KEMA Limited

Energy Market Authority of Singapore

Review of the LRMC costs of CCGT electricity generation in Singapore to establish the technical parameters for setting the Vesting Price for the period 1 January 2009 to 31 December 2010

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Update Report – November 2008

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Table of Contents

Executive summary

KEMA was engaged by the Energy Market Authority of Singapore to provide settings for the technical parameters used in the vesting contract computation for the calendar years 2009-10. These technical parameters are based on the development by a new investor of a new efficient green field power plant (i.e. Best New Entrant) referred to hereafter as the Proxy Plant. It is required that this Proxy Plant should be of a technology that is already operational in Singapore with a total installed capacity servicing at least 25% of the Singapore electricity demand.

Thus, in order to evaluate the required Best New Entrant technical parameters KEMA assumed the Proxy Plant comprises a type "F" Combined Cycle Gas Turbine (CCGT) with an economic lifecycle of 20 years, and operating under local conditions in Singapore. The total plant capacity used by KEMA was 800 MW_e (ISO rated) in two trains of 400 MW_e each. The cost of the infrastructure, land, land preparation, life time extension, residual value, impact of local ambient conditions, aging and relative construction costs in SE Asia were all used in KEMA's computation of the parameters. Additionally, in order to validate the plant factor, KEMA used fundamental modelling to forecast the plant operation over a 20 year operating period. As part of its assessment, KEMA had utilised certain price indices for June 2008 for determining the change in costs for some key cost components.

The Singapore EMA has in Oct 2008 requested that KEMA provide an update of this Report, taking into consideration of the exceptional volatility in the prices of fuel oil, diesel oil and other commodities in 2008. This November 2008 Update Report presents KEMA's revised technical parameter calculations. In this Update, KEMA has utilised updated price indices for Oct 2008. The technical LRMC parameters computed in this November 2008 Update Report (versus the original study) are summarised in the table below:

Item		Parameter	Value 2009-10 (Nov 08 report)	Value 2009-10 (Sept 08 Report)
1		Capital cost US$/KW	523	523
2		Capacity (MW)	359.0	359.0
3		Total capital and land, infrastructure & development cost (Sing$m)	533.0[1]	510.5[2]
	3a	*Initial power island equipment capital costs (Sing$m)*	*325.1*	*302.7*
	3b	*Land, infrastructure & development costs (Sing$m)*	*200.6*	*201.0*
	3c	*Net upfront cost of re-investment to extend life from 12yrs*	*7.4*	*6.7*
4		HHV heat rate (Btu/kWh)	7,085	7,085
5		Build duration (Years)	2.5	2.5
6		Economic Lifetime (Years)	20	20
7		Plant factor	74%	75%
8		Fixed annual running cost (Sing$m per annum)	41.0	50.1
9		Variable non-fuel cost (Sing$/MWh)	1.05	1.05

[1] Note: Figures may not add up precisely due to rounding.
[2] Note: Figures may not add up precisely due to rounding.

In terms of cost movements between June 2008 and October 2008, (i) increases in capital costs are due to the weakening of Sing$/US$ exchange rate; and (ii) the decrease in Fixed Running Costs are due to strong falls in Singapore labour costs and the price of back up fuel (gasoil).

1. Introduction

1.1 Background

In the context of electricity market reform in Singapore, the Energy Market Authority (EMA) has implemented Vesting Contracts to curb the exercise of market power by the generation companies (Gencos) in the National Electricity Market of Singapore. These Vesting Contracts have been in place from the 1 January 2004.

The regulatory framework prescribes for these Vesting Contracts to be reviewed every 24 months (or as may otherwise become appropriate). Consequently, this project has been designed to assist the determination of the technical parameters for the Vesting Contracts that will be put in place in the coming regulatory period, starting 1 January 2009. The technical parameters exclude commercial factors such as the weighted Average Cost of Capital (WACC) which are calculated elsewhere.

The determination by EMA of the currently active Vesting Contracts was based on the determined legal and regulatory framework. This prescribes as the benchmark for the Vesting Contracts the LRMC of a Best New Entry (BNE) generator. The BNE generator is costed based on the most efficient generation technology serving at least 25% of the total electricity demand currently in Singapore. This technology is currently determined as CCGT F class generation technology, and hence the determination of the technical and capital cost parameters of this technology will form the basis of the regulatory methodology for the determination of Vesting Contracts in Singapore.

1.2 Overview of approach

Overall, KEMA's approach to the project comprised two distinct tasks:

- **Task 1** involved review of KEMA's previous equivalent work conducted for the Singapore EMA in 2006. KEMA reviewed the market information, assumptions used for the LRMC calculations done at that time. This included review of the existing vesting contract arrangements in order to revisit the setting of the various technical parameters for the determination of the LRMC of CCGT and whether any refinements were required. [These parameters were then updated/determined to reflect the current market situation in Singapore for a specified determination month – for this Update Report that month is November 2008, i.e. using data as of October 2008.]

- **Task 2** involved the development of recommendations for the setting of technical parameters for the coming regulatory period, taking into account as appropriate three considerations:

    International experience with CCGT technology;

    EMA's existing determination of parameters; and

The views of the gencos and customers regarding the setting of parameters and the performance of the current Vesting Contracts.

In accordance with the Terms of Reference the technical parameters KEMA addressed:

Capital cost

Capacity

Land, infrastructure and development cost

HHV Heat rate

Build duration

Economic lifetime

Plant factor

Fixed annual running costs

Variable non-fuel costs

For the avoidance of doubt, in accordance with the Terms of Reference for this work, commercial parameters such as WACC are not addressed by KEMA under this review.

1.2.1 Key assumptions for the LRMC calculations

Under the above approach, the basis of the calculation of the LRMC technical parameters in this (November 2008) Update Report is as follows:

1. The vesting price is the LRMC of a Proxy Plant. This Proxy Plant is defined to be a green field plant constructed by a new industry player; using most efficient technology that currently serves at least 25% of the total Singapore electricity demand – this is deemed to be a Type "F" CCGT of 800 MW_e (ISO rated) capacity in two trains of 400 MW_e. This is fully addressed in **Section 2** of this Report.

2. This (November 2008) Update Report, November as the determination month i.e. for setting price indices – data as of October 2008 is used) proposes settings for the technical LRMC parameters, these being:

    - Plant output on site at 100% load
    - Heat rate
    - Investment Cost
    - Running Cost – Fixed annual and Variable Non-Fuel
    - Operating Characteristics
    - Plant Factor (and Yearly average Heat rate)

Each of these is addressed individually in **Sections 3 to 8** respectively of this Report.

2. Details of Type F CCGT Technology

The most efficient technology that currently serves at least 25% of Singapore's electricity demand is the CCGT F-technology. This is illustrated in the table below where we provide details of the most modern CCGT power stations in Singapore; and the assumption KEMA adopts for the Proxy Plant.

Table 2.1 Type F CCGT technology in Singapore

Power station	Train capacity MW_e	Number of trains	Total station Frame F capacity MW_e	CCGT technology	GT type	Original Equipment Manufacturer (OEM)
Senoko Converted CCGT	365	3	1095	Type F	GT 26	Alstom
TUAS CCGT	367.5	2	735	Type F	M701F	Mitsubishi
TUAS new CCGT	367.5	2	735	Type F	M701F	Mitsubishi
Seraya CCGT	364	2	728	Type F	V94.3A	Siemens
Sembcorp Cogen[3]	785	1	785	Type F	9FA	General Electric
Proxy Plant	364	2	728	Type F		
Total F class			**4806**			
Total F class excluding. proxy			*4078*			
Market total installed capacity (all classes)			**10625**			
Market share			**38.38%**			

Technical details of the Type F CCGT technology produced by the main gas turbine manufacturers (as sourced from Gas Turbine World, Feb 2008) and the comparative values used by KEMA for the Proxy Plant are shown below.

Table 2.2 Type F CCGT turbines produced by manufacturers (as designed for 50Hz use)

Manufacturer	Alstom	General Electric[4]	Mitsubishi[5]	Siemens	Proxy Plant - value used by KEMA
Type designation CCGT	KA26-1	S109FB	MPC1 (M701F)	SCC5-4000F 1sft	
Type designation GT	GT26B	MS9001FB	M701F	V94.3A	
Net capacity (MW, ISO, new, at generator terminals)	424.0	412.9	416.4	416.0	400
Net efficiency (on LHV, ISO, new, at generator terminals) 2006-2007	58.3%	58.0%	58.3%	58.3%	58.2% (average)
Type steam cycle	3-pressure, reheat	3-pressure, reheat	3-pressure, reheat	3-pressure, reheat	
Power island equipment only cost FOB (USD/kW_e)	521	520	529	521	523 (average)

To be clear, the derived average power island equipment cost of US$523/kW is recommended by KEMA for use for the Proxy Plant and is shown for Item 1 of the Table in the Executive Summary.

[3] Since Sembcorp is a cogen plant although it suffices to qualify the 25% share of F class technology it does not contribute to the heat rate calculation which is limited to pure CCGT plant.
[4] The latest GE Type F turbine is the MS9001FB but this has not logged enough operating hours yet to be considered a reliable machine for a risk avoiding new entrant.
[5] The 2008 GTW entry suggests different assumptions on plant configuration; thus Mitsubishi net efficiency based on information KEMA has access to M701F performance under comparable basis is deemed to be equivalent to Alstom and Siemens equivalent turbines.

3. Plant capacity on site at 100% load

This section discusses the actual effective plant capacity which would be achievable in Singapore from a Type F CCGT of ISO rated capacity 400 MW_e, taking into account the key factors which will affect this.

3.1 ISO capacity new

As indicated in the previous section, the typical single unit capacity at ISO conditions, in new-state for the F-technology is circa 400 MW_e. A typical green field plant constructed by a new industry player in Singapore would in KEMA's view be 800 MW_e, comprising two trains of 400 MW_e (ISO) capacity each.

A single train with two gas turbines and one steam turbine could also be adopted. This would lead to a reduction in investment cost, but would lead to less favourable operational flexibility with respect to low load and start-stop operation. For this reasons, international experience indicates that the 2*400MW_e option is typically adopted. Furthermore, in the Singapore market a single 800 MW_e train would also attract significant cost of reserve power in the market; which would also make it a less attractive investment/design option.

As the typical energy loss of the generation step-up transformer is 0.3%, the capacity downstream of the CCGT would be 797.6 MW_e. Assuming net capacities and efficiencies are measured without blow down and consumption of some auxiliaries such as the water treatment plant, we subtract an estimated further 0.05% or 0.4 MW_e. This results in a net single train capacity under ISO conditions in new-state of 797.2 MW_e.

3.2 Impact of ambient conditions

3.2.1 Air temperature

At higher ambient temperatures than that used to determine the ISO capacity, the actual CCGT capacity will be lower than the ISO rated capacity.

This is because the gas turbines that drive the combined cycles are essentially constant volume machines. They take in a volume flow of air that is indifferent to ambient conditions. As the ambient temperature increases, its density decreases. At constant volume flow the mass flow of air taken in decreases. To keep operating conditions within the envelope the amount of gas fired has to decrease proportionally. Consequently, the effective MW_e capacity of the combined cycle decreases. The Figure below shows this temperature/capacity relationship for Type F CCGTs produced by the three main manufacturers worldwide i.e. General Electric (GE), Alstom, and Siemens. KEMA understands from TUAS Power that the Mitsubishi turbines exhibit very similar performance to the GE turbines and thus we assume this in determining the average for the Proxy Plant for the purposes of this project.

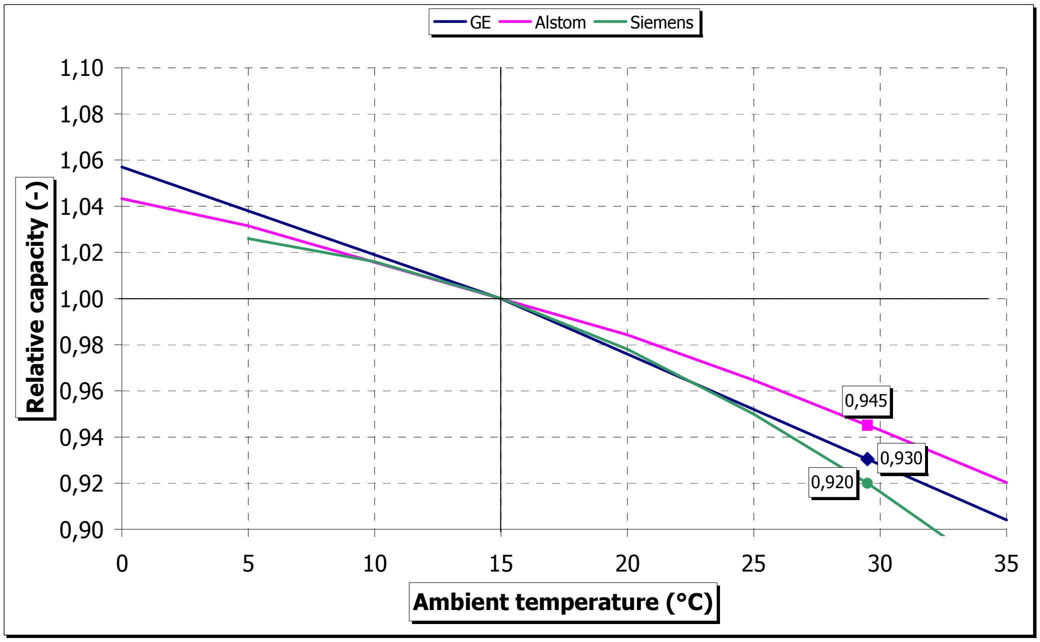

Figure 3.1 Impact of ambient temperature on Type F CCGT capacity (GE, Alstom, Siemens)

Inspection of the temperature data provided by EMA in 2006 indicated an average temperature at the Seraya, Senoko and TUAS sites of 29½ °C, with a minimum (2*standard deviation) of 26°C. Thus based on the charted temperature/capacity relationship curves above, the average air temperature of 29½ °C resulted in reductions to 94.5%, 93.0% and 92.0% of the ISO capacity for GE, Alstom and Siemens respectively; as illustrated above.

However, within this 2008 review, Singapore industry participants and the PSO have clarified that all generators are required to prove their capacity capability at 32°C and this is deemed to set a cap on the plant capacity. Consequently KEMA proposes to use the values from the above chart which align with 32°C, specifically 93%, 92% and 90% for GE, Alstom and Siemens respectively. Based on feedback from TUAS Power we also assume 93% for Mitsubishi. On this basis KEMA derives an average value of 92%.

3.2.2 Air pressure

Ambient pressure does not feature as a factor impacting of effective CCGT capacity, because Singapore is at sea level.

3.2.3 Cooling water temperature

As indicated in the Figure below, there is a significant impact of the cooling water temperature on both the capacity and the Heat rate of a Type F CCGT. For Singapore, as adopted in 2006, KEMA assumes the cooling water temperature is 28 °C and based on the charted relationship below, at this temperature there is a reduction of circa 2% in effective CCGT capacity.

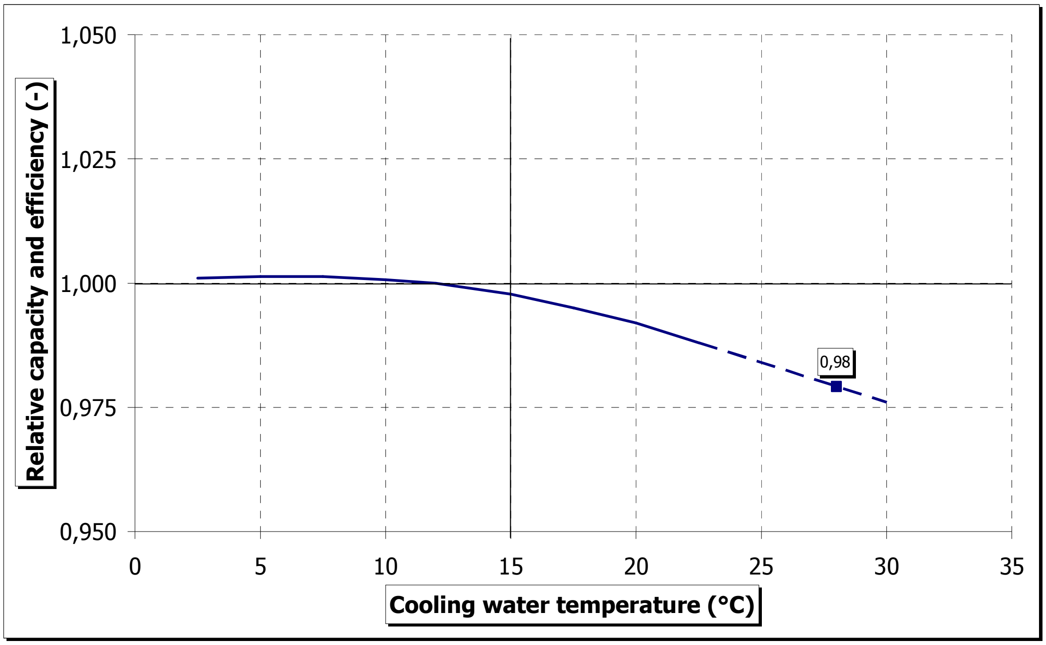

Figure 3.2 Representative impact cooling water temperature on F class CCGT capacity and efficiency

3.2.4 Effective plant capacity on site at 100% load in new state

Based on the arguments above we calculate the average net plant capacity on site at full load in new state to be:

797.2 * 0.92 (ambient temperature) * 0.98 (cooling water temperature) to give **719 MW_e**.

Given the assumption the CCGT comprises two trains, this value divided by 2 to give a train capacity of 359 MW_e. This is the value of capacity KEMA recommends is the one to be used in the calculation of the vesting price and thus is the value under item 2 in the Table in the Executive Summary.

(The effects of ageing, compressor fouling are incorporated in the market simulation and expressed by relating the plant factor to the capacity of 719 MW_e.)

3.3 Impact of ageing

The performance of CCGTs is subject to ageing, predominantly in the gas turbine. This impact of ageing (for both overall capacity and plant heat rate) is illustrated in the Figure below. It indicates that over a period of 15 years (120 000 operating hours), despite regular maintenance and plant overhauls (indicated by the "saw tooth" curves), the capacity will have decreased by approximately 3%. We take account of this in the 20 year model that we use to validate the plant factor.

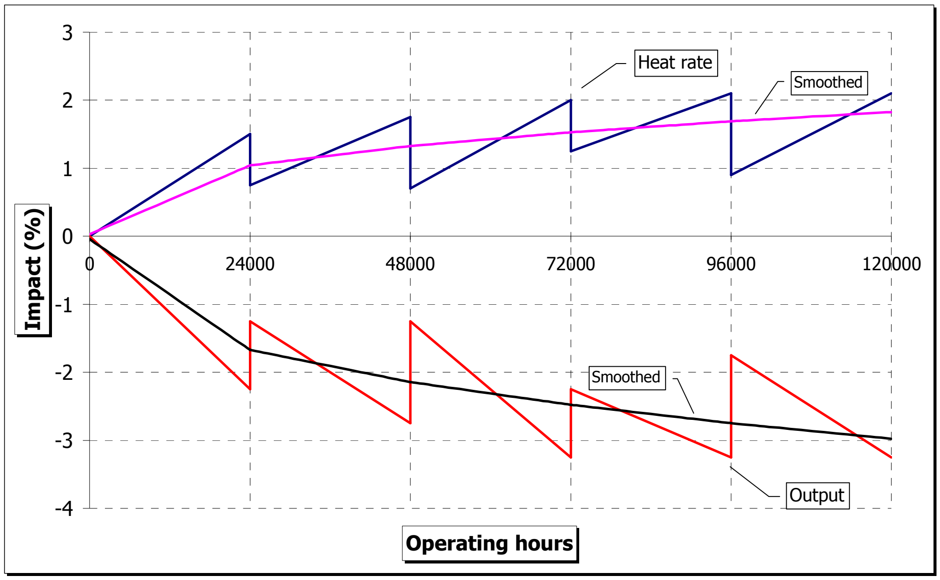

Figure 3.3 **Representative impact of ageing on CCGT heat rate and capacity**

3.4 Compressor fouling

Both the effective capacity and Heat rate of a Type F CCGT can be affected by compressor fouling. Compressor fouling is dependant on the quality of the ambient air, the quality of the inlet filters, and the washing regime. KEMA believe a plausible cleaning regime in Singapore would be a combination of on-line cleaning and semi-annual off-line washing. With respect to CCGT capacity, with this regime a deterioration of 2% in capacity just before off-line washing is reasonable to assume for Singapore. The combined effect of ageing and compressor fouling is shown in the figure below.

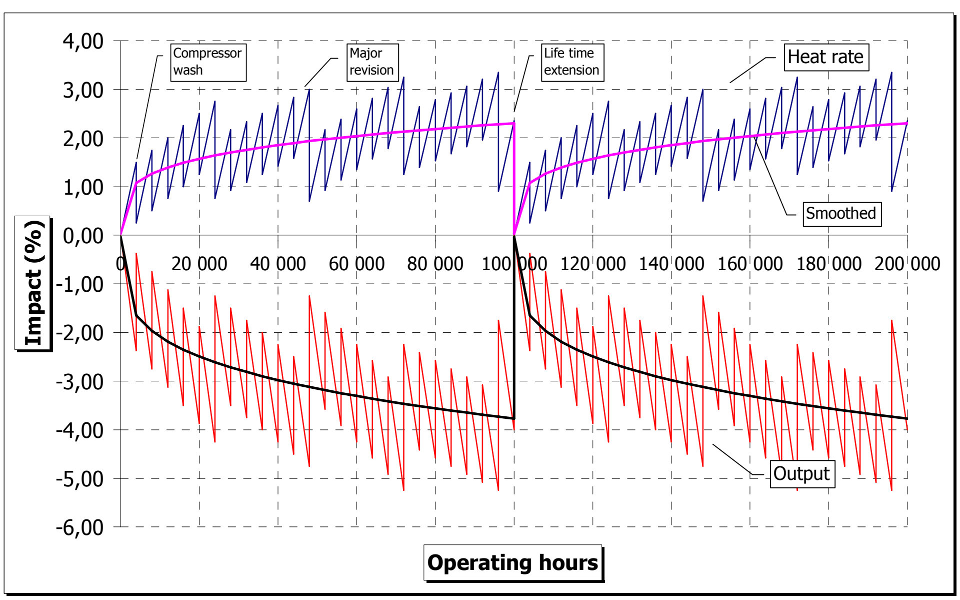

Figure 3.4 **Combined effect of ageing and compressor fouling on CCGT**

KEMA's experience is that after 100,000 operating hours the capacity is reduced by 3.8%.

After 100,000 hours, which KEMA assumes would represent the end of the first Long Term Service Agreement (LTSA) a life time extension would be expected to be planned, resetting aging and fouling to "as new" values. This resetting to "as new" values, is because KEMA have assumed that improved upgrades of the parts to be replaced will be available at this time. These improved upgrades are expected to have better performance than the original parts as they follow in the wake of evolving gas turbines technology. Therefore KEMA would expect these upgrades will more than compensate for the 'non-recoverable' deterioration incurred.

In summary KEMA will use a combined aging and fouling impact of 3.8% on plant capacity after 100 000 operating hours. Values between 0 and 100 000 operating hours are established according to the appropriate fat solid line in the Figure above.

3.5 Summary of derivation of "effective" capacity

The table below presents a summary of the capacity derivation.

Capacity	MW_e	Correction
ISO, net, new, 100%, at generator	800.0	
Downstream step-up transformer	797.6	-0.3%
Additional auxiliary equipment, blow-down	797.2	-0.05%
Ambient temperature	733.0	-8.0%
Cooling water temperature		-2.0%
Eventual on site, net, new, 100% load	**719**	
Ageing and compressor fouling	In market simulation: according to Figure 3.4	

4. Heat rate

The yearly average heat rate for a Type F CCGT depends on a number of key factors as outlined below:

- ISO efficiency at 100% load
- Ambient conditions
    - Air temperature
    - Air pressure
    - Cooling water temperature
- Ageing
- Load profile
    - Part-load
    - No of starts
    - Regulation

Each of these is addressed in the following sub-sections

4.1 ISO efficiency at 100% load in new-state

As indicated in Section 2, KEMA's assumed efficiency for the Proxy Plant under ISO conditions in new-state at the generator terminals is 58.2 % on Lower Heating Value (LHV). This corresponds to a heat rate of 5,864 Btu/kWh on a LHV basis. As the typical energy loss of the step-up transformer is 0.3%, the heat rate downstream of it is 5,882 Btu/kWh on LHV. *(This is not double counting as a 0.3% loss in the step-up transformer does not lead to a decrease in fuel consumption.)*

Assuming net capacities and efficiencies are measured without blow down and consumption of some auxiliaries such as the water treatment plant, as indicated in Section 3.1 we subtract 0.4 MW_e. This results in a net single train heat rate on a LHV basis under ISO conditions in new-state of 5 885 Btu/kWh.

4.2 Impact of ambient conditions

4.2.1 Air temperature

The efficiency of a CCGT is relatively independent of the ambient temperature. As is illustrated in Figure 4.1 below, for temperatures above 15 °C the impact is negligible for the GE and Alstom CCGTs and KEMA understands the Mitsubishi turbines also exhibit very similar performance. However ambient temperature does degrade Siemens CCGT performance above 20°C falling to 0.985 at 29½ °C as used in 2006 and to 0.98 at 32°C, which as explained in Section 3.2.1 above, is being used by KEMA for site temperature for the 2009-10 Vesting Contract LRMC calculations.

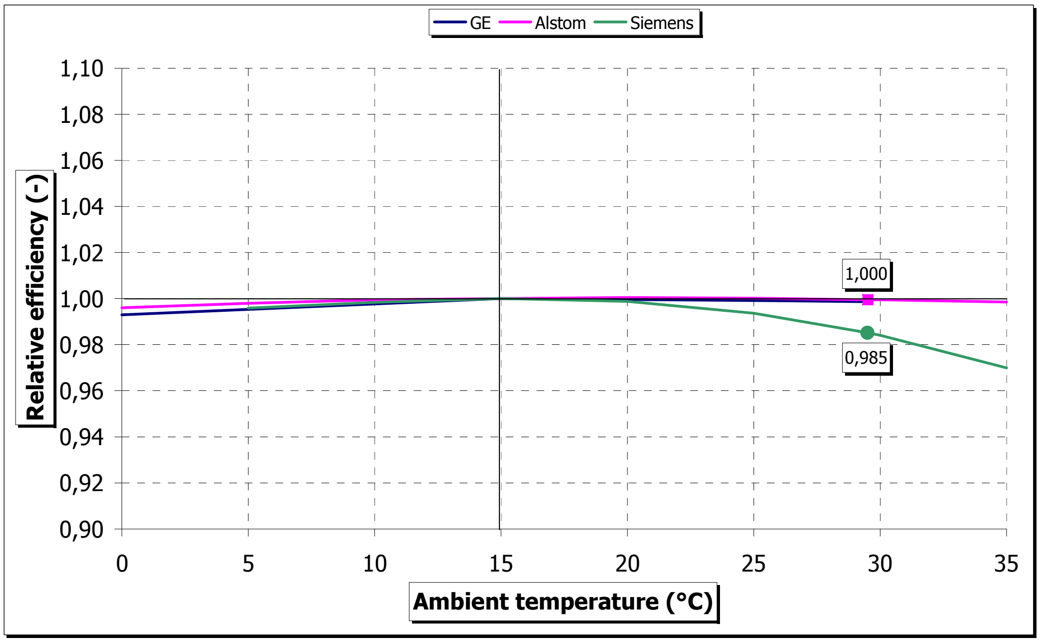

Figure 4.1 Impact of ambient temperature on F class CCGT efficiency (GE, Alstom, and Siemens)

Based on the average performance for GE, Alstom, Mitsubishi and Siemens, for the Proxy Plant KEMA proposes to use the average impact of 0.995, that is a 0.5% increase in heat rate, resulting in a heat rate of

5,885 / 0.995 = 5,914 BTU/kWh on a LHV basis.

4.2.2 Air pressure

Ambient pressure does not feature as a factor impacting of effective CCGT heat rate, because Singapore is at sea level.

4.2.3 Cooling water temperature

As indicated in the Section 3.2.3, there is a significant impact of the cooling water temperature on the efficiency (as well as capacity) of a Type F CCGT. For Singapore, as adopted in 2006 KEMA assumes the cooling water temperature is 28 °C and based on the charted relationship in Figure 3.2, at this temperature there is a reduction of circa 2% in effective efficiency of the CCGT. This corresponds to an increase of 2% in Heat rate, resulting in a higher Heat rate of

5,914 / 0.98 = 6,035 BTU/kWh on a LHV basis.

4.3 Impact of regulation

Industry feedback from 2006 highlighted that generation schedules will not match load instantaneously and that in Singapore, Automatic Generation Control (AGC) systems provide “regulation” to keep generation (with small generation output) and load in balance in real-time.

Clearly, this regulation will increase fuel consumption due to non-steady state operation. KEMA estimate this will increase the Heat rate with by approximately a further ½ %, resulting in a Heat rate of:

6,035 / 0.995 = 6,065 BTU/kWh on a LHV basis.

4.4 Plant heat rate on site at 100% load in new state

Based on the above, the net Type F CCGT plant heat rate on site, in new state, at full load in regulation mode is 6,065 BTU/kWh on a LHV basis. This corresponds to 56.27% plant efficiency on a LHV basis.

Taking into account the ratio of Higher Heat Value (HHV) to LHV (i.e. HHV/LHV) for gas of 1.108, the plant heat rate on an HHV basis on site at 100% load in new-state is

6,065 * 1.108 = 6,721 Btu/kWh.

The impact of ageing, compressor fouling, load profile, are incorporated in the market simulation and expressed as yearly average heat rate.

4.5 Impact of ageing

As indicated in Section 3.3, the performance of CCGTs is subject to ageing, predominantly in the gas turbine. This impact on the capacity and Heat rate performance of the type F CCGT is illustrated in Figure 3.3. It indicates that over a period of 15 years (120,000 operating hours), despite regular maintenance and plant overhauls (indicated by the “saw tooth” curves), the Heat rate will increase by approximately 3%. We take account of this in the 20 year model that we use to validate the plant factor.

4.6 Compressor fouling

As indicated in Section 3.4, the Heat rate of a Type F CCGT can be affected by compressor fouling and that compressor fouling is dependant on the quality of the ambient air, the quality of the inlet filters, and the washing regime. Also as indicated in Section 3.4, KEMA believe a plausible cleaning regime in Singapore would be a combination of on-line cleaning and semi-annual off-line washing. With this regime KEMA a deterioration of 1¼% in heat rate just before off-line washing is reasonable to assume for Singapore.

KEMA’s experience is that after 100,000 operating hours the heat rate is increased by 2.3%. Again as indicated in Section 3.4, after 100,000 hours, which KEMA assumes would represent the end of the first Long Term Service Agreement (LTSA) a life time extension would be expected to be planned, resetting aging and fouling to "as new" values.

In summary, KEMA will use a combined aging and fouling impact of 2.3% on Heat rate after 100 000 operating hours and 2.3% on heat rate. Values between 0 and 100 000 operating hours are established according to the relevant fat solid line in Figure 3.4 above.

4.7 Load profile

4.7.1 Impact of part load

Figure 4.2 shows the impact of part loading on the efficiency performance of Type Fs CCGTs from GE and Alstom. For example, we see that at 60 % loading the efficiency decreases to 91% of the value at 100% load for the GE Type F CCGT and to 94% for the Alstom Type F CCGT and thus the Heat rate increases by 9.9 % and 6.4 % respectively. KEMA understands the Mitsubishi turbines also exhibit very similar performance.

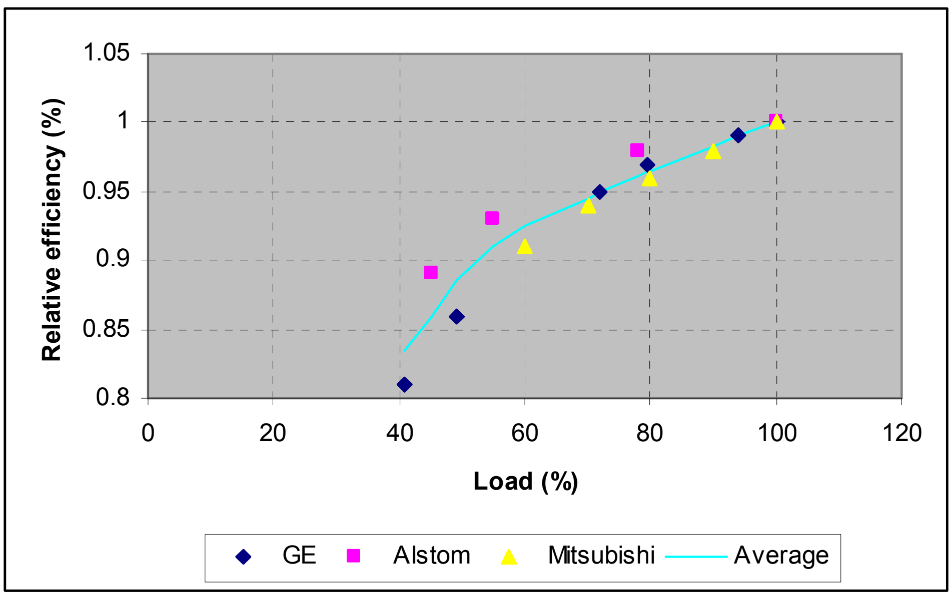

Figure 4.2 Impact of part load on F class CCGT efficiency (GE, Alstom)

For the purposes of this assignment, as adopted in 2006, KEMA proposes to use the average of the three curves in its LRMC calculations; as illustrated in Figure 4.2 above.

4.7.2 Impact of number of starts

The additional fuel consumption of a start (i.e. fuel used which does not generate electricity) is conveniently expressed as the number of operating hours at full load that has equal fuel consumption. For a hot start (after a night shutdown) this is ½ operating hour and for a warm one this amounts to 1 operating hour. Expressed in fuel consumption these numbers are 700 and 1400 MWh respectively. These numbers are used in the determination of the annual average efficiency.

4.8 Summary of derivation of "effective" heat rate

The table below presents a summary of the heat rate derivation.

Heat rate	% LHV	kJ/kWh LHV	Btu/kWh LHV	Btu/kWh HHV	Correction efficiency
ISO, net, new, 100%, at generator	58.20%	6,187	5,864	6,498	
Downstream step-up transformer	58.03%	6,206	5,882	6,517	-0.3%
Additional auxiliary equipment, blow-down	58.00%	6,209	5,885	6,521	-0.05%
Ambient temperature	57.71%	6,240	5,914	6,553	-0.5%
Cooling water temperature	56.55%	6,367	6,035	6,687	-2.0%
Regulation					-0.5%
Eventual on site, net, new, 100% load	**56.27%**	**6,399**	**6,065**	**6,721**	
Ageing and compressor fouling	In market simulation: according to figure 3.4				
Part load	In market simulation: according figure 4.2				
Starts	In market simulation: according section 4.7.2				

Unit Conversion Notes: (i) 1KWh = 3413 Btu
(ii) 1 Btu = 1.055056kJ.

5. Investment cost

This section describes the estimation of the investment cost for a Type F natural gas-fired CCGT operating in Singapore: the so-called Proxy Plant.

The derivation is summarised in Table 5.1 in Section 5.3 at the end of this Section. However, each element is addressed individually in the sub-sections which follow under Section 5.2, and the italic numbers in brackets in each sub-section refer to the corresponding rows in Table 5.1. Firstly Section 5.1 outlines the key assumptions underpinning the estimation of component costs for the Proxy Plant.

5.1 Key assumptions

5.1.1 Plant capacity

The net electric capacity at ISO conditions in new-state is 800 MW, divided over two trains of 400 MW each (*1*).

In Section 3.2.4 the site capacity was determined at **728 MW_e**. The maximum capacity on site is reached in new-state when the air and cooling water temperature are at its lowest. From Section 3.2 these temperatures are 26 and 24½ °C respectively. Using these values, from Figure 3.1, we are able to calculate a maximum site capacity of 754 MW_e (*3*). This capacity determines the relevant connection charges and costs *(17-18)*.

5.1.2 Exchange rates used in costings

Furthermore for the purposes of this analysis KEMA, in line with methodology adopted for the previous determination of the LRMC parameters and thus applied in this 2008 review, the exchange rates for Sing$/US$ and Sing$/Euro were required to adjust cost values to Singapore Dollars. For this November 2008 Update Report, the EMA has specified that these should be for October 2008; and thus we use the average of the daily values for October 2008, to obtain applicable exchange rates of:

(i) 1.4763 Sing$/US$; and

(ii) 1.9678 Sing$/Euro

5.1.3 Treatment of Interest During Construction

Interest during construction (IDC) should be included in a correctly executed discounted cash flow analysis. However, as was the case in KEMA's original 2006 methodology, it was not included as the EMA indicate they conduct this calculation separately within the overall Vesting Contracts calculations they make, of which the technical parameters provided by KEMA are just one part. Thus, for KEMA to include IDC would introduce double counting into the Vesting Contracts' price calculations.

Indeed, since the Draft Report to address user feedback, KEMA has reviewed the EMA's Vesting

Contracts calculation model which uses KEMA's technical parameters, other commercial parameters and the WACC to derive the Vesting Contract prices; to verify that the EMA explicitly include IDC in their calculations. Within the EMA's overall Vesting Contracts price calculation spreadsheet, it is clearly IDC is calculated explicitly and separately to KEMA inputs as a "Construction period financing cost at WACC". To be clear, IDC is not treated as part of WACC but costed via application of WACC in the manner indicated above. KEMA therefore confirms there is therefore no reason to explicitly include IDC in the technical parameter computations as this would result in double accounting.

5.2 Initial plant construction and commissioning costs

There are a number of component costs associated with the construction and commissioning of a Type F CCGT in Singapore. These are:

The estimated costs for each of these items are discussed in the following sub-sections.

5.2.1 Initial capital cost

Taking the average of the power island equipment only costs from Table 2.2, KEMA estimates the equipment cost on a Free On Board (FOB) basis for the Proxy Plant CCGT as US$523/$kW_{e,ISO}$ (i.e. Sing$617.7m for a single gaseous fuel plant *(4)*.

For dual fuel hot switching capability an estimated cost of 5m Euros per GT is added *(5)* – equivalent to Sing$19.7m for the site. This includes fuel forwarding, fuel treatment and day storage. For the transport cost *(6)* we estimate 2% of the equipment cost (items *4, 5*) – equivalent to Sing$12.7m. Provision of spare parts including initial ones *(8)* is assumed to form part of the LTSA with the manufacturer.

Thus in total this yields an initial capital cost for the power island of **Sing$650.1m** (*8*). This value divided by two (i.e. Sing$325.1m) is the value under item 3a in the Table in the Executive Summary and is the one to be used in the calculation of the vesting price.

5.2.2 Land cost

It is assumed that the Proxy Plant would require an area of 12.5ha and waterfront of 200m.

The latest JTC figures shown as effective from July 2008, indicate an upfront premium of Sing$164/sqm-Sing$206/sqm (Sing$1.64m – Sing$2.06m per ha) for a period of 30 years in the Jurong area[6]. Consistent with the 2006 methodology, KEMA takes a centre value of Sing$185/sqm to get a value of Sing$23.1m *(9)*.

In addition, JTC quote an additional water front fee of Sing$792–Sing$1188 per meter per year effective from July 2008. Again, consistent with the 2006 methodology KEMA takes a centre value of

[6]The figure used is that for a TUAS view within the Jurong area which is deemed to be the most economic site for a new entrant CCGT.

Sing$990 per meter per year. We convert land costs into an upfront premium for 30 year, using a discount rate of 9.25% post-tax nominal as prescribed by the EMA to be adopted for the 2009-10 Vesting Contracts. We also assume upfront monthly payments of these waterfront fees. This calculation derives an upfront premium of Sing$10,028 per meter or Sing$2.0m in total (*10*).

In 2006 we added land preparation cost (m) at a Western European cost level of 100,000 Euros/ha adjusted by relative Singapore to Western European labour cost rates. Since the 2006 KEMA Report Western European labour costs have increased by c.5% giving a value of 105,000 Euros/ha. Unit labour cost statistics from March 2006 KPMG Guide to International Business Location indicated the Singapore unit labour cost price level was 56% of those in Western Europe.

However, since the 2006 KEMA Report, Singapore's Monthly Digest of Statistics indicates Singapore labour costs for construction work have increased by c.11% between Q3 2006 and Q2 2008 and trending to Q3 2008 and October 2008 gives an increase of 13% - this is a far more rapid cost increase than seen in Europe. Hence there needs to be an adjustment made to the assumed relative costs of Singapore and Western European construction labour. On this basis, as at Q3 2008, Singapore labour costs are now c.60% of Western European cost levels. Using this adjustment factor on the land preparation costs this then amounts to approximately Sing$124,526/ha and Sing$1.5m in total *(11)*.

Thus the total land costs amounts to **Sing$26.6m** *(12)*.

5.2.3 Facility costs

Facility costs are very much dependant on the actual conditions and therefore can vary considerably. KEMA assumes the same component and associated costs as it estimated in December 2006 to provide a typical breakdown of the facility cost (including commissioning). The 2006 values were as follows:

- Ancillary Building Sing$4.0m
- Demineralisation plant Sing$4.0m
- Seawater intake/outfall Sing$11.0m
- Jetty emergency fuel unloading Sing$16.0m
- Gas receiving costs Sing$11.0m
- TOTAL facility costs Sing$46.0m

KEMA has identified a formal Singapore cost index which is felt to be most relevant to assessing the cost increases in these items in Singapore since 2006. This index is calculated by the Building & Construction Association (BCA) of Singapore; and measures the change in costs of Construction tenders issued in Singapore. For this exercise, KEMA uses the All Buildings Construction Tender Price Index as the appropriate measure to increase construction costs from Q3 2006 (index value =

103.3) to Q3 2008 (index value = 139.9). For the purpose of extrapolation of the BCA Price Index to Oct 2008, while the Tender Price Index since Q3 2006 has shown an upward trend, KEMA noted that the raw construction material market prices published by BCA in Oct 2008 have fallen with respect to the prices in Aug 2008 and Sep 2008. Given the uncertainty of how tender prices could be in Oct 2008, KEMA proposes to use the Q3 2008 index as a proxy for the index for Oct 2008. Hence, the increase in construction costs over the period is 35% which KEMA then applies universally to the total facility costs. Thus the updated costs for individual facility costs components are as follows:

- Ancillary Building Sing$5.4m
- Demineralisation plant Sing$5.4m
- Seawater intake/outfall Sing$14.9m
- Jetty emergency fuel unloading Sing$21.7m
- Gas receiving costs Sing$14.9m

Applying this increase derives revised total facility costs of **Sing$62.3m** (*14*).

5.2.4 Emergency fuel facilities

In Singapore, a generation licensee is required to keep emergency fuel facilities for 60 days on site. This amounts to 1.1 million barrels or 175 million litres. Following information provided by TUAS in 2006, the cost of emergency fuel facilities (encompassing two storage tanks of equal capacity) was determined by the EMA to be $Sing209 m^3 for the current Vesting Contracts. For 175 million litres this equated to a cost of Sing$36.6m consisting of the following elements:

- Civils – 31%
- Mechanical works – 41% (of which steelwork comprised approximately half)
- Electrical works – 11%
- Control Systems – 5%
- Other – 12%

KEMA highlights that it assumes commissioning is included within these costs. *However, the cost of fuel treatment and fuel forwarding is included in the power island cost.*

As for facility costs in 5.2.3 above, KEMA proposes to increase the cost of emergency fuel facilities in line with observed increases in the costs of materials. In the case of emergency fuel facilities it is proposed to apply a disaggregated set of different cost increase factors which are believe to representative for each part. These are outlined below:

- Civils – use average construction cost increases from Singapore BCA data as calculated in Section 5.2.3 above (35%)

- Mechanical works – use Imported Iron & Steel price index from Monthly Digest of Singapore Statistics for 50% and DSPI for 50%

    - Note the Imported Iron &Steel price index was set at 100 for 2006 and in September 2008 was 136.3, which is used as the proxy value for Oct 2008 for similar reasons as using the BCA Tender Price Index in Q3 2008 as a proxy for that in Oct 2008, as explained in Section 5.2.3. This translates into an increase in imported iron & steel costs of 36% over the period.

    - Domestic Supply Price Index (DSPI) in Singapore reflects the costs of products, is used by the EMA in its overall Vesting Contracts price calculation as an escalator of capex items and is thus deemed an appropriate default index where a more specific one is not available. DSPI has increased from 97.3 in October 2006 to 112.4 in September 2008 i.e. a 15.5% cost increase over the period. Extrapolating this forward to October 2008 gives a 16.2% cost increase for October 2006 to October 2008.

- Electrical works – use DSPI for period October 2006 to September 2008 (latest figure available) extrapolated forward to October 2008 (16.2%)

- Control Systems – use derived DSPI for period October 2006 to October 2008 (16.2%)

- Other – use derived DSPI for period October 2006 to October 2008 (16.2%)

Given these assumptions, this derives updated component installation costs for each of the above items as follows:

- Civil works Sing$15.4m *(15a)*
- Mechanical works Sing$18.9m *(15b)*
- Electrical works Sing$4.7m *(15b)*
- Control Systems Sing$2.1m*(15c)*
- Other Sing$5.1m*(15d)*

This results in a cost of Sing$264/$m^3$ and a total cost of **Sing$46.2m** (*16*).

5.2.5 Connection costs

KEMA understands that the standard connection charge of Sing$50,000/$MW_e$ for the current Vesting period is still valid deriving a cost for the deemed max site capacity (754MWe) of Sing$37.7m (17).

In addition to this, KEMA have estimated the cost for 230 kV switch gear, switch house, underground cable and connection to the grid; based on KEMA's view of latest costs for Singapore, including use of information provided by market participants. As for 2006, we have assumed a 2 x 100% connection and 1 km of trench length in sand. KEMA estimate the following cost break down (- again KEMA assumes commissioning is included in these costs):

• Substation (at plant, with switchhouse)	2	Sing$10.0m
• XLPE Cable in sand (underground)	2 x 1km	Sing$8.5m
• Substation extension (at network)	2	Sing$10.0m
• End joint (at network)	4	Sing$2.0m
• TOTAL network connection cost		**Sing$30.5m** *(18)*

Applying the connection charge to the deemed connection capacity of 754MW, both items add up to total connection costs of **Sing$68.2m** *(19)*.

5.2.6 Installation costs

These costs are defined as the construction (i.e. installation) cost of the power island and exclude the initial capital cost. KEMA assumes the same component and associated costs as it estimated in December 2006 namely (i) Civil works (Sing$13.0m); (ii) Erection and assembly (Sing$57.0m); (iii) Detailed engineering and start-up (Sing$13.0m); and (iv) Contractor soft cost (Sing$44.0m); giving a total power island construction cost (equivalent to the installation cost) of Sing$127.0m.

As defined in 2006, civil works for the power island consist of laying the foundations and building the turbine hall. Erection and assembly consists of erection of the equipment, installation of the connecting piping, constructing the steel works and electrical assembly and wiring. Contractor soft cost (for the power island) consists of contractors' fees (inc. profit), construction insurance, miscellaneous spare parts and materials. KEMA assumes commissioning of the power island is included in the construction cost.

In 2008, as for estimating emergency fuel storage facilities costs, in 5.2.4 above, KEMA proposes to increase the cost of installation in line with observed increases in the costs of materials and to apply a disaggregated set of different cost increase factors which are believed to representative for each part. These are outlined below:

- Civil works - use average construction cost increases from Singapore BCA data as calculated in Section 5.2.3 above (35%)
- Erection and assembly - use average construction cost increases from Singapore BCA data as calculated in Section 5.2.3 above (35%)

- Detailed engineering and start-up – use average increase in Western European labour costs as outlined in Section 5.2.2 (5%)

- Contractor soft cost - use derived DSPI for period October 2006 to October 2008 (16.2%)

Given these assumptions this derives installation costs for each of the above items as follows:

- Civil works Sing$17.6m *(20a)*

- Erection and assembly Sing$77.2m *(20b)*

- Detailed engineering and start-up Sing$13.7m*(20c)*

- Contractor soft cost Sing$51.1m*(20d)*

Consequently, this derives a total value for installation costs of **Sing$159.6m** *(21)*.

5.2.7 Miscellaneous owner and start-up costs

This item includes all other internal costs not covered in the previous sections. In 2006, KEMA assumed these included (i) owner's manpower up to an including contract award (Sing$3.5m); (ii) owner's manpower during construction (Sing$7.5m); (iii) taxes and insurances during construction (Sing$3.0m); and (iv) purchased electricity, water and fuel during construction (Sing$2.0m) to give a total of Sing$16.0m

Owner's manpower up to and including contract award includes bid preparation, contractor selection and permitting. Owner's manpower during construction includes overseeing the project, construction support, witnessing commissioning, setting up the production organisation, training and recruiting personnel. This results in a relatively high cost, but is driven by KEMA's assumption that the Proxy Plant will be built by a new investor; and the organisation has to be built from an initial zero position.

For its 2008 assessment, KEMA assumes that manpower related costs increase by 13% in accordance with the derived increase in construction wages costs over the period Q3 2006 to Q3 2008 and October 2008 (based on the Singapore Monthly Digest of Statistics reported increase in monthly earnings for construction in as applied previously for land costs in Section 5.2.2 above). All other costs are assumed to have risen in line with derived DSPI for the period October 2006 to October 2008 (16.2%).

This derives the following levels of miscellaneous costs;

- Owner's manpower up to an including contract award Sing$4.0m (*22a*)

- Owner's manpower during construction Sing$8.5m (*22b*)

- Taxes and insurances during construction Sing$3.5m (*22c*)

- Purchased electricity, water and fuel during construction Sing$2.3m *(22d*)

On this basis the revised total miscellaneous owner and start-up costs is **Sing$18.2m**[7] *(23*).

5.2.8 Consultancy costs

Detailed engineering costs are included in the previous items. Hence only basic engineering and advice is covered here. KEMA's international experience is that the cost of supporting consultancy for new build covering basic engineering, legal and financial advice is currently typically circa 5% of total land, infrastructure and development cost, resulting in **Sing$20m** *(24*).

5.2.9 Total initial investment cost of Proxy Plant

The considerations of the component costs outlined in Sections 5.2.1-5.2.8 above lead to an initial total construction and commissioning cost of:

650.1 + [26.6 + 62.3 + 46.2 + 68.2 + 159.6 + 18.2 + 20] = **Sing$1051.2m** *(26)*.

i.e. comprising:

(i) capital costs of **Sing$650.1m** *(8)* - This value divided by two is the value under item 3a in the Table in the Executive Summary (i.e. Sing$325.1m) and is the one to be used in the calculation of the vesting price;

and

(ii) total other construction costs (covering land purchase, infrastructure costs and project development costs) of **Sing$401.1m** *(25)* - This value divided by two is the value under item 3b in the Table in the Executive Summary (i.e. Sing$200.6m) and is the one to be used in the calculation of the vesting price.

5.3 Net upfront cost of lifetime extension

In addition to the above costs there is a net upfront cost associated the need to re-invest in the Proxy Plant after a defined operating period to ensure it operates for at least the 20 year production period defined as the economic lifetime for the purpose of Vesting Contracts. This additional cost is determined below:

5.3.1 Re-investment cost

After 100 000 hours or 12 operating years (end of first LTSA, see Section 6.1.3) a life time extension is planned. In 2006, KEMA estimated re-investment costs of Sing$120m comprising (i) Distributed

[7] NOTE: Totals may not add up precisely due to rounding.

Control Systems (Sing$30m); (ii) Balance of Plant (Sing$35m); and (iii) Gas Turbines (Sing$55m).

The latter two items have increased in Sing$ terms by c.14% since 2006 in line with power island equipment cost increases since 2006 (US$523/kW vs. US$432/kW) adjusted by the change in Sing$/US$ exchange rate over the period (1.57 in 2006 to 1.4763 in October 2008). However, control systems costs have been seen to remain static in real terms over the period so we increase these costs in line with DSPI (16.2%).

Thus for 2008, we propose:

- Distributed Control Systems Sing$34.9m
- Balance of Plant Sing$45.5m
- Gas Turbines Sing$74.0m

This derives a total value of re-investment costs of **Sing$154.4m** *(27)*.

5.3.2 Residual value

The lifetime extension extends the life time of the plant to 2*12 is 24 years. Thus, after 20 years of operation there is a residual value corresponding to 4 years of remaining lifetime, that is

(Initial total capital, land, infrastructure and development cost + re-investment cost) * remaining lifetime / total lifetime

= [(1051.2) * (4/24)] + [(154.4) * 4 /12] = Sing$226.7m *(28)*.

5.3.3 Derived up-front value

The EMA method uses only one value for investment cost, so we have to convert the re-investment cost and residual value to up-front values. We use the EMA prescribed real, pre-tax discount rate of 9.25%% to do so. The upfront value of the re-investment cost becomes:

$154.5/(1+0.0925)^{12}$ = Sing$53.4m

The upfront value of the residual value becomes:

$226.8/(1+0.0925)^{20}$ = Sing$38.6m

Thus the net upfront cost of the life extension of the Proxy Plant is

53.4 – 38.6 = **Sing$14.8m** *(29)* - This value divided by two ids the value under item 3c in the Table in the Executive Summary (i.e. Sing$7.4m) and is the one to be used in the calculation of the vesting price.

5.4 Total investment cost of Proxy Plant

The total investment cost of the Proxy Plant is deemed to be the aggregation of the initial total construction and commissioning cost as outlined in Section 5.2.9, and the net upfront cost of re-investment for lifetime extension as outlined in Section 5.3.3, giving:

1051.2 + 14.8 = **Sing$1066.0m** *(30)*.

This value divided by 2 (i.e. **Sing$533.0m**) is the value under item 3 in the Table in the Executive Summary and is the one to be used in the calculation of the vesting price.

5.5 Summary of Proxy Plant costs

The summary table of all of the component investment costs discussed in this Section are provided in Table 5.1 below:

Table 5.1 Derivation of investment cost for two 400 MW_e ISO trains built side by side

No.	Item	Parameter	Specific Price	Total Cost (Sing$m)
Proxy Plant Capacity				
1	Unit ISO Capacity	400 x 2		
2	Unit Capacity	364 x 2		
3	Unit maximum site capacity	377 x 2		
Power Island Costs				
4	Equipment (inc. step-up transformers		US$523/ kW_e	617.7
5	Hot switching capability		5m Euros/GT	19.7
6	Transport cost	2% of items (4) & (5)		12.7
7	Spare parts (inc. initial ones)			in LTSA
8	**Total power island equipment**	(4)+(5)+(6)+(7)		**650.1**
Land, infrastructure & development cost				
	Land Cost			
9	Land Lease	12.5ha	Sing$1.85m/ha	23.1
10	Waterfront fee	200m	Sing$10,028/m	2.0
11	Land preparation	12.5ha	Sing$124,526/ha	1.5
12	**Total land cost**			**26.6**
	Facility Cost			
13a	Ancillary buildings			5.4
13b	Demineralisation plant			5.4
13c	Seawater intake/outfall			14.9
13d	Jetty emergency fuel unloading			21.7
13e	Gas receiving facilities			14.9
14	**Total facility cost**			**62.3**
	Emergency fuel facilities			
15a	Civil works			15.4

No.	Item	Parameter	Specific Price	Total Cost (Sing$m)
15b	Mechanical works			18.9
15c	Electrical works			4.7
15d	Control systems			2.1
15e	Other			5.1
16	**Emergency fuel facilities**	175,000m^3	Sing$264/$m^3$	**46.2**
	Connection Charge			
17	Standard connection charge	754MW_e	Sing$50k/ MW_e	37.7
18	Cost of 230kV switchgear (inc. switch yard and underground cable)	754MW_e		30.5
19	**Total connection charge**			**68.2**
	Construction of power island (i.e. installation costs			
20a	Civil works			17.6
20b	Erection & assembly			77.2
20c	Engineering & power island set-up			13.7
20d	Contractor (power island) soft costs			51.1
21	**Total construction of power island costs**			**159.6**
	Miscellaneous owner's & start up costs			
22a	Owner's manpower up to & inc. contract award			4.0
22b	Owner's manpower during construction			8.5
22c	Taxes and insurances during construction			3.5
22d	Purchases of electricity, water and fuel during construction			2.3
23	**Miscellaneous owner's & start-up costs**			**18.2**
24	**Total additional consultancy costs**	5% of item (25)		**20.0**
25	**Total land, infrastructure & development cost**	(12) + (14) + (16) + (19) + (21) + (23) +(24)		**401.1**
26	**Total initial investment cost**	(8) + (25)		**1051.2**
	Net upfront costs of lifetime extensions			
27	**Cost of plant re-investment**			154.4
28	**Residual value after 20 years**			226.7
29	**Net upfront cost of lifetime extension**			**14.8**
30	**Total investment cost**	(26) + (29)		**1066.0**
31	**Total investment cost per $kW_{e,site}$**	Site, new		**1.483**
32	**Total investment cost per $kW_{e,ISO}$**	ISO, new		**1.333**

6. Running costs

In calculating the running costs of the Proxy Plant, we distinguish between fixed running cost and variable non-fuel cost. Each of these is addressed separately below.

6.1 Fixed running costs

This aspect of running costs comprises a number of specific components each of which are addressed in the following sub-sections to derive a total annual fixed running cost for the Proxy Plant.

6.1.1 Manpower, overhead, etc

In December 2006, KEMA estimate the cost for manpower, corporate overheads, working capital and other expenses (insurance, property tax, etc) at Sing$16m per annum, broken down into (i) manpower, corporate overheads, and working capital (Sing$6m per annum) and (ii) insurance, property tax and miscellaneous (Sing$10m per annum)

The Singapore Monthly Digest of Statistics indicates overall labour costs have increased by c.15% between Q3 2006 and October 2008 (data up to Q2 2008 and extrapolated to October 2008) . KEMA believes it is more appropriate to use the overall labour cost measure for manpower costs in this context in this instance rather than that for construction labour as previously used e.g. in Section 5.2.3. Thus this is the cost increase which we apply this to the manpower costs. For insurance etc, KEMA would expect these costs to rise in line with the inflation in the Singapore Consumer Price Index (CPI) over the period. The CPI for October 2006 was 101.6 and the CPI figure for September 2008 was 111.2 (an increase of 9.4%). Extrapolating this forward to cover the period to October 2008 this represents a cost increase of 9.9%.

Applying the relevant growth in costs gives:

- Manpower, corporate overheads, and working capital Sing$6.9m per annum
- Insurance, property tax and miscellaneous Sing$11.0m per annum

Thus these cost increases derives revised total manpower & overhead costs of **Sing$17.9m**.

6.1.2 Carrying backup fuel

For the cost of carrying backup fuel, based on its international experience, KEMA estimate a cost of approximately **Sing$20.6m per annum**. The derivation is as follows:

Site capacity (MW_e)	718
Yearly average site efficiency	56.27%
Daily fuel consumption (GWh)	30.9
90 Days fuel consumption (TWh)	2.759
LHV diesel oil (MWh/b)	1.70
Barrels needed for 90 days	1.623million
Diesel (50 ppm) price (US$/b) including delivery on site*	92.73

Stock value (US$m)	150.5
Carrying cost (US$m per annum) at 9.25% real, pre-tax discount rate	13.9
Carrying cost in Sing$m per annum	**20.6**

* Assumed to be LFO (nr 2 fuel oil/distillate) and is based on delivered price to Singapore

6.1.3 Maintenance

In 2006, for maintenance of the power plant main components KEMA estimated a cost of 225m Euros, including spare parts in West-Europe, based on an LTSA with the manufacturer for 100,000 Equivalent Operating Hours (EOH) or 12 years (whichever comes first).

This is 18.75m Euros per annum or 2,250 Euros/EOH of which spares materials account for two thirds of the cost and labour the remaining one third. For Singapore, in 2006 we assumed a mark-down of 10% (consisting of no mark down for materials and c. 30% mark down for labour and supervision), resulting in 16.89 m Euros per annum or 2,025 EUR/EOH. In 2006, this equated to Sing$34.1m per annum or Sing$4,095/EOH.

In 2008, as indicated in Section 5.2.3 above we believe it appropriate to apply a mark down of 40% (i.e. Singapore labour costs are 60% of Western European levels); continuing to assume Singapore labour will do routine maintenance work. For the spares themselves we believe it appropriate to increase these cost in line with the cost increases in the Type F turbines adjusted for the movement in Sing$/US$ exchange rate over the period (i.e. c.14% as indicated in Section 5.3.1 above). Further taking into account the change in Euro:Sing$ forex rate; this derives a revised cost of **Sing$37.8m per annum** or Sing$4,533/EOH.

In December 2006, KEMA also assumed that for the routine maintenance of the plant there would be an additional Sing$5m per annum. Assuming this cost has increased in line with the general increase in overall labour costs (40% as outlined above) this becomes **Sing$5.8m per annum**.

6.1.4 Business interruption insurance

In computation of the cost of capital a number of elements are taken into consideration. These include, inter alia, the forecast Bank Lending rate, and a risk factor. The risk factor is intended to consider the likelihood of the project not delivering on expected value.

Risk factors can increase the effective cost of capital by quite a lot depending on the type of project concerned, its location, technology and other risks. One risk factor that is normal to include in cost of capital computations for power plant is the risk of interruption. This will consider how likely an interruption is and how long it is likely to last. This factor will introduce lost revenue probabilities to the project. It is normal to express these in terms of an increased risk to the cost of capital.

KEMA has experience in many projects throughout the world and whilst has found it normal practise to include the risk of interruption in the costs of capital computations. It is not normal practise to procure an insurance policy to protect against it. Having said that even were the project owner to decide to procure Business Interruption Insurance it is expected that this would be only at a price, which is no greater than the likely cost of failure, computed in the cost of capital. That being the case then the insurance policy would be effectively funded through the project cost of capital computation.

Therefore, even where such a policy is purchased, it is not something KEMA would expect to cost separately as a project cost. For that reason, and as the cost of capital is not part of the mandate given to KEMA to compute the LRMC technical parameters KEMA is of the opinion it is inappropriate to include the cost of Business Interruption Insurance in the project costs its being already accounted for elsewhere.

6.1.5 Cost of debt

Cost of debt does not feature in our calculation, but should be included in the discount rate of a correctly executed discounted cash flow analysis. This analysis is outside the scope of our review and KEMA will exclude it to avoid double accounting from its application elsewhere.

6.1.6 Total fixed annual running cost

Based on above KEMA calculates a total fixed running cost of:

17.9 + 20.6 + 43.5[8] = **Sing$82.0m per annum**.

This value divided by 2 (i.e. Sing$41.0m) is the value under item 8 in the table in the Executive Summary and is the one to be used in the calculation of the vesting price.

6.2 Variable non-fuel running costs

This aspect of running costs also comprises a number of specific components each of which are addressed in the following sub-sections to derive estimated total annual variable non-fuel running costs for the Proxy Plant.

6.2.1 EMC Fees

EMC, the Energy Market Company in Singapore, is the market operator under the New Electricity Market rules. Generators pay an administrative fee to this company, based on the number of MWh injected to the network grid. For the fiscal year April 2008 – March 2009 this fee is indicated at **Sing$0.3661/MWh**.

6.2.2 PSO fees

The Market Rules require EMC to publish the Power System Operator's schedule of fees for a given fiscal year. The PSO's administrative fee for the wholesale electricity market for the period April

[8] Note: Totals may not add up precisely due to rounding.

2008 to 31 March 2009 is **Sing$0.2104/MWh**[9].

6.2.3 EMA Licence fee

Generators are also required to pay an EMA Licence Fee. In the first year of operation this comprises a lump sum of Sing$50k. In each subsequent year of operation this same lump sum applies plus an output related variable fee of Sing$1.55/GWh. Thus assuming the plant factor of 74% for the Proxy Plant (as specified in Section 8.1) and a maximum capacity of 359MW (as derived in Section 3.2.4); this derives the following:

Year 1 Fee: Sing$50k

Year 2 Fee: Sing$53.6k

Thus the average annual Licence Fee is Sing$51.8k and for 74% plant factor this derives a cost of **Sing$0.0224/MWh**.

6.2.4 Consumables

In 2006, KEMA estimated the cost of consumables (feed water, oil, chemicals) at Sing$0.40/MWh electricity produced, comprising (i) feed water make up (Sing$0.08/MWh) and (ii) chemicals and oil (Sing$0.33MWh).

For feed water make up we believe it appropriate to apply the derived CPI for the period October 2006 to October 2008 (9.9%). For chemicals and oils we have been provided by the following data by a market participant on cost increases for chemicals used by their Type F technology based CCGT and an indication of relative use.

Chemical	Increase in costs between 2006 and 2008 purchases*	Relative proportion of use
Hydrochloric acid 33%, kg	6.7%	65.64%
Caustic soda 45%. kg	17.4%	30.39%
Catalytic hydrazine 35%, kg	8.1%	0.07%
Ammonia solution 25%, kg	105.0%	3.85%
Trisodium phosphate, kg	78.6%	0.04%

* These costs are confidential but have been audited and verified by KEMA

Based on the mix of use we derive a weighted average increase in costs between 2006 and 2008 of 13.7%. Consequently, for 2008, we estimate consumables as follows:

[9] http://www.emcsg.com; Budgets and Fees; PSO budget & fees (FY2007/08)

- Feed water make up Sing$0.0769/MWh$_e$
- Chemicals and oil Sing$0.3754MWh$_e$

On this basis we derive a total cost of consumables of **Sing$0.4523/MWh**.

6.2.5 Total variable non-fuel cost

Based on above the total variable non-fuel cost are calculated at:

0.3661 + 0.2104 + 0.0224 + 0.4523 is **Sing$1.05/MWh**.

This is the value under item 6 in the table in the Executive Summary and the value that should be used in the calculation of the vesting price.

7. Operational characteristics of the Proxy Plant

This section sets the parameters for the operational characteristics of the Proxy Plant. These additional parameters will be used in the simulation to estimate the plant factor (see Section 8).

7.1 Availability

KEMA expect an availability of at least 90% based on the work of Alstom Power and KEMA's own international experiences.

7.2 Practical minimum load

KEMA expect a practical minimum load of app. 55% based on allowable NO_x-emissions. Below this load the emissions increase strongly.

7.3 Ramp-up speed

KEMA expect an achievable ramp rate (from practical minimum load to full load) of app. 3% or 24 MW per minute.

7.4 Start-up time

Start-up time for to full load for a hot start (after a night outage) is expected to be app. 1½ hours. For a warm start (after a weekend outage) we expect 2½ hours to full load. For a completely cold start we expect 6 hours.

7.5 Cost of a start

A start has two effects, that is:

1. Additional fuel consumption
2. Additional wear and tear on the plant

The additional fuel consumption is conveniently expressed in a consumption corresponding to a number of equivalent operating hours (EOH) at full load. For a hot start (after a night shutdown) this is ½ operating hour and for a warm start this is 1 operating hour. Expressed in fuel consumption, for the Proxy Plant this equates to 700MWh and 1,400MWh respectively.

To assess the additional wear and tear on the plant EOH is also used. For a CCGT, international experience indicates that one start corresponds to approximately 10 EOH. Expressed as a cost this equates to about Sing$42,000 per start (see also previous section).

8. Plant factor and yearly average heat rate

8.1 Estimation of the plant factor

As specified by the EMA, for use in the Vesting Contract calculations, plant factor will be taken as the average plant factor achieved by Class F units operating in CCP configuration for the year ending 31 October 2008. Accordingly, the EMA have indicated that the value to be adopted is 74%. This is the value under item 7 in the Table in the Executive Summary.

8.2 Estimation of the heat rate

In the Singapore market the dispatch is done by the PSO, the Power System Operator. The PSO uses the Market Clearing Engine (MCE) to determine the least-cost dispatch schedule and market prices.

KEMA uses a similar software tool called Prosym to simulate the optimum dispatch of the Singapore generating units. Prosym takes into account all the influences mentioned in the previous section. The plant factor of the proxy CCGT is determined by simulation of the Singapore wholesale market for a period of 20 years (the deemed economic lifetime of the Proxy Plant; as indicated in Item 6 of the table in the Executive Summary).

For market simulation in Prosym by KEMA, the information described in the previous section is required to feed the model. The key static modelling assumptions adopted are outlined in Appendix 1 and the assumed heat rate (and capacity) performance degradation of the Proxy Plant over its economic lifetime (taking into account reinvestment for life extension after 12 years) with age is outlined in Appendix 2.

In addition, as we are examining the costs over a 20 year forecast period; it is necessary to seek to model the development of the system in the coming 20 years is important; covering changes in demand and in generation as new plant commission and existing plant potentially close. KEMA has established a 20 year forecast for demand and generation for use in Prosym based on the expected load development, the commissioning dates and technology of the new units and assumptions on the life time of the units. Details of generation assumptions are provided in Appendix 3.

Detailed outputs from the model simulation are provided in two tables within Appendix 4.

8.2.1 Assumptions for Singapore market development

As indicated above in modelling the Singapore market a number of modelling assumptions need to be made. Listed below are the main assumptions concerning the market development in Singapore:

(i) Load development (MW, GWh) for 2009-29 is based on forecast data provided by the EMA 30 April 2008

(ii) Load pattern is based on 2006 half hourly load data (EMA web site)

(iii) Initial expansion plan is based on an Reserve Margin falling below 30% in any year

(iv) For initial simulations existing units are decommissioned after 25 years (CCGTs) and 35 years (Steam units)

(v) Decommissioned units are replaced by CCGT units with better performance than the proxy CCGT due to the expected better technology available by the time new capacity is required

(vi) New capacity additions are consistent with a reserve factor not falling below 30%

(vii) The must-run units are assumed to live until the end of the evaluation period or be replaced between times by similar units with the same generating capacity

(viii) Spinning reserve requirement is 1.5 times largest dispatched capacity

(ix) CHP units are considered must-run units. This implies that these units will run at maximum capacity when they are available

(x) The *Environment* plant is also considered must-run

(xi) The plant characteristics are according to the KEMA data base and actual site conditions

(xii) Characteristics of the Proxy Plant are according to this report

(xiii) Fuel prices for the whole period are based on a crude oil price of 91.5 USD/b (ORBP). This price is calculated back from the 431 USD/ton for fuel oil.

(xiv) HSFO price is 80% of ORBP

(xv) Orimulsion price is 40% of ORBP

(xvi) Gas prices are according to EMA calculations and adjusted for increase of crude oil price (x 91.5/60)

(xvii) Initial efficiency of future CCGTs is adjusted for improved technology

(xviii) Efficiency and capacity derating due to ageing and compressor fouling of running CCGTs is accounted for as indicated in Figures 3.3 and 3.4.

(xix) Variable operation and maintenance costs are not considered in the commitment and dispatch of the units

(xx) Co-optimisation is not taken into account initially (an adjustment is made later – see Section 8.2.2.2), as the simulations are performed to determine the merit order in a competitive market without strategic behaviour of market participants. We assume that the owner of the Proxy Plant will bid low enough to ensure dispatch of the plant during all available hours. Owners of all other plants are assumed to do the same.

To illustrate the interaction between the demand and the supply Figure 8.1 shows the supply curve and the Load duration curve (LDC) of 2009.

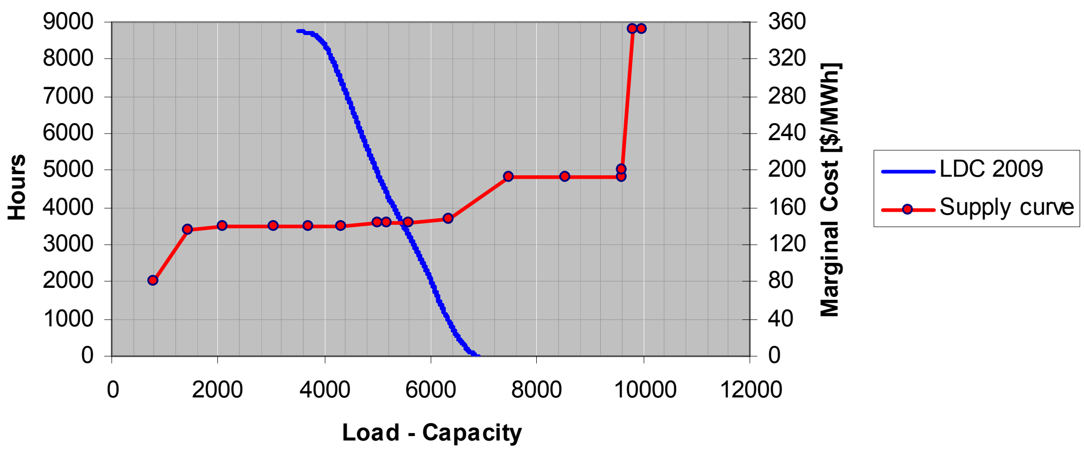

Figure 8.1 Supply and load duration curves of 2009

KEMA highlights the following:

- The load is always more than 3500 MW. Of this 3500 MW about 1200MW (present view) is served by must run capacity. Also there is 750MW of Orimulsion capacity in the system which is cheaper than the CCGTs. This makes about 2000MW of capacity placed in the merit order and running before the CCGT capacity. A new CCGT unit would come right on top of this 2000MW and would therefore be pure base load capacity. In the course of time new units would come in and would push the proxy CCGT down in the merit order at the same time the LDC would shift to the right, due to increasing demand. How this impacts on the plant factor in the course of time is shown in the next section.

8.2.2 Results

The expansion plan with the forecast load, the new generating capacity, the total capacity and the reserve factor is shown in Figure 8.2.

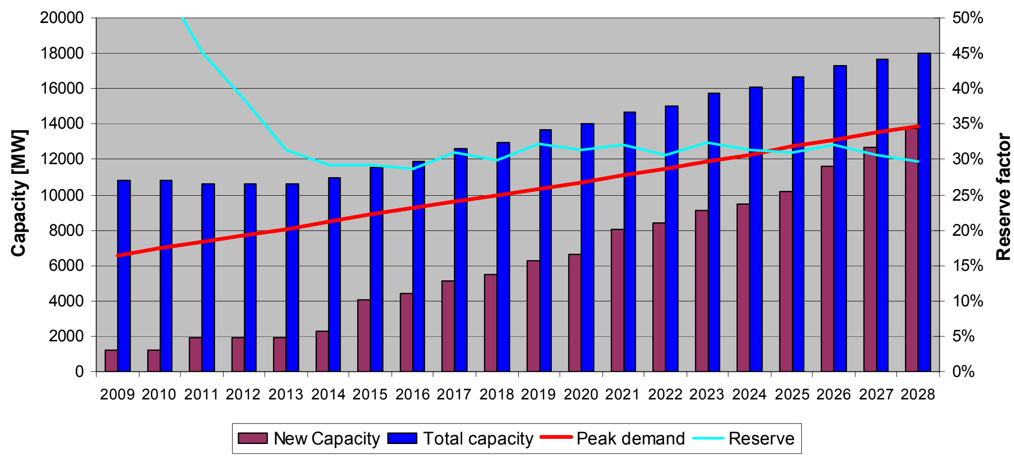

Figure 8.2 Expansion plan based on used assumptions

KEMA highlights the following:

- For a reliable supply (reserve not falling below 30%) no additional capacity, apart from the proxy CCGT would be required before 2015. The reserve factor would decrease from over 40% to about 30%. After 2015 new additions would be required regularly to maintain the desired reliability.

The break down of generating capacity and load is indicated in Figure 8.3. The capacity for each type of plant (CCGT, OCGT, Steam, must-run) is shown together with the maximum and minimum forecasted load. The red line shows the peak load according to EMA and the yellow one is the minimum load development. Assumed is that all required capacity expansion is by means of new CCGT units. Each unit will be slightly more efficient than the last one added.

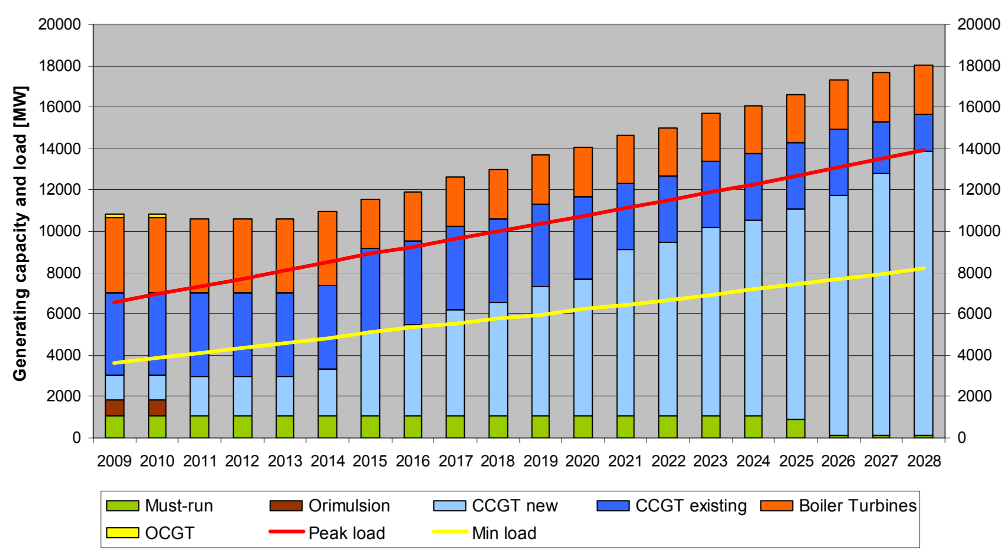

Figure 8.3 Capacity per type of plant according to expansion plan

8.2.2.1 Yearly average heat rate

The other result from KEMA's modelling in Prosym is the yearly average heat rate, taking into account

- Average plant heat rate on site at 100% load in new state
- Impact of ageing – see Appendix 2
- Impact of part load
- Impact of number of starts
- Life time extension

The results are indicated in the table below:

Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
E production (GWh)	5436	5433	5451	5449	5449	5401	5022	4589	3085	3026
Fuel consumption (MBTU)	36626	36883	37068	37101	37115	36854	34559	31615	21192	20763
Heat rate (BTU/kWh)	6738	6788	6801	6808	6812	6823	6882	6889	6869	6863

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
E production (GWh)	4212	4927	4629	4497	4010	3969	3750	3279	2772	1625
Fuel consumption (MBTU)	29052	34067	31512	30968	27765	27514	26045	22893	19364	11421
Heat rate (BTU/kWh)	6898	6914	6808	6887	6924	6933	6946	6982	6985	7028

KEMA highlights a gradual increase in heat rate due to aging and operation away from base load. After 12 operating years the heat rate is reset, because of the lifetime extension of the combined cycle. The pure average of annual heat rate achieved over the 20 year period is 6879 BTU/kWh on a HHV basis.

8.2.2.2 Simple average heat rate for the operating period adjusted for reserve holding

As agreed with the EMA, KEMA uses the results for annual heat rates as shown in the table above to derive a simple average heat rate for the deemed operating period of the Proxy Plant, which as indicated above is 6,879 BTU/kWh on a HHV basis.

However, in addition it is important to acknowledge the impact of holding the requisite amount of reserve on the Proxy Plant across the year. KEMA applies this in the same way as for 2006, specifically to adjust the annual plant factor by the appropriate percentage taking into account the required share of holding of reserve (500MW assumed each year) and to then derive the adjusted average heat rate based on an assumed adjustment factor per percent plant factor reduction. Appendix 4 – Table B provides details of this calculation. However, the table below summarises the key elements:

Proxy Plant Performance Parameter	**20yr average value**
Plant Factor (unadjusted for reserve holding)	70.22%
Heat Rate (unadjusted for reserve holding)	6879 BTU/kWh (HHV)
Required reserve holding (as a percentage of 359MW plant capacity)	4.26%
Plant Factor (adjusted for reserve holding)	65.96%
Assumed Heat Rate degradation per % loss of plant factor	0.17%
Heat Rate (adjusted for reserve holding)	6946 BTU/kWh (HHV)

As indicated the adjusted average heat rate to account for reserve holding is 6,946 BTU/kWh on a HHV basis. Consequently, the adjusted average heat rate of 6**,946 BTU/kWh** on a HHV basis is the value under item 4 in the table in the Executive Summary and is the value that should be used in the calculation of the vesting price.

8.2.2.3 Simple average heat rate for the operating period further adjusted for house load

All generation plant have house load. This has previously not been accounted for within the deemed costs of the Proxy Plant. Thus it is appropriate to adjust the heat rate derived in 8.2.2.2 further to recognise the impact of self-supplying house load. The impact of this for a CCGT is typically to degrade heat rate performance by circa 2%.

Consequently, the finally adjusted average heat rate is **7,085 BTU/kWh** on a HHV basis and is the value under item 4 in the table in the Executive Summary and is the value that should be used in the calculation of the vesting price.

9. Summary of final technical LRMC parameters

In this section, we summarise the key technical LRMC parameters for the 2009-10 Vesting Contracts prices determination as calculated in the previous sections.

9.1 Capacity per generating unit

The capacity per generating unit is 719.0 MW_e / 2 is **359.0 MW** (Section 3.2.4). The effects of ageing and compressor fouling are incorporated in the market simulation and expressed by relating the resulting plant factor in each year to the capacity of 719 MW_e.

9.2 HHV heat rate

The HHV heat rate is **7,085 BTU/kWh**. This is a simple average of the annual heat rates over the 20 year production period; adjusted to take into account the impact of holding reserve (Section 8.2).

9.3 Build duration

Given the current strong demand for gas turbines and supply capacity being reached there has been an impact on delivery lead times. Based on feedback and evidence received from market participants we have increased the assumed build duration from the 27 months assumed in December 2006, to the apparent current build duration of **30 months** i.e. **2.5 years**.

9.4 Plant factor

The plant factor is **74%**. This is the average plant factor achieved by Class F units operating in CCP configuration for the year ending 31 October 2008 as provided by the EMA and specified by them should be used within the Vesting Contracts calculations (Section 8.2).

9.5 Total capital and land, infrastructure and development cost

The total capital and land, infrastructure and development cost per generating unit (including net upfront cost of re-investment for lifetime extension) amounts to Sing$1066m / 2 which is **Sing$533m** (Section 5).

9.6 Fixed annual running cost

The fixed annual running cost per generating unit amount to Sing$82m / 2 which is **Sing$41m** (Section 6.1.6).

9.7 Variable non-fuel cost

The variable non-fuel cost amount to **Sing$1.05/MWh** (Section 6.2.4).

Appendix 1 - Assumptions for heat rate estimation

General assumptions on generating units

	Lifetime	Start-uptime (hours)	Planned maintenance	Forced Outage	Minimum load
Steam units	35	4	5.0%	5.0%	30%
CCGTs	25	2	5.0%	5.0%	55%
OCGT	25	1	5.0%	3.0%	60%

Fuel pricing

Fuel prices are based on an OPEC Reference Basket Price (ORBP) for crude oil of 69.16 USD/bbl. Prices of other crude oil related fuels can be derived from the crude oil price using historically determined ratios. However, the price for natural gas was originally been provided by EMA but is adjusted for changes in crude oil price against the assumption they used) and the price of LFO has been sourced from an average October 2008 monthly price (US$89/b) plus a delivery premium from an actual contract for a Singapore generator (Sing$5.50 – adjusted to US$ at October 2008 exchange rate of 1.4763).

	ORBP USD/b	Ratio to ORBP	Fuel price* Sing$/GJ
HSFO	69.16	0.80	13.4
LFO	69.16		15.1
Orimulsion	69.16	0.40	6.7
Natural gas	69.16		11.2

** Assume 6.12 GJ per barrel*

Reserve Share

Generator carries its own share of reserve in proportion to its output compared to the total system demand. Reserve capacity required by the system is approximated at 1.5*Load of the Max Loaded Plant as seen from the model outputs.

Appendix 2 - Assumed degradation of heat rate and capacity

As indicated in Section 8.2, within its modelling, KEMA assumes degradation of both the heat rate performance and the capacity capability of the Proxy Plant over the course of its economic life, as the plant ages.

The assumptions KEMA incorporated in line with a smoothed representation of the performance charts in sections 4.5 and 3.3 for heat rate and capacity respectively and reflecting lifetime extension investment after 12 years (as discussed in Section 5.3) is provided below:

Year	Heat rate	Capacity
1	0.65%	-1.00%
2	1.38%	-2.16%
3	1.57%	-2.48%
4	1.70%	-2.71%
5	1.78%	-2.86%
6	1.83%	-2.94%
7	1.88%	-3.02%
8	1.92%	-3.11%
9	1.97%	-3.19%
10	2.02%	-3.27%
11	2.07%	-3.36%
12	2.11%	-3.44%
13	0.65%	-1.00%
14	1.38%	-2.16%
15	1.57%	-2.48%
16	1.70%	-2.71%
17	1.78%	-2.86%
18	1.83%	-2.94%
19	1.88%	-3.02%
20	1.92%	-3.11%
21	1.97%	-3.19%
22	2.02%	-3.27%
23	2.07%	-3.36%
24	2.11%	-3.44%

Appendix 3 - Details of Singapore power plants

The table below provides details for existing Singapore power plants, the Proxy Plant and "dummy" plants used to model new entry in future years.

#	Utility	Plant	Region	Company	First start	Nr of units	Decommissioning	Re-invest-ment	Base capacity [MW]	Maximum capacity [MW]	Minimum capacity [MW]	Type of fuel	Max. efficiency
1	Senoko_Original_CCGT	SNKCP1	North	Senoko	1996	2	2021	2008	425	410	226	Gas	52.4%
2	Senoko_Converted_CCGT	SNKCP3	North	Senoko	2004	3	2029	2016	365	355	195	Gas	55.3%
3	Senoko_Steam	SNKSt	North	Senoko	1980	5	2015	n.a.	250	247	74	HSFO	39.7%
4	Pasir_Panjang_OCGT	Pasir_GT	SouthWest	Senoko	1983	2	2008	n.a.	105	102	61	LFO	29.6%
5	Tuas_Oil	TuasSt	SouthWest	TUAS	1999	2	2034	n.a.	600	594	178	HSFO	39.7%
6	Tuas_CCGT	TuasCP1	SouthWest	TUAS	2002	2	2027	2014	368	357	196	Gas	55.3%
7	Tuas_New_CCGT	TuasCP2	SouthWest	TUAS	2005	2	2030	2017	368	358	197	Gas	55.4%
8	Seraya_Orimulsion	Ser_St1	SouthWest	Seraya	2005	3	2011	n.a.	250	247	74	Orimulsion	39.7%
9	Seraya_Oil	Ser_St2	SouthWest	Seraya	1998	5	2033	n.a.	237	235	70	HSFO	39.7%
10	Seraya_CCGT	Ser_CCP	SouthWest	Seraya	2003	2	2028	2015	364	354	194	Gas	55.3%
11	Jurong_OCGT	Jur_GT	SouthWest	Seraya	1986	2	2011	n.a.	100	97	58	LFO	29.6%
12	Sembcorp_Cogen	SKRA	SouthWest	SembCogen	2001	1	2026	2013	785	761	650	Gas	53.9%
13	Exxon_Mobil_Cogen	Exxon	SouthWest	Exxon	2000	1	2025	2012	180	174	150	Gas	53.7%
14	Environment	ENV1	SouthWest	Environment	2000	1	2035	n.a.	135	131	120	Refuse	38.2%
15	Syngas_Pte_Ltd	Syngas	SouthWest	PTE	2000	1	2035	n.a.	15	15	14	Gas	38.2%
16	Merlimau_CCGT	Merlimau	SouthWest	Merlimau	2006	1	2031	2018	470	470	259	Gas	53.7%
17	Proxy CCGT	Proxy	Unkonown	Proxy	2009	2	2034	2021	370	359	197	Gas	56.7%
18	Seraya_CHP1_2	Seraya_CHP	SouthWest	New	2011	2	2036	2023	370	359	204	Gas	57.2%
19	New_2	New_2	SouthWest	New	2014	1	2039	2026	370	359	197	Gas	57.9%
20	New_3	New_3	SouthWest	New	2015	5	2040	2027	370	359	197	Gas	58.1%
21	New_4	New_4	SouthWest	New	2016	1	2041	2028	370	359	197	Gas	58.4%
22	New_5	New_5	SouthWest	New	2017	2	2042	2029	370	359	197	Gas	58.6%
23	New_6	New_6	SouthWest	New	2018	1	2043	2030	370	359	197	Gas	58.9%
24	New_7	New_7	SouthWest	New	2019	2	2044	2031	370	359	197	Gas	59.1%
25	New_8	New_8	SouthWest	New	2020	1	2045	2032	370	359	197	Gas	59.4%
26	New_9	New_9	SouthWest	New	2021	4	2046	2033	370	359	197	Gas	59.6%
27	New_10	New_10	SouthWest	New	2022	1	2047	2034	370	359	197	Gas	59.9%
28	New_11	New_11	SouthWest	New	2023	2	2048	2035	370	359	197	Gas	60.1%
29	New_12	New_12	SouthWest	New	2024	1	2049	2036	370	359	197	Gas	60.4%
30	New_13	New_13	SouthWest	New	2025	2	2050	2037	370	359	197	Gas	60.6%
31	New_14	New_14	SouthWest	New	2026	4	2051	2038	370	359	197	Gas	60.9%
32	New_15	New_15	SouthWest	New	2027	3	2052	2039	370	359	197	Gas	61.6%
33	New_16	New_16	SouthWest	New	2028	3	2053	2040	370	359	197	Gas	61.8%

Appendix 4 - Detailed Prosym simulation results

Table A below provides detailed result from the modelling simulation of Singapore conducted by KEMA for the purposes of determining heat rates.

Table A

Production GWh

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SNKCP1	2,756	3,328	3,888	4,605	5,162	5,091	2,629	2,494	1,916	1,961	1,535	1,577	-	-	-	-	-	-	-	-
SNKCP3	7,196	7,455	7,613	7,807	7,811	7,759	5,635	8,086	7,280	7,286	7,027	6,277	4,233	4,306	3,644	3,736	3,549	3,166	2,536	780
SNKSt	760	1,265	1,892	2,469	3,453	3,516	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pasir_GT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TuasSt	133	324	705	1,139	1,384	1,503	1,263	1,217	823	884	632	679	588	600	535	562	535	498	572	257
TuasCP1	3,904	4,315	4,790	5,010	5,337	5,709	4,919	4,746	4,670	4,567	2,571	2,586	1,430	1,449	1,136	1,253	1,231	992	-	-
TuasCP2	5,086	5,269	5,359	5,442	5,518	5,367	4,585	3,237	5,346	5,236	4,914	4,823	3,707	3,784	3,213	3,261	3,036	2,712	2,273	1,056
Ser_St1	5,872	5,871	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ser_St2	13	54	90	224	394	375	315	315	229	209	108	165	215	169	200	190	258	250	271	180
Ser_CCP	4,408	4,623	4,797	4,914	5,028	5,003	5,329	4,839	4,495	4,635	3,112	3,023	1,998	1,975	1,781	1,859	1,672	1,448	1,096	-
Jur_GT	-	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SKRA	5,232	5,307	5,411	5,480	5,682	5,641	5,298	5,309	5,240	5,228	5,208	5,216	5,169	5,182	5,165	5,172	5,178	-	-	-
Exxon	1,204	1,220	1,240	1,285	1,296	1,290	1,218	1,224	1,208	1,203	1,198	1,199	1,195	1,194	1,191	1,193	-	-	-	-
ENV1	1,028	1,028	1,027	1,028	1,028	1,028	1,028	1,027	1,026	1,026	1,027	1,027	1,027	1,027	1,027	1,027	1,027	1,027	1,027	1,026
Syngas	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Merlimau	2,786	2,910	3,036	3,140	3,226	3,226	2,879	2,902	2,768	2,878	2,758	2,727	2,497	2,501	2,398	2,410	2,431	2,384	2,305	2,123

Plant load factor (not adjusted for reserve)

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SNKCP1	37.8	45.8	53.7	63.7	71.4	70.5	36.4	34.6	26.6	27.2	21.4	21.9	-	-	-	-	-	-	-	-
SNKCP3	77.3	80.1	81.9	84.1	84.2	83.7	60.8	85.2	77.6	77.9	75.3	67.4	45.5	46.3	39.2	40.2	38.2	34.1	27.4	8.4
SNKSt	7.0	11.7	17.5	22.8	31.8	32.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pasir_GT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TuasSt	1.3	3.1	6.8	10.9	13.3	14.4	12.1	11.7	7.9	8.5	6.1	6.5	5.6	5.8	5.1	5.4	5.1	4.8	5.5	2.5
TuasCP1	62.6	69.2	76.9	80.5	85.8	89.6	78.1	75.6	74.6	73.0	41.1	41.4	22.9	23.2	18.2	20.1	19.8	16.0	-	-
TuasCP2	81.3	84.3	85.8	87.2	88.5	86.2	73.7	52.1	83.9	83.1	78.3	77.0	59.3	60.6	51.5	52.3	48.7	43.5	36.5	17.0
Ser_St1	90.3	90.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ser_St2	0.1	0.5	0.9	2.2	3.8	3.6	3.1	3.1	2.2	2.0	1.1	1.6	2.1	1.6	1.9	1.8	2.5	2.4	2.6	1.7
Ser_CCP	71.3	74.8	77.7	79.7	81.6	81.2	84.4	77.6	72.3	74.7	50.2	48.8	32.3	32.0	28.8	30.1	27.1	23.5	17.8	-
Jur_GT	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SKRA	78.6	79.8	81.4	82.5	83.5	83.8	79.0	79.4	78.4	78.3	78.1	78.3	77.6	77.9	77.7	77.9	78.0	-	-	-
Exxon	78.9	80.1	81.5	82.3	84.0	83.9	79.4	79.9	78.9	78.6	78.4	78.5	78.4	78.3	78.2	78.4	-	-	-	-
ENV1	89.7	89.7	89.6	89.8	89.7	89.7	89.7	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6
Syngas	89.1	89.1	89.0	89.2	89.1	89.1	89.1	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0
Merlimau	68.1	71.2	74.3	76.9	79.1	79.2	70.7	71.4	68.1	69.1	67.0	66.4	61.0	61.2	58.7	59.1	59.6	58.5	56.6	52.1

Heat rate (kJ/kWh) - based on HHV

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
SNKCP1	7,860	7,836	7,804	7,773	7,736	7,748	7,919	7,966	8,097	8,079	8,171	8,151								
SNKCP3	7,344	7,321	7,304	7,287	7,289	7,299	7,393	7,163	7,301	7,315	7,356	7,377	7,415	7,423	7,427	7,428	7,455	7,470	7,456	7,527
SNKSt	11,257	11,070	10,907	10,767	10,620	10,584														
Pasir_GT																				
TuasSt	11,323	11,285	11,172	11,079	11,056	11,058	11,049	11,019	11,139	11,020	11,185	11,112	11,057	11,127	10,979	11,001	10,929	10,909	10,885	10,888
TuasCP1	7,380	7,354	7,334	7,319	7,274	7,127	7,292	7,337	7,359	7,380	7,356	7,316	7,416	7,419	7,422	7,422	7,402	7,426		
TuasCP2	7,294	7,273	7,265	7,256	7,249	7,273	7,372	7,388	7,174	7,240	7,313	7,329	7,384	7,389	7,401	7,400	7,420	7,442	7,441	7,505
Ser_St1	10,038	10,038																		
Ser_St2	11,365	11,292	11,266	11,180	11,123	11,155	11,118	11,188	11,275	11,186	11,262	11,228	10,990	11,263	10,997	11,031	10,959	10,943	10,879	10,953
Ser_CCP	7,408	7,382	7,353	7,337	7,318	7,323	7,166	7,298	7,376	7,359	7,394	7,399	7,444	7,449	7,450	7,451	7,459	7,478	7,444	
Jur_GT		15,512																		
SKRA	7,525	7,515	7,501	7,495	7,356	7,415	7,484	7,491	7,507	7,512	7,521	7,523	7,534	7,535	7,542	7,545	7,544			
Exxon	7,554	7,545	7,532	7,395	7,440	7,460	7,520	7,520	7,534	7,542	7,549	7,552	7,559	7,564	7,569	7,568				
ENV1	10,457	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456
Syngas	10,487	10,481	10,481	10,481	10,489	10,483	10,483	10,481	10,486	10,486	10,490	10,490	10,490	10,490	10,480	10,480	10,481	10,481	10,481	10,485
Merlimau	7,735	7,690	7,648	7,620	7,597	7,601	7,722	7,714	7,775	7,619	7,721	7,754	7,893	7,896	7,968	7,963	7,952	7,986	8,042	8,184

Table B, overleaf, provides further results from the modelling simulation of Singapore conducted by KEMA for the purposes of determining heat rates. It indicates year on year plant factors (inc. adjustment for reserve usage.)

Table B

Production factor	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
1 SNKCP1	37.8	45.8	53.7	63.7	71.4	70.5	36.4	34.6	26.6	27.2	21.4	21.9	-	-	-	-	-	-	-	-	
2 SNKCP3	77.3	80.1	81.9	84.1	84.2	83.7	60.8	85.2	77.6	77.9	75.3	67.4	45.5	46.3	39.2	40.2	38.2	34.1	27.4	8.4	
3 SNKSt	7.0	11.7	17.5	22.8	31.8	32.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
4 Pasir_GT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
5 TuasSt	1.3	3.1	6.8	10.9	13.3	14.4	12.1	11.7	7.9	8.5	6.1	6.5	5.6	5.8	5.1	5.4	5.1	4.8	5.5	2.5	
6 TuasCP1	62.6	69.2	76.9	80.5	85.8	89.6	78.1	75.6	74.6	73.0	41.1	41.4	22.9	23.2	18.2	20.1	19.8	16.0	-	-	
7 TuasCP2	81.3	84.3	85.8	87.2	88.5	86.2	73.7	52.1	83.9	83.1	78.3	77.0	59.3	60.6	51.5	52.3	48.7	43.5	36.5	17.0	
8 Ser_St1	90.3	90.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
9 Ser_St2	0.1	0.5	0.9	2.2	3.8	3.6	3.1	3.1	2.2	2.0	1.1	1.6	2.1	1.6	1.9	1.8	2.5	2.4	2.6	1.7	
10 Ser_CCP	71.3	74.8	77.7	79.7	81.6	81.2	84.4	77.6	72.3	74.7	50.2	48.8	32.3	32.0	28.8	30.1	27.1	23.5	17.8	-	
11 Jur_GT	-	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
12 SKRA	78.6	79.8	81.4	82.5	83.5	83.8	79.0	79.4	78.4	78.3	78.1	78.3	77.6	77.9	77.7	77.9	78.0	-	-	-	
13 Exxon	78.9	80.1	81.5	82.3	84.0	83.9	79.4	79.9	78.9	78.6	78.4	78.5	78.4	78.3	78.2	78.4	-	-	-	-	
14 ENV1	89.7	89.7	89.6	89.8	89.7	89.7	89.7	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	
15 Syngas	89.1	89.1	89.0	89.2	89.1	89.1	89.1	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	89.0	
16 Merlimau	68.1	71.2	74.3	76.9	79.1	79.2	70.7	71.4	68.1	69.1	67.0	66.4	61.0	61.2	58.7	59.1	59.6	58.5	56.6	52.1	**20yr average**
17 Proxy	**87.3**	**88.3**	**88.9**	**89.0**	**89.2**	**88.5**	**82.3**	**75.3**	**50.7**	**49.7**	**69.3**	**81.1**	**74.3**	**73.1**	**65.4**	**64.9**	**61.4**	**53.7**	**45.4**	**26.6**	70.22%
18 Seraya_CHP1_2	-	-	90.3	90.3	90.3	90.3	88.8	89.2	87.1	87.3	86.2	85.4	78.6	80.6	81.4	80.4	78.8	76.5	74.5	70.5	
19 New_2	-	-	-	-	-	89.1	88.7	86.1	63.3	62.3	81.2	86.2	81.8	80.7	74.0	75.6	71.4	64.0	51.8	31.3	
20 New_3	-	-	-	-	-	-	89.8	89.8	88.4	87.5	89.4	89.1	87.5	87.3	85.7	85.7	84.4	81.3	72.3	47.9	
21 New_4	-	-	-	-	-	-	-	89.1	87.8	87.7	88.1	89.3	88.8	87.9	87.4	87.3	86.0	82.9	78.9	58.6	
22 New_5	-	-	-	-	-	-	-	-	89.1	88.8	89.8	89.5	89.7	89.6	89.1	88.8	88.0	85.4	82.8	67.2	
23 New_6	-	-	-	-	-	-	-	-	-	88.5	88.9	87.3	87.1	88.3	88.4	87.5	87.5	86.7	83.8	70.3	
24 New_7	-	-	-	-	-	-	-	-	-	-	89.9	90.0	89.9	90.0	89.9	89.7	89.2	87.9	86.4	77.3	
25 New_8	-	-	-	-	-	-	-	-	-	-	-	89.2	89.3	88.9	89.3	89.1	88.8	88.0	87.3	81.5	
26 New_9	-	-	-	-	-	-	-	-	-	-	-	-	90.0	90.2	90.0	90.1	89.9	89.1	88.7	85.6	
27 New_10	-	-	-	-	-	-	-	-	-	-	-	-	-	89.7	88.9	88.3	88.4	88.4	88.4	87.4	
28 New_11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	90.2	90.2	89.8	89.6	89.3	
29 New_12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89.7	89.6	89.7	89.3	89.0	
30 New_13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.2	90.0	89.7	89.9	
31 New_14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.1	90.1	90.1	
32 New_15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	89.9	90.1	
33 New_16	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	90.1	
Peak demand [MW]	6,572	6,942	7,302	7,659	8,075	8,489	8,923	9,244	9,622	9,983	10,351	10,697	11,105	11,492	11,888	12,260	12,709	13,113	13,527	13,913	
System demand [GWh]	45,928	48,517	51,033	53,664	56,398	59,314	62,355	64,776	67,245	69,749	72,336	74,947	77,609	80,314	83,078	85,907	88,775	91,599	94,425	97,281	

Reserve	500 Avail Gen	90%	Proxy Capacity		359	Max Avail Capacity		323.1													**20yr average**
Av Demand	5,243	5,538	5,826	6,126	6,438	6,771	7,118	7,394	7,676	7,962	8,258	8,556	8,859	9,168	9,484	9,807	10,134	10,456	10,779	11,105	8,135
Res %	10%	9%	9%	8%	8%	7%	7%	7%	7%	6%	6%	6%	6%	5%	5%	5%	5%	5%	5%	5%	6.46%
Res Share of Total (MW)	27	26	25	23	22	21	19	16	11	10	14	15	14	13	11	11	10	8	7	4	15
Res Share % of Capacity	7.49%	7.17%	6.87%	6.54%	6.23%	5.88%	5.20%	4.58%	2.97%	2.81%	3.78%	4.27%	3.77%	3.59%	3.10%	2.98%	2.73%	2.31%	1.90%	1.08%	4.26%
Res Adj Plant Factor 2	79.81%	81.13%	82.03%	82.46%	82.97%	82.62%	77.10%	70.72%	47.73%	46.89%	65.52%	76.83%	70.53%	69.51%	62.30%	61.92%	58.67%	51.39%	43.50%	25.52%	65.96%
Avg Output	287	291	294	296	298	297	277	254	171	168	235	276	253	250	224	222	211	184	156	92	237
%age Loading reduction	8.58%	8.13%	7.72%	7.35%	6.99%	6.65%	6.32%	6.09%	5.86%	5.65%	5.45%	5.26%	5.08%	4.91%	4.74%	4.59%	4.44%	4.30%	4.17%	4.05%	5.82%

Efficiency adjustment per %		
Loading		0.17%
Total efficiency adjustment		0.97%
Av heat Rate before reserve adj		6879
Av heat rate after reserve adj		**6946**