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Setting of technical parameters for LRMC of CCGT

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Authors H. Koetzier, W. van der Veen, T.J. McInally (OnLine Energy Services)
KEMA Consulting Arnhem

By order of Energy Market Authority of Singapore

author	: H. Koetzier	*HKo*	06-12-13	reviewed	: W. van der Veen	*WvdV*	06-12-13
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ABBREVIATIONS

ACG	Automatic generation control
b	Barrel (159 l)
BoP	Balance of plant
CCGT	Combined cycle gas turbine
DCF	Discounted cash flow
EMA	Energy market authority
EMC	Energy market company
FOB	Free on board
GSO	Gas system operator
HHV	Higher heating value
HSFO	High sulphur fuel oil
ISO	International standards organization
	ISO conditions combined cycles:
	15 °C ambient temperature, 1.013 bar ambient pressure
LDC	Load duration curve
LFO	Light fuel oil
LHV	Lower heating value
LRMC	Long run marginal cost
LTSA	Long term service agreement
MCE	Market clearing engine
MEUR	Million Euros
MSGD	Million Singapore dollars
MTI	Ministry of trade and industry
OEM	Original equipment manufacturer
ORBP	OPEC reference basket price (the crude oil price)
PSO	Power system operator
WE	Western Europe

SUMMARY

KEMA have been engaged by the Energy Market Authority of Singapore to provide settings for the technical parameters used in the vesting contract computation for years 2007/8. These technical parameters are based on the development by a new investor of a new efficient green field power plant referred to hereinafter as the Proxy plant. 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.

In order to evaluate these parameters KEMA have assumed a plant type which is of Combined Cycle Gas Turbine type “F”, an economic lifecycle of 20 years, and local conditions in Singapore. The total plant capacity chosen by KEMA is 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 have all been used in our computation of the parameters. Additionally, in order to validate the plant factor, we have used fundamental modelling to forecast the plant operation over a 20 year operating period.

The technical LRMC parameters computed in this initial study are summarized in the table below (S.1).

Table S.1 Settings for technical LRMC parameters for
one of two CCGT trains of 400 MW_e ISO, built side by side

No	Name	Value 2007/8	Value 2005/6
1	Capacity (MW)	364.0	370.0
2	HHV heat rate (Btu/kWh)	6 916	7 492
3	Build duration (month)	27	27
4	Plant factor	73.09%	76%
5	Total capital and land, infrastructure & development cost (MSGD)	443.30	341.24
6	Variable non-fuel cost (SGD/MWh)	0.99	0.91
7	Fixed annual running cost (MSGD/a)	38.00	25.67

The derivation of these parameters follows.

1 INTRODUCTION AND METHODOLOGY

The following statement (slightly adapted) taken from EMA's tender notice (a) serves very well as an introduction to this report: *The Energy Market Authority has implemented vesting contracts to curb the exercise of market power by the generation companies in the National Electricity Market of Singapore. The vesting contracts will commit the gencos to sell a specified amount of energy at a specified price (viz. vesting price) and thereby prevent the gencos from exercising their market power to drive up prices. The vesting price is set at the long-run marginal cost (LRMC) of the most efficient generation technology serving at least 25% of the total electricity demand. At this time the most efficient generation technology is the combined cycle gas turbine (CCGT). The vesting price is hence set at the long run marginal cost of the CCGT. The underlying concept of LRMC, as it has been determined, is to find the average price at which the most efficiently configured generation facility with the most economic technology in operation in Singapore will cover its variable and fixed cost and provide reasonable return to investors*.

1.1 Methodology

Thus the vesting price is the LRMC of a proxy plant. This proxy plant is:

- 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 report proposes initial draft settings for the technical LRMC parameters, being:

- Plant output on site @ 100% load
- Plant factor
- Yearly average heat rate
- Investment cost
- Build duration
- Fixed annual running cost
- Variable running cost (non fuel)
- Economic lifetime

1.2 Approach

KEMA follow the approach indicated by EMA that is:

1. Meet with the generation companies and electricity consumers to secure individually their views on how to set the technical LRMC parameters, and provide its assessment of those views. KEMA have met with Senoko, Seraya, Tuas, SembCorp, NERA, PCS, Keppel Merlimau, Island Power Company and Exxon

2. Show the assumptions and approach that KEMA have taken illustrated by model results and an initial rough view of how these may impact on the LRMC Parameters..

3. Take inventory of feedback received from gencos and large consumers on draft recommendation and recommend final settings of technical LRMC parameters.

1.3 Assumptions

The following assumptions underpin our analysis.

1.3.1 Choice of Plant type

We have assumed F class CCGT plant technology and used the average of available plant characteristics for plant from several manufacturers currently supplying Singapore in setting the characteristics of the proxy plant. KEMA used the latest figures available, that is of the year 2006.

1.3.2 Which figures to use in setting the LRMC Parameters

There are a variety of opinions regarding which figures should be used to set some of the technical parameters. This in particular applies to the plant factor, the yearly average heat rate and the investment cost. For the plant factor and yearly average heat rate the opinions range from using the values forecast for the two years of application of the technical parameters (i.e. 2007, 2008) to applying a simple arithmetic average of the same over the 20 year period. The former has the benefit of being more accurate than the latter as the accuracy of forecasting diminishes as years go forward. An alternative, however, which takes account of the relative importance of the plant factor in early years (thus also in some way reducing the importance of the latter years forecast) has drawn KEMA to suggest something in between. As the financial analysis and modelling is performed over a 20 year operating period, KEMA recommend the same is used in setting the technical parameters. In so doing, however, it is important to weight the figures in accordance with the revenues and expenditures from the plant over said 20 years. As a result we recommend the following items to be determined (table 1.1). These are reflected in the parameter set which we have already included in table S.1 above. Items written in italics translate directly into the ones in table S.1. The treatment of the other items is explained below.

Table 1.1 Underlying parameter set for LRMC parameters

No	Name	Value 2007/8	Value 2005/6
1	*Capacity, (MW_e)*	364.0 on site, as new, downstream of step-up transformer	370.0
2	Capital cost (MSGD)	287.00	236.77
3	Land, infrastructure and development cost (MSGD)	149.90	104.47
4	Total investment cost (MSGD)	436.90	341.24
4a	Re-investment cost (MSGD, after 12 operating years)	60.00 As defined in section 1.3.2.3, 5.12 and 5.14	
4b	Plant residual value (MSGD, after 20 operating years)	82.80 As defined in sections 1.3.2.4, 5.13 and 5.14	
5	Net HHV heat rate (Btu/kWh)	6 916 As output from model adjusted to discount at same rate as plant. C.F. See section 1.3.2.2 and 8.2.2.5	7 492
6	*Build duration (month)*	27	27
7	Economic lifetime (a)	20	20
8	Time weighted plant factor over 20 production years	73.09% C.F. 5 above and section 1.3.2.1 and 8.2.2.3	76%
9	*Fixed annual running cost (MSGD/a)*	38.00	25.67
10	*Variable non-fuel cost (SGD/MWh_e)*	0.99	0.91

1.3.2.1 Plant factor

KEMA's recommended approach to computing this is to use a discounted approach to compute the LRMC plant factor parameter. This has the effect of front loading the value of the plant operation in a way that is consistent with the discounted cash flow applied to the capital costs. The net result being, in KEMA's opinion, a consistent application of parameters throughout the computation of the outturn LRMC prices.

1.3.2.2 Average heat rate

The average heat rate once again has been discussed as the actual heat rate from the first two years of the modelling exercise, to the arithmetic average over the 20 year lifetime of the plant. Once again, consistent with the plant factor KEMA believe it is appropriate to use a discounted approach to arrive at the figure to be used in the LRMC computation.

1.3.2.3 Re-investment cost

Re-investment (or refurbishment) cost is seen to arrive at the end of year 12 of the plant operation. This is a cost which has the effect of increasing the plant lifetime and resetting capacity and heat rate to their as-new values. In order to translate the future cost in to a capital investment effective cost, KEMA propose again to use a discounted approach.

1.3.2.4 Residual value of the plant

The re-investment increases the lifetime of the plant beyond the production period of 20 year and therefore generates a residual value at the end of the production period, that provides for a level of residual value reflecting that the refurbishment extends the lifetime of the plant beyond 20 years. In order to translate the future benefit into a reduction of capital investment effective cost, KEMA propose again to use a discounted approach.

1.3.2.5 Real, pre-tax discount rate

Each of the above items requires a view on the real, pre-tax discount rate. KEMA will use the EMA prescribed value of 8.62 %/a.

2 TECHNOLOGY

The most efficient technology that currently serves at least 25% of Singapore's electricity demand is the so-called F-technology. This is explained below (table 2.1), while table 2.2 gives some more information about the F-technology (b).

Table 2.1 F-technology in Singapore

Power station	Train cap MW_e	No of trains	Total cap MW_e	Techn	GT type	OEM
Senoko Converted CCGT	365	3	1116	F	GT 26	Alstom
Tuas CCGT	367.5	2	735	F	M701F	Mitsubishi
Tuas new CCGT	367.5	2	735	F	M701F	Mitsubishi
Seraya CCGT	370	2	740	F	V94.3A	Siemens
Sembcorp Cogen	785	1	785	F	9FA	General Electric
Proxy plant	364	2	728	F		
Total			**4826**			
Total Market with proxy			10381			
Market share			**46 %**			

Table 2.2 50 Hz representatives of the 2006 F technology (b)

Manufacturer	Alstom	General Electric	Mitsubishi	Siemens	Value used in this report
Type designation CCGT	KA26-1	S109FA	MPC1 (M701F)	SCC5-4000F 1sft	
Type designation GT	GT26B	MS9001FA	M701F	V94.3A	
Net capacity (MW, ISO, new, at generator terminals)	424.0	390.8	416.4	416.0	400
Net efficiency (on LHV, ISO, new, at generator terminals) 2004-2005	58.3%	56.7%	59.0%	58.3%	58,1% (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)	422	439	440	428	432 (average)

3 PLANT CAPACITY ON SITE @ 100% LOAD

3.1 ISO capacity new

The typical single train capacity at ISO conditions, in new-state for the F-technology is app. 400 MW_e (see table 2.2). A typical green field plant constructed by a new industry player would in KEMA's view be 800 MW_e, realized in two single trains of 400 MW_e (ISO). A single train with two gas turbines and one steam turbine could also be realized. 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. In practice often the 2*400 option is chosen (KEMA (c, d)). In the Singapore market a single 800 MW_e train would also attract significant cost of reserve power in the market.

As the typical energy loss of the step-up transformer is 0.3%, the capacity downstream of it is 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 0.05% or 0.4 MW_e[1]. 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

Due to higher ambient temperatures, plant site capacity will be lower than the ISO capacity. 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. Ergo the capacity of the combined cycle decreases.
Figure 3.1 shows the relation for F-class CCGTs of three manufacturers (GE (e), Alstom (e1), Siemens (e2)). Inspection of the temperature data provided by EMA[2] indicated an average temperature at the Seraya, Senoko and Tuas sites of 29½ °C[3], with a minimum (2*standard deviation) of 26°C. The average air temperature of 29½ °C results in reductions to 94.5, 93.0 and 92% of the ISO capacity. We will use the average value of 93.2%.

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[1] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.17.1.4&5

[2] EMA, Pwee Inn Loy. E-mail May 5th, 2006

[3] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.17.2.1&2

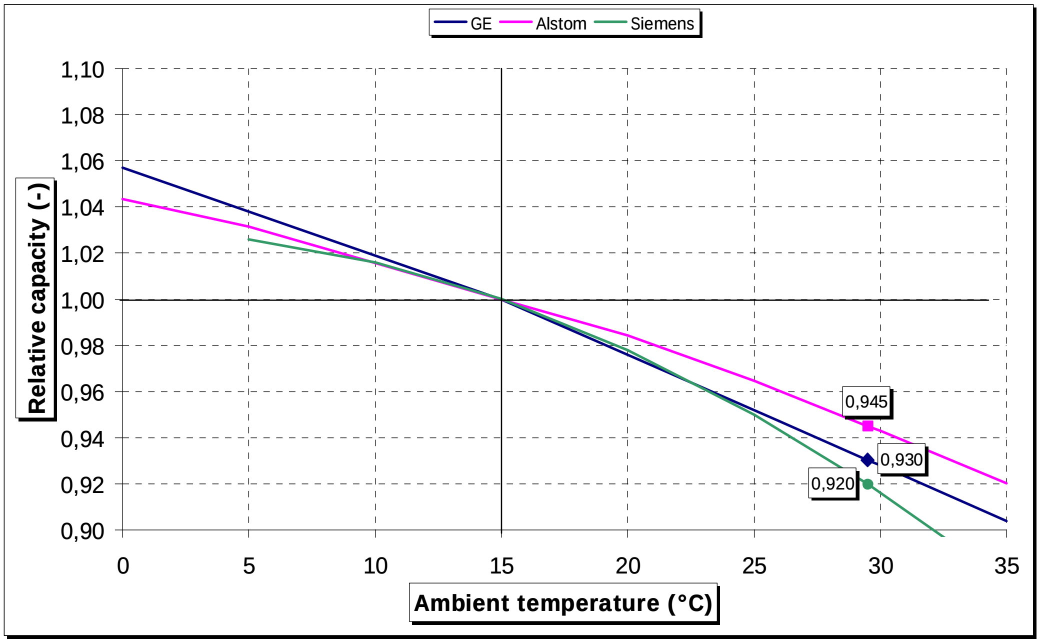

Figure 3.1 Impact of ambient temperature on F class CCGT capacity (GE (e), Alstom (e1), Siemens (e2))

3.2.2 Air pressure

Ambient pressure does not feature, because Singapore is at sea level.

3.2.3 Cooling water temperature

There is a significant impact of the cooling water temperature on the capacity of the combined cycle (figure 3.2). Cooling water temperature is taken at 28 °C[4]. At this temperature there is a reduction of app. 2%.

[4] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.19.2

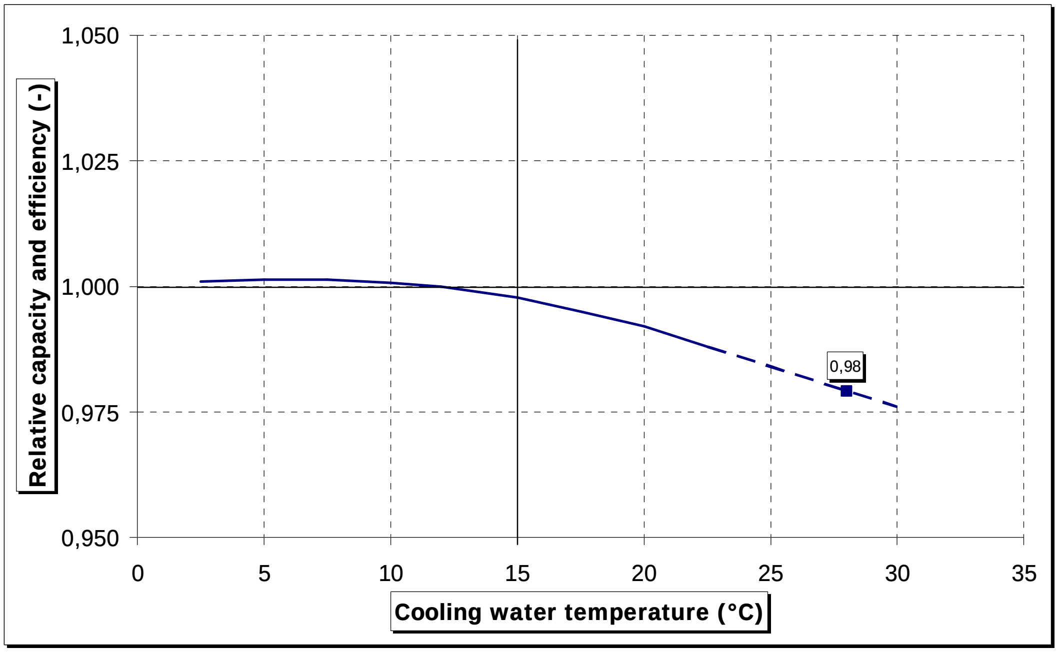

Figure 3.2 Representative impact cooling water temperature on F class CCGT capacity and efficiency (e)

3.3 Plant capacity on site @ 100% load in new state

Based on the arguments above we calculate the average net plant capacity on site @ full load in new state to be 797.2 * 0.932 (ambient temperature) * 0.98 (cooling water temperature) is **728 MW_e**. This value divided by 2 is the value under item 1 in table S.1 and is the one to be used in the calculation of the vesting price. The effects of ageing, compressor fouling are incorporated in the market simulation and expressed by relating the plant factor to the capacity of 728 MW_e.

3.4 Impact of ageing

The performance of combined cycle power plants is subject to ageing, predominantly in the gas turbine. Figure 3.3 shows the expected relation (g). We observe that over a period of 15 years (120 000 operating hours), 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.

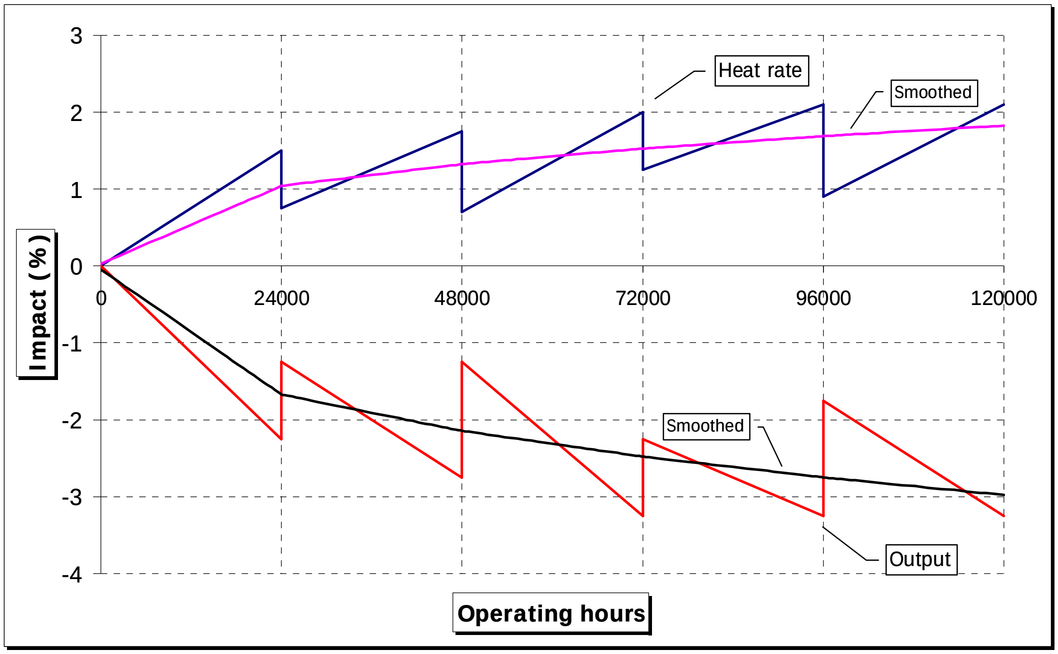

Figure 3.3 Representative impact of ageing on CCGT heat rate and capacity (g). Discontinuities indicate revisions and overhauls

3.5 Compressor fouling

Compressor fouling is dependant on the quality of the ambient air, the quality of the inlet filters, and the washing regime. We believe a plausible cleaning regime in Singapore would be a combination of on-line cleaning and semi-annual off-line washing. With this regime a deterioration of 2% in capacity and 1¼% in heat rate just before off-line washing is plausible in Singapore. The combined effect of ageing and compressor fouling is shown in figure 3.4. We observe that after 100 000 operating hours the capacity is reduced by 3.8%. The heat rate is increased by 2.3%. After 100 000 hours (end of first LTSA, section 6.1.3) a life time extension in planned, resetting aging and fouling to as new values[5].

In summary KEMA will use a combined aging and fouling impact of 3.8% on plant capacity after 100 000 operating hours and 2.3% on heat rate[6]. Values between 0 and 100 000 operating hours are established according to the fat solid lines in figure 3.4.

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[5] KEMA have assumed that improved upgrades of the parts to be replaced will be available. 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 we expect these upgrades will more than compensate for the 'non-recoverable' deterioration incurred.

[6] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.13.1 and 2.21.2.1

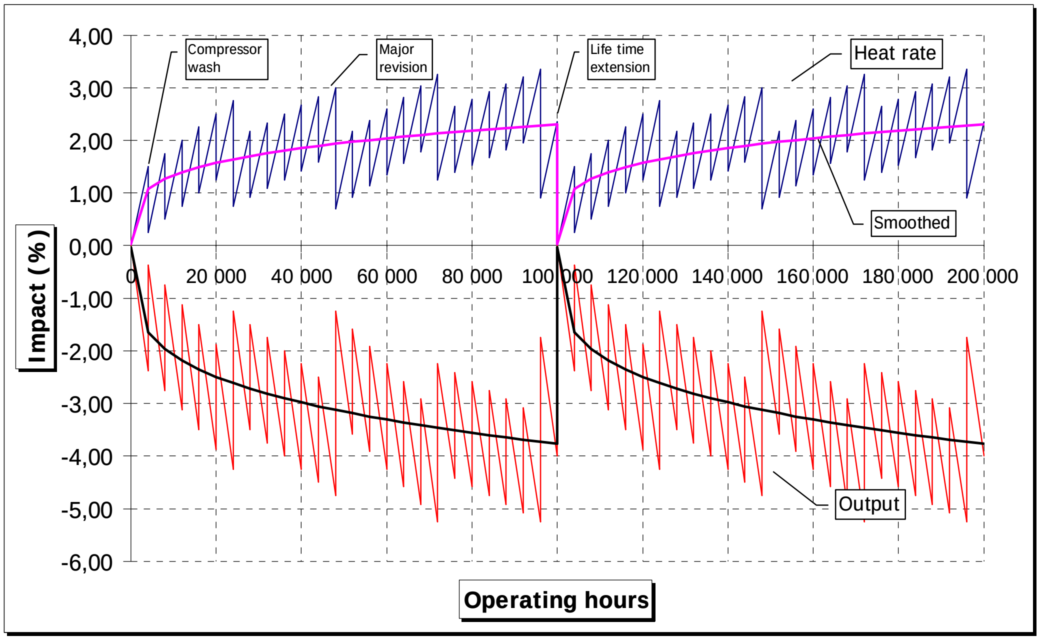

Figure 3.4 Combined effect of ageing and compressor fouling on CCGT

3.6 Summary capacity

Table 3.1 presents a summary of the capacity derivation.

Table 3.1 Summary of capacity derivation

Capacity	MW_e	Correction
ISO, net, new, 100%, at generator	800.0	
Downstream step-up Xmer	797.6	-0.3%
Additional auxiliary eqt, blow-down	797.2	-0.05%
Ambient temperature	743.0	-6.8%
Cooling water temperature		-2.0%
Eventual on site, net, new, 100% load	**728**	
Ageing and compressor fouling	In market simulation: according to figure 3.4	

4 HEAT RATE

The yearly average heat rate depends on the following parameters:

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

4.1 ISO efficiency at 100% load in new-state

The typical efficiency under ISO conditions in new-state at MCR is 58.1 % on lower heating value at the generator terminals (table 2.2). This corresponds to a heat rate of 5 873 Btu/kWh. As the typical energy loss of the step-up transformer is 0.3%, the heat rate downstream of it is 5 891 Btu/kWh on LHV[7].

Assuming net capacities and efficiencies are measured without blow down and consumption of some auxiliaries such as the water treatment plant, we subtract 0.4 MW_e (section 3.1). This results in a net single train heat rate under ISO conditions in new-state of 5 894 Btu/kWh on LHV.

[7] This is not double counting. A 0.3% loss in the step-up transformer does not lead to a decrease in fuel consumption.

4.2 Impact of ambient conditions

4.2.1 Air temperature

The efficiency of a combined cycle is relatively independent of the ambient temperature. For temperatures above 15 °C the impact is negligible (figure 4.1) for the GE and Alstom CCGTs and 0.985 for the Siemens at 29½ °C. We use the average impact of 0.995, that is 0.5% increase in heat rate[8], resulting in a heat rate of 5 894 / 0.995 is 5 923 BTU/kWh on LHV.

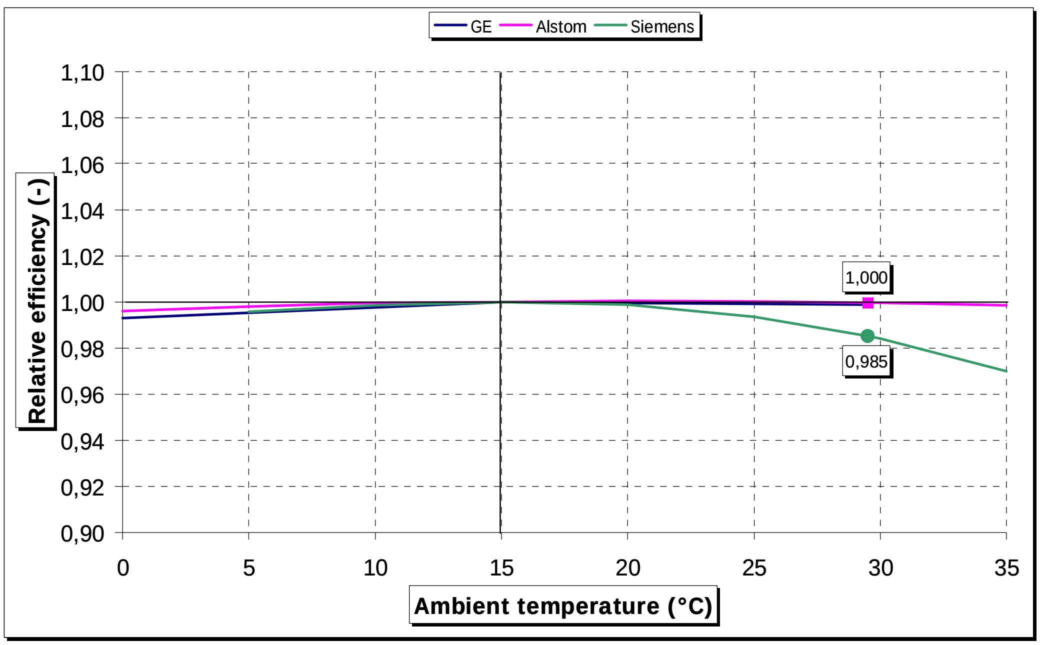

Figure 4.1 Impact of ambient temperature on F class CCGT efficiency (GE (e), Alstom (e1), Siemens (e2))

4.2.2 Air pressure

Ambient pressure does not feature, because Singapore is at sea level.

4.2.3 Cooling water temperature

There is a significant impact of the cooling water temperature on the efficiency of the combined cycle (figure 4.2). At a cooling water temperature of 28 °C (section 3.2.3), there is a decrease of efficiency of app. 2%. This corresponds to an increase of 2% in heat rate, resulting in a heat rate of 5 923 / 0.98 is 6 044 BTU/kWh on LHV.

[8] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.17.2.3

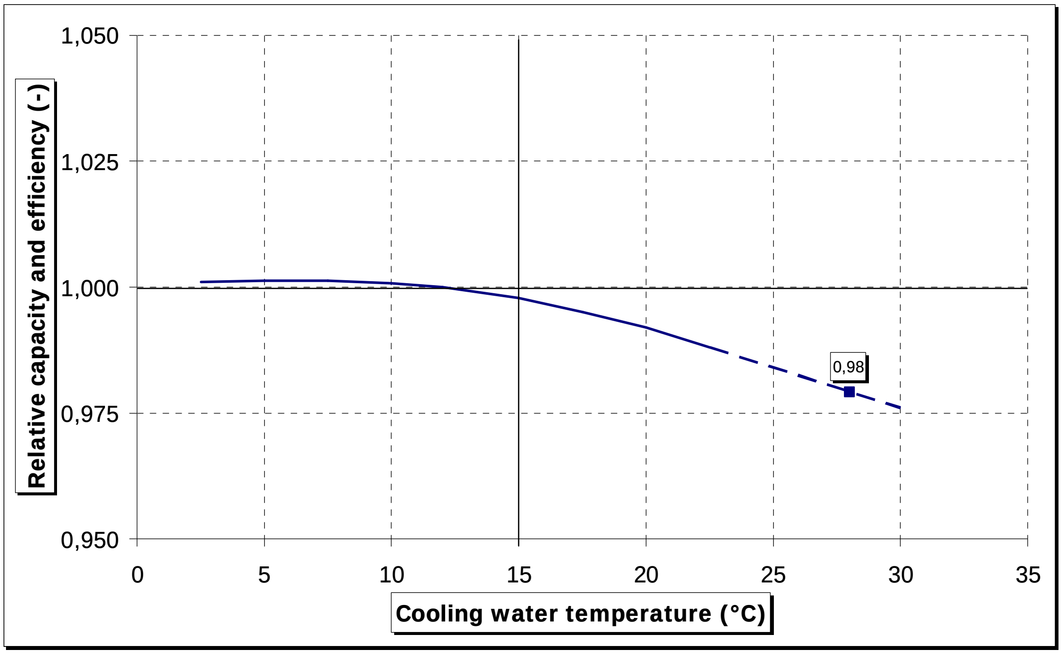

Figure 4.2 Representative impact cooling water temperature on F class CCGT capacity and efficiency (e)

4.3 Impact of regulation

According to Tuas (i) *Generation schedules (supply) will not match load (demand) instantaneously. Automatic Generation Control (AGC) systems provide "regulation" to keep generation (with small generation output) and load in balance in real-time*.
This regulation will increase fuel consumption due to non-steady state operation. We estimate this will increase the heat rate with app. ½ % (j)[9], resulting in a heat rate of 6 044 / 0.995 is 6 075 BTU/kWh on LHV.

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

The net plant heat rate on site, in new state, at full load in regulation is 6 075 BTU/kWh on LHV, corresponding to 56.17% efficiency on LHV. Taking into account a ratio HHV/LHV of the gas of 1.108, the plant heat rate on site @ 100% load in new-state based on HHV is 6 075 * 1.108 is 6 731 Btu/kWh. The impact of ageing, compressor fouling, load profile, are incorporated in the market simulation and expressed as yearly average heat rate.

[9] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.25.2

4.5 Impact of ageing

The performance of combined cycle power plants is subject to ageing, predominantly in the gas turbine. Figure 4.3 shows the expected relation (g). We observe that over a period of 15 years (120 000 operating hours), the heat rate will have increased by approximately 2%. We take account of this in the 20 year model that we use to validate the plant factor.

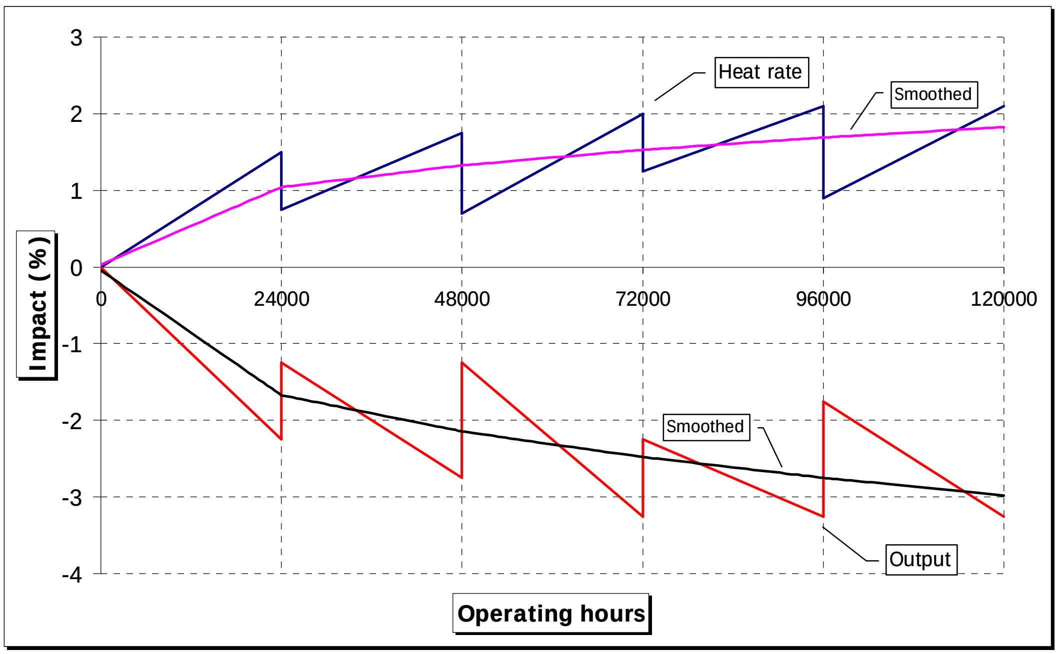

Figure 4.3 Representative impact of ageing on GTCC heat rate and capacity (g). Discontinuities indicate revisions and overhauls

4.6 Compressor fouling

Compressor fouling is dependant on the quality of the ambient air, the quality of the inlet filters, and the washing regime. We believe a plausible cleaning regime in Singapore would be a combination of on-line cleaning and semi-annual off-line washing. With this regime a deterioration of 2% in capacity and 1¼% in heat rate just before off-line washing is plausible in Singapore. The combined effect of ageing and compressor fouling is shown in (figure 4.4). We observe that after 100 000 operating hours the capacity is reduced with 3.8%. The heat rate is increased with 2.3%. After 100 000 hours (end of first LTSA, section 6.1.3) a life time extension is planned, resetting aging and fouling to as new values[10].

[10] KEMA have assumed that improved upgrades of the parts to be replaced will be available. These improved upgrades are expected to have better performance than the original parts as they follow in

In summary KEMA will use a combined aging and fouling impact of 3.8% on plant capacity after 100 000 operating hours and 2.3% on heat rate[11]. Values between 0 and 100 000 operating hours are established according to the fat solid lines in figure 4.4.

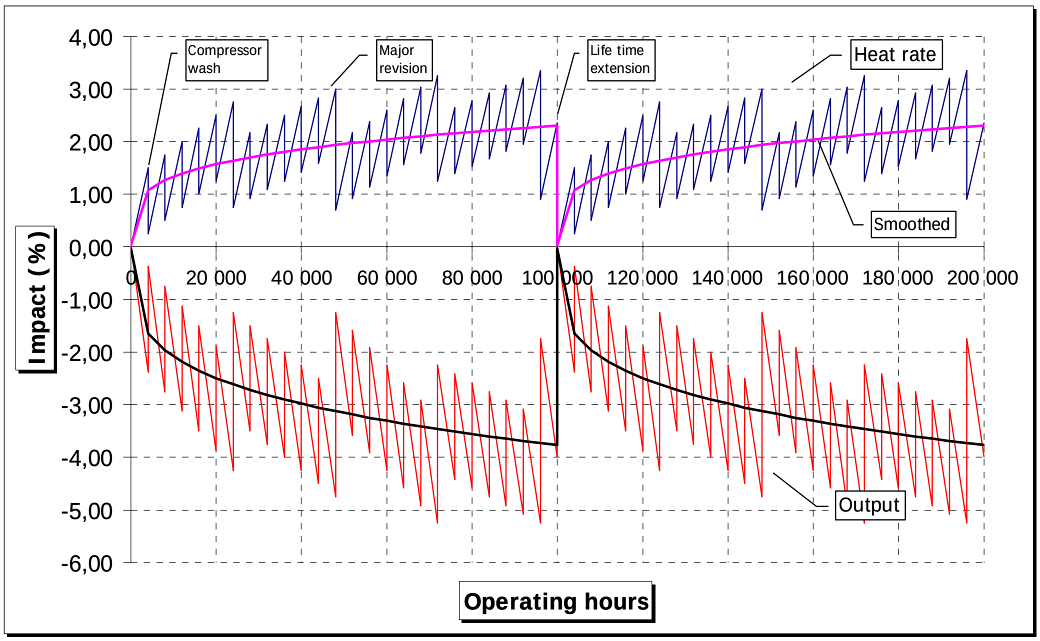

Figure 4.4 Combined effect of ageing and compressor fouling on CCGT

the wake of evolving gas turbines technology. Therefore we expect these upgrades will more than compensate for the 'non-recoverable' deterioration incurred.

[11] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.13.1 and 2.21.2.1

4.7 Load profile

4.7.1 Impact of part load

Figure 4.5 shows the impact of part load on F class CCGTs of GE and Alstom. We see e.g. that at 60 % load the efficiency decreases to 91% of the value at 100% load for the GE CCGT and to 94% for the Alstom. The heat rate increases by 9.9 % and 6.4 % respectively. We use the average of the two curves in our calculations.

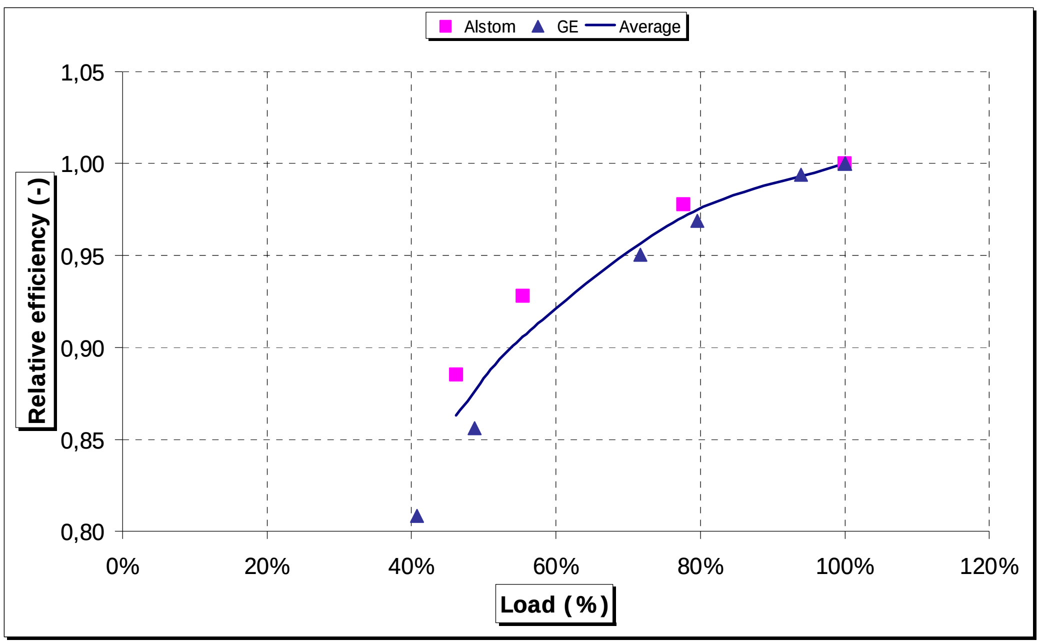

Figure 4.5 Impact of part load on F class CCGT efficiency (GE (e), Alstom (e1[12]))

4.7.2 Impact of number of starts

The additional fuel consumption of a start[13] is conveniently expressed as the number of operating hours at full load that has equal fuel consumption (h). 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.

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[12] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.23.1.1

[13] The fuel consumption that does not lead to electricity consumption

4.8 Summary heat rate

Table 4.1 presents a summary of the heat rate derivation[14].

Table 4.1 Summary of heat rate derivation

Heat rate	% LHV	kJ/kWh LHV	Btu/kWh LHV	Btu/kWh HHV	Correction efficiency
ISO, net, new, 100%, at generator	58.10%	6 196	5 873	6 507	
Downstream step-up Xmer	57.93%	6 215	5 891	6 527	-0.3%
Additional auxiliary eqt, blow-down	57.90%	6 218	5 894	6 530	-0.05%
Ambient temperature	57.61%	6 249	5 923	6 563	-0.5%
Cooling water temperature	56.46%	6 377	6 044	6 697	-2.0%
Regulation					-0.5%
Eventual on site, net, new, 100% load	**56.17%**	**6 409**	**6 075**	**6 731**	
Ageing and compressor fouling	In market simulation: according figure 4.4				
Part load	In market simulation: according figure 4.5				
Starts	In market simulation: according section 4.7.2				

[14] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.26.2.1

5 INVESTMENT COST

This section describes the estimation of the investment cost for natural gas-fired CCGT operating in Singapore: the so-called proxy plant. The derivation is summarized in table 5.1. The italic numbers in brackets in the text below refer to the corresponding rows in the table.

Interest during construction (IDC) should be included in a correctly executed discounted cash flow analysis. This analysis is outside the scope of our exercise. KEMA will exclude it to avoid double accounting[15].

KEMA used, in line with the previous determination of the LRMC parameters, three-month forward exchange rates, being: 1.57 SGD/USD and 2.02 SGD/EUR[16].

5.1 Plant capacity

The net electric capacity at ISO conditions in new-state is 800 MW, divided over two trains of 400 MW each (*1*). The site capacity was determined at **728 MW_e** in section 3.3 (2). 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 temperature are 26 and 24½ °C respectively. From figure 3.1 and 3.2 we calculate a maximum site capacity of 754 MW_e (*3*). This capacity determines the connection charge (*20 – 22*).

5.2 Initial capital cost

KEMA estimates the equipment cost (FOB) for the combined cycle at 432 USD/$kW_{e,ISO}$[17] for a single gaseous fuel plant (4) or 542.6 MSDG. For dual fuel hot switching capability an estimated cost of 5 MEUR per GT is added (5), including fuel forwarding, fuel treatment and day storage (n1). For the transport cost (6) we estimate 2% of the equipment cost (4, *5*)[18]. Provision of spare parts including initial ones *(8)* is part of the LTSA with the manufacturer (section 6.1.3)[19]. This yields an initial capital cost for the power island of **574.0 MSGD** (*8*)[20].

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[15] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.36.1.2

[16] October, November, December 2006. Euro forward used September avg. actual trended forward.

[17] This is the average of the power island equipment only cost FOB (USD/kWe) in table 2.2

[18] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.29.2.2

[19] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.29.1.1

[20] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.29.2.3

5.3 Land cost

For land lease JTC (l) quote an upfront premium of 1 240 000 SGD per ha for a period of 30 years in the Jurong area (*9*). Water front fee is quoted at 360 – 540 SGD/meter per year. We take the centre value of 450. This is the same as in the previous vesting period. We convert into an upfront premium for 30 year, using a discount rate of 8.62% real, pre-tax prescribed by EMA. This results in an upfront premium of 4 780 SGD per meter (*10*). We have added land preparation cost (m) at 100 000 EUR/ha (*12*), West European price level. At a 56% Singapore price level[21] this amounts to app 113 000 SGD/ha and 1 413 000 SDG total. Thus the total land costs amount to **17.9 MSGD** (*12*)[22].

5.4 Facility cost

Facility cost are very much dependant on the actual conditions and therefore can vary considerably. A typical breakdown of the facility cost (including commissioning) in MSGD would be (*13 – 18*):

- Ancillary buildings 4.0
- Demin plant 4.0
- Seawater intake/outfall 11.0
- Jetty emergency fuel unloading 16.0[23]
- Gas receiving facilities 11.0
- Total facility cost (MSGD) **46.0**

5.5 Emergency fuel facilities

A generation licensee is required to keep emergency fuel facilities for 60 days on site. This amounts to 1.1 million barrels (section 6.1.2) or 175 million litres. KEMA estimate the cost for floating roof tankage and auxiliaries for this storage of this volume at 80 EUR/m^3 at West European price level. At a Singapore price level of 87%[24] this results in specific cost of 141 SGD/m^3 and a total cost of **24.7 MSGD** (*19*). Commissioning is included in these cost. Cost of fuel treatment and fuel forwarding is included in the power island cost (section 5.2)[25].

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[21] 56% for labour (KPMG's guide to international business cost, 2006 Edition, Exhibit 5.2, last column)

[22] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.30.2.1&2

[23] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.31.2

[24] Same price level for equipment, 56% for labour (KPMG's guide to international business cost, 2006 Edition, Exhibit 5.2, last column) and a 30/70% division between labour and equipment results in 30%*56%+70%*100% is 87%

[25] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.32.2

5.6 Connection charge

The standard connection charge (n) of 50 000 SGD/MW$_e$ of the previous vesting period is still valid (*20*)[26]. KEMA have estimated the cost for 230 kV switch gear, switch house, underground cable and connection to the grid. We have assumed a 2 x 100% connection and 1 km of trench length in sand. KEMA estimate the following cost break down in MSGD (21). Commissioning is included in these cost.

• Substation (at plant, with switchhouse)	2	7.0
• Cable in sand (underground)	2 x 1 km	4.5
• Substation extension (at grid)	2	5.0
• End joint (at grid)	4	2.0
• Total grid connection (MSGD)		18.5[27]

Both items add up to a total connection charge of **56.2 MSGD**.

5.7 Installation cost

These cost are defined as the construction cost of the power island and exclude the initial capital cost. KEMA estimate these cost at **127.0 MSGD**[28]. Commissioning of the power island is included in the construction cost. The break-down is estimated as follows:

• Civil works (MSGD)	13.0
• Erection & assembly (MSGD)	57.0
• Detail engineering & start-up (MSGD)	13.0
• Contactor soft cost (MSGD)	44.0
• Total power island construction cost (is by definition installation cost)	127.0

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) consist of contractors fee and profit, construction insurance, miscellanious spare parts and materials.

[26] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.33.2.1
[27] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.33.2.2
[28] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.34.2

5.8 Consultancy cost

Detailed engineering cost are included in the previous items. Basic engineering is covered here. Cost for basic engineering, legal and financial advice are estimated at 4% of total land, infrastructure and development cost, resulting in **12.0 MSGD** *(24 – 27)*[29].

5.9 Miscellaneous owner and start-up cost

This item includes cost items not covered in the previous sections, that is:

§ Owners manpower up to and including contract award	3.5
§ Owners manpower during construction	7.5
§ Taxes and insurance during construction	3.0
§ Purchased electricity, water, fuel during construction	2.0
§ **Total miscellaneous owner and start-up cost (MSGD)[30]**	**16.0**

Owners manpower up to and including contract award includes bid preparation, contractor selection and permitting. *Owners 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 amount, but is caused by the fact we have assumed a new investor. Being a new investor, the organization has to be built from scratch.

5.10 Initial total land, infrastructure and development cost

The considerations above lead to initial total land, infrastructure and development cost of 17.9 + 46.0 + 24.7 + 56.2 + 127.0 + 12.0 + 16.0 = **299.8 MSGD** *(29)*.

[29] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.35.2
[30] KPMG's guide to international business cost, 2006 Edition, Exhibit 5.2, last column (k) indicate a labour cost level in Singapore of 56%.

5.11 Initial total capital, land, infrastructure and development cost

Consequently initial total capital, land, infrastructure and development cost amount to 574.0 + 299.8 is **873.8 MSGD**.

5.12 Re-investment cost

After 100 000 hours or 12 operating years (end of first LTSA, section 6.1.3) a life time extension is planned. KEMA estimate re-investment cost of app. **120 MSGD**[31]. The break-down is as follows:

- DCS 30 MSGD
- BoP 35 MSGD
- GTs 55 MSGD

5.13 Residual value

The lifetime extension extends the life time of the plant to 2*12 is 24 years. Thus, after 20 year 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 = (873.8+120.0) * 4 /24 is **165.6 MSGD**.

5.14 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 8.62% to do so. The upfront value of the re-investment cost becomes:

$$\frac{120}{(1+0.0862)^{12}} = 44.5 MSGD$$

The upfront value of the residual value becomes:

$$\frac{165.6}{(1+0.0862)^{20}} = 31.7 MSGD$$

[31] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.29.1.1

5.15 Total capital, land, infrastructure and development cost

So the value of the total capital, land, infrastructure and development cost becomes: 873.8 + 44.5 – 31.7 is **886.6 MSGD**. This value divided by 2 is the value under item 5 in table S.1 and is the one to be used in the calculation of the vesting price.

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

		Parameter	Specific price	Total cost kSGD	Ditto MSGD
1	Unit ISO capacity	400 x 2			
2	Unit capacity	364 x 2			
3	Unit max site Capacity	377 x 2			
	Power island				
4	Equipment (including step-up transformers)		432 USD/$kW_{e,ISO}$	542 592	
5	Hot switching capability		5 000 kEUR/GT	20 200	
6	Transport cost	2% of *4, 5*		11 256	
7	Spare parts (including initial ones)			Included in LTSA	
8	**Power island equipment**			**574 048**	574,0
	Land, infrastructure & development cost				
	Land cost				
9	Land lease	12,5 ha	1 240 000 SGD/ha	15 500	
10	Water front fee	200 m	4 780 SGD/m	956	
11	Land preparation	12,5 ha	113 000 SGD/ha	1 413	
12	**Total Land cost**			**17 869**	**17,9**
	Facility cost				
13	Ancillary buildings			4 000	
14	Demin plant			4 000	
15	Seawater intake/outfall			11 000	
16	Jetty emergency fuel unloading			16 000	
17	Gas receiving facilities			11 000	
18	**Total Facility cost**			**46 000**	**46,0**
19	**Emergency fuel facilities**	175 000 m^3	141 SGD/m^3	**24 700**	**24,7**
	Connection Charge				
20	Standard connection charge	754 MW	50 000 SGD/MW_e	37 700	
21	Cost of 230 kV switch gear (including switch yard and underground cable)	754 MW		18 500	
22	**Total Connection Charge**			**56 200**	**56,2**
	Construction power island				
23	(is by definition installation cost)				
23a	Civil			13 000	
23b	Erection & assembly			57 000	
23c	Engineering & power island start-up			13 000	
23d	Contractor (power island) soft cost			44 000	
23e	**Total construction power island**			**127 000**	**127,0**
	Consultancy Cost				
24	Basic Engineering				
25	Legal Advice				
26	Financial Advice				
27	**Total Consultancy Cost**	4,0% of 29		**12 000**	**12,0**
28	**Miscellanious owners & start-up cost**			**16 000**	**16,0**
29	**Total Land, infrastructure & development cost**			**299 769**	**299,8**
30	***Total investment cost***			***873 816***	***873,8***
31	***Ditto specific (SGD/kW_e)***	***Site, new***		***1 200***	
32	***Ditto specific (SGD/kW_e)***	***ISO, new***		***1092***	

6 RUNNING COST

We distinguish between fixed running cost and variable non-fuel cost.

6.1 Fixed running cost

6.1.1 Manpower, overhead, etc

KEMA estimate the cost for manpower, corporate overheads, working capital and other expenses (insurance, property tax, etc) at **16 MSGD/a**[32], broken down into:

- Manpower, corporate overheads, working capital 6 MSGD/a
- Insurance, property tax, miscellaneous 10 MSGD/a

6.1.2 Carrying backup fuel

For the cost of carrying backup fuel we estimate a cost of app. 25 MSGD/a. The derivation is as follows:

Site capacity (MW_e)	728
Yearly average site efficiency	54%
Daily fuel consumption (GWh)	32,4
90 Days fuel consumtion (GWh)	2 912
LHV diesel oil (MWh/b)	1,70
Barrels needed for 90 days	1 712 941
Diesel (50 ppm) price (USD/b) including delivery on site	90
Stock value (MUSD)	154
Carrying cost (USD/a) @ 8.62% real, pre-tax discount rate	13,3
Ditto SGD/a	**21**

[32] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.38.2

6.1.3 Maintenance

For maintenance of the power plant main components we estimate a cost of 225 MEUR, including spare parts (o) in West-Europe, based on an LTSA with the manufacturer for 100 000 EOH or a duration of 12 years (whichever comes first). This is 18.75 MEUR/a or 2 250 EUR/EOH. For Singapore we assume a mark-down of 10%[33], resulting in 16.88 MEUR/a or 2 025 EUR/EOH**.** This corresponds to **34 MSGD/a** or 4 100 SGD/EOH. For the routine maintenance of the plant we estimate an additional **5 MSGD/a**.

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. It is therefore, even where said policy is purchased, not something we 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 exercise. KEMA will exclude it to avoid double accounting[34].

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[33] materials no mark-down; labor & supervision 30% mark-down

[34] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.38.2.3

6.1.6 Total fixed annual running cost

Based on above we calculate a total fixed running cost of 16 + 21 + 34 + 5 is **76 MSGD/a**. This value divided by 2 is the value under item 7 in table S.1 and is the one to be used in the calculation of the vesting price.

6.2 Variable non-fuel cost

6.2.1 EMC fees

EMC, the Energy market company, 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 grid. For the fiscal year April 2006 – March 2007 this fee is indicated at **0.38 SGD/MWh** (p).

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 budget for the period 01 April 2006 to 31 March 2007 is SDG 15 043 million. PSO's administrative fee for the wholesale electricity market for this period is **0.208 SGD/MWh**[35].

6.2.3 Consumables

KEMA estimate the cost of consumables (feed water, oil, chemicals) at **0.40 SGD/MWh** electricity produced, broken down as follows (p1):

- Feed water make-up (SGD/MWh_e) 0.07
- Chemicals & oil (SGD/MWh_e) 0.33

6.2.4 Total variable non-fuel cost

Based on above the total variable non-fuel cost are calculated at 0.38 +0.208 +0.40 is **0.99** SGD/MWh. This is the value under item 6 in table S.1 and the value that should be used in the calculation of the vesting price.

[35] http://www.emcsg.com; Budgets and Fees; PSO budget & fees (FY2006/07)

7 OPERATIONAL CHARACTERISTICS

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 (g) and our own experiences[36].

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 (see e.g. ref (q, r)).

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 (q, r).

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 (o).

7.5 Cost of a start

A start has two effects, that is:

1. Additional fuel consumption
2. Additional wear of the installation

[36] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.59.2

The additional fuel consumption is conveniently expressed in a consumption corresponding to a number of operating hours 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 (h). Expressed in fuel consumption this is 700 respectively 1 400 MWh.
For the additional wear we reckon in equivalent operating hours as well. For a combined cycle one start corresponds to approximately 10 operating hours. Expressed in cost this is about 42 000 SGD/start (see also previous section).

8 PLANT FACTOR AND YEARLY AVERAGE HEAT RATE

8.1 Introduction

The plant factor is defined as:

Actual GWh delivered to grid in one year / *Theoretical maximum*

The theoretical maximum is determined by running full load for the whole year (8766 hours, including leap years). So for a plant with an average site capacity of 728 MW_e, the theoretical maximum is 728 * 8766 / 1000 is 6382 GWh.

The plant factor is a result of the dispatch of the plant. The optimum dispatch depends on:
§ Marginal cost of the plant
§ Marginal cost of the other plants in the market
§ Operational characteristics of the plant
§ Operational characteristics of the other plants in the market
§ System load
§ System constraints like network constraints and requirements for ancillary services

The contributors to the marginal cost of the proxy plant are:
§ Fuel price
§ Heat rate (section 4)
§ Variable non-fuel cost (section 6.2)

Operational characteristics of the plant that impact on the dispatch are (section 7):
§ Availability
§ Practical maximum and minimum load
§ Ramp-up speed
§ Start-up time
§ Cost of a start

8.2 Estimation of the plant factor

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 economic lifetime of the proxy plant). For this simulation the information described in the previous section is required to feed the model. In Appendix I the relevant numbers are recorded. Apart from these data the development of the system in the coming 20 years is important. The supply and demand balance will change due to a growing demand and changes in the composition of the supply. This will influence the plant factor of the CCGT. Old plants will probably be taken out of operation and new plants will be commissioned. A plan has been made for this development based on the expected load development, the commissioning dates and technology of the new units and assumptions on the life time of the units.

8.2.1 Assumptions concerning market development

Below the main assumptions concerning the market development are compiled

- Load development (MW, GWh) according to *Elec Forecast (EMA March 2006 Review.xls)*
- Load pattern is based on 2005 half hourly load data (EMA web site)
- Initial expansion plan is based on an Reserve Margin falling below 30% in any year
- For initial simulations existing units are decommissioned after 25 years (CCGTs) and 35 years (Steam units)
- 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
- New capacity additions are consistent with a reserve factor not falling below 30%
- 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
- Spinning reserve requirement is 1.5 times largest dispatched capacity
- CHP units (Sembcorp, Exxon, Syngas and Merlimau) are considered must-run units. This implies that these units will run at maximum capacity when they are available
- The *Environment* plant is also considered must-run
- The plant characteristics are according to the KEMA data base and actual site conditions (Appendix I)
- Characteristics of the Proxy plant are according to this report
- Fuel prices for the whole period are based on a crude oil price of 60 USD/b (ORBP). Sensitivity calculations are performed for 40 and 80 USD/b
- HSFO price is 80% of ORBP
- Orimulsion price is 60% of ORBP
- Gas prices are according to EMA calculations
- Initial efficiency of future CCGTs is adjusted for improved technology
- Efficiency and capacity derating due to ageing and compressor fouling of running CCGTs is accounted for as indicated in figure 3.4 and 4.4.

- Variable operation and maintenance costs are not considered in the commitment and dispatch of the units
- Co-optimisation is not taken into account initially[37], 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 2007.

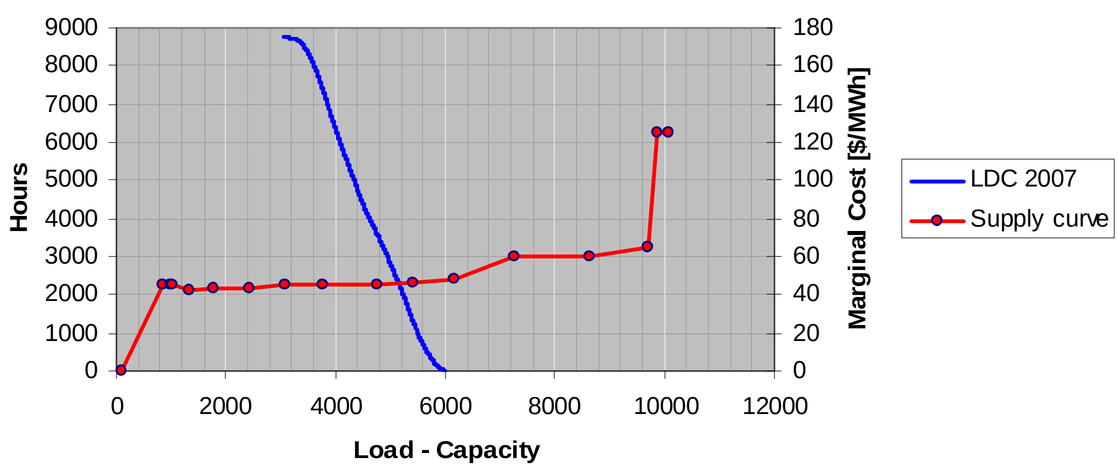

Figure 8.1 Supply and load duration curves of 2007

We observe the following. The load is always more than 3500 MW. Of this 3500 MW about 1200 MW (present view) is served by must run capacity. Also there is 750 MW of Orimulsion capacity in the system which is cheaper than the CCGTs. This makes about 2000 MW of capacity placed in the merit order and running before the CCGT capacity. A new CCGT unit would come right on top of this 2000 MW 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.

[37] An adjustment is made in section 8.2.2.2 to take this onto account

8.2.2 Results

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

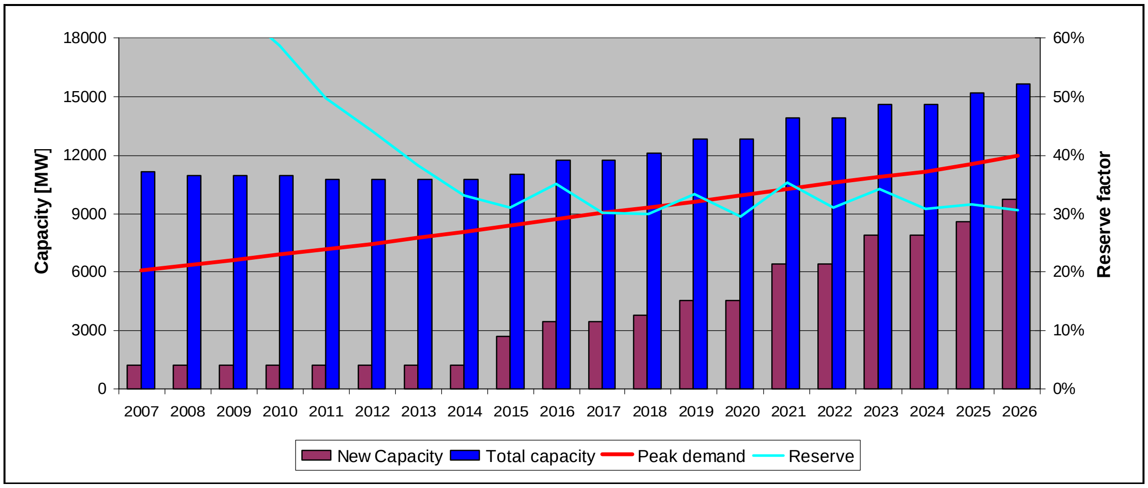

Figure 8.2 Expansion plan based on used assumptions

We observe the following. For a reliable supply (reserve not falling below 30%) no additional capacity, apart from the proxy CCGT and the Merlimau plant (under construction) would be required before 2015. The reserve factor would decrease from over 40% to about 30%. After 2015 new additions would be required every 2 years 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.

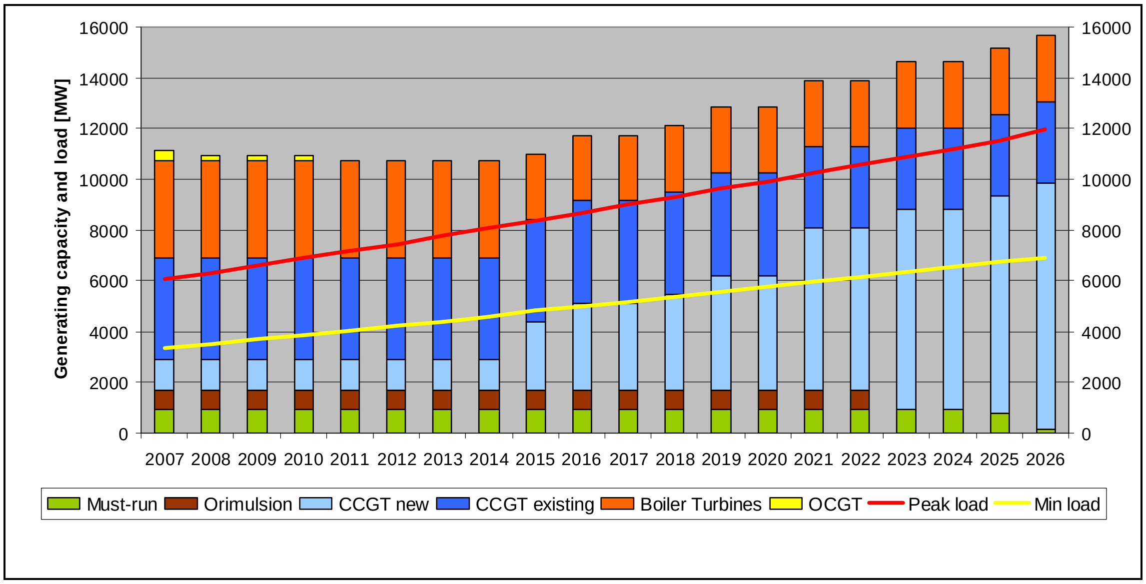

Figure 8.3 Capacity per type of plant according to expansion plan

8.2.2.1 Plant factor

One of the results of the initial simulations is the annual plant factor for the proxy CCGT for each year from 2007 up to and including 2026, that is tabulated below (table 8.1) and calculated relative to the site capacity of the proxy CCGT in new state (728 MW_e). We observe a plant factor of over 80% for the first 9 years. After 2015 the plant factor decreases due to increasing new (more efficient) capacity being added to the system. From 2019 the capacity factor is higher again due to reinvestments in the proxy CCGT resulting in a higher efficiency and higher capacity.

Table 8.1 Plant factor of proxy CCGT relative to site capacity in new state (728 MW_e)

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
E-production GWh	5 637	5 463	5 588	5 584	5 596	5 577	5 591	5 594	5 454	3 485
Plant factor	88.3%	85.5%	87.5%	87.4%	87.6%	87.3%	87.6%	87.6%	85.4%	54.6%
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
E-production GWh	2 862	2 661	5 591	5 583	4 826	5 021	4 469	4 816	4 406	4 241
Plant factor	44.8%	41.7%	87.6%	87.4%	75.6%	78.6%	70.0%	75.4%	69.0%	66.4%

To enable the participants to confirm that the gas take-or-pay obligations of the incumbent generatores are not compromized, production, plant factor and heat rate of all units simulated are provided in Appendix II.

8.2.2.2 Plant factor adjustment for reserve share allocation[38]

Generators in Singapore are both paid for and charged for reserves. A such it is considered prudent for a generator to provide its own proportion of reserve cover. Based on this the plant factor will reduce to accommodate the requisite reserve holding. Based on a reserve margin of 1.5 * the load of the largest loaded generator, and using loading figures from the modelling exercise table 8.2 shows the adjusted plant factors.

Table 8.2 Plant factors adjusted for reserve share

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Reserve Share (%)	10%	10%	10%	9%	9%	9%	9%	9%	8%	7%
Ditto MW	33	30	30	30	30	30	29	28	25	14
Reserve adjusted plant factor (%)	79.3%	77.2%	79.2%	79.2%	79.3%	79.2%	79.5%	79.8%	78.7%	50.6%
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Reserve Share (%)	7%	8%	7%	7%	6%	6%	6%	6%	5%	5%
Ditto MW	12	12	21	21	17	17	15	15	14	13
Reserve adjusted plant factor (%)	41.6%	38.2%	81.8%	81.7%	71.0%	74.0%	66.0%	71.2%	65.3%	62.9%

8.2.2.3 Weighted average plant factor

The economic life time is set at 20 production years. This means that the investor expects to have recovered its cost (including a certain rate of return) in 20 years. This means that he or she expects income over 20 year. We know that in later years the capacity factor will decrease, decreasing the income of the investor. Also the heat rate will increase, increasing the fuel cost of the investor. Also the performance of new plants will be better than the proxy plant. If we only look at the first two years, we overestimate the yearly income and underestimate the yearly cost of the investor. The fact that the vesting price is re-determined every two year is of no relevance for the original investor, because his plant won’t be the proxy plant in that re-determination, but eventually a better one. The new vesting price will then generate too little income for him/her to recover all cost. Therefore we need to look at the whole economic lifetime of 20 years. The best way to do this is to consider explicitly the plant factor and heat rate over 20 years and put them all in the discounted cash flow analysis. The LRMC Technical Parameters, however require one number for the heat rate and one for the plant factor so we have to average in some way. From the discounted cash flow analysis we know that revenues and expenditures in later years have less present value than revenues and expenditures earlier, so people discount. So we discount the plant factor and heat rate also.

[38] KEMA response to participant feedback on interim report 3063002-draft-2.0, section 2.56.2.2

As both have a direct relation to revenues and expenditures, KEMA believe this reasoning is correct. In conclusion we aggregate the different adjusted plant factors over 20 production years (table 8.2) into one weighted average one by the following formula:

$$PF_{A,W} = \frac{\sum_{y=1}^{PT} \frac{PF(y)}{(1+DR)^{(y-1)}}}{\sum_{y=1}^{PT} \frac{1}{(1+DR)^{(y-1)}}}$$

with

$PF_{A,W}$ Weighted average plant factor
PF(y) Plant factor in production year y
y Production year
DR Real, pre-tax discount rate, expressed as fraction (0.0862)
PT Production period (20 years)

This results in a weighted average reserve adjusted plant factor of **73.09%**. This is the value under item 4 in table S.1 and the value that should be used in the calculation of the vesting price.

8.2.2.4 Yearly average heat rate

The other result is the yearly average heat rate, taking into account

- Average plant heat rate on site @ 100% load in new state
- Impact of ageing
- Impact of part load
- Impact of number of starts
- Life time extension
- Impact of reserve allocation[39]

The results are indicated in table 8.3. We observe 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.

[39] If the plant factor decreases with about 10% resulting from Reserve allocation then it is reasonable to assume that the average generating level of the proxy plant (and the other efficient plants) will drop also by 10%. Some less efficient units will be loaded to a higher level. A 10% lower output level means a somewhat higher heat rate. We assume the output level will only be reduced when the optimum dispatch indicates a level higher than 90% of the maximum capacity. Below 90% there would be no reserve issue for the Proxy plant. Normally the plant will probably be loaded at full capacity. This means a 10% decrease due to reserve effect. The end result is a correction of up to 1% rise in heat rate. We have modelled this in our latest forecast dispatch.

Table 8.3 Yearly reserve adjusted heat rate

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
E production (GWh)	5 062	4 925	5 052	5 057	5 062	5 053	5 076	5 091	5 019	3 230
Fuel consumption (BBTU)	34 653	34 014	34 917	35 003	35 047	34 999	35 166	35 285	34 863	22 552
Heat rate (BTU/kWh)	6 846	6 906	6 911	6 921	6 924	6 926	6 928	6 931	6 946	6 982
Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
E production (GWh)	2 654	2 441	5 221	5 214	4 529	4 721	4 210	4 544	4 164	4 015
Fuel consumption (BBTU)	18 565	17 141	35 659	35 873	31 329	32 718	29 199	31 503	28 913	27 944
Heat rate (BTU/kWh)	6 996	7 023	6 830	6 881	6 917	6 931	6 936	6 933	6 943	6 961

8.2.2.5 Weighted average heat rate

We aggregate the different heat rates over 20 production years (table 8.2) into one weighted average one by the following formula:

$$HR_{A,W} = \frac{\sum_{y=1}^{PT} \frac{FC(y)}{(1+DR)^{(y-1)}}}{\frac{EP(y)}{(1+DR)^{(y-1)}}}$$

with

$HR_{A,W}$ Weighted average heat rate

FC(y) Fuel consumption in year y (BTU, HHV)

EP(y) Electricity production in production year y (kWh)

y Production year

DR Real, pre-tax discount rate, expressed as fraction (0.0862)

PT Production period (20 years)

This results in a weighted average heat rate of **6 916** BTU/kWh on HHV. This is the value under item 2 in table S.1 and the value that should be used in the calculation of the vesting price.

9 SUMMARY OF FINAL TECHNICAL LRMC PARAMETERS

In this section we derive the final technical LRMC parameters based on the content of the previous sections.

9.1 Capacity per generating unit

The capacity per generating unit is 728.0 MW_e / 2 is **364.0 MW** (section 3.3). 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 728 MW_e.

9.2 HHV heat rate

The HHV heat rate is **6 916 BTU/kWh**. This is a weighted average over the production period of 20 years (section 8.2.2.5).

9.3 Build duration

The build duration is **27 month**.

9.4 Plant factor

The plant factor is **73.09 %**. This is a discounted weighted average over the production period of 20 years (section 8.2.2.3).

9.5 Total capital and land, infrastructure and development cost

The total capital and land, infrastructure and development cost per generating unit amount to 886.6 MSGD / 2 is **443.3 MSGD** (section 5.15). This value incorporates re-investment cost and residual value, which were converted to up-front values using the EMA prescribed real, pre-tax discount rate of 8.62 %/a.

9.6 Variable non-fuel cost

The variable non-fuel cost amount to **0.99 SGD/MWh** (section 6.2.4).

9.7 Fixed annual running cost

The fixed annual running cost per generating unit amount to 76.0 MSGD / 2 is **38.0 MSGD** (section 6.1.6).

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APPENDIX I ASSUMPTIONS FOR PLANT FACTOR ESTIMATE

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 60 USD/b. Prices of other crude oil related fuels can be derived from the crude oil price using historically determined ratios. The price for natural gas has been provided by EMA based on the crude oil price.

	ORBP USD/b	Ratio to ORBP	Fuel price SGD/GJ
HSFO	60	0.80	13.3
LFO	60	1.25	20.8
Orimulsion	60	0.40	6.7
Natural gas	60		13.7

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.

Real pre-tax discount rate 8.62 %/a.

Details on power plants

#	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	51.5%
2	Senoko_Converted_CCGT	SNKCP3	North	Senoko	2004	3	2029	2016	365	355	195	Gas	54.4%
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	54.3%
7	Tuas_New_CCGT	TuasCP2	SouthWest	TUAS	2005	2	2030	2017	368	358	197	Gas	54.5%
8	Seraya_Orimulsion	Ser_St1	SouthWest	Seraya	2005	3	2023	n.a.	250	247	74	Orimulsion	39.7%
9	Seraya_Oil	Ser_St2	SouthWest	Seraya	1998	6	2033	n.a.	237	235	70	HSFO	39.7%
10	Seraya_CCGT	Ser_CCP	SouthWest	Seraya	2003	2	2028	2015	364	354	194	Gas	54.4%
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	53.0%
13	Exxon_Mobil_Cogen	Exxon	SouthWest	Exxon	2000	1	2025	2012	180	174	150	Gas	52.8%
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	52.8%
17	Proxy CCGT	Proxy	Unkonown	Proxy	2007	2	2032	2019	370	364	200	Gas	55.0%
18	New_1	New_1	SouthWest	New	2015	4	2040	2027	370	370	204	Gas	57.2%
19	New_2	New_2	SouthWest	New	2016	2	2041	2028	370	370	204	Gas	57.4%
20	New_3	New_3	SouthWest	New	2018	1	2043	2030	370	370	204	Gas	57.9%
21	New_4	New_4	SouthWest	New	2019	2	2044	2031	370	370	204	Gas	58.1%
22	New_5	New_5	SouthWest	New	2021	5	2046	2033	370	370	204	Gas	58.6%
23	New_6	New_6	SouthWest	New	2023	4	2048	2035	370	370	204	Gas	59.1%
24	New_7	New_7	SouthWest	New	2025	2	2050	2037	370	370	204	Gas	59.6%
25	New_8	New_8	SouthWest	New	2026	3	2051	2038	370	370	204	Gas	59.9%

APPENDIX II DETAILED SIMULATION RESULTS

Production GWh

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
SNKCP1	654	2,607	2,057	2,498	2,919	3,407	3,900	4,349	2,205	1,501	1,979	1,856	1,215	1,723	-	-	-	-	-	-
SNKCP3	8,022	7,877	8,205	8,257	8,292	8,294	8,268	8,196	5,120	8,466	8,192	8,191	7,934	7,331	4,074	4,639	3,899	4,415	3,948	3,736
SNKSt	102	222	377	644	1,145	1,751	2,385	3,119	-	-	-	-	-	-	-	-	-	-	-	-
Pasir_GT	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TuasSt	33	47	83	131	255	403	632	975	876	428	735	711	357	666	209	402	212	368	313	334
TuasCP1	2,197	2,522	3,207	3,671	4,069	4,520	4,825	5,732	5,603	5,314	5,209	5,278	2,330	2,669	792	1,183	709	1,133	906	957
TuasCP2	5,517	5,336	5,550	5,586	5,598	5,593	5,601	5,583	4,856	2,513	5,696	5,572	5,456	5,519	3,752	4,199	3,525	3,865	3,489	3,354
Ser_St1	5,854	5,858	5,850	5,858	5,853	5,860	5,852	5,851	5,859	5,857	5,857	5,855	5,853	5,855	5,861	5,858	-	-	-	-
Ser_St2	8	7	9	26	42	76	115	205	201	90	170	195	63	133	33	92	51	83	101	98
Ser_CCP	3,546	3,595	4,406	4,821	5,091	5,225	5,201	4,929	5,633	5,388	5,305	5,034	2,963	3,391	1,584	1,987	1,476	1,872	1,571	1,549
Jur_GT	0	0	0	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SKRA	5,476	5,426	5,497	5,620	5,668	5,673	6,136	6,065	5,778	5,543	5,569	5,391	5,523	5,597	5,497	5,506	5,484	5,500	5,442	-
Exxon	1,231	1,224	1,238	1,268	1,279	1,408	1,318	1,325	1,268	1,249	1,259	1,220	1,243	1,258	1,233	1,237	1,232	1,235	-	-
ENV1	1,027	1,027	1,027	1,026	1,026	1,027	1,027	1,027	1,027	1,027	1,026	1,027	1,027	1,027	1,027	1,027	1,027	1,026	1,027	1,025
Syngas	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113	113
Merlimau	2,907	2,880	2,921	2,990	3,154	3,227	3,287	3,327	3,057	2,905	2,993	3,604	2,945	3,024	2,833	2,880	2,830	2,870	2,811	2,751

Plant load factor (not adjusted for reserve)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
SNKCP1	9.1	35.4	28.2	34.4	40.3	47.1	54.0	60.2	30.6	20.8	27.5	25.8	16.9	24.0	-	-	-	-	-	-
SNKCP3	85.9	84.5	88.1	88.7	89.2	89.3	89.1	88.4	55.3	89.1	87.3	87.6	85.0	78.7	43.8	49.9	41.9	47.5	42.5	40.3
SNKSt	0.9	2.0	3.5	5.9	10.6	16.2	22.0	28.8	-	-	-	-	-	-	-	-	-	-	-	-
Pasir_GT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TuasSt	0.3	0.5	0.8	1.3	2.5	3.9	6.1	9.4	8.4	4.1	7.1	6.8	3.4	6.4	2.0	3.9	2.0	3.5	3.0	3.2
TuasCP1	35.2	40.4	51.4	58.9	65.3	72.6	77.6	89.9	88.9	84.6	83.1	84.4	37.3	42.7	12.7	19.0	11.4	18.2	14.6	15.4
TuasCP2	87.9	85.2	88.7	89.4	89.6	89.6	89.8	89.6	78.0	40.4	89.4	88.4	86.9	88.1	60.0	67.2	56.4	61.9	56.0	53.8
Ser_St1	90.0	90.1	89.9	90.1	90.0	90.1	90.0	89.9	90.1	90.0	90.0	90.0	90.0	90.0	90.1	90.1	-	-	-	-
Ser_St2	0.1	0.1	0.1	0.2	0.3	0.6	0.9	1.7	1.6	0.7	1.4	1.6	0.5	1.1	0.3	0.7	0.4	0.7	0.8	0.8
Ser_CCP	57.2	58.1	71.2	78.0	82.4	84.7	84.4	80.0	89.2	86.4	85.3	81.1	47.8	54.8	25.6	32.2	23.9	30.3	25.5	25.2
Jur_GT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SKRA	82.1	81.4	82.6	84.5	85.3	85.4	90.1	90.1	86.2	82.8	83.4	80.8	82.8	84.0	82.6	82.8	82.5	82.8	81.9	-
Exxon	80.6	80.2	81.1	83.2	84.0	90.2	85.4	86.2	82.6	81.5	82.3	79.8	81.3	82.4	80.8	81.2	80.9	81.1	-	-
ENV1	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.5	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.6	89.5
Syngas	89.0	89.0	88.9	89.0	89.0	89.0	88.9	89.0	89.0	88.9	89.0	89.0	89.0	88.9	88.9	89.0	88.9	88.9	88.9	88.9
Merlimau	70.6	70.2	71.3	73.1	77.2	79.0	80.6	81.7	75.1	71.4	73.6	86.5	71.5	73.7	69.2	70.4	69.3	70.3	68.9	67.5

Heat rate (kJ/kWh)

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
SNKCP1	7,315	6,904	7,050	7,084	7,095	7,068	7,059	7,050	7,143	7,197	7,172	7,188	7,238	7,195	-	-	-	-	-	-
SNKCP3	6,645	6,660	6,640	6,640	6,643	6,645	6,651	6,661	6,721	6,537	6,607	6,622	6,654	6,650	6,690	6,686	6,698	6,694	6,707	6,730
SNKSt	9,754	9,759	9,732	9,657	9,552	9,473	9,417	9,340	-	-	-	-	-	-	-	-	-	-	-	-
Pasir_GT	14,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TuasSt	10,112	10,182	10,161	10,024	9,882	9,807	9,762	9,728	9,686	9,801	9,719	9,696	9,783	9,724	9,950	9,809	9,856	9,838	9,856	9,906
TuasCP1	6,677	6,705	6,673	6,670	6,669	6,667	6,673	6,534	6,595	6,646	6,665	6,662	6,672	6,671	6,736	6,721	6,749	6,730	6,749	6,767
TuasCP2	6,620	6,636	6,629	6,631	6,635	6,639	6,643	6,649	6,679	6,720	6,536	6,602	6,629	6,631	6,668	6,653	6,679	6,676	6,687	6,705
Ser_St1	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	9,059	-	-	-	-
Ser_St2	10,272	10,188	10,272	10,019	10,055	9,946	9,982	9,887	9,920	9,982	9,891	9,810	10,033	9,995	10,216	9,941	10,030	10,002	9,901	10,080
Ser_CCP	6,694	6,726	6,682	6,681	6,677	6,679	6,691	6,689	6,534	6,614	6,634	6,683	6,682	6,680	6,735	6,728	6,746	6,736	6,757	6,788
Jur_GT	11,000	12,000	12,000	13,200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SKRA	6,863	6,873	6,867	6,852	6,849	6,851	6,691	6,750	6,800	6,841	6,843	6,872	6,857	6,849	6,867	6,868	6,875	6,875	6,883	-
Exxon	6,908	6,915	6,910	6,894	6,890	6,713	6,815	6,824	6,868	6,886	6,883	6,912	6,900	6,893	6,913	6,913	6,920	6,917	-	-
ENV1	9,437	9,438	9,438	9,438	9,437	9,437	9,438	9,438	9,437	9,438	9,438	9,437	9,437	9,437	9,437	9,437	9,438	9,438	9,437	9,438
Syngas	9,466	9,467	9,466	9,465	9,462	9,462	9,468	9,462	9,467	9,463	9,462	9,467	9,468	9,460	9,464	9,466	9,460	9,464	9,464	9,464
Merlimau	7,030	7,052	7,048	7,031	6,986	6,970	6,958	6,951	7,027	7,084	7,056	6,797	7,020	7,007	7,083	7,069	7,094	7,081	7,109	7,138