

Margin Peak and Margin Off-Peak Review – Market Evolution Program

ASSUMPTIONS AND METHODOLOGY REPORT
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1. Introduction

As part of the Market Evolution Program (MEP), the Rule Change Proposal: Competitive Balancing and Load Following Market (RC_2011_10) proposes changes to the Wholesale Electricity Market Rules (Market Rules) relating to balancing and load following ancillary service (LFAS) market arrangements¹. These changes will impact on the choice of margin values to be used in calculating availability payments to Verve Energy, as availability payments will provide compensation for the provision of spinning reserve only and will no longer provide compensation for the provision of load following. The Independent Market Operator (IMO) has engaged SKM MMA (formerly McLennan Magasanik Associates) to assist it in determining the appropriate margin values to be applied for the periods 1 April 2012 to 30 June 2012, and the financial year commencing 1 July 2012 if the proposed MEP changes are approved.

To determine appropriate Margin_Peak and Margin_Off-peak parameters for the periods of interest, we intend to calculate 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 amended Market Rules.

We propose to simulate 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, using the same techniques that are used to clear the NEM, New Zealand and Singaporean electricity markets.

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

¹ http://www.imowa.com.au/RC_2011_10



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 Balancing Price set by the marginal generator. From previous modelling experience, we have found that this availability cost can be sensitive to key assumptions such as fuel costs (for new and existing plant), unit commitment (based on start-up cost assumptions) and the ability of various units to provide load following reserve.

In recognition of the importance of these assumptions, we have prepared this Assumptions Report for review by key stakeholders prior to undertaking any MEP analysis. All prices and costs in this report are given in June 2011 dollars.

Furthermore, to validate the modelling methodology and verify the reasonableness of assumptions used, the previous market modelling outcomes used in the assessment of the margin values for the 2010/11 review period were compared against actual market outcomes for that financial year. Some differences in market outcomes were observed, most notably, the market modelling was projecting much higher MCAP prices and a greater level of Verve Energy generation than observed in reality. MCAP prices on average were 38% lower than the modelled outcomes, and Verve Energy generation was 13% lower than the modelled outcomes. Much of these discrepancies was attributed to inaccuracies in input assumptions relating to demand, system outages, minimum generation levels and new entrant timing, assumptions which would result in differences in outcomes regardless of forecasting technique used.

To assess the impact of the inaccuracy in these input assumptions, a back-cast was undertaken to remove variations in results due to differences in input assumptions outside our control such as actual load, timing of new entry and unit availability. With these input assumptions corrected, modelled market outcomes for the 2010/11 were much closer to actual outcomes, although actual MCAP prices were still lower than projected, as summarised in Table 1-1.

■ **Table 1-1** **Variation rate before and after improved assumptions**

Item	Actual	Modelled	% variation from original modelled outcome	Back-cast	% variation from back-cast outcome
MCAP, \$/MWh (TWA)	37.08	59.99	-38%	47.55	-22%
Peak	45.90	77.64	-41%	58.60	-22%
Off Peak	23.37	35.21	-34%	32.03	-27%
Verve Energy generation, TWh²			-12%		7%

² [Actual](#) generation volumes confidential.



On close inspection of the market modelling outcomes from the analysis of the 2010/11 outcomes, and the back-casting exercise, it was recommended that the following input assumption modifications be adopted for the review of margin values for the new market arrangements to improve the accuracy of the forecasts:

- Correct minimum generation levels, as advised by System Management
- Reduce gas price assumptions
- Increase value of steam revenue assumed for cogeneration units
- Endeavour to include any known large outages scheduled for the review period.

These assumption modifications have been included in this Assumptions Report.



2. Methodology for calculating margin values

Load following and spinning reserve ancillary services for the WEM are currently provided by Verve Energy³. The IMO pays Verve Energy for these services in accordance with the formula prescribed in clause 9.9.2(a) of the Market Rules. Under the changes proposed in RC_2011_10, IPPs will also be able to offer provision of load following services by bidding into the Load Following Ancillary Service market. Load following providers will no longer be compensated through availability payments (for Verve Energy) or Ancillary Service Contract payments (for IPPs). Spinning reserve services will still be provided by Verve Energy, with payment determined in accordance with clause 9.9.2(f) under the proposed new 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 foregone 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:*

³ With the exception of a small quantity of spinning reserve provided by Interruptible Load under Ancillary Service Contracts.



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 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:

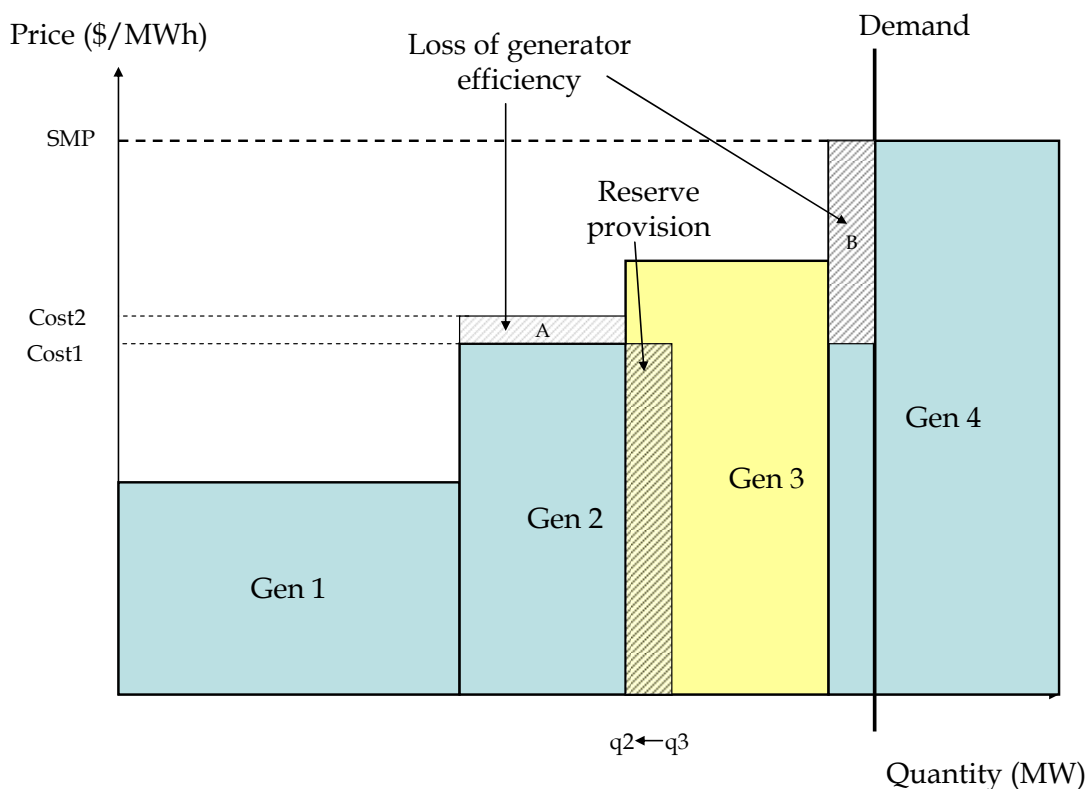
- movement to a less efficient point on a unit's heat rate curve
- an increase in either production from higher cost Verve Energy plant or Short Term Energy Market (STEM) or Balancing Market purchases, to counteract lower cost generation backed off to provide reserve
- additional start-up costs that 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 $q_3 - q_2$). 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 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 ($q_3 - q_2$) and the reserve availability cost was equal to area A + area B.

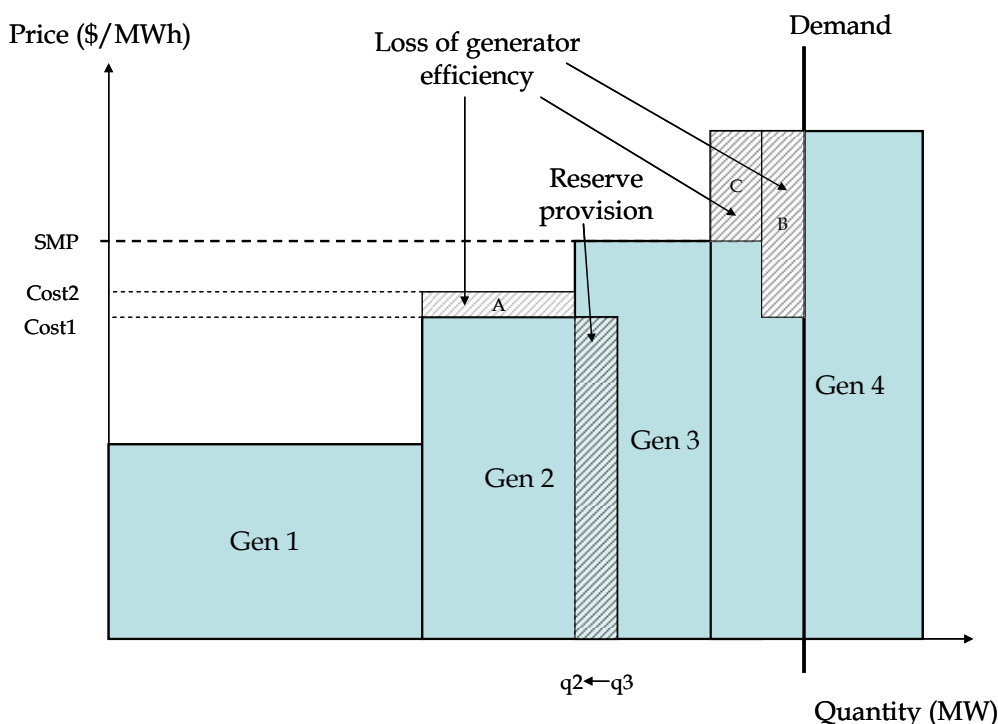
Now, consider the situation whereby Gen 4 has a minimum level greater than ($q_3 - q_2$). In order to meet the reserve requirement, Gen 2 must still back off generation from q_3 to q_2 , but Gen 4 is now constrained on to its minimum level. Consequently, Gen 3’s output is reduced as there is insufficient demand for Gen 3 to operate at maximum capacity and for Gen 4 to operate at minimum 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 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 SKM MMA understands that this unit has a relatively high minimum 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).

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 8.1.4.

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, LF_Up_Capacity and Balancing Price in the period. Margin values can therefore be calculated by rearranging this formula and using key outputs from the market simulations.

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 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 LF_Up_Capacity parameter represents the amount of load following upwards ancillary service required in the Trading Interval. Assumptions regarding this requirement are discussed in Section 9.2.



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
- A services component, 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 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. Over 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.

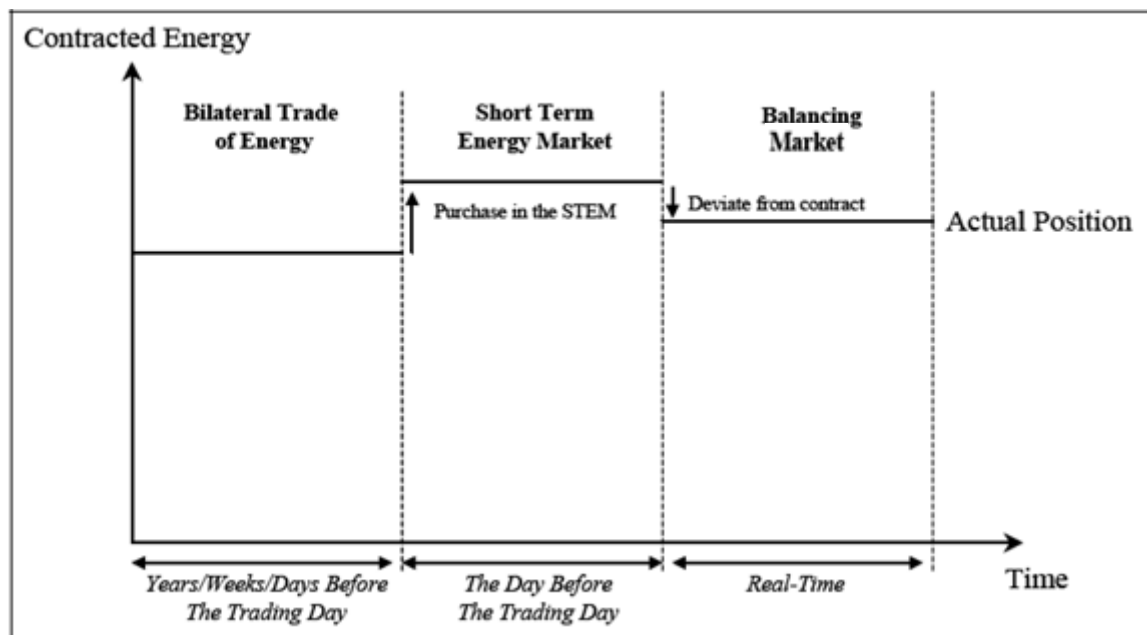
The IMO is responsible for clearing the offers and bids in the STEM. The STEM price is set at the point where the marginal offer price and marginal bid price are equal.

There will inevitably be slight differences between the day-ahead net contract volumes and the real time demand. Under the changes proposed in RC_2011_10, all Balancing Facilities (Verve Energy and IPPs) will be required to compete in a Balancing Market to accommodate these deviations and maintain system security. Balancing Facilities will be 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.3.9 of the proposed Amending 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

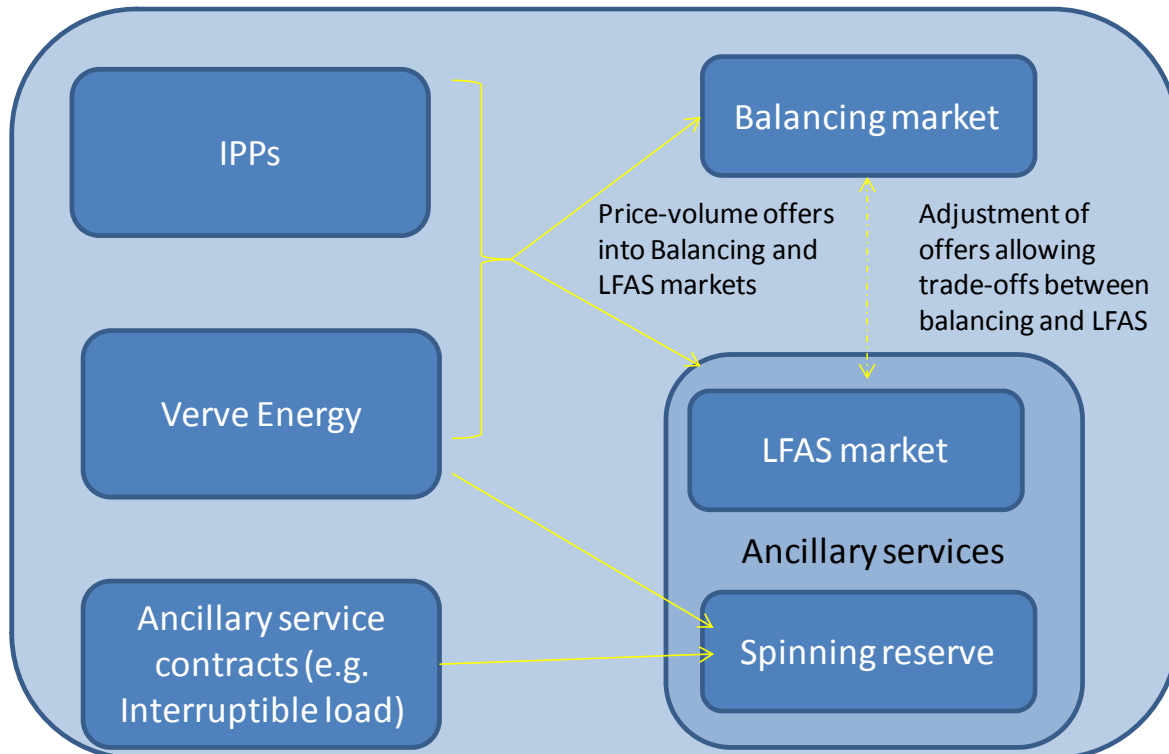
Additionally, the proposed rule changes allow IPPs to compete with Verve Energy for the provision of LFAS through an LFAS market. Payment for LFAS will be determined based on the market price for this service (excluding payments made for any emergency backup LFAS provided by Verve Energy on a “pay as bid” basis).

Verve Energy will remain the default provider of all ancillary services. Moreover, SR will only be provided by Verve Energy or through Ancillary Service Contracts such as interruptible load contracts. Figure 3-2 summarises participation by Verve Energy and IPPs in the Balancing Market, LFAS Market and provision of SR. A more detailed explanation of the proposed rule changes can be found in IMO (2011) *New Balancing Market Proposal: Design Details*⁴.

⁴ http://www.imowa.com.au/f4799,1958190/RC_2011_10_Final_12_Boxes.pdf



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

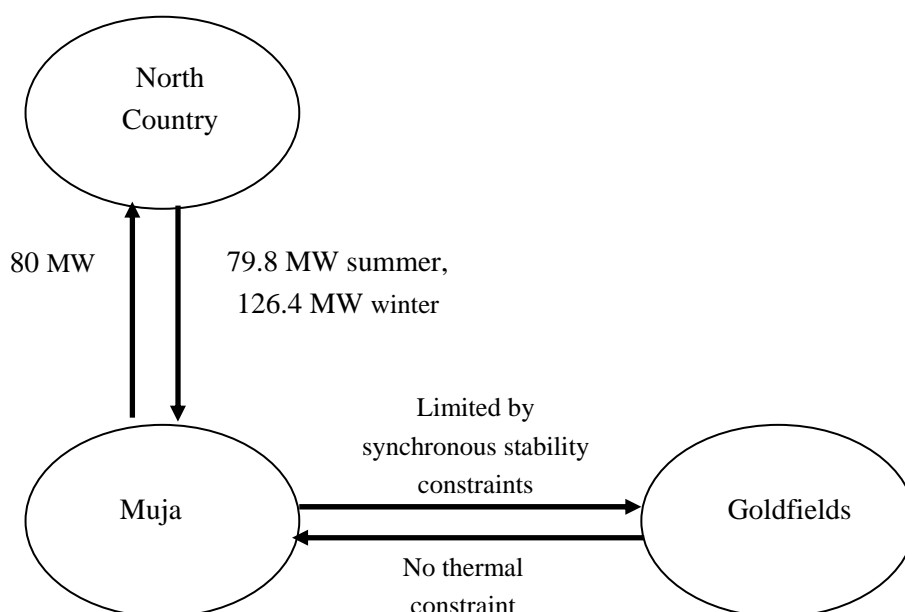


In the PLEXOS model we do not explicitly model the bilateral trades, STEM and Balancing Market separately. Instead, a gross pool is modelled, assuming economically efficient dispatch, and energy and ancillary services are co-optimised. Any discrepancies between the WEM and a PLEXOS market model are expected to be reduced by the introduction of the Balancing and LFAS Markets proposed under RC_2011_10, as this will bring the WEM closer towards the dispatch and competitive behaviour that would be expected in a gross pool model of operation.

4. 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 Alinta 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.

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 67 MW, one Mungarra unit must be in operation, increasing to two units in operation when load exceeds 77 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.



5. Demand assumptions

5.1. Regional demand forecasts

Table 5-1 shows our assumptions for sent-out energy and summer and winter maximum demand across the 3 nodes. These values are based on the 2011 Statement of Opportunities (SOO) load forecasts (medium growth scenario, 50% PoE), distributed among the three regions in accordance with the 2009/10 actual loads. Intermittent non-scheduled load information was provided by the IMO.

■ **Table 5-1 2011/12 and 2012/13 load assumptions**

Financial year	Parameter	Muja (Perth)	Goldfields	North Country	Total SWIS
2011/12	Energy (GWh)	18033	661	682	19377
	Summer Peak Demand 50% PoE (MW)	3972	144	138	4181
	Winter Peak Demand 50% PoE (MW)	3095	140	106	3274
	Intermittent non-scheduled load (MW)	98.3	46	0	144.3
2012/13	Energy (GWh)	18118	664	686	19468
	Summer Peak Demand 50% PoE (MW)	4123	149	143	4340
	Winter Peak Demand 50% PoE (MW)	3146	143	107	3328
	Intermittent non-scheduled load (MW)	98.3	46	0	144.3

In Table 5-1, 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 2011/12 and 2012/13 years.

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 5-1.

5.2. 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.



6. 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 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,
- 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.

6.1. Fuel costs

Table 6-1 shows our assumptions on fuel prices:

■ Table 6-1 Fuel prices (real June 11 dollars)

Name	Price (\$/GJ)
Coal	2.06
Cogeneration contract gas	2.64
Verve contract gas	3.09
NewGen contract gas	3.09
IPP contract gas	4.12
New gas	6.18
Landfill gas	2.25
Distillate	22.15

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For coal, gas and landfill gas, but excluding the NewGen contract gas, the prices used are the same as the prices used in the calculation of the FY2011/12 margin values that were determined by the ERA on 31 March 2011, adjusted by CPI. The gas price for NewGen contract gas was estimated based on publicly available data referring to contract gas prices negotiated around the time that the NewGen Kwinana gas contract was negotiated, and observed dispatch outcomes for the unit which indicated that the marginal price offered into the market was lower than previously estimated through the SKM MMA market modelling.

Distillate prices come from SKM MMA's Draft Electricity Price Limits 2011 study⁵, which estimated a price of \$22.61/GJ applying a calorific value of 38.6 MJ/litre. The additional transport cost to the Goldfields is estimated to be 67c/GJ.⁶

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 8-1. These charges have been provided by the IMO based on advice provided by ACIL Tasman. The fixed component of the gas transport charge in the ACIL Tasman numbers was converted to a variable cost per GJ assuming a load factor of 75%. For gas from the Dampier to Bunbury Pipeline (DBPNG), the resulting fixed cost component of the gas transport cost was approximately \$1.65/GJ. 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. After discussion with the IMO, SKM has therefore conservatively assumed that only 50% of the fixed cost component should be included in formulating the marginal costs for gas-fired generators. This equates to a reduction in gas transport cost from the DBPNG of approximately \$0.80/GJ, and a reduction of approximately \$2.20/GJ from the Goldfield's Gas Pipeline.

The gas transport charges provided by ACIL Tasman were assumed to be in December 2012 dollars, and have been de-escalated back to real June 2011 dollars assuming annual out-year inflation for 2012 and 2013 of 2.75%, consistent with the CPI assumptions made by ACIL Tasman. The difference between the calendar year 2012 transport charges applicable for the April to June 2012 period, and the average of the calendar year 2012 and calendar year 2013 transport charges used from the 2012/13 financial year was negligible once rounded to two decimal places. Therefore the same transport charges have been used for both periods of interest.

⁵ http://www.imowa.com.au/f4153,1540757/SKM_MMA_Draft_2011_EPL_Report.pdf

⁶ Prices in the SKM MMA "Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2011" report are nominal for the capacity year 2011/12. In order to convert them to real June 2011 dollars, we assumed they are from March 2012 (mid-point of the 2011-12 capacity year) and then scaled them back to June 2011 dollars using a CPI index estimated for March 2012 of 182.1 (obtained assuming an annual out-year inflation rate of 2.75%).



6.2. Fuel constraints

Based on our understanding of the market and historical data, we include gas constraints limiting the contract gas daily availability. We also include some constraints on the total gas available in different locations. These figures correspond to estimations 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.



7. Carbon price and emission intensities

The Federal Government intends to introduce a price on carbon through the Clean Energy Future scheme starting on 1 July 2012. The price will be set at \$23/t CO₂-e for the 2012/13 financial year. No carbon price applies for the period from April 2012 to June 2012.

The introduction of a carbon price will impact on the marginal cost of supply and Balancing Prices in the market simulations. For a given carbon price, PLEXOS automatically recalculates the short-run marginal cost for each generator, 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 CO₂-e emission production rates assumed for each fuel are listed in Table 7-1 and the basis for these assumptions are described in detail below. These emission production rates include both combustion and fugitive emissions. The heat rates are summarised in Table 8-1. The resulting CO₂-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 CO₂-e emission production by the \$23/t carbon price (\$22.08/t real June 2011 dollars). The resulting emission intensities for individual power stations, at maximum output, are included in Table 8-1.

■ **Table 7-1** **CO₂ emission production rate assumed for each fuel (kg/GJ)**

Fuel type	CO ₂ -e Production Rate (kg/GJ)
Coal	93.1
Cogen gas	52.3
Verve gas	52.3
NewGen gas	52.3
IPP gas	52.3
New gas	52.3
Distillate	74.8

7.1. Coal fired generation

In Table 1 of the National Greenhouse Accounts (NGA) Factors⁷ the emission intensity for black coal is assessed as 88.43 kg CO₂-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, an emission intensity of 93.1 kg CO₂-e /GJ, consistent with assumptions in

⁷ <http://www.climatechange.gov.au/~media/publications/greenhouse-acctg/national-greenhouse-factors-july-2010-pdf.pdf>



Griffin Power's *Greenhouse Gas Abatement Programme, Bluewaters Project, 2008*⁸. It is assumed that this emission intensity includes fugitive emissions from mining.

7.2. Gas fired generation

The combustion of natural gas is assessed as 51.33 kg CO₂-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 CO₂-e /km of pipeline⁹. The total emission of the Dampier to Bunbury Pipeline is published in the NGERs Greenhouse and Energy Information for 2009/10¹⁰ as 357,468 t CO₂-e. The average throughput of the pipeline is approximately 1000 TJ/day which gives an annual value of 365 PJ. Dividing the published emissions into the throughput gives a transport emission of 0.979 kg CO₂-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 CO₂-e/GJ, we obtain a total pipeline emission combustion figure of 25,151.7 t CO₂-e. The pipeline is 1,378 km from Yarraloola to Kalgoorlie¹¹. Based on the transmission factor of 8.72 t CO₂-e/km, the standard emission for the pipeline would be 12,016 t CO₂-e, resulting in a total emissions of 37,185 t CO₂-e. Dividing this quantity into the estimated contract capacity of 105.64 TJ/day¹², gives a transport emission intensity of 0.964 kg CO₂-e /GJ delivered. These calculations are summarised in Table 7-2.

■ **Table 7-2 Analysis of gas transport emissions**

	Units	DBNP	GGT
Energy Consumption	TJ	N/A	490
Gas Combustion	t CO ₂ -e	345269	25152
Pipeline	t CO ₂ -e	12199	12034
Total	t CO ₂ -e	357468	37185
NGER Emissions	t CO ₂ -e	357468	N/A
Transported	TJ	365000	38558.6
	TJ/day	1000	105.64

⁸ Greenhouse Gas Abatement Programme for Bluewaters Power Station, cited <http://www.griffinenergy.com.au/default.aspx?MenuID=76>

⁹ Table 15: Natural gas transmission emission factors, NGA Factors.

¹⁰ <http://www.climatechange.gov.au/government/initiatives/national-greenhouse-energy-reporting/publication-of-data/nger-greenhouse-energy-information-2009-10.aspx>

¹¹ <http://www.apa.com.au/media/176981/ggt%20approved%20proposed%20revised%20access%20arrangement%20information%20for%20ggp.pdf>

¹² <http://www.apa.com.au/media/176981/ggt%20approved%20proposed%20revised%20access%20arrangement%20information%20for%20ggp.pdf>



Emissions	t CO ₂ -e /GJ	0.979	0.964
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The total emission factor for gas is therefore considered to be:

52.31 kg CO₂-e /GJ for Muja and North Country

52.29 kg CO₂-e /GJ for the Goldfields.

The emissions are slightly higher for the Perth area due to slightly higher transport emissions on the Dampier to Bunbury Pipeline relative to throughput.

7.3. Distillate fired generation

The combustion of distillate (described as diesel oil for stationary energy purposes) is assessed as 69.5 kg CO₂-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 CO₂-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 CO₂-e /GJ to represent the likely emission of distillate delivered to peaking generators.



8. Generation assumptions

8.1. Existing generators

The modelling of the existing generation system includes the larger private power stations owned by Alcoa and the Goldfields miners. Table 8-1 shows the existing generators in the model and some of the key properties driving the calculation of the short run marginal costs sent-out (SRMC)¹³. Some of the objects listed may represent the aggregation of one or more actual facilities.

8.1.1. 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 2011 Energy Price Limits report. Start-up costs for other Verve and non-Verve facilities 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. The current Market Rules require the order in which the units are shutdown to be Cockburn, Muja 5/6, Collie and Muja 7/8 then Windfarms/Kwinana Newgen/Bluewaters depending on the Dispatch Merit Order provided by the IMO unless there is a security issue. In the absence of MEP proposed rule changes, the margin value assessment for 2012/13 assumed that Kwinana NewGen was also must-run, as the observed operating profile to date has indicated that this unit rarely shuts down. However, for this MEP analysis, this assumption has been relaxed since Kwinana NewGen can now participate in the Balancing Market and so should be allowed to shutdown if economic to do so.

¹³ Note that Bremer Bay wind farm has been excluded as its 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 2012/13 financial year.

Table 8-1 Properties of existing generators – fuel costs, carbon costs and short-run marginal costs

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 2011/12 (\$/MWh sent out)	SRMC 2012/13 (\$/MWh sent out)	MLF
BW1_BLUEWATERS_G2	9.75	10.79	Coal	2.06		2.25	908	20.04	22.33	42.37	1.00
BW2_BLUEWATERS_G1	9.75	10.79	Coal	2.06		2.25	908	20.04	22.33	42.37	1.00
COLLIE_G1	9.5	10.38	Coal	2.06		1.12	884	19.53	20.69	40.22	1.00
MUJA_G5	11.04	14.06	Coal	2.06		4.50	1028	22.70	27.24	49.94	1.00
MUJA_G6	11.04	14.06	Coal	2.06		4.50	1028	22.70	27.24	49.94	1.00
MUJA_G7	9.85	11.37	Coal	2.06		4.22	917	20.25	24.51	44.76	1.00
MUJA_G8	9.85	11.37	Coal	2.06		4.22	917	20.25	24.51	44.76	1.00
ALINTA_PNJ_U1	12	12	Cogen gas	2.64	1.09	-27.41*	628	13.86	17.30	31.16	0.99
ALINTA_PNJ_U2	12	12	New gas	6.18	1.09	-27.41*	628	13.86	59.82	73.68	1.01
ALCOA_WGP	12	12.62	Cogen gas	2.64	1.09	-24.11*	628	13.86	20.60	34.46	0.99
PPP_KCP_EG1	8	10.48	Verve gas	3.09	1.09	-25.25*	418	9.24	8.18	17.42	1.03
SWCJV_WORSLEY_COGEN_COG1	12	12.02	Verve gas	3.09	1.09	-25.70*	628	13.86	24.45	38.31	0.99
TIWEST_COG1	13	21.33	Verve gas	3.09	1.09	-29.19*	680	15.01	25.14	40.15	1.03
COCKBURN_CCG1	8	8.43	Verve gas	3.09	1.09	3.88	418	9.24	37.31	46.55	1.01
KWINANA_G5	11.7	14.42	Verve gas/Coal	2.58	1.09	4.33	851	18.78	47.19	65.98	1.01
KWINANA_G6	11.7	14.42	Verve gas/Coal	2.58	1.09	4.33	851	18.78	47.19	65.98	1.01
KWINANA_GT1	14.6	25.99	Verve gas	3.09	1.09	22.68	764	16.86	83.69	100.55	1.01
MUNGARRA_GT1	13.5	21.85	Verve gas	3.09	0.79	4.61	706	15.59	57.05	72.64	1.02
MUNGARRA_GT2	13.5	21.85	Verve gas	3.09	0.79	4.61	706	15.59	57.05	72.64	1.02

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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 2011/12 (\$/MWh sent out)	SRMC 2012/13 (\$/MWh sent out)	MLF
MUNGARRA_GT3	13.2	21.56	Verve gas	3.09	0.79	4.61	690	15.24	55.89	71.13	1.02
PINJAR_GT01	13.5	21.85	Verve gas	3.09	1.09	confidential	706	15.59	confidential	confidential	1.03
PINJAR_GT02	13.5	21.85	Verve gas	3.09	1.09	confidential	706	15.59	confidential	confidential	1.03
PINJAR_GT03	13.2	22.46	Verve gas	3.09	1.09	confidential	690	15.24	confidential	confidential	1.03
PINJAR_GT04	13.2	22.46	Verve gas	3.09	1.09	confidential	690	15.24	confidential	confidential	1.03
PINJAR_GT05	13.2	22.46	Verve gas	3.09	1.09	confidential	690	15.24	confidential	confidential	1.03
PINJAR_GT07	13.2	22.46	Verve gas	3.09	1.09	confidential	690	15.24	confidential	confidential	1.03
PINJAR_GT09	12.5	19.28	Verve gas	3.09	1.09	4.50	654	14.44	56.74	71.17	1.03
PINJAR_GT10	12.5	19.28	Verve gas	3.09	1.09	4.50	654	14.44	56.74	71.17	1.03
PINJAR_GT11	12.2	21.74	Verve gas	3.09	1.09	5.23	638	14.09	56.22	70.30	1.03
NEWGEN_KWINANA_CCGT	confidential	confidential	NewGen gas	3.09	1.09	2.25	413	confidential	confidential	confidential	1.02
STHRNCRS_EG	confidential	confidential	IPP gas	4.12	2.41	4.55	607	confidential	confidential	confidential	1.26
KEMERTON_GT11	12.2	13.25	Verve gas/distillate	3.09	1.09	2.40	638	14.09	53.38	67.47	1.01
KEMERTON_GT12	12.2	13.25	Verve gas/distillate	3.09	1.09	2.40	638	14.09	53.38	67.47	1.01
ALINTA_WGP_GT	11.5	16.2	New gas/distillate	6.18	1.09	2.40	601	13.28	85.99	99.27	1.01
ALINTA_WGP_GT2	11.5	16.2	New gas/distillate	6.18	1.09	2.40	601	13.28	85.99	99.27	1.01
NEWGEN_NEERABUP	confidential	confidential	New gas	6.18	1.09	2.40	612	confidential	confidential	confidential	1.04
PRK_AG	confidential	confidential	IPP gas	4.12	2.40	4.55	531	confidential	confidential	confidential	1.30
GERALDTON_GT1	15.25	15.95	Distillate	22.15		2.59	1141	25.19	340.42	365.61	1.04
WEST_KALGOORLIE_GT2	13.5	13.5	Distillate	22.15	0.66	33.76	1010	22.30	341.69	363.99	1.22
WEST_KALGOORLIE_GT3	14.75	14.75	Distillate	22.15	0.66	33.76	1103	24.36	370.21	394.57	1.22

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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 2011/12 (\$/MWh sent out)	SRMC 2012/13 (\$/MWh sent out)	MLF
GENERIC LANDFILL GAS <<refer to table of projects>>	11.3	11.3	Landfill Gas	2.25		-25.26			0.12	0.12	1.02
ALBANY_WF1			Wind			-39.55			-39.55	-39.55	1.04
ALINTA_WWF			Wind			-39.55			-39.55	-39.55	0.95
EDWFMAN_WF1			Wind			-39.55			-39.55	-39.55	1.00
SKYFRM_MTBARKER_WF1			Wind			-39.55			-39.55	-39.55	1.04
KALBARRI_WF1			Wind			-39.55			-39.55	-39.55	1.04
COLLGAR			Wind			-39.55			-39.55	-39.55	1.13
PERTH_ENERGY_GT1	10.7	16.06	New gas	6.18	1.09	19.94	560	12.36	97.72	110.07	1.03
KWINANA_GT2	9.3	15.23	Verve gas/distillate	3.09	1.09	6.40	486	10.74	45.26	56.00	1.01
KWINANA_GT3	9.3	15.23	Verve gas/distillate	3.09	1.09	6.40	486	10.74	45.26	56.00	1.01
TESLA_PICTON	14.44	14.44	Distillate	22.15		2.59	1080	23.85	322.48	346.33	1.00
KALAMUNDA	15.27	18.7	Distillate	22.15		2.59	1142	25.22	340.86	366.08	1.01

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



8.1.2. 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. Ten Monte Carlo simulations are to be 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 2011/12 and 2012/13 in that study, provided by the IMO for nominated plant. No outage rates are included for wind farms since the historical generation profiles of these units will already include outages.

8.1.3. Short run marginal cost calculations

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

$$SRMC = \text{marginal heat rate} * (\text{fuel price} + \text{variable transport charge}) + VOM \text{ cost} + \text{carbon cost}$$

For the period April to June 2012, the carbon cost is zero in the above equation.

This SRMC is then multiplied by the marginal loss factor prior to determining the merit order of dispatch. The assumed marginal loss factors have been obtained from the IMO website for 2011/12¹⁴ and are listed for each facility in Table 8-1.

The SRMC values in Table 8-1 are estimated for 2011/12 and 2012/13, based on the primary fuel only and considering the average heat rate and (for 2012/13) 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

¹⁴ <http://www.imowa.com.au/market-data-loss-factors>



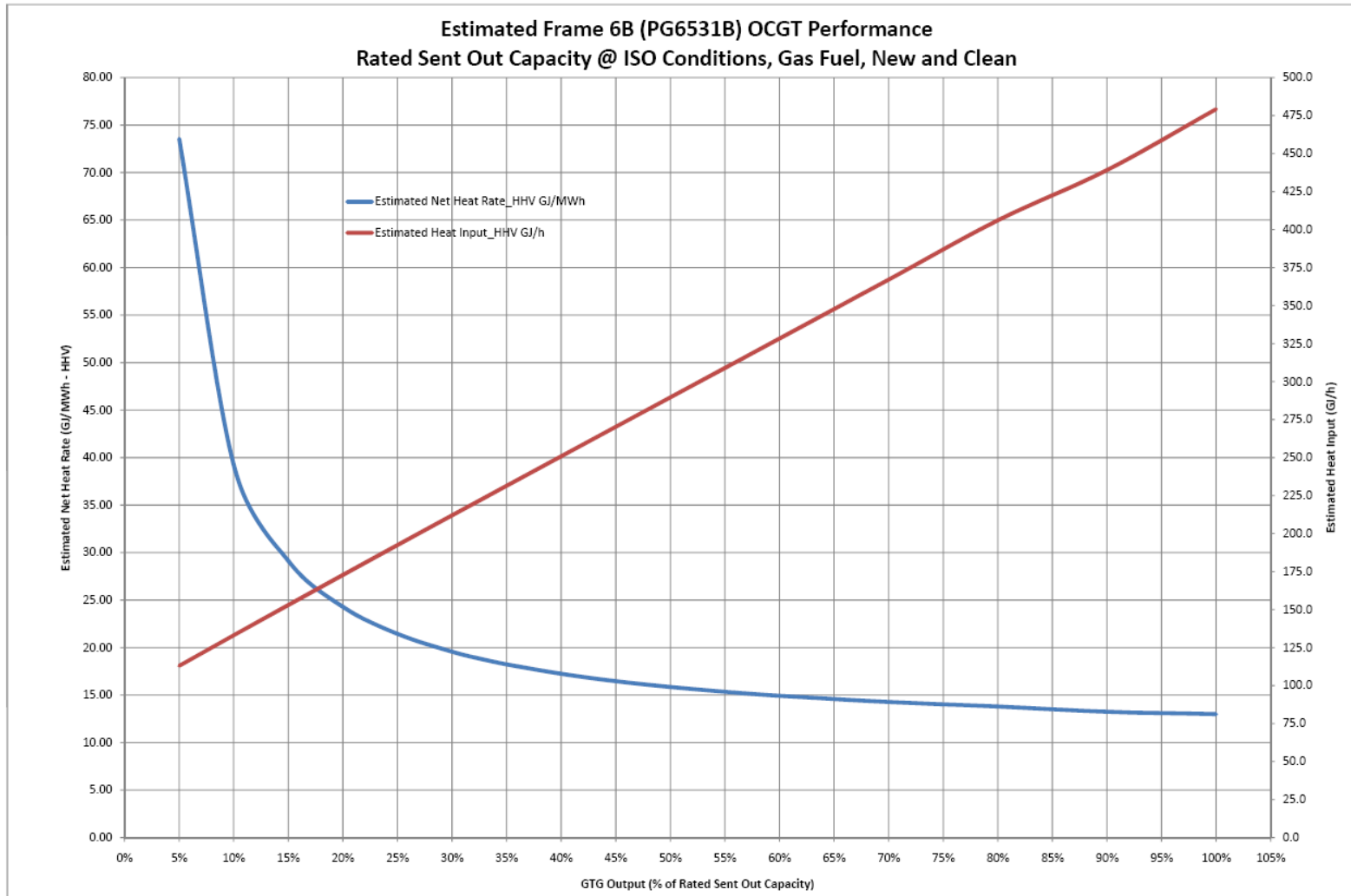
Energy Price Limits report, taking the reported VOM cost per hour of \$270 adjusted to real June 2011 dollars, multiplying by an estimate of hours operating based on 2010/11 actual data, and then dividing by an estimate of annual generation also based on the 2010/11 actual data.

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. The REC price assumed in this study is \$39.55/MWh based on 2012 and 2013 prices currently being traded. There is no discernable difference between REC prices traded for the 2012 and 2013 calendar year, so the same REC price is used for the two periods of interest in this study. Generation profiles for Albany, Emu Downs, and Alinta wind farms use historical data so that they are properly correlated to the 50POE load profile.

8.1.4. Heat rates

The sent out heat rates presented in Table 8-1 are based on available published or calculated values, using engineering judgement, for the rated plant capacities at ISO conditions, expressed as HHV. In some instances, generators have provided more accurate information on a confidential basis following a request for details made by the IMO as part of the consultation process for the 2011 Margin Values Review undertaken under the current Market Rules. The figures in Table 8-1 represent the average sent out heat rates at maximum and minimum capacity. However, 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. An example heat input function and resulting average heat rate curve are provided in Figure 8-1. The marginal heat rate at any level of output is defined as the gradient of the heat input curve.

■ **Figure 8-1** Example of performance curve for a typical GTG unit, at ISO conditions





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 in Table 8-1 are likely to be slightly over-estimated.

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 or Balancing is operating at a relatively efficient point on its heat rate curve.

8.1.5. 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.

8.2. Future generators

Table 8-2 shows the SRMC related properties of future generators assumed to become operational within the review period. In summary, we have considered the following units for commissioning:

- Bridgewater Biomass: This plant will be excluded from our analysis following advice from IMO that it is not expected to be available during the 2012/13 financial year or the period from April to June 2012.
- Tesla Kemerton 9.9 MW of diesel units in Muja region assumed to be available from August 2012
- Tesla Northam 9.9 MW of diesel units in Muja region assumed to be available from August 2012
- Tesla Geraldton 9.9 MW of diesel units in North Country region assumed to be available from August 2012
- 13.8 MW Grasmere WF assumed to be available from April 2012



- Merredin Energy 2 x 41 MW GE Frame 6 diesel peakers located in the Muja region assumed to be available from August 2012
- Muja 1-4 60 MW coal units that are being recommissioned and assumed to be in service for all of 2012/13, with one unit in service from May 2012, three units in service from June 2012, and all units in service from July 2012
- 55 MW Mumbida WF, assumed to be available from December 2012 (based on publicly available information)
- Greenough 10 MW Solar Farm (PV), assumed to be available from August 2012.

■ **Table 8-2 Properties of future generators – fuel costs, carbon costs and short-run marginal costs**

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 2011/12 (\$/MWh sent out)	SRMC 2012/13 (\$/MWh sent out)	MLF
TESLA_GERALDTON_G1	14.44	14.44	Distillate	22.15	-	\$2.59	1080	23.85	322.48	346.33	1.04
TESLA_KEMERTON_G1	14.44	14.44	Distillate	22.15	-	\$2.59	1080	23.85	322.48	346.33	1.01
TESLA_NORTHAM_G1	14.44	14.44	Distillate	22.15	-	\$2.59	1080	23.85	322.48	346.33	1.00
GRASMERE_WF			Wind		-	-\$39.55			-39.55	-39.55	1.04
NAMKKN_MERR_SG1	12.58	12.58	Distillate	22.15	-	\$4.61	941	20.78	283.30	304.08	1.03
MUJA_G1	12.43	12.89	Coal	2.06	-	\$4.50	1157	25.55	30.11	55.66	1.00
MUJA_G2	12.43	12.89	Coal	2.06	-	\$4.50	1157	25.55	30.11	55.66	1.00
MUJA_G3	12.43	12.89	Coal	2.06	-	\$4.50	1157	25.55	30.11	55.66	1.00
MUJA_G4	12.43	12.89	Coal	2.06	-	\$4.50	1157	25.55	30.11	55.66	1.00
Mumbida Wind Farm			Wind		-	-\$39.55			-39.55	-39.55	0.95
Greenough Solar Farm (PV)			Solar		-	-\$39.55			-39.55	-39.55	1.04



9. 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.

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

9.1. 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.

9.2. 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.

Based on the estimate of the load following requirement following the commissioning of Collgar provided in System Management's Ancillary Service Report for 2011¹⁵, we assume a load following requirement of ± 90 MW for the period from April 2012 to June 2013 year with a ramp rate of ± 18 MW/min. This increases the load following requirement from 60 MW prior to the commissioning of the Collgar wind farm. Under the new arrangements, System Management will be able to reduce the load following requirement for some Trading Intervals where, for example, calm conditions are forecast. However, as System Management has not been able to provide an estimated pattern for these reductions, the modelling will assume the full ± 90 MW requirement for all Trading Intervals.

The generators providing load following reserve 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 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.

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.

¹⁵ http://www.imowa.com.au/f2841,1297737/Ancillary_Service_Report_2011_FINAL.pdf



9.3. 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. Under the MEP proposal, both Verve Energy and IPPs may provide LFAS subject to meeting technical requirements (e.g. being connected to Automatic Generation Control). However, System Management has advised that at present only NewGen Kwinana and NewGen Neerabup are able to meet these technical requirements and it is unlikely that others will be able to meet the requirements in less than 6 months. For the purpose of this analysis, IMO has sought advice from selected IPPs regarding their intention to participate in the LFAS market over the review periods. At this stage, two IPPs have indicated an intention to participate in the LFAS market within the review period, albeit potentially not at market start. SR will continue 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 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.

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 SR and LFR. For LFR, the maximum response represents a unit's ability to increase or decrease output within a 10 minute period. These values represent the total amount of LFR that can be provided by a unit within 10 minutes, be it upwards or downwards service, or some combination of the two. For SR, additional restrictions are imposed on some units, as suggested by System Management.

9.4. Ancillary service contracts

Some SR may be provided by reducing load through interruptible load ancillary service contracts. Consistent with System Management's Ancillary Service Report for 2011¹⁶, 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 SR.

No other Ancillary Service contracts for SR are assumed for the purposes of this study.

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

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

¹⁶ http://www.imowa.com.au/f2841,1297737/Ancillary_Service_Report_2011_FINAL.pdf



9.5. 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.