MWh sent out)	MLF
TESLA_KEMERTON_G1	14.44	14.44	Distillate	23.27	-	$2.61	1080	25.13	363.78	1.01
TESLA_NORTHAM_G1	14.44	14.44	Distillate	23.27	-	$2.61	1080	25.13	363.78	1.00
Mumbida Wind Farm			Wind		-	-39.11			-39.11	0.95

4.5.7. Heat rates

The sent out heat rates presented in Table 4-5 are based on available published or calculated values, using engineering judgement, for the rated plant capacities at ISO conditions, expressed as Higher Heating Value (HHV). In some instances, generators have provided more accurate information on a confidential basis, following requests for details made by the IMO as part of the consultation processes for this review and for the 2012/13 financial year review under the current Market Rules. It should be noted that the marginal HHV heat rate is typically lower than the average HHV heat rate at maximum sent-out rated capacity so the SRMC values are likely to be slightly over-estimated in Table 4-5. In the market modelling, polynomial heat input functions are specified for most generators, and the SRMC at any output level is calculated based on the marginal heat rate at that point on the curve.

In some instances, no information on the heat input function was available. For these units, a static heat rate value is assumed regardless of output level. These units are not ones that would be expected to provide reserve, so the lack of heat input function is not considered material for this analysis.

For the generators servicing intermittent load only an average heat rate is assumed, since the full capacity range of the generator is not modelled in the simulation. For these generators, only the generation in addition to the private load is offered into the STEM, up to the maximum scheduled generation volume. On average, it is assumed that a generator servicing private load that is offering additional generation into the STEM is operating at a relatively efficient point on its heat rate curve.

4.6. Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both spinning reserve and load following reserve have been modelled in PLEXOS.

System Management has been consulted on the information in this section to verify its accuracy.

4.6.1. 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 (clause 3.10.2(a)). Spare capacity on other generating units and/or interruptible load is made available to support system frequency in the event of a contingency.

4.6.2. Load following reserve

Load following reserve is required to meet fluctuations in supply and demand in real time. The load following reserve 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 total spinning reserve requirement in the WEM is therefore reduced by the amount of load following reserve that is being provided.

There are two LFAS's in the WEM: raise and lower. Based on the estimate of the LFAS requirement provided in System Management's Ancillary Service Report for 2012[20], for the 2013/14 financial year we assume a LFAS requirement of 90 MW for raise and 90 MW for lower with a ramp rate of +/- 18 MW/min. Under the Market Rules, System Management is able to reduce the LFAS requirement for some Trading Intervals where, for example, calm conditions are forecast. However, as System Management was unable to provide an estimated pattern for these reductions, the modelling assumed the full ± 90 MW requirement for all Trading Intervals.

The generators providing LFAS must be able to raise or lower their generation in response to AGC signals. The same generator does not need to provide both the raise and lower LFAS. Indeed, the LFAS market allows participants to offer for one and not the other. However, in aggregate across all generators providing LFAS the total required amounts of raise and lower service must be available.

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.

4.6.3. Reserve provision

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

Under the current Market Rules, both Verve Energy and IPPs may provide load following reserve subject to meeting technical requirements. The generators providing load following reserve must be able to raise or lower their generation in response to Automatic Generation Control (AGC) signals. The same generator does not need to provide both the raise and lower load following reserve, provided that in aggregate across all generators providing load following reserve the total required amounts of raise and lower service are available.

[20] *http://www.imowa.com.au/f2841,2379223/Ancillary_Service_Report-2012_FINAL.pdf*

For this review period, two IPPs have been assumed to participate in the LFAS market. Spinning reserve continues to be provided by Verve Energy or through ancillary service contracts under the new MEP arrangements.

For all generators specified as being able to provide reserve, PLEXOS assumes by default 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.

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. For spinning reserve, additional restrictions are imposed on some units, as suggested by System Management.

4.6.4. Ancillary service contracts

Some spinning reserve may be provided by reducing load through interruptible load Ancillary Service Contracts. Consistent with System Management's Ancillary Service Report for 2012[21], provided to the IMO under clause 3.11.11, 42 MW of interruptible load is assumed to be available. This interruptible load can be used at all times to provide spinning reserve.

No other Ancillary Service Contracts for spinning reserve are assumed for the purposes of this study.

Effectively, the spinning reserve requirement to be provided by Verve Energy is therefore equal to:

70% largest generating unit – 42 MW interruptible load – 90 MW load following reserve.*

4.6.5. Value of reserve shortage

Clause 3.10.2 (d) of the Market Rules states that the spinning reserve 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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[21] *http://www.imowa.com.au/f2841,2379223/Ancillary_Service_Report-2012_FINAL.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 (f).

The margin values, availability cost and system marginal prices are presented in Table 5-1 averaged over 12 random outage samples.

▪ **Table 5-1 Parameter estimates**

Parameter	Average	Standard Error
Margin_Off-Peak	27%	0.9%
Margin_Peak	17%	1.0%
SR_Capacity_Off-Peak (MW)	197.18	0.18
SR_Capacity_Peak (MW)	220.16	0.04
Availability cost ($M)	7.22	0.32
Off-peak price ($/MWh)	47.01	0.07
Peak price ($/MWh)	50.81	0.09

On average, a Margin_Off-Peak value of 27% is recommended, based on time-weighted average system marginal off-peak prices of $47.01/MWh. For Margin_Peak, an average value of 17% has been estimated, based on time-weighted average system marginal peak prices of $50.81/MWh.

In conducting its review of the margin values for the 2012/13 Financial Year under the new balancing and LFAS market in early 2012, SKM MMA recommended a Margin_Peak value of 32% and a Margin_Off-Peak value of 31% for the financial year 2012/13.

Table 5-2 summarises the parameter estimates for the 2012/13 and 2013/14 reviews for comparison. For the 2013/14 financial year, the Margin_Peak and Margin_Off-Peak values have decreased, with the change in Margin_Peak being most noticeable. Peak and off-peak prices, and SR_Capacity peak and off-peak have also decreased in this current review.

Table 5-2 Comparison of 2013/14 and 2012/13 parameters

Parameter	2013/14	2012/13
Margin_Off-Peak	27%	31%
Margin_Peak	17%	32%
SR_Capacity_Off-Peak (MW)	197.18	205.78
SR_Capacity_Peak (MW)	220.16	221.49
Availability cost ($M)	7.22	12.51
Off-peak price ($/MWh)	47.01	52.57
Peak price ($/MWh)	50.81	55.93

There are several modelling changes causing the differences between the margin values determined for the 2012/13 financial year and this review's simulations:

- Updated demand projections from 2012 SOO. In this latest SOO, the energy projection for 2013/14 financial year has decreased by 9% while the peak reduces by 3% when compared to the 2013/14 projections from the 2011 SOO. Moreover, the 2013/14 projections are lower than the 2012/13 projections used in the previous margin value analysis. This creates surplus capacity in the system, making it easier to provide ancillary services and reducing the cost of these services.
- The voltage stability constraint in North Country has been relaxed so that two Mungarra units must be in operation when demand exceeds 95 MW, compared to 77 MW previously. Combined with lower demand, this means that the Mungarra units now operate less frequently, which affects unit commitment decisions of other generators. Since Mungarra is higher in the merit order in terms of SRMC, this will enable reserve to be provided at lower cost.
- Changes in the modelling approach to load following reserve such that the maximum response represents a unit's ability to increase or decrease output within a 5 minute period, regardless of whether providing raise or lower. Previously, if a generator was only providing raise (or only providing lower) the maximum response was assumed to be double what is currently assumed. This would generally increase the cost of providing reserve, all other things being equal, however in this instance the impact was swamped by the surplus supply situation.
- Revised parameters for generators following consultation that were provided on a confidential basis. These include fuel price, start-up costs, heat rates, outage rates.

- In some instances during peak periods, IPP generation was backed off and total Verve Energy output was increased in order to meet the spinning reserve requirements. If the resulting increase in sales revenue was greater than the increase in cost, the net benefit reduced the reserve availability cost.

Table 5-3 shows how the Margin_Peak and Margin_Off-Peak values vary between Monte Carlo samples. This variation is largely due to differences in forced outages and wind availability between samples.

▪ **Table 5-3 Key margin value parameters by sample**

Sample	S01	S02	S03	S04	S05	S06	S07	S08	S09	S10	S11	S12	Average
Margin off-peak	29%	26%	24%	27%	26%	29%	27%	34%	24%	31%	26%	23%	27%
Margin peak	19%	15%	15%	18%	16%	17%	17%	26%	14%	20%	18%	14%	17%
Availabilty cost ($M)	$7.76	$6.43	$6.44	$7.43	$6.58	$7.44	$7.14	$10.02	$6.01	$8.21	$7.19	$5.97	$7.22
OP availability cost ($M)	$3.35	$3.06	$2.90	$3.23	$3.02	$3.48	$3.20	$4.06	$2.82	$3.68	$3.06	$2.76	$3.22
P availability cost ($M)	$4.41	$3.37	$3.54	$4.20	$3.57	$3.97	$3.94	$5.96	$3.19	$4.53	$4.13	$3.21	$4.00
Off-peak price ($/MWh)	$46.45	$47.01	$47.26	$46.95	$46.73	$47.34	$47.15	$47.06	$46.90	$47.22	$46.91	$47.12	$47.01
Peak price ($/MWh)	$50.03	$50.67	$50.98	$50.97	$50.49	$51.06	$50.94	$51.12	$50.90	$50.70	$50.81	$51.06	$50.81
SR_Capacity_Peak (MW)	220.51	219.97	220.05	220.13	220.14	220.16	219.97	220.24	220.02	220.16	220.29	220.25	220.16
SR_Capacity_Off-Peak (MW)	196.52	196.75	197.59	198.15	196.46	197.79	196.49	198.16	197.15	197.09	196.67	197.33	197.18

6. Conclusions

Based on the market modelling, SKM MMA recommends the following margin values for the financial year commencing July 2013:

- Margin_Off-Peak 27%
- Margin_Peak 17%.

These values are sensitive to a number of factors including:

- the price and volume assumptions relating to existing and new gas contracts
- the unit commitment decisions, which are based on start-up costs, minimum generation assumptions and the maximum reserve provision for each unit
- the extent of IPP participation in the LFAS market.

Moreover, these margin values have been developed assuming that no Ancillary Service Contracts for spinning reserve (apart from the existing contracts for Interruptible Load) are negotiated for the 2013/14 financial year.

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

Appendix A Errata to assumptions report

Minor changes have been detected between the input assumptions reported in Table 8-1 of the 2012 Margin Peak and Margin Off-peak Review, Assumptions and Methodology Report (Public) V3.0, 10th September 2012 and the actual inputs used in the market modelling to assess these margin values.

Page 21, Table 8-1: VO&M charge for ALINTA_PNJ_U1 and U2 should be $-27.69/MWh, not $-27.34/MWh. The table had not been updated correctly in the original report.

Page 21, Table 8-1: VO&M charge for ALCOA_WGP should be $-24.36/MWh, not $-24.01/MWh. The table had not been updated correctly in the original report.

Page 21, Table 8-1: VO&M charge for PPP_KCP_EG1 should be $-25.51/MWh, not $-25.16/MWh. The table had not been updated correctly in the original report.

Page 21, Table 8-1: VO&M charge for SWCJV_WORSLEY_COGEN_COG1 should be $-25.96/MWh, not $-25.61/MWh. The table had not been updated correctly in the original report.

Page 21, Table 8-1: VO&M charge for TIWEST_COG1 should be $-29.49/MWh, not $-29.14/MWh. The table had not been updated correctly in the original report.

Page 22, Table 8-1: Average Electrical HR (GJ/MWh sent out HHV) for PINJAR_GT09 and PINJAR_GT10 should be 12.08 not 12.5 due to a change in maximum capacity assumed

Page 22, Table 8-1: Average Electrical HR (GJ/MWh sent out HHV) for PINJAR_GT11 should be 12.01 not 12.2 due to a change in maximum capacity assumed

Page 22, Table 8-1: Fuel price ($/GJ) for GERALDTON_GT1, WEST_KALGOORLIE_GT2 and WEST_KALGOORLIE_GT3 should be $23.27, not $23.33. This change is due to a change in Perth CPI assumption that was corrected in the text but the figures were not updated in the corresponding table.

Page 22, Table 8-1: SRMC 2013/14 ($/MWh sent out) for GERALDTON_GT1 should be $384.04, not $348.92. This change is due to a change in distillate fuel price (see note above).

Page 22, Table 8-1: SRMC 2013/14 ($/MWh sent out) for WEST_KALGOORLIE_GT2 should be $384.30, not $385.11. This change is due to a change in distillate fuel price (see note above).

Page 22, Table 8-1: SRMC 2013/14 ($/MWh sent out) for WEST_KALGOORLIE_GT3 should be $416.72, not $417.60. This change is due to a change in distillate fuel price (see note above).

Page 22, Table 8-1: VO&M charge and SRMC 2013/14 ($/MWh sent out) for ALBANY wind farm should be $-39.11/MWh, not $-38.64/MWh. This is due to a slight change in LGC price assumption.

Page 23, Table 8-1: VO&M charge and SRMC 2013/14 ($/MWh sent out) for ALINTA_WWF, EDWFMAN_WF1, SKYFRAM_MTBARKER_WF1, KALBARR_WF1, COLLGAR, GRASMERE_WF and Greenough Solar Farm (PV) should be $-39.11/MWh, not $-38.64/MWh. This is due to a slight change in LGC price assumption.

Page 23, Table 8-1: Average Electrical HR (GJ/MWh sent out HHV) for KWINANA_GT2 and KWINANA_GT3 should be 9.35, not 9.3 due to a change in maximum capacity assumed

Page 23, Table 8-1: Fuel price ($/GJ) for TESLA_PICTON, KALAMUNDA, TESLA_GERALDTON_G1 and NAMKKN_MERR_SG1 should be $23.27, not $23.33. This change is due to a change in Perth CPI assumption that was corrected in the text but the figures were not updated in the corresponding table.

Page 23, Table 8-1: SRMC 2013/14 ($/MWh sent out) for TESLA_PICTON and TESLA_GERALDTON_G1 should be $363.78, not $364.61. This change is due to a change in distillate fuel price (see note above).

Page 23, Table 8-1: SRMC 2013/14 ($/MWh sent out) for KALAMUNDA should be $384.54, not $385.42. This change is due to a change in distillate fuel price (see note above).

Page 23, Table 8-1: SRMC 2013/14 ($/MWh sent out) for NAMKKN_MERR_SG1 should be $319.31, not $320.03. This change is due to a change in distillate fuel price (see note above).