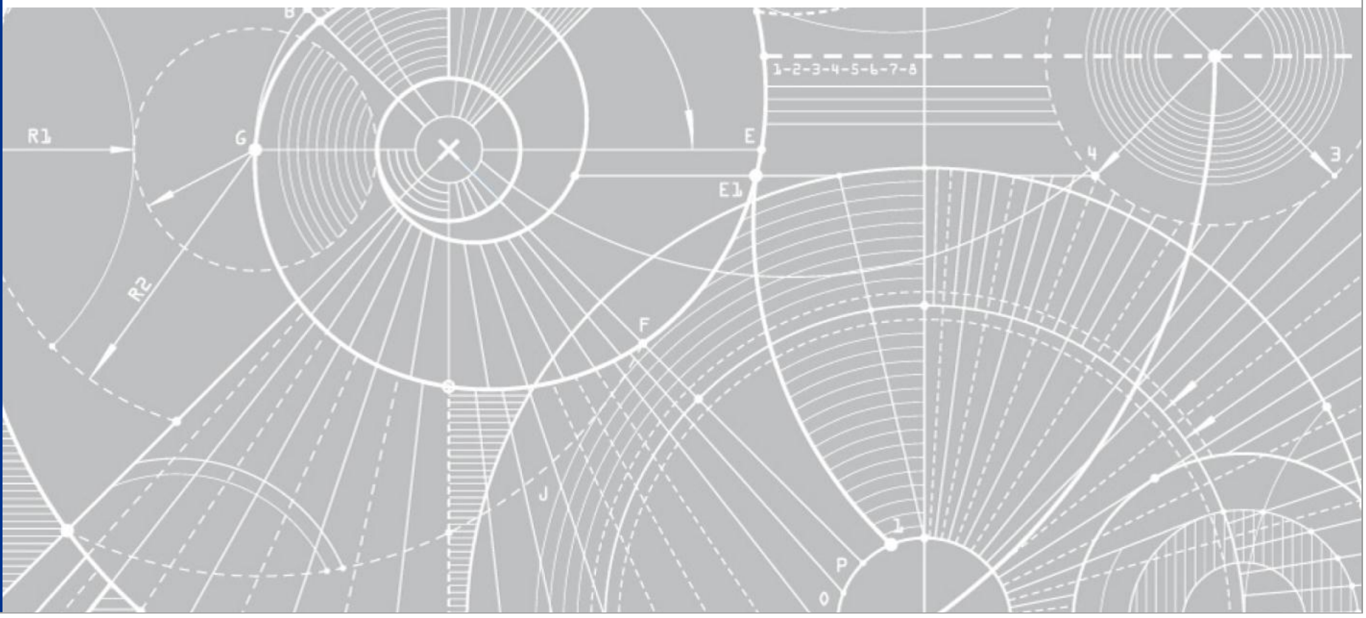
2016/17 Margin Peak and Margin Off-peak Review

INDEPENDENT MARKET OPERATOR

Assumptions report - PUBLIC

1.3

18 September 2015



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1.1	15 Sep 2015	Incorporated IMO feedback	P Nidras		P Nidras
1.2	16 Sep 2015	Additional IMO feedback incorporated	P Nidras		P Nidras
1.3	18 Sep 2015	Final Jacobs review	P Nidras	W Gerardi	W Gerardi

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Contents

Important note about your report

The sole purpose of this report and the associated services performed by Jacobs is to determine margin peak and margin off-peak values that will apply to Synergy for its provision of ancillary services in the WEM in accordance with the scope of services set out in the contract between Jacobs and the Client. That scope of services, as described in this report, was developed with the Client.

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1. Introduction

The Independent Market Operator (IMO) has engaged Jacobs to assist in determining the appropriate margin values to be applied for the financial year commencing 1 July 2016.

To determine appropriate Margin_Peak and Margin_Off-Peak parameters for the period 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 Market Rules to calculate the required parameters.

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.

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. From previous modelling experience, we have found that this availability cost can be sensitive to 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 analysis.

All prices and costs in this report are given in June 2015 dollars, unless specified. Where the same cost assumptions have been adopted as previously used in the calculation of the 2015/16 financial year margin values that were determined by the ERA on 31 March 2015, the costs have been adjusted from June 2014 to June 2015 dollars using the Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics.

2. Methodology for calculating margin values

Spinning reserve ancillary services for the WEM are currently provided by Synergy and as of 2014 some spinning reserve is provided under a number of Ancillary Service Contracts[1]. The IMO pays Synergy 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 Synergy 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 Synergy 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 Synergy 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 Synergy 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 Synergy 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 Synergy should be equal to the sum of generator efficiency losses and energy sales foregone (resulting from reduced generation quantity due to the commitment of capacity for providing spinning reserve), which may be incurred through:

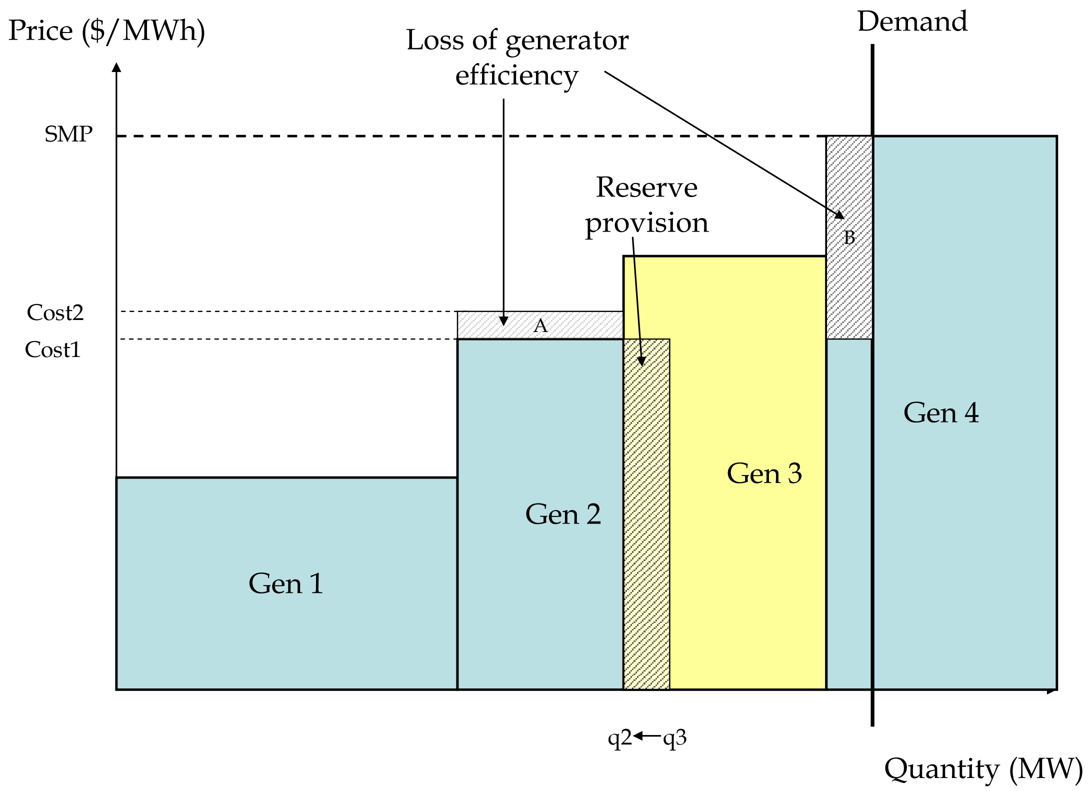
- movement to a less efficient point on a unit's heat rate curve
- an increase in production from higher cost Synergy plant to counteract lower cost generation backed off to provide reserve
- additional start-up costs that may be incurred due to commitment of additional units that would otherwise not have been required
- a reduction in generation from Synergy plant and a corresponding increase in generation from Independent Power Producers (IPP), resulting in loss of profit for Synergy

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

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 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

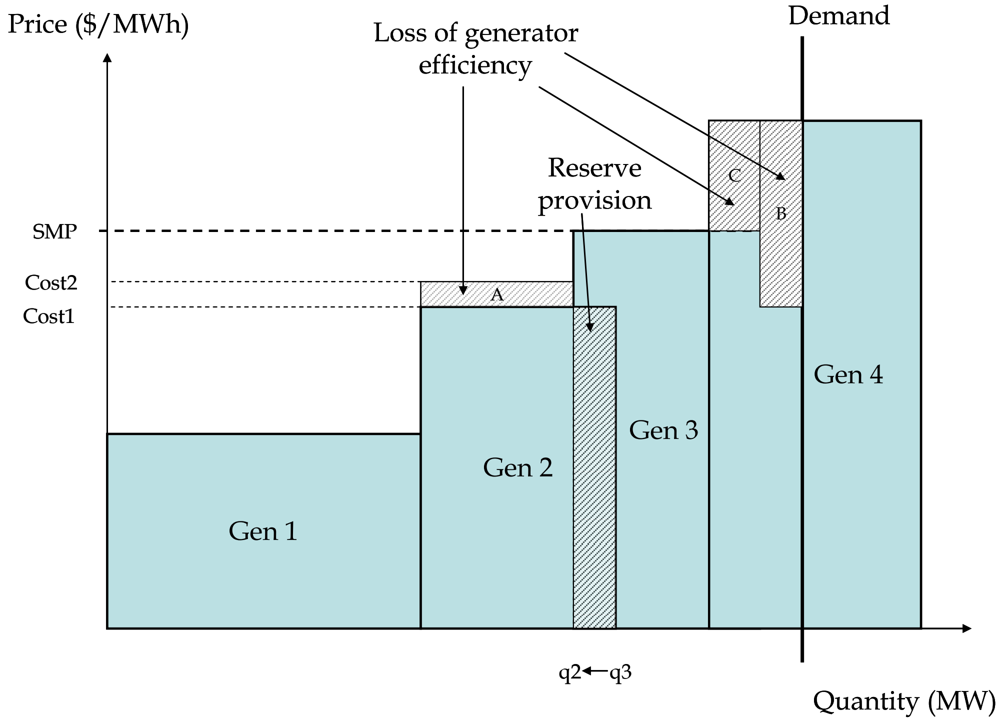
During the off-peak, some units may be constrained on at minimum generation level to meet the reserve requirements but a lower cost generator may be the marginal generator setting the price. Therefore, the availability cost could be quite high relative to the SMP.

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 Synergy unit constrained on to provide reserve if demand is low and the level of generation from IPP's is relatively high, since Synergy provides the majority of SR in the WEM.

2.3 Calculating availability cost

In previous years, the availability cost is calculated for peak and off-peak periods by comparing Synergy's total generation costs and generation quantities, with and without providing SR. This approach changed last year because Load Rejection Reserve (LRR), which is a reserve lower service accommodating the sudden disconnection of large loads, was also included in the modelling of the SWIS, and this meant that the cost impact of including LRR had to be separated from the cost of providing SR. LRR constraints were introduced to the Jacobs WEM model in mid- 2014 when modelling LRR costs for System Management. To maximise the model accuracy it was decided to continue to use these enhancements in both last year's study and this year's study. The methodology for separating Synergy's cost of providing LRR from its cost of providing SR is given below.

The formula for calculating the availability cost for providing a reserve service is as follows:

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

where:

GenCost_Res	= Synergy's total generation costs, including start-up costs, with reserve provision
GenCost_NRP	= Synergy's total generation costs, including start-up costs, without any reserve provision apart from LFAS[2]
GenQ_Res	= Synergy's total generation volume, with reserve provision
GenQ_NRP	= Synergy's total generation volume, without any reserve provision apart from LFAS
SMP	= system marginal price with reserve provision

Reserve provision can refer to any type of reserve service. It is necessary to calculate the availability cost relative to a specific reserve configuration, since this is the only way to separate out the cost contribution of each reserve type. For example, the availability cost of providing Spinning Reserve can be modelled relative to a base case where Load Rejection Reserve is also modelled (where both market simulations include LRR), or relative to a base case where no Load rejection reserve is modelled (where neither market simulation includes LRR).

Simulation of Spinning Reserve costs in the previous study revealed that there is an interaction cost effect between the cost of providing Spinning reserve and the cost of providing Load Rejection reserve. That is, the cost of providing both forms of reserve is generally higher than the sum of providing each reserve separately. The difference between these two quantities is labelled as the Interaction Cost.

Following consultation with the IMO, it was determined that the availability cost of providing spinning reserve should be the Base SR availability cost[3] plus the Interaction cost of providing both SR and LRR, allocated proportionally to the average level of SR required across the study horizon relative to the sum of the SR and LRR requirements.

That is:

Availability Cost(SR) = Availability Cost(SR only) + [Interaction Cost * SR_Proportion]

where:

Interaction Cost = Availability Cost(SR and LRR) – Availability Cost(SR only) – Availability Cost(LRR only)

SR_Proportion = Average SR provision / (Average SR provision + Average LRR provision)

For calculating losses in generator efficiency resulting from reducing output to provide SR, heat rate curves are considered within Jacobs' WEM database, as discussed in Section 7.1.4.

[2] Load Following Ancillary Services
[3] That is, the availability cost of providing SR only, with no provision of LRR.

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 Synergy generators, a long-term 42MW interruptible load contract (denoted below as IL) and Ancillary Service Contracts, the availability cost defined by clause 9.9.2(f) is as follows:

Availability cost =

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

Margin Off-Peak * ∑BalancingPrice_Off-peak * {SR_Capacity_Off-peak – LFR_Off-Peak – ASC_SR_provision_t – IL }

where the sums are over all relevant time periods (i.e. peak or off-peak), and ASC_SR_provision_t denotes the level of spinning reserve provided by ancillary service contracts in time period *t*.

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

The SR_Capacity_Peak and SR_Capacity_Off-peak parameters represent 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 LFR parameter represents the amount of load following raise ancillary service required in the Trading Interval. Assumptions regarding this requirement are discussed in Section 8.2.

3. Modelling the wholesale electricity market

The WEM for the SWIS commenced operation on 21 September 2006. Currently this market consists of three components:

- A gross dispatch pool energy market with net settlement. Participants may trade bilaterally and via a day-ahead energy market (STEM) to hedge their exposure to the market (balancing) energy price.
- A Load Following Ancillary Service (LFAS) Market to allow IPPs to contribute to LFAS.
- 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 IMO. Other services are controlled by System Management with cost allocated via IMO's settlements process[4].

The WEM is relatively small to other energy markets, and a large proportion of the electricity demand is for mining and industrial use, which is supplied under long-term contracts. Up to 85% of energy sales in the SWIS are traded through bilateral contracts.

The STEM is a residual day ahead trading market which allows contract participants to trade out any imbalances in bilateral positions and expected load or generation. It is essentially a financial hedge allowing users to lock in a price one day ahead rather than be exposed to the real-time balancing price.

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.

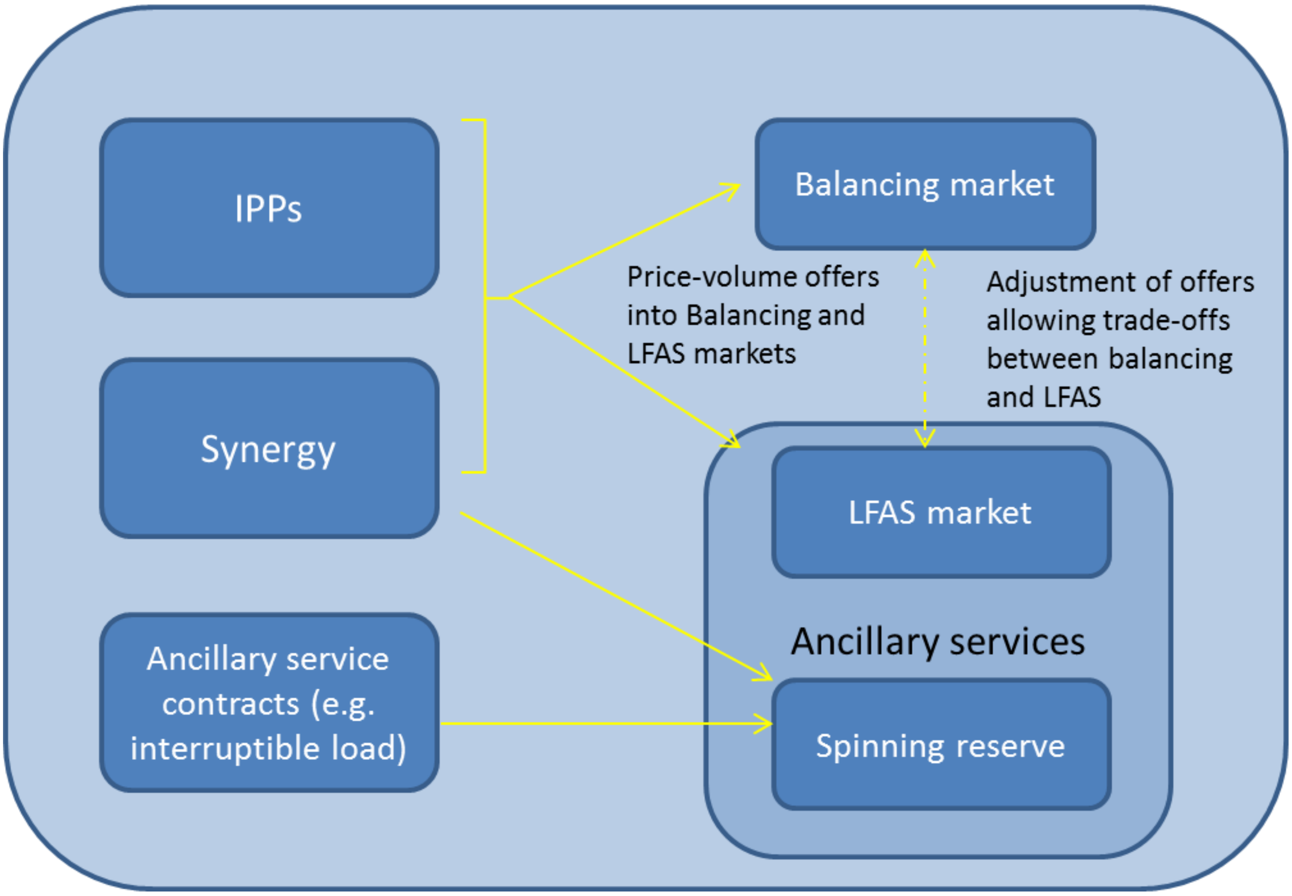
All Balancing Facilities (Synergy and IPPs) are required to compete in a Balancing Market, which is used to determine the actual dispatch of each facility. Balancing Facilities participate in the Balancing Market through price-based submissions, using multiple price-volume bands to represent the facility’s 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. The IMO settles the balancing market as the net of actual (metered) generation and consumption, bilateral contracts, and STEM position.

Synergy is the default provider of all ancillary services in the WEM. However, in the LFAS Market, IPPs can compete with Synergy 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 Synergy on a “pay as bid” basis). SR can only be provided by Synergy or through Ancillary Service Contracts. Figure 3-1 summarises participation by Synergy and IPPs in the Balancing Market, LFAS Market and provision of SR.

[4] A project has been initiated, under Western Australia’s Electricity Market Review - Phase 2, to transfer the functions of System Management to the Independent Market Operator.

In the PLEXOS model Jacobs does not explicitly model the bilateral trades, STEM and the Balancing Market separately. Instead, a gross pool is modelled and energy and ancillary services are co-optimised, assuming economically efficient dispatch. With the introduction of the Balancing Market in July 2012, the WEM and PLEXOS market model outcomes are expected to be closely aligned.

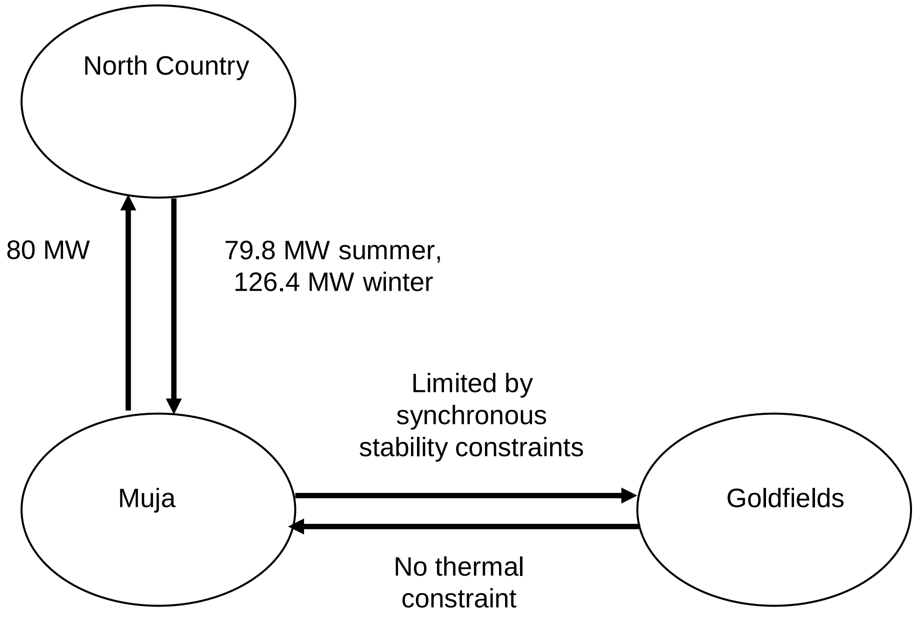
Figure 3-1 Balancing Market and Ancillary Service Provision



4. Network topography

The SWIS is modelled as a 3-node system with a single uniform price. Interconnectors between the 3 nodes, Muja, Goldfields and North Country, allow representation of 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



This network configuration has taken into consideration the impact of the commissioning of the Mid West Energy Project (MWEP), Southern Section, which has strengthened the network connection between Neerabup and Three Springs. Construction of this network augmentation was completed in March 2015. With MWEP completed, the limits between Muja and North Country will represent constraints on flow between Three Springs and Geraldton.

The Mungarra units, Synergy, 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 units, are assumed to be located at Muja.

Voltage stability constraints in the North Country previously influenced unit commitment decisions for the Mungarra units. In previous years, on advice from System Management, when North Country load exceeded 65 MW one Mungarra unit was required to be in operation, increasing to two units in operation when load exceeded 95 MW. We understand that System Management's observations since the commissioning of the MWEP suggest this constraint will only exist under certain generator outage scenarios in future, so for modelling purposes it will no longer be included.

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 2014 Electricity Statement of Opportunities (ESOO) load forecasts (expected scenario, 50% PoE), distributed among the three regions in accordance with the 2012/13 actual loads after separately accounting for the Karara mining development. The Karara mining development is now fully operational, with a maximum demand of 70 MW and an 85% load factor. The load split between North Country and Muja is based on the regional boundary definition we have assumed after commissioning of MWEP, with Three Springs being part of the Muja region.

Table 5-1 2016/17 load assumptions

Financial year	Parameter	Muja (Perth)	Goldfields	North Country	Total SWIS
2016/17	Energy (GWh)	17,863	701	451	19,105
	Summer peak demand 50% PoE (MW)	3,725	104	144	3,886
	Winter peak demand 50% PoE (MW)	3,437	117	114	3,487
	Nominated intermittent non-scheduled load (MW)	58.25	13	0	71.25

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 2012/13 profiles, to calculate the individual region peaks at time of system peak for the 2016/17 financial year.

For our chronological modelling in PLEXOS, we use half hourly load profiles for the 3 nodes (based on 2012/13 historical data including losses), which are then grown to match the energy and peak demand values in Table 5-1. The energy and peak demand forecasts provided in Table 5-1 are net of IMO assumptions on small-scale solar PV uptake. For the 2016/17 financial year, IMO estimated that small-scale solar PV would contribute 187 MW during the summer peak demand[5]. 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 (estimated using an assumed solar PV capacity factor for Perth of 18.3%[6]), 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.

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 the nominated capacity of

[5] IMO, 2014 Electricity Statement of Opportunities, June 2015, p.5.
[6] CEC, Consumer Guide to Solar PV, 19 December 2012, http://www.cleanenergycouncil.org.au/cec/resourcecentre/Consumer-Info/solarPV-guide

the associated Intermittent Load. 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 C and D and Collie
- Vinalco coal: used by Muja A and Muja B
- Griffin coal: used by the Bluewaters units
- Cogeneration contract gas: gas for Alcoa Wagerup and one of the two Alinta cogeneration units
- Synergy contract gas: gas under existing Synergy contracts
- NewGen contract gas: gas for NewGen Kwinana plant
- NewGen peak contract gas: gas for NewGen Neerabup plant
- Parkeston contract gas: gas under contract for Parkeston plant
- Goldfields Contract gas: gas under contract for Southern Cross plant.
- Perth energy contract gas: gas for Perth Energy's Kwinana Swift GT
- New gas: reflects the estimated price for new gas contracts and acts as a secondary fuel for some of the other units if they have used up their contract gas supply. May also include some proportion of spot gas purchases
- Distillate: used as a primary fuel by the Geraldton, West Kalgoorlie, Tesla, Kalamunda and Merredin Energy units, and as a secondary fuel for some of the other units if they have used up their gas supply

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 (exclusive of transport charges):

Table 6-1 Fuel prices (real June 15 dollars)

Name	Price ($/GJ)
Coal	2.53
Vinalco Coal	Confidential
Griffin Coal	Confidential
Cogeneration contract gas	2.85
Synergy contract gas	3.35
NewGen contract gas	Confidential
NewGen contract peak gas	Confidential
Parkeston contract gas	Confidential
Goldfields Contract gas	Confidential

Name	Price ($/GJ)
Perth Energy contract gas	Confidential
New gas	6.69
Landfill gas	Confidential
Distillate	17.95

For all gas fuels the prices used are the same as the prices used in the calculation of the 2015/16 financial year margin values that were determined by the ERA on 31 March 2015, adjusted by Perth CPI. Synergy's coal price was also escalated by Perth CPI from last year's estimate. The new gas price of $6.69/GJ represents a mix of new contracts and spot gas. This is slightly lower than the 2016/17 forecast contract gas price reported in the Dec 2014 GSOO.

It is noted that the new gas price assumption is higher than where the spot market has been trading over the last 9 months ($3. 53/GJ on average).

Distillate prices come from Jacobs SKM's Energy Price Limits 2015 study[7], which estimated a nominal price of $18.17/GJ ($17.95/GJ in June 2015 dollars) applying a calorific value of 38.6 MJ/litre. The additional nominal transport cost to the Goldfields is estimated to be $1.46/GJ($1.44/GJ in June 2015 dollars).[8]

6.1.1 Gas transport charges

Gas transport charges, reflecting variable gas pipeline costs, vary based on the generator's geographic location.

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 Natural Gas Pipeline (DBNGP), applying the same load factor, the resulting fixed cost component of the gas transport cost is approximately $1.64/GJ in real June 2015 dollars. 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 2015/16 financial year margin value review, Jacobs has conservatively assumed that only 50% of the fixed cost component should be included in formulating the marginal costs for gas-fired generators.

A detailed explanation of how the gas transport charges are derived is included in Appendix A.

6.2 Fuel constraints

Based on our understanding of the market and historical data, we have included gas constraints limiting the contract gas daily availability.

We also included some constraints on the total gas available in different locations. Where possible, these figures have been obtained from the capacities standing data listed in the Western Australia Gas Bulletin Board[9]. Otherwise, the figures correspond to estimates from historical dispatch data and

[7] http://www.imowa.com.au/home/electricity/consultations/2015-energy-price-limits-review, accessed 8 September 2015
[8] Prices in Jacobs SKM "Energy Price Limits for the Wholesale Electricity Market in Western Australia" 2015 report are nominal for the 2015/16 financial year. In order to convert them to real June 2015 dollars, we assumed they are from December 2015 (mid-point of the 2015/16 financial year) and then scaled them back to June 2015 dollars assuming a Perth annual out-year inflation rate of 2.5%).
[9] https://gbb.imowa.com.au/#capacities

liquid fuel usage for 2008, and fine-tuned in our PLEXOS model during previous SWIS back-casting exercises.

7. General assumptions

7.1 Existing generators

The modelling of the existing generation system includes the larger private power stations owned by Alcoa and the Goldfields miners.

For 2016/17 modelling, Jacobs assumes that all Muja units that were being recommissioned are now fully operational.

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

7.1.1 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 were derived from assumptions provided in Jacobs 2015 Energy Price Limits report[10].

Start-up costs for some other facilities were updated in accordance with confidential advice previously provided by market participants. For the remaining facilities, start-up costs were based on a Perth CPI escalation of the values used in the 2015/16 financial year margin values 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, Muja 7 and 8, Collie, Kwinana NewGen, cogeneration units and other generators meeting private loads are treated as units that must generate whenever they are available.

7.1.2 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. Outage rates have been provided by the IMO, based on historical full and partial outage data and consideration of major outages planned for 2016/17. No outage rates are included for wind farms since the historical generation profiles of these units will already include outages.

During the 2013 stakeholder consultation process, Tiwest provided an updated mean time to repair for its facility on a confidential basis, based on observed repair times from March 2012 to February 2013. This information has been included in this analysis.

[10] http://www.imowa.com.au/home/electricity/consultations/2015-energy-price-limits-review, accessed 8 September 2015

7.1.3 Short run marginal cost calculations

Within the PLEXOS software, the SRMC is calculated as follows[11]:

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

This SRMC is then divided by the marginal loss factor (MLF) to determine the merit order of dispatch. The assumed MLFs have been obtained from the IMO website for 2015/16[12].

SRMC values for all generators are estimated for 2016/17 based on the primary fuel only and considering the average heat rate 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. For example for the 2013 review Vinalco provided updated heat rate, fuel price and variable operating and maintenance (VOM) cost values for its facilities.

Missing parameters such as VOM costs were estimated by Jacobs, considering the nature and known characteristics of the facilities, or based on actual half-hourly dispatch information. The VOM cost for Perth Energy was derived from the Energy Price Limits report 2011[13], taking the reported VOM cost per hour of $270.00 in March 2012 dollars[14] adjusted to June 2015 dollars, multiplying by an estimate of hours operating based on 2013/14 actual data, and then dividing by an estimate of annual generation also based on the 2013/14 actual data. More recent Energy Price Limit reports have not provided any updated to these VOM assumptions.

For the wind farms and landfill gas plants the assumed value of Large-scale generation certificates (LGC) 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 LGC revenue if they were shut down. The LGC price assumed in this study is $49.27/MWh in real June 2015 dollars, based on LGC certificates currently being traded. The recent government agreement on the RET has resulted in elevated LGC prices since March 2015, so this figure is based on certificates traded since that date. Generation profiles for Albany, Emu Downs, Collgar and Alinta wind farms use 2012/13 historical data so that they are properly correlated to the load profile. For the smaller wind farms such as Denmark and Blairfox Karrakin, are modelled using an assumed average annual capacity factor.

7.1.4 Heat rates

The sent out heat rates used in the modelling 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 a request for details made by the IMO as part of the consultation process for previous margin value reviews. 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 7-1. The marginal heat rate at any level of output is defined as the gradient of the heat input curve. It should be

[11] Note that the carbon cost for the 2016/17 simulations will be zero.
[12] http://www.imowa.com.au/market-data-loss-factors
[13] http://www.imowa.com.au/f4153,1608610/SKM_MMA_Final_2011_EPL_Report_v1.1.pdf
[14] Prices in the SKM MMA "Energy Price Limits for the Wholesale Electricity Market in Western Australia from October 2011" report are nominal for the year commencing October 2011. In order to convert them to real June 2013 dollars, we assumed they are from March 2012 (mid-point of the year commencing October) and then scaled up to June 2013 dollars assuming a Perth annual out-year inflation rate of 2.5%).

noted that the marginal HHV heat rate is typically lower than the average HHV heat rate at maximum sent-out rated capacity.

In some instances, no information on the heat input function is 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 market, 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 market is operating at a relatively efficient point on its heat rate curve.

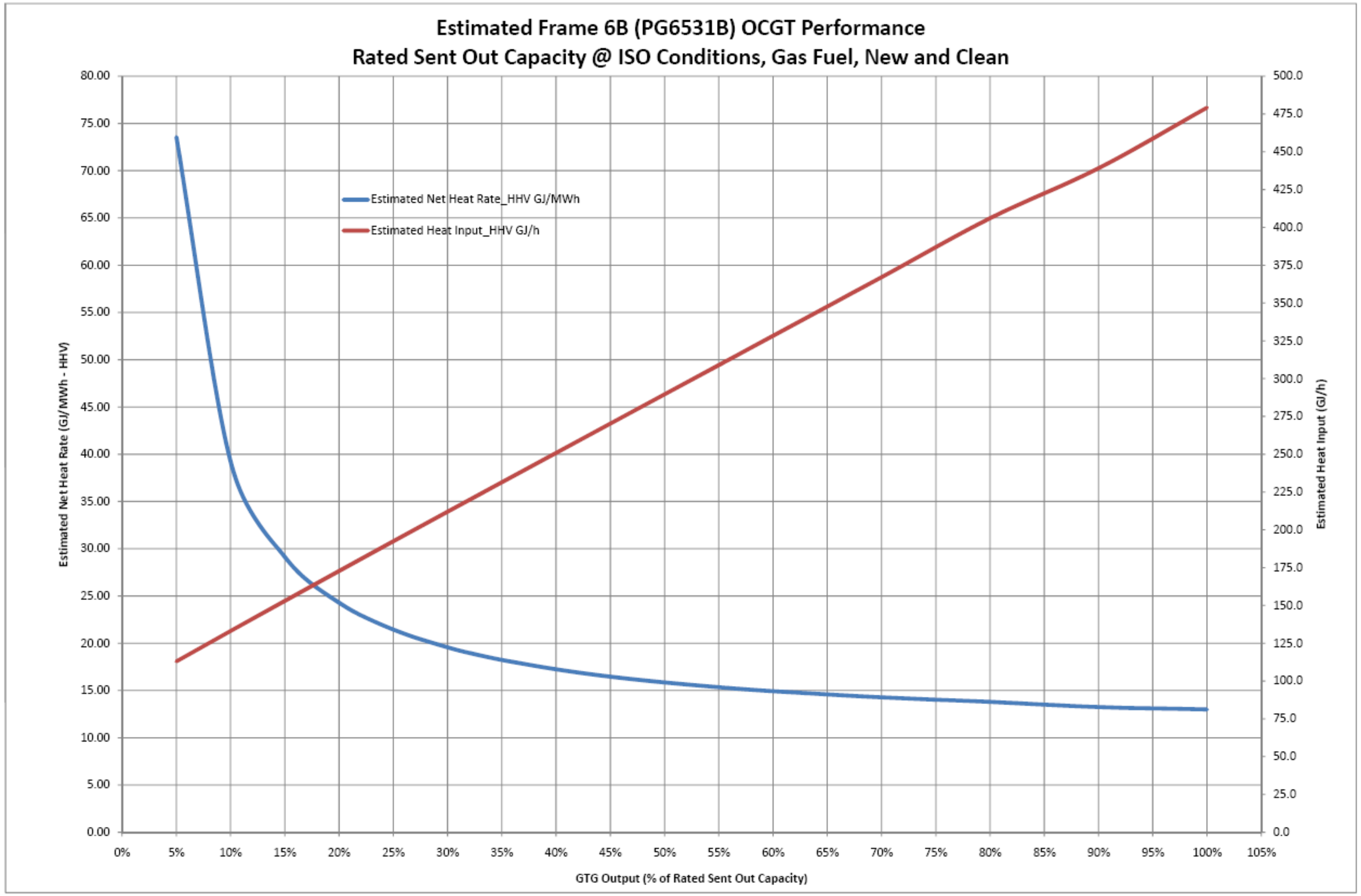
7.1.5 Kwinana NewGen

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 80 MW 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.

7.2 Future generators

No new generators are assumed to be committed within the review period.

Figure 7-1 Example of performance curve for a typical GTG unit, at ISO conditions



8. Reserve modelling assumptions

In determining the availability cost of providing ancillary services, both SR and LFAS will be modelled in PLEXOS.

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

8.1 Spinning reserve

The SR 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.

8.2 Load following reserve

LFAS is required to meet fluctuations in supply and demand in real time. The LFAS is a component of the SR. Therefore, the same MW of reserve may be used to meet both the LFAS and SR requirements. The total SR requirement in the WEM is therefore reduced by the amount of LFAS that is being provided. The exception to this is any LFAS that is provided by NewGen Kwinana CCGT and Cockburn CCGT, both of which are too slow to be a suitable substitute for SR.

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 2015[15], for the 2016/17 financial year we assume a LFAS requirement of 72 MW for raise and 72 MW for lower with a ramp rate of +/- 14.4 MW/min. System Management is able to reduce the LFAS requirement for some Trading Intervals where, for example, calm conditions are forecast. However, as no guidelines are available to support the modelling of such reductions, the modelling will assume the full ± 72 MW requirement for all Trading Intervals.

The generators providing LFAS 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 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.

8.3 Load rejection reserve

Load rejection reserve (LRR) is required to provide system stability in the event of sudden, unplanned load disconnection. LRR is modelled in PLEXOS as a lower reserve. The generators providing LRR must be able to lower their generation in response to Load Rejection. Spare lowering capacity in a generator that provides LRR can also be available for LFAS, although the exception.

Only Synergy units are able to provide LRR. The amount of LRR required in any time period t is as follows:

LRR = 120MW – (72MW – NewGen_LFAS_provision_t – Cockburn_LFAS_provision_t)

where the 72MW represents the current LFAS requirement, and NewGen_LFAS_provision_t and Cockburn_LFAS_provision_t is the amount of LFAS provided by NewGen Kwinana and Cockburn CCGT respectively.

[15](http://www.imowa.com.au/docs/default-source/System-Management-Reports/final-2015-ancillary-services-report-for-imo-website.pdf?sfvrsn=0.

8.4 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 LFAS, and some may not be suitable for providing reserve at all, depending on their operational flexibility and the commercial objectives of their owners. Both Synergy and IPPs are able to provide LFAS subject to meeting technical requirements (i.e. being connected to AGC). At present NewGen Kwinana is the only IPP providing LFAS. System Management has confirmed that no other IPP is currently in the process of qualifying as an LFAS Facility. We have therefore assumed that NewGen Kwinana will remain the only IPP providing LFAS during this period. SR is provided by Synergy or through ancillary service contracts.

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, LFAS and LRR. For LFAS, the maximum response represents a unit's ability to increase or decrease output within a 5 minute period. Both LFAS raise and lower could be provided by a unit simultaneously. For SR and LRR, additional restrictions are imposed on some units, as suggested by System Management.

8.5 Ancillary service contracts

Some reserve may be provided by reducing load through interruptible load ancillary service contracts. System Management's latest advice is that 42 MW of interruptible load is assumed to be available. This interruptible load can be used at all times to provide SR.

Effectively, the SR requirement to be provided by Synergy in period *t* is therefore equal to:

70% largest generating unit – 42 MW interruptible load –* (*72 MW load following reserve – NewGen_LFAS_provision_t – Cockburn_LFAS_provision_t*).

NewGen's provision of LFAS is subtracted off the 72MW of LFAS provided each period because NewGen's LFAS is much slower than Synergy's LFAS, and is not therefore a suitable substitute for SR.

8.6 Value of reserve shortage

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

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

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

Appendix A. Pipeline tariffs

A.1 DBNGP tariffs

A.1.1 Tariff components

Dampier to Bunbury Natural Gas Pipeline (DBNGP) tariffs have been calculated using the same approach as that which was used for the 2012 margin values review.

The relevant tariffs for all but one shipper are those paid under the Standard Shipper Contract (SSC) which is available on the DBP website. Although the Base T1 Tariff referred to in the SSC is $1.053 at 1 January 2003, this does not take into account tariff adjustments for capacity expansions. When account is taken of this, ACIL Tasman referred to an SSC T1 tariff at 1 January 2010 of $1.4942 which, when escalated at the Perth Consumer Price Index (All Groups)[16] results in a tariff of $1.5411/GJ at 1 January 2011. This 2011 tariff has been confirmed by DBP which quotes a tariff paid under this contract of $1.5411/GJ.

According to the SSC, from 1 January 2012 to 1 January 2017 Base T1 tariffs escalate at Perth CPI-2.5%. However, our understanding is that the Aggregate Tariff Adjustment Factor (ATAF) to account for capacity reservation increases continues to escalate at the full CPI.

Thus, we have calculated tariffs in two parts:

- A Base T1 Tariff of $1.349/GJ at 1 January 2011 (calculated by escalating the $1.053/GJ referred to in the SSC) which we assume escalates at Perth CPI-2.5%
- An ATAF adjustment of $0.192/GJ at 1 January 2011 (calculated by difference from the $1.5411) which we assume escalates at full Perth CPI[17].

A.1.2 CPI numbers and estimates

The Perth CPI for 2012-13 was 2.5%. The Western Australian 2013-14 budget forecasts for Perth CPI were 2.5% each year from 2013-14 to 2016-17.

In its calculations, Jacobs has used the following September to September quarter Perth CPI increases:

- 3.1% for Sept 2009 to Sept 10 actual which determined the pricing for calendar year 2011
- 2.8% for Sept 2010 to Sept 11 actual which determined the pricing for calendar year 2012
- 2.0% for Sept 2011 to Sept 12 (including carbon price effect) actual which set the price for calendar year 2013
- 2.6% for Sept 2012 to Sept 2013 actual, which determined the price for calendar year 2014
- 2.6% for Sept 2013 to Sept 2014, actual, which determined the price for calendar year 2015
- 2.5% for Sept 2014 to Sept 2015 assumed, which will set the price for calendar year 2016
- 2.5% for Sept 2015 to Sept 2016 assumed, which will set the price for calendar year 2017

Where relevant, Jacobs has assumed that Australia CPI[18] will be 2.5% pa in each year.

A.1.3 Full-haul tariff calculations in nominal dollars

The Perth CPI assumptions and tariffs calculated are provided in Table A-1.

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[16] The Perth Consumer Price Index (All Groups) published by the Australian Bureau of Statistics is referred to in this report as Perth CPI.
[17] We note that the reference period for the CPI calculations was changed by the ABS in 2012. We have used the new reference period in our calculations. As a result, there are minor rounding differences from our previous report.
[18] In this report Australia CPI refers to the Consumer Price Index All Groups weighted average for All Capital Cities published by the Australian Bureau of Statistics.

Table A- 1 Actual and forecast CPI and tariffs for the DBNGP, nominal dollars

	Calendar 2014 (actual)	Calendar 2015 (part forecast)	Calendar 2016 (forecast)	Calendar 2017 (forecast)
Perth CPI increase*	2.6%	2.6%	2.5%	2.5%
Base Tariff	$1.35	$1.35	$1.35	$1.35
ATAF	$0.21	$0.22	$0.22	$0.23
Total	$1.56	$1.56	$1.57	$1.57

* From September to September. Calendar 2015 is based on Sept 2014 to forecast Sept 2015 Perth CPI and Calendar 2016 and 2017 tariffs are based on forecast Perth CPI. Note that numbers in the table may not add to total due to rounding.

A.1.4 Full-haul tariff calculations in real dollars of June 2015

Based on our calculations and assumptions we have estimated that the tariffs will be $1.56/GJ for calendar year 2016 and $1.57 for calendar year 2017 in nominal terms.

Assuming equal quantities off-taken in each of the four quarters and using the Perth CPI Index of 107.7 in June 2015 as the base and assuming that Perth CPI growth will be 2.5% pa between June 2015 and 2017, we have estimated the average tariff in 2016-17 in real June 2015 dollars to be $1.51/GJ at 100% load factor.

A.1.5 Commodity and capacity components

The Base Tariff has a capacity reservation to commodity ratio of approximately 80% to 20%. As a result we have assessed:

- The capacity reservation tariff to be $1.21/GJ of capacity reserved
- The commodity component to be $0.302/GJ of gas transported.

A.1.6 Part haul transport

All gas which is delivered south of Compressor Station 9 (north of the Muchea offtake point) is deemed to be full haul, regardless of inlet point.

Part haul transport, for gas delivered north of Compressor Station 9, is essentially calculated at the full haul tariff multiplied by the distance factor. The distance factor as defined in the Part Haul Shipper Contract is the distance from the inlet to the outlet points divided by 1400.

For the tariffs calculated above, the part-haul tariffs in real $June 2015 are:

- A capacity reservation tariff of $0.000860/GJ of capacity reserved multiplied by the distance transported
- A commodity tariff of $0.000215/GJ transported multiplied by the distance transported.

A.2 Goldfields Gas Pipeline (GGP)

A.2.1 Tariffs for transport through uncovered expansions

While part of the GGP is regulated by the ERA, uncovered expansions, such as those under which new gas supply contracts would likely be transported, are not regulated. As a result, applicable tariffs are not readily available in the public arena.

The GGP website provides a tariff range which it states are rates that typically apply. These are:

- Toll charge: $0.243512 - $0.294649/GJ MDQ
- Capacity reservation charge: $0.001685 - $0.002040/GJ MDQ/km
- Throughput charge $0.000634 - $0.000767/GJ/km.

These rates are at June 1997 with quarterly indexation using the Australia All Groups CPI, for which the June 1997 index value was 66.9.

The upper end of the range applies to shorter contracts (1-5 years) and the lower end of the range to long contracts (15-20 years). In addition, tariffs are negotiated, taking into account the particular needs of the shipper.

Given the high price of gas plus transport through the GGP, we expect that prices can be negotiated towards the lower end of the range. As a result, while we do not expect transportation contracts to be 15-20 years duration, we have used the lower end of the range in our calculation and escalated prices from June 1997. This approach is similar to that taken by ACIL Tasman in its February 2013 draft report to IMO entitled Gas Prices in Western Australia[19].

The escalation of tariffs at 100% Australia CPI between June 1997 and June 2013 results in a Toll charge of $0.384/GJ MDQ, a Capacity reservation charge of $0.00259/GJ MDQ/km and a Commodity charge of $0.000974/GJ/km applicable in September 2013.

In order to calculate the tariffs, the Toll charge is multiplied by the contracted capacity, the Capacity reservation charge is multiplied by the contracted capacity times the pipeline distance from the inlet to the offtake point and the Commodity charge is multiplied by the throughput times the pipeline distance from the inlet to the offtake point.

This results in an indicative tariff of $5.37/GJ in June 2015 dollars, for a 100% load factor customer in Kalgoorlie (1380 km) in 2016-17[20].

A.3 Transport costs for SWIS generators in 2016-17

Based on the above analysis, the transport costs for individual generators in the SWIS are set out below in Table A-2.

The calculations show the variable and fixed components in $/GJ, assuming a 75% load factor of which only 50% is included in the calculation and take account of distances specified by ACIL Tasman where relevant.

Table A- 2 Transport costs for SWIS generators in 2016-17 in $June 2015/GJ

Generator	Tariff Used	Distance	Variable transport charge	Fixed Transport Charge, 75% LF, $June 2015	Total transport Charge (50% of fixed component) $June 2015
Alinta Pinjarra	DBNGP T1		0.30	1.61	1.10
Alcoa Wagerup	DBNGP T1		0.30	1.61	1.10
PPP_KCP_EG1	DBNGP T1		0.30	1.61	1.10
SWCJV Worsley	DBNGP T1		0.30	1.61	1.10

19 ACIL Tasman draft report to the Independent Market Operator, “Gas prices in Western Australia: 2013-14 review of inputs to the Wholesale Electricity Market”, February 2013. available at http://www.imowa.com.au/f7054,3421460/Gas_Prices_in_WA_2013-14_Draft_for_consultation.pdf

20 Thus, for Parkeston, for example, which has a pipeline distance of 1380 km at an annual load of 365 GJ at 100% load factor this results in a Toll Charge of (0.380 x 365) plus a Capacity reservation charge of ($0.00263 x 365 x 1380) plus a Throughput charge of ($0.000988 x 365 x 1380) all divided by the throughput (365 GJ) = $5.37/GJ in September 2015. Assuming a 75% load factor, the Toll Charge and Capacity Reservation Charge are divided by 0.75 resulting in a transportation charge of $6.74GJ.

Generator	Tariff Used	Distance	Variable transport charge	Fixed Transport Charge, 75% LF, $June 2015	Total transport Charge (50% of fixed component) $June 2015
TiWest	DBNGP T1		0.30	1.61	1.10
Cockburn	DBNGP T1		0.30	1.61	1.10
Perth Energy	DBNGP T1		0.30	1.61	1.10
Kwinana	DBNGP T1		0.30	1.61	1.10
Mungarra	DBNGP P1	1020	0.22	1.17	0.80
Pinjar	DBNGP T1		0.30	1.61	1.10
NewGen Neerabup	DBNGP T1		0.30	1.61	1.10
NewGen Kwinana	DBNGP T1		0.30	1.61	1.10
Goldfields Power Parkeston	GGP	1380	1.36	5.34	4.03
Kemerton	DBP T1		0.30	1.61	1.10
Alinta Wagerup	DBP T1		0.30	1.61	1.10

Jacobs estimates of tariffs. ACIL Tasman distances