Energy Market Authority of Singapore

Review of the Parameters for Setting the Vesting Contract Price for 2011 and 2012 – Final Report

27 September 2010

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Executive summary

The Singapore electricity market uses the Vesting Contract regime for the mitigation of market power. The Vesting Contract price, Vesting Contract level and period weighting factors under the Vesting Contract regime are scheduled to be 'reset' at two yearly intervals. This is the fourth such reset, applying to the period commencing on 1st January 2011 and running through until 31st December 2012.

The biennial review is managed by the Energy Market Authority of Singapore (EMA) and PA Consulting Group (PA) has been engaged by EMA to review the recommended values of the parameters used to set the Vesting Contract price to be applied for the period 1 January 2011 to 31 December 2012. Note that this report does not review the value of the level of Vesting Contract cover and period weighting factors, which will be covered in a separate report.

This report sets out PA's analysis and recommendations for the Vesting Contract parameters used to set the Vesting Contract price for the period 1 January 2011 to 31 December 2012.

Financial Parameters

The financial parameters defined in this document are as follows:

Reference	Parameter	Value	Unit
E26	Exchange Rate	1.393	USD/SGD
	Exchange Rate	1.838	EUR/SGD
E44	Proportion of Debt-to-Total Assets	0.342	
E45	Risk Free Rate	3.31%	
E46	Debt Premium	250	bps
E47	Market Risk Premium	7.0%	
E48	Equity Beta	1.00	
E50	Corporate Tax Rate	17.0%	

Technical Parameters

The technical parameters, based on an "F" class CCGT, single shaft "1+1" block, are as follows:

Reference	Parameter	Value	Unit
E27	Capital cost of new unit	$1,053	$US/kW
	- Comprising EPC Cost: (incl gas compressors)	550.9	$SGD Million
	- and Discounted Through-Life Capital Cost:	8.3	$SGD Million
E29	Capacity of new unit (including 2.45% degradation and at 32ºC and deducting gas compressor power consumption)	381	MW
E30	Land, infrastructure & dev cost	$152.0	$SGD Million
E34	HHV Heat Rate (including degradations & gas compressor impact)	7,010	Btu/kWh
E36	Build duration	2.5	Years
E37	Economic Lifetime	24	Years
E38	Utilisation factor	74.9%	
E41	Fixed annual running cost	$22.49	$SGD Million/year
E42	Variable non-fuel cost	$6.55	$SGD/MWh

Contents

1 Introduction

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1.1 Structure of this Document

The parameters used to set the Vesting Contract price fall into two broad categories:

- Financial Parameters
- Technical Parameters

The following two sections consider each category of parameters in turn.

2 Financial Parameters

This section describes the setting of parameters for the calculation of the Weighted Average Cost of Capital (WACC). The resulting rate will be used to discount projected cash flows for a hypothetical new generation development in Singapore.

For the purpose of reducing volatility of results, the data used in the estimation of parameters has been averaged, where appropriate, over a three month period leading up to the "base month." This differs from previous biennial reviews of the vesting parameters, where the data used had been averaged over a one month period only. During the mid-term review of the vesting parameters in 2009 to set the vesting price for 1 January 2010 to 31 December 2010 (“mid-term 2010 review”), EMA had identified certain base parameters which can be very volatile. As such, to minimize the volatility and to avoid the contention of the choice of the base month, EMA had determined that data for the following "base parameters" would be based on the 3 months leading to the base month:

a. Exchange rate to convert the costs denominated in foreign currencies into Singapore Dollars;

b. Diesel price to calculate cost of carrying fuel;

c. Risk-free rate;

d. Debt premium to calculate cost of debt;

e. Consumer Price Index;

f. Domestic Supply Price Index; and

g. Imported Iron & Steel Index.

For this review, May 2010 has been selected as the "base month".

2.1 Exchange Rates

In setting the exchange rates to be used in the calculation of the vesting contract parameters, PA has averaged the 3-month forward exchange rates published by Bloomberg BGN for March, April, and May 2010, the three months leading up to the base month.

The average USD/SGD and EUR/SGD rates have been calculated as **1.393** and **1.838**, respectively.

2.2 Selection of Comparator Companies

In selecting its panel of comparator companies, PA started with publicly-listed companies classified as either "Electric Utilities" or "Independent Power Producers and Energy Traders", two industries with company risk profiles most likely to match that of a Singapore CCGT owner. This group of companies was narrowed down to the final panel using the following criteria:

1. Availability of data - Only public companies with five years of available data were considered.
2. Financial health - Companies must be in good financial health. Companies experiencing significant financial losses or bankruptcy proceedings in recent years are more likely to feature different capital structures and risk profiles than typical generation investments.
3. Location of operations - The majority of the company's operations occur in economies that feature risk characteristics similar to that of Singapore.[1] A company's market equity beta will be impacted by the country risk experienced in the countries in which it operates.

[1] As rated in Standard & Poor's Sovereign Ratings. Singapore receives an AAA rating, reflecting country risk levels similar to that of the United States, Canada, Australia, New Zealand, and most European nations.

4. Source of revenues - The majority of revenues should come from unregulated generation activities. A firm's equity beta is impacted by the risk associated with its principle revenues streams. Revenues stemming from regulated markets or alternative business verticals such as natural gas supply are subject to different risks than those experienced in the merchant generation sector.
5. Generation type - The majority of generation assets should be fossil-fired. The risk to a company's stream of generation-related cash flows will be reflected in its equity beta. All generation can be impacted by fuel prices, weather, and regulatory change, among other factors, but the impact of volatility in any of these areas will impact returns from nuclear or renewable generation quite differently than fossil-fired resources.
6. Credit rating - Credit rating must be investment grade: companies rated below BBB- will be excluded. A company's debt premium will of course be impacted by its credit rating. Worldwide credit markets remained constrained -- the resulting "flight to quality" will increase bond spreads and make access to debt difficult for non-investment grade companies.

See Appendix B for a list of the comparator companies.

2.3 Risk Free Rate

The risk free rate represents the rate of return an investor would receive if holding a risk free asset until maturity. This is typically represented by a government backed security. As a proxy for this rate, PA has chosen the yield to maturity of an "AAA" rated Singapore Government Bond, the 20-year CTSGD20Y, which matures in March 2027.

The average daily closing yield of this bond for March, April, and May 2010, the three months leading up to the base month, is **3.31%**. Refer to Appendix C.1 for details.

2.4 Proportion of Debt to Total Assets

The proportion of debt-to-total assets is an indicator of financial leverage. It is an expression of how a company's assets are funded, either through financed debt or shareholder equity, and can be affected by the nature of the industry, regional tax rates, or a given firm's ability to access debt markets.

As a proxy for the capital structure of a new market entrant, PA has used the average (simple arithmetic mean) debt-to-equity ratio of the three comparator companies.[2] This was accomplished using the following formula:

$$\text{Proportion of debt - to - total assets} = \frac{D}{E} \Big/ \left(1 + \frac{D}{E}\right)$$

As a result, the proportion of debt-to-total assets is assessed to be **0.342**. Refer to Appendix D for the individual debt-to-equity ratios of the three comparator companies.

2.5 Debt Premium

The debt premium represents the necessary return, over the risk free rate that a lender would expect when providing credit to a given investment. It is a measure of the inherent risk of the investment, and can generally be quantified according to the associated credit rating.

In determining this parameter, PA has used the comparator companies as a benchmark. As shown in Appendix D, the companies' credit ratings range from BBB to A-. This suggests that an investment

[2] The average debt-to-equity ratio of the comparator companies was assessed to be 0.520.

grade cost of debt would be appropriate for a new generation development, [3] not a surprising finding given the general "flight to quality" in today's tight credit environment.

To test this assumption, PA researched natural gas-fired generation projects that initiated construction in the United States during 2009 or 2010 and reviewed the credit ratings of the parent companies. The U.S. was deemed to be an appropriate market because of its similar risk profile to Singapore - both have received an AAA from Standard and Poor's Sovereign ratings - and the representative sample size of projects that started construction during the period.[4]

Of the 11 projects reviewed, only three projects featured any owner with sub-investment grade credit ratings. Of these three projects, two were joint ventures with investment grade companies, and the third had a long-term power purchase contract in place for 80% of its planned capacity (See Appendix E for the list of construction projects reviewed). These findings support the assessment that securing access to generation financing in today's environment will typically require investment grade credit, affiliation with an investment grade company, or the risk mitigation that accompanies long-term bilateral off-take agreements.

This assessment is shared by other regulators in similar international markets. In its 2009 review of costs for a new entrant, the Commission for Energy Regulation in Ireland stated that an assumed investor would be of investment grade, in the range of BBB to A[5], in order to be able to raise the necessary funding.

PA identified the median rating of the comparator companies, BBB+, as an appropriate benchmark for a new generation development in Singapore. The comparator panel was selected to reflect the likely risk profile of a new project, based in part on the above hypothesis; and consequently, the median credit rating is a reflection of the typical financial risk of a new project, thus making it a suitable basis for the calculation of the cost of debt. However, instead of solely basing the credit rating on the median of the comparator companies, a balanced view was taken so as to incorporate the views of industry participants. This resulted in a revision of the credit rating from BBB+ to BBB-, which is the lowest investment grade credit rating.

The resulting debt premium was calculated as the difference between a) the average yield of Moody's Utility Bond Index, adjusted upwards by 24bps,[6] and Bloomberg's Fair Value US Utility BBB- Index (6.34%); and b) the yield on a 30-year US Treasury Bond with 20 years remaining until maturity (4.37%).

The averages were calculated from the daily closing values for March, April, and May 2010, the three months leading up to the base month. The resulting debt premium was assessed to be 197 bps. (Refer to Appendix C.2 for details). However, Island Power Company, a new entrant with an investment-grade parent company -- GMR -- has indicated its financing spread is 250 basis points. Based on this evidence, the debt premium is set at 250 basis points, which is higher than the other empirical data determined by PA.

The approach used in this review differs from that of the biennial review of the vesting contract parameters for the period 1 January 2009 to 31 December 2010 (“2009-2010 review”) in two respects: firstly, in the choice of credit rating selected for a likely new entrant; and secondly, in the selection of data used to determine the debt premium.

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[3] Standard and Poor's defines investment grade credit ratings as those of BBB- and higher.

[4] PA limited the analysis to only those plants that began construction in 2009 or later. If one assumes that the plants' closed on their financing shortly before initiating construction, one can assume that the plants in this analysis secured their capital in a credit environment similar to that faced in Singapore today.

[5] Commission for Energy Regulation: Single Electricity Market, 'Fixed Cost of a Best New Entrant Peaking Plant & Capacity Requirement for the Calendar Year 2010', 07/01/2009.

[6] It is observed that the difference between the Baa (BBB) and Baa3 (BBB-) US utility bonds is 24 bps (Source: Bloomberg)

The proxy credit rating selected this year (BBB-) and that selected in the 2009-2010 review and the biennial review of the vesting contract parameters for the period 1 January 2007 to 31 December 2008 ("2007-2008 review") (BB+) differ significantly, but more as a result of the evolving state of financial markets than from any distinct difference in methodology. In all cases, the credit ratings were selected at least in part based on the credit rating of the comparator companies. The 2007-2008 review, upon which the 2009-2010 review's rating was based, appears to have also incorporated comments received from industry participants.

The debt premium used in the 2009-2010 review was determined by benchmarking against the debt spread of 10-year utility bonds, sourced from the BondsOnline Group. This review has instead used the spread of 20-year utility bonds, represented by the average of the Bloomberg and Moody's utility indices over a risk-free government rate. The 20-year term of debt was chosen as that closest to the economic life of the plant. The Bloomberg and Moody's indices were chosen because these indices only include bonds whose minimum maturity is also 20 years.

2.6 Corporate Tax Rate

The applicable corporate tax rate has been chosen as that set by the Singapore Ministry of Finance. This is currently **17.0%** for 2010 and future years.

2.7 Equity Beta

Equity beta measures the correlation between the returns of an investment and that of the market. It is a measure of the risk of long-run returns relative to those of the market as a whole. To calculate the proxy beta, PA initially considered the equity beta derived from the panel of comparator companies, consistent with the methodology used to determine the equity beta in previous reviews. The average asset beta[7] of the comparator panel (0.545) was re-levered according to the formula below, using the average debt-to-equity ratio of the comparators (0.52) and Singapore's 17% corporate tax rate.

$$\beta_{asset} = \beta_{equity} / \left(1 + (1 - T_c) \times \frac{D}{E}\right)$$

The resulting equity beta was 0.778, unexpectedly low relative to the equity beta values determined in previous reviews. Given the current lack of long-term contracting in the Singapore power market, one would expect electricity returns there to be more closely correlated with general economic returns than they might be in other markets (all else being equal). To account for the higher expected degree of correlation in Singapore, PA has assumed an equity beta of **1.00** for the purposes of this review.

Refer to Appendix D for comparator panel details.

[7] The unlevered asset beta reflects a firm's business risk without the distortion of risk associated with financing

2.8 Market Risk Premium

The market risk premium represents the rate of return, over and above the risk free rate, that an investor would require in order to invest in a diversified portfolio of risky assets. In estimating this premium, PA has taken a balanced consideration of several approaches. These have included the Historical Premium and Volatility Adjusted approach; the expected long-run return of the Singapore market, less the risk free rate described in section 2.3[8]; and the values used by Singapore listed companies and regulators in Australia and the UK.

The resulting premium was assessed to be **7.0%**. This was the midpoint from the identified range of values, between 5% and 9%, an approach consistent with that of the 2009 review. See Appendix H for details.

2.9 Escalators

The calculations in various places require price escalators.

For minor capital cost elements of a civil/structural nature, where no new capital cost data is available, the costs have been escalated from the values used in 2009 using the "All Buildings" Tender Price Index published by the Building and Construction Association (BCA) of Singapore. This is the same treatment as applied in 2009.

Between Q2 2009 and Q1 2010, the index fell from 113.7 to 113.3.

A value for Consumer Price Index (CPI) is required for the calculation of the real WACC in Section 2.10. The 3 months period leading to May 2010 is to be considered.

The arithmetic average year-on-year CPI change for March, April, and May 2010, the three months leading up to the base month, was **3.56%** based on monthly reports published by the Singapore Department of Statistics as shown in Appendix I.

2.10 WACC

The post-tax nominal WACC calculated using these parameters is **8.43%**.

The pre-tax nominal WACC calculated using the Corporate Tax Rate from Section 2.6 is **10.16%.**

The pre-tax real WACC using the CPI escalator from Section 2.9 is **6.37%**.

[8] The expected market return in Singapore estimated by the Dividend Discount Model is 11.45% (Source: Bloomberg)

3 Technical Parameters

Parameters for the existing generation fleet in Singapore are assumed to be the same as were assessed in 2009 except that the parameters have been adjusted to reflect the current licensed parameters with EMA[9].

Where parameters have been compared against those applied in previous determinations, these have considered:

- EMA's final determination for the biennial review of the vesting contract parameters for the period 1 January 2009 to 31 December 2010[10], and the associated KEMA report[11] ("2009-2010 review"); and
- KEMA's update report of 2009[12] for the mid-term review of the vesting contract parameters for the period 1 January 2010 to 31 December 2010. ("Mid-term 2010 review").

The technical parameters for new entrant plant, including performance parameters, capital and operating costs, are estimated in this Section.

3.1 Generating Technology

The parameters for the existing relevant power stations in Singapore, extracted from the 2009 report are given in Table 1:

Table 1 Existing Singapore station parameters (large CCGT units)[13]

Power station	Train capacity MWe	Number of trains	Total station Frame F capacity MWe	CCGT technology	GT type	Original Equipment Manufacturer (OEM)
Senoko Converted CCGT	365	3	1095	Type F	GT26	Alstom
TUAS CCGT	367.5	4	1470	Type F	M701F	Mitsubishi
Seraya CCGT	368 364	2	732	Type F	V94.3A	Siemens
Sembcorp Cogen[14]	392.5	2	785	Type F	9FA	General Electric

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[9] http://www.ema.gov.sg/page/115/id:129/

[10] EMA, Final Determination, "Long Run Marginal Cost (LRMC) parameters for setting vesting price for 1 January 2009 to 31 December 2010", 22 December 2008

[11] KEMA, "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", Report for EMA dated 11 November 2008

[12] KEMA, "LRMC of CCGT generation in Singapore for technical parameters used for setting the Vesting Price for the period 1 January 2009 to 31 December 2010", Report for EMA dated 22 June 2009

[13]. KEMA 2009 op cit. Adjustments based on licensed capacity (EMA) as at July 2010

[14] Evaluations have been made based on CCGT performance only

The Vesting Contract procedures published by EMA[15] specify that:

The Vesting Contract price is to be determined to reflect approximately the Long Run Marginal Cost (LRMC) of the most economic technology in operation in Singapore.

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 generation technology in operation in Singapore will cover its variable and fixed costs and provide reasonable return to investors. The plant to be used for this purpose is to be based on a theoretical generation station with the most economic plant portfolio (for existing CCGT technology, this consists of 2 to 4 units of 370MW plants).

The profile of the most economic power plants is as follows:

- Utilises the most economic technology available and operational within Singapore at the time. This most economic technology would have contributed to more than 25% of demand at that time.
- The generation company is assumed to operate as many of the units of the technology necessary to achieve the normal economies of scale for that technology.
- The plants are assumed to be built adjacent to one another to gain infrastructure economies of scale.
- The plants are assumed to share common facilities such as land, buildings, fuel supply, connections and transmission access. The cost of any common facilities should be prorated evenly to each of the plants.
- The plants are assumed to have a common corporate overhead structure to minimise costs. Any common overhead costs should be prorated evenly to each of the plants.

PA believes that the technology that should be selected according to these criteria would be CCGT units based on "F" class gas turbines. The existing large CCGT/Cogen plants in Singapore are based on "F" class gas turbine technology (refer Table 1).

PA expects that the existing plants, and any new plant in Singapore, would be optimised for performance at the site Reference Conditions. For this review it is assumed that the site Reference Conditions are the all-hours average conditions of:

- 29.5ºC dry bulb air temperature,
- 85% Relative Humidity (RH);
- Sea-level;
- 28ºC cooling water inlet temperature.

Operation at other ambient or sea water conditions represents off-design operation. This includes operation at the ambient conditions specified in the Singapore Market Manuals for the Maximum Generation Capacity, which includes an ambient temperature of 32ºC. Consistent with the treatment in 2009, a correction factor for the plant's capacity to 32ºC has been applied.

As shown in Table 1, the Singapore market includes "F" class units from each of the following OEMs[16]:

- Alstom;
- Siemens;
- General Electric (GE); and
- Mitsubishi.

[15] Energy Market Authority, "EMA's procedures for calculating the components of the vesting contracts", April 2010, Version 1.5

[16] Original Equipment Manufacturers

The market for supply of such plants is competitive and it generally cannot be determined, without competitive bidding for a specific local project, which design is the most economic generation technology on an LRMC basis for new built plant. It is often the case for example that the configuration offered with the lowest heat rate is the bid with a higher capital cost. In order to model the performance of the most economic generator it is therefore considered appropriate to consider the performance of all these OEM's latest "F" class CCGT configurations and to use an arithmetic average of the performance parameters of each of these OEMs' plants in CCGT configuration[17].

In order to estimate these performance parameters, the GTPro/GTMaster[18] (Version 20) thermodynamic analysis software suite was applied. Representative schematics of the resulting configurations are shown in Appendix F.

3.2 Capacity per Generating Unit

The generation capacities of new entrant CCGT configurations, on a clean-as-new condition, and at the Reference Conditions of 29.5ºC are given in Table 2.

Table 2 Generation capacity of new entrant CCGT units (clean-as-new at Reference Conditions, excluding gas compression impacts)

Configuration	Gross MW	Net MW
Frame 9FB	406.2	397.7
M701F	430.6	422.0
GT26	404.8	395.5
SGT5-4000F	383.5	375.9
Average	**406.3**	**397.8**

This thermodynamic modelling includes all corrections necessary for:

- Ambient conditions of 29.5ºC;
- Boiler blow-down; and
- Step-up transformer losses.

No further allowances need to be made for these except as discussed below regarding ambient temperature.

The impact of gas compression requirements is discussed separately below (Section 3.3).

The capacities and heat rates of operating gas turbine and CCGT power plants degrade from the time the plant is clean-as-new. The primary drivers for performance degradation are fouling, erosion and roughening of the gas turbine compressor and material losses in the turbine section. A CCGT plant has a slightly reduced degradation profile than a simple cycle gas turbine installation due to partial recovery of this effect in the steam cycle, and that the gas turbine only comprises approximately 2/3rds of the plant output. This degradation effect is typically described as having two components:

[17] It is noted that the Sembcorp plant is a cogeneration plant. In evaluating the parameters for this review the performance of plants in CCGT configuration only has been applied.

[18] TM, Thermoflow, inc

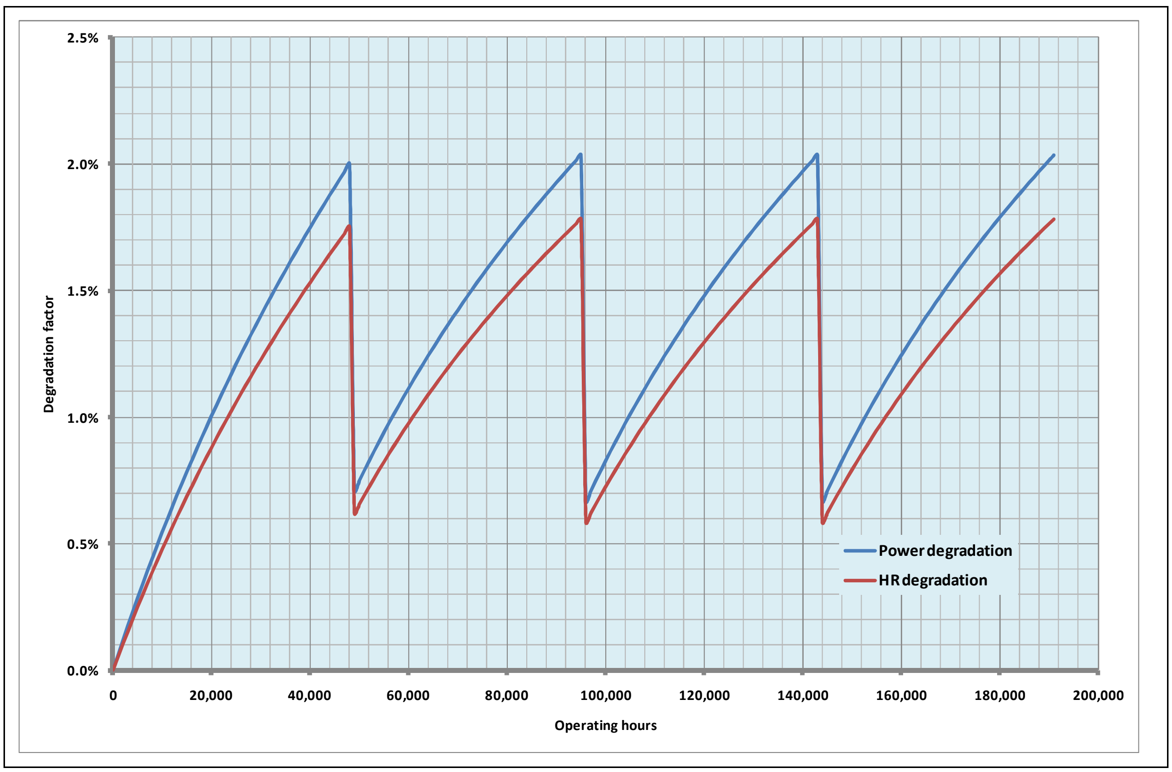
"Recoverable" degradation is degradation of performance that occurs to the plant that can be recovered within the overhaul cycle. Recoverable degradation can be substantially remediated by cleaning of air inlet filters, water washing of the gas turbine, ball-cleaning of condensers and the like. These cleaning activities are typically undertaken several or many times within a year depending on the site characteristics and the economic value of performance changes; and

"Non-recoverable" degradation is caused by the impacts of temperature, erosion and corrosion of parts within the plant. This type of degradation is typically substantially remediated over the overhaul cycle of the plant as damaged parts are replaced with new parts. Because the typical industry repair philosophy uses an economic mix of new and refurbished parts within overhauls, it is typically the case that not all of the original clean-as-new performance is recovered at the overhauls.

The average capacity reduction due to recoverable degradation is estimated at 1%. That is, the degradation amount varies from approximately zero to approximately 2% over the cleaning cycle.

Additional to this, an allowance for the non-recoverable degradation of capacity should be made. These typically have the form shown in Figure 1 (the allowances for recoverable degradation are additional to these).

Figure 1 Form of CCGT non-recoverable degradation[19]



Based on an 85% operation factor, the suggested degradation allowance amounts for capacity and heat rate are shown in Table 3.

[19] Considering GE publication 519HA745 for example.

Table 3 Expected performance degradation profiles

Year	Non-recoverable		Recoverable		Total		Factor to apply	
	Power degr	HR degr	Power degr	HR degr	Power degr	HR degr	Power degr	HR degr
1	0.1%	0.1%	1.0%	0.5%	1.1%	0.6%	98.9%	100.6%
2	0.4%	0.4%	1.0%	0.5%	1.4%	0.9%	98.6%	100.9%
3	0.8%	0.7%	1.0%	0.5%	1.8%	1.2%	98.2%	101.2%
4	1.1%	1.0%	1.0%	0.5%	2.1%	1.5%	97.9%	101.5%
5	1.4%	1.2%	1.0%	0.5%	2.4%	1.7%	97.6%	101.7%
6	1.6%	1.4%	1.0%	0.5%	2.6%	1.9%	97.4%	101.9%
7	1.9%	1.7%	1.0%	0.5%	2.9%	2.2%	97.1%	102.2%
8	0.8%	0.7%	1.0%	0.5%	1.8%	1.2%	98.2%	101.2%
9	1.1%	1.0%	1.0%	0.5%	2.1%	1.5%	97.9%	101.5%
10	1.3%	1.2%	1.0%	0.5%	2.3%	1.7%	97.7%	101.7%
11	1.5%	1.4%	1.0%	0.5%	2.5%	1.9%	97.5%	101.9%
12	1.7%	1.5%	1.0%	0.5%	2.7%	2.0%	97.3%	102.0%
13	1.9%	1.7%	1.0%	0.5%	2.9%	2.2%	97.1%	102.2%
14	1.1%	1.0%	1.0%	0.5%	2.1%	1.5%	97.9%	101.5%
15	1.0%	0.9%	1.0%	0.5%	2.0%	1.4%	98.0%	101.4%
16	1.2%	1.1%	1.0%	0.5%	2.2%	1.6%	97.8%	101.6%
17	1.5%	1.3%	1.0%	0.5%	2.5%	1.8%	97.5%	101.8%
18	1.7%	1.4%	1.0%	0.5%	2.7%	1.9%	97.3%	101.9%
19	1.8%	1.6%	1.0%	0.5%	2.8%	2.1%	97.2%	102.1%
20	1.7%	1.5%	1.0%	0.5%	2.7%	2.0%	97.3%	102.0%
21	0.9%	0.8%	1.0%	0.5%	1.9%	1.3%	98.1%	101.3%
22	1.1%	1.0%	1.0%	0.5%	2.1%	1.5%	97.9%	101.5%
23	1.4%	1.2%	1.0%	0.5%	2.4%	1.7%	97.6%	101.7%
24	1.6%	1.4%	1.0%	0.5%	2.6%	1.9%	97.4%	101.9%
25	1.8%	1.5%	1.0%	0.5%	2.8%	2.0%	97.2%	102.0%

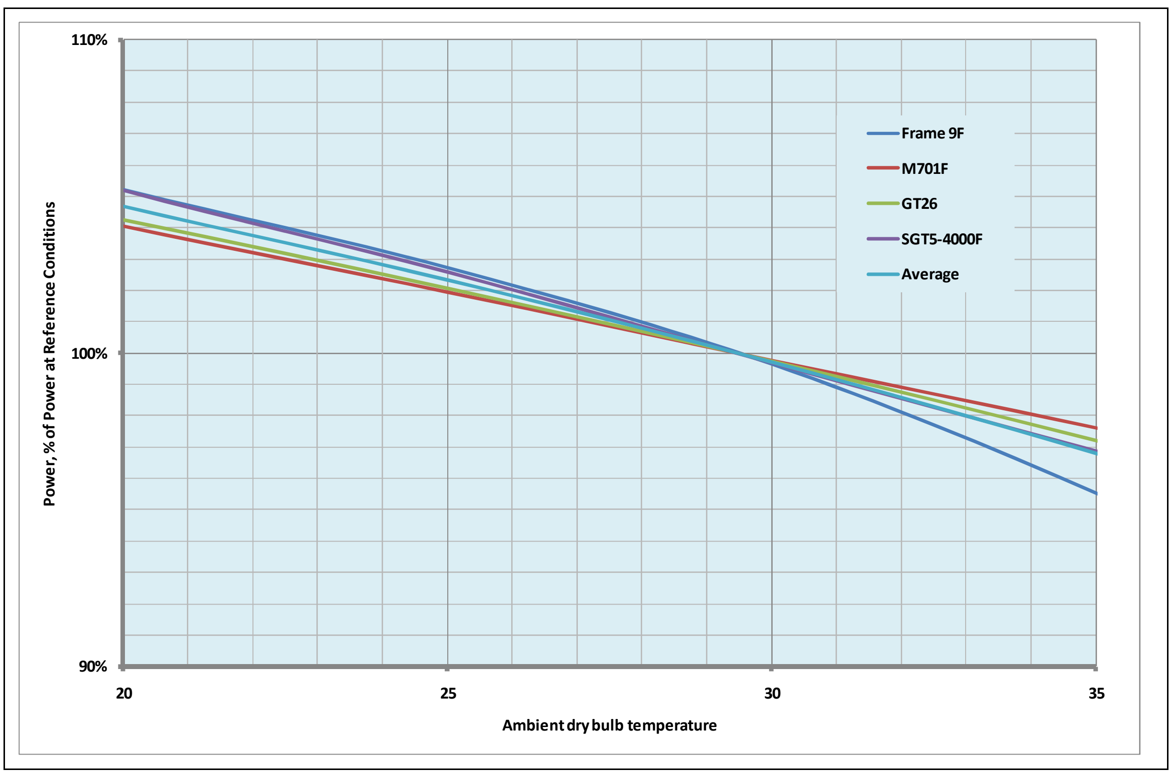
A weighted average capacity degradation rate over the plant's life of 2.42% is suggested (calculated as a weighted average per Appendix G:). Note that the average capacity degradation is not materially affected by the OEM's nomenclature for describing major outages for the gas turbine units. Degradation rates are dominated by compressor fouling rates and the timing of major compressor refurbishments and scouring, similar between OEM's.

Variations in ambient temperature affect the capacity of the generating units. The modelled impacts of variations in ambient temperature on the new entrant configurations and the average impact across the four modelled configurations are shown in Table 4 and Figure 2.

Table 4 Variation in net power output with ambient temperature (relative to Reference Conditions)

Configuration	Ambient temperature (dry bulb), ºC								
	0	5	10	15	20	25	30	35	40
Frame 9FB	112%	112%	110%	108%	105%	103%	100%	96%	91%
M701F	112%	111%	109%	106%	104%	102%	100%	98%	95%
GT26	111%	110%	108%	106%	104%	102%	100%	97%	95%
SGT5-4000F	113%	114%	111%	108%	105%	103%	100%	97%	94%
Average	**112%**	**112%**	**109%**	**107%**	**105%**	**102%**	**100%**	**97%**	**94%**

Figure 2 Effect of ambient temperature on power output



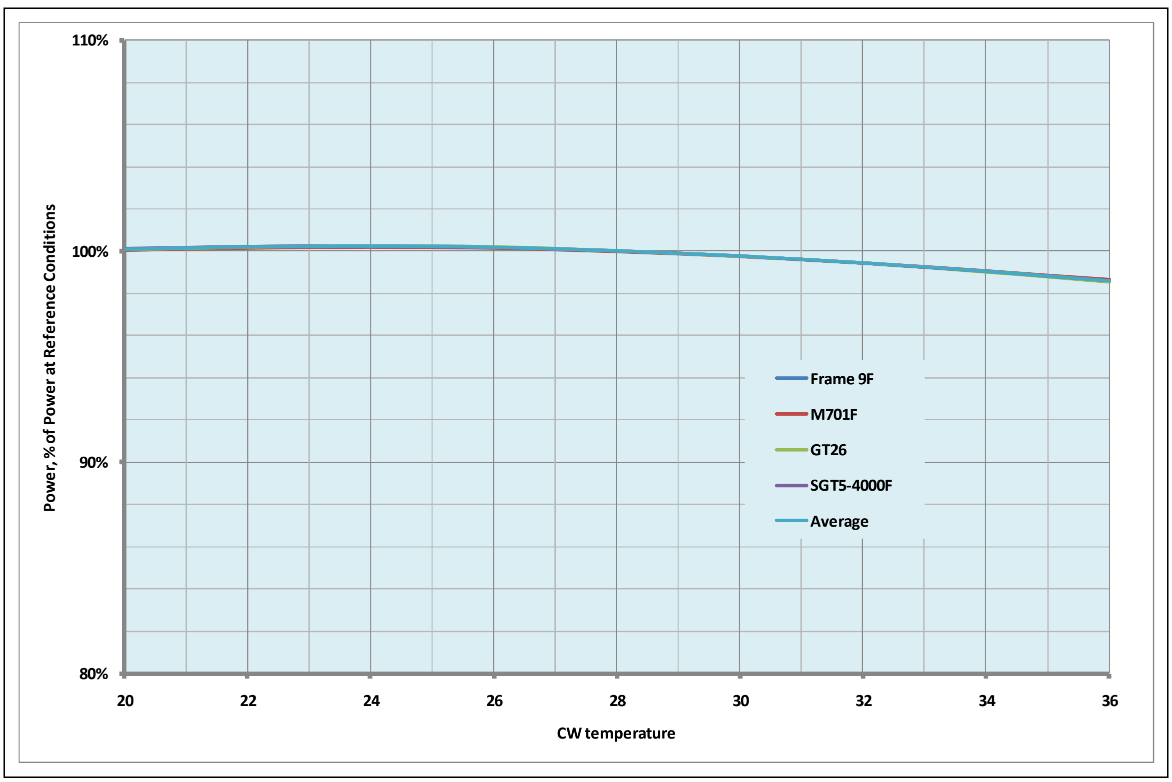
The correction factor for operation at 32ºC relative to the Reference Conditions of 29.5ºC is a reduction in capacity of 1.5%. Note that for variations of ambient relative humidity between 75% and 95% there is negligible difference in the performance of CCGT plants with once-through cooling.

Variations of the cooling water temperature supplying the plant also have an impact on plant capacity. The modelled impacts are shown in Table 5 and Figure 3.

Table 5 Variation in net power output with cooling water temperature (relative to Reference Conditions)

Configuration	Cooling temperature, ºC								
	20	22	24	26	28	30	32	34	36
Frame 9FB	100.1%	100.2%	100.2%	100.2%	100.0%	99.8%	99.4%	99.1%	98.6%
M701F	100.1%	100.2%	100.2%	100.2%	100.0%	99.8%	99.5%	99.1%	98.7%
GT26	100.1%	100.2%	100.2%	100.2%	100.0%	99.8%	99.4%	99.0%	98.6%
SGT5-4000F	100.1%	100.2%	100.2%	100.2%	100.0%	99.8%	99.4%	99.0%	98.6%
Average	**100.1%**	**100.2%**	**100.2%**	**100.2%**	**100.0%**	**99.8%**	**99.4%**	**99.1%**	**98.6%**

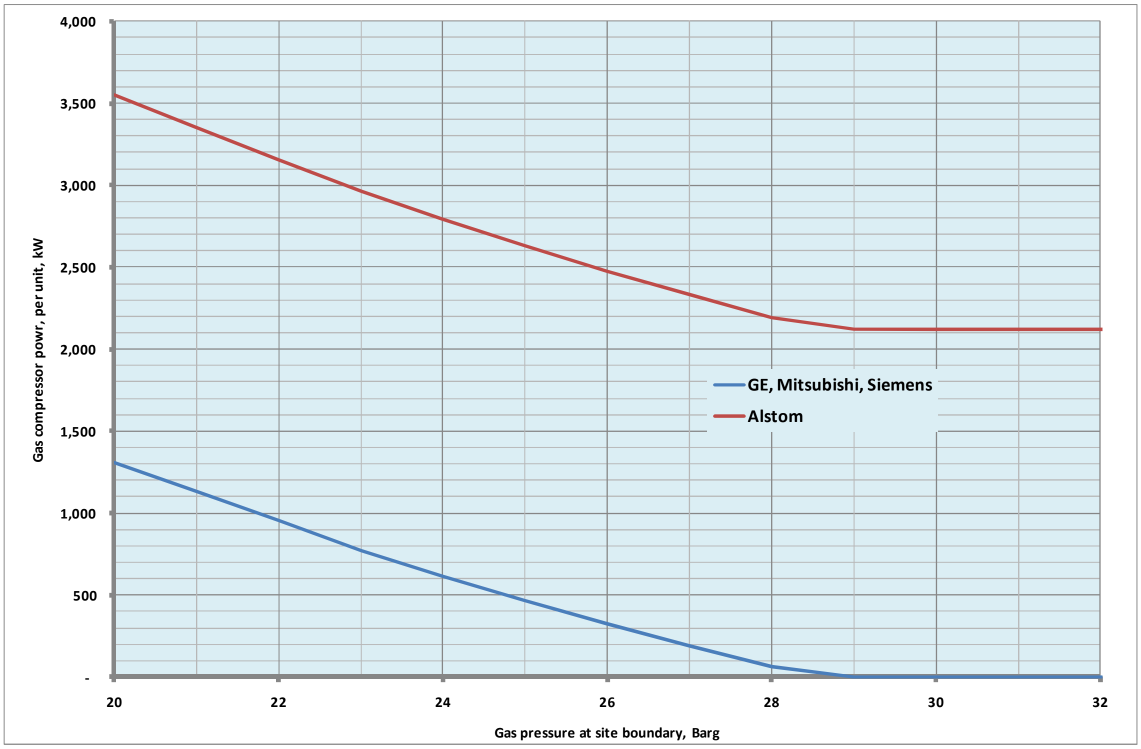
Figure 3 Variation in power output with cooling water temperature



3.3 Impact of Gas Compression and Resulting Net Capacity

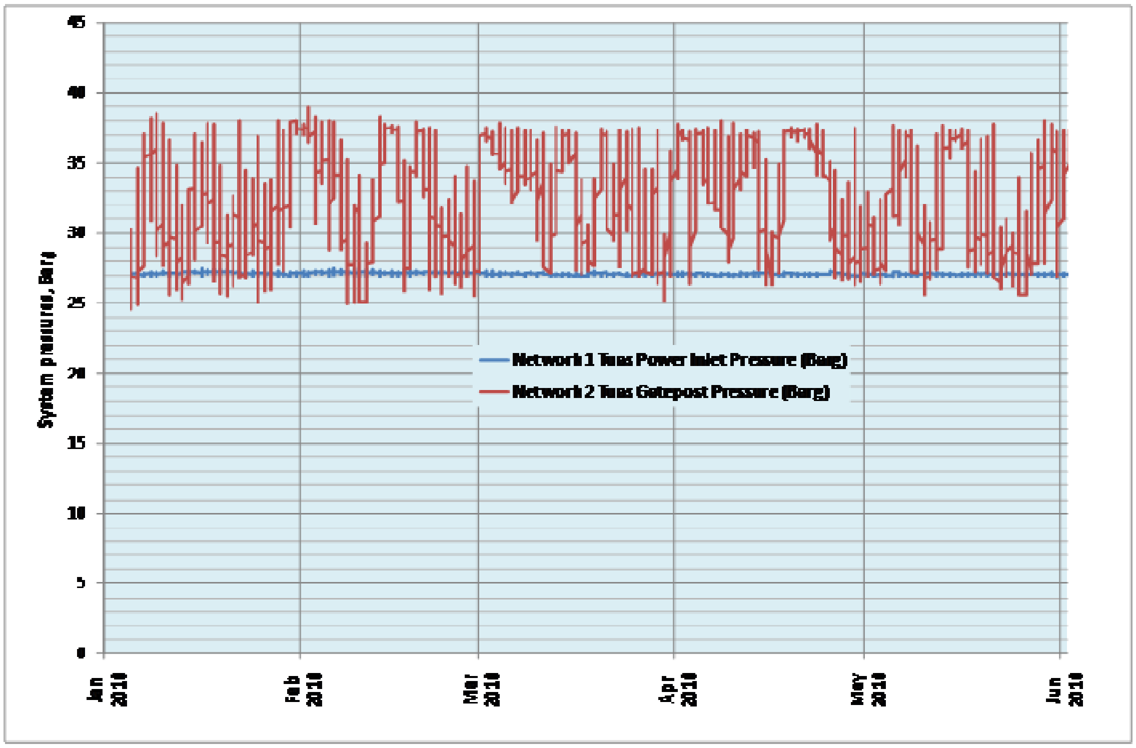
Previous reviews have not incorporated allowances for on-site gas compressors within the plant. Note that off-site gas compression would be included within the gas costs. Three of the CCGT configurations noted use natural gas at approximately 30 Barg and one configuration (the GT26) uses natural gas at approximately 50 Barg at the site boundary. The gas compressor power requirements calculated for the relevant gas turbines at varying site boundary gas pressures are shown in Figure 4. Allowances are made for pressure losses between the site boundary and the gas turbine unit.

Figure 4 Gas compressor power requirements for relevant gas turbines



Data for gas pressures in the TUAS area of Singapore is shown in Figure 5, for the months of January through May 2010. The Network 1 pressure may be downstream of a regulator in which case the upstream pressure will be higher.

Figure 5 Gas pressures in TUAS area, Jan-May 2010



The data indicates that gas compression is sometimes required under current conditions. Should the system pressures reduce further (e.g. because of load growth) then gas compression would be required more often[20].

For the purposes of this review it is assumed:

- Gas compressors would be incorporated in a new plant in the TUAS vicinity;
- The specification of the compressors would allow for further reductions in local gas pressures from those presently seen. It is assumed they would be capable of operating from a site boundary gas pressure of 20 Barg; and
- The average pressure at the site boundary during operation is 25 Barg in the relevant period.

On this basis the average gas compressor auxiliary/parasitic load impact is 1.008MW per unit based on the averaged pressure requirements of the four gas turbine models under consideration.

The resulting net capacity calculation after considering the above is shown in Table 6.

Table 6 Generation capacity of new entrant CCGT units

Parameter/factor	MW
Gross capacity (clean-as-new, reference conditions)	406.3
Less parasitics = net capacity at Reference Conditions (clean-as-new)	-8.5 = 397.8

[20] The introduction of LNG should support local gas pressures. LNG re-gasification plants necessarily incorporate gas compression.

Parameter/factor	MW
Less allowance for gas compression	-1.008
Adjust for 32ºC maximum registered capacity (-1.5%)	-6.0
Adjust for average degradation (-2.42%)	-9.7
Net capacity	**381**

3.4 Heat Rate

The heat rates of new entrant CCGT configurations, on a clean-as-new condition, and at the Reference Conditions of 29.5ºC are given in Table 7.

Table 7 Heat rate of new entrant CCGT units (clean-as-new at Reference Conditions excluding gas compression)

Configuration	Gross HR, LHV, GJ/MWh	Gross HR, HHV, GJ/MWh	Net HR, LHV, GJ/MWh	Net HR, HHV, GJ/MWh	Net HR, LHV, Btu/kWh	Net HR, HHV, Btu/kWh
Frame 9FB	6.210	6.887	6.343	7.034	6,012	6,668
M701F	6.175	6.848	6.301	6.988	5,973	6,624
GT26	6.143	6.813	6.287	6.972	5,959	6,609
SGT5-4000F	6.234	6.914	6.360	7.053	6,028	6,686
Average	**6.191**	**6.865**	**6.323**	**7.012**	**5,993**	**6,646**

This thermodynamic modelling includes all corrections necessary for:

- Ambient conditions of 29.5ºC;
- Boiler blow-down; and
- Step-up transformer losses.

No further allowances need to be made for these except as discussed below regarding ambient temperature and gas compression impacts.

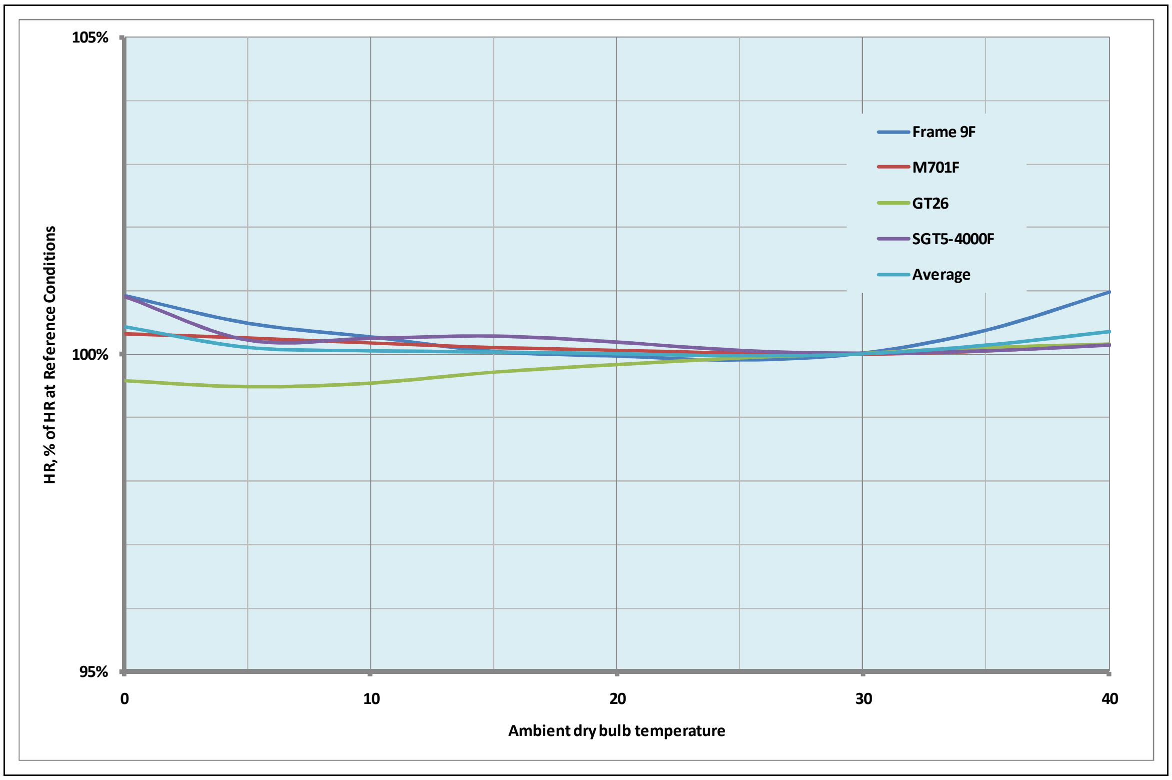
As noted in Section 3.2 above, heat rates for CCGT plants are also subject to degradation. The suggested factors to apply are given in Table 3 above. A weighted average heat rate degradation over the plant's life of 1.75% is estimated (Appendix G:).

Variations in ambient temperature affect the heat rates of the generating units. The modelled impacts of variations in ambient temperature on the new entrant configurations and the average impact across the four modelled configurations are shown in Table 8 and Figure 6.

Table 8 Variation in net heat rate with ambient temperature (relative to Reference Conditions)

	Ambient temperature (dry bulb), °C								
Configuration	**0**	**5**	**10**	**15**	**20**	**25**	**30**	**35**	**40**
Frame 9FB	100.9%	100.5%	100.3%	100.0%	100.0%	99.9%	100.0%	100.4%	101.0%
M701F	100.3%	100.3%	100.2%	100.1%	100.1%	100.0%	100.0%	100.1%	100.2%
GT26	99.6%	99.5%	99.5%	99.7%	99.8%	99.9%	100.0%	100.1%	100.2%
SGT5-4000F	100.9%	100.2%	100.2%	100.3%	100.2%	100.1%	100.0%	100.0%	100.1%
Average	**100.4%**	**100.1%**	**100.1%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.2%**	**100.4%**

Figure 6 Impact of ambient temperature on heat rate



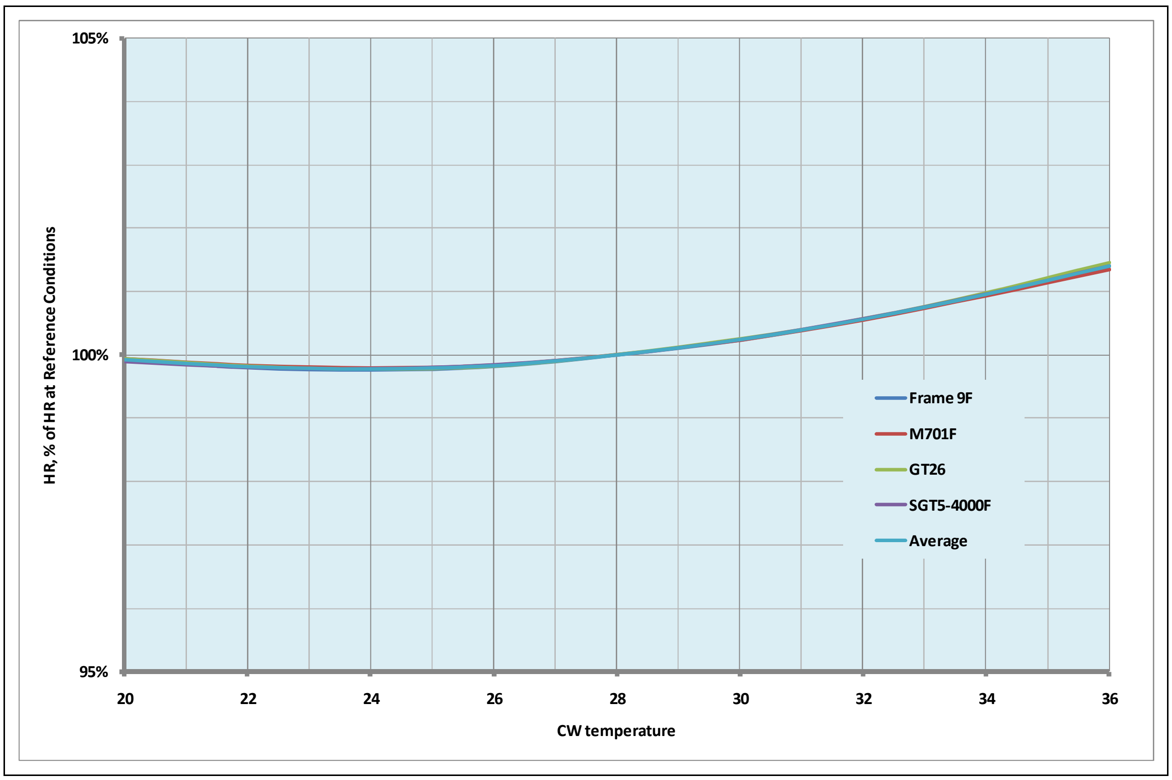
Note that for variations of ambient relative humidity between 75% and 95% there is negligible difference in the performance of CCGT plants with once-through cooling.

The heat rate is also affected by cooling water supply temperature variations. This effect is shown in Table 9 and Figure 7.

Table 9 Variation in net heat rate with cooling water temperature (relative to Reference Conditions)

	Cooling temperature, ºC								
Configuration	**20**	**22**	**24**	**26**	**28**	**30**	**32**	**34**	**36**
Frame 9FB	99.9%	99.8%	99.8%	99.8%	100.0%	100.2%	100.6%	101.0%	101.4%
M701F	99.9%	99.8%	99.8%	99.8%	100.0%	100.2%	100.6%	101.0%	101.4%
GT26	99.9%	99.8%	99.8%	99.8%	100.0%	100.2%	100.5%	100.9%	101.3%
SGT5-4000F	99.9%	99.8%	99.8%	99.8%	100.0%	100.2%	100.6%	101.0%	101.4%
Average	**99.9%**	**99.8%**	**99.8%**	**99.8%**	**100.0%**	**100.2%**	**100.6%**	**101.0%**	**101.4%**

Figure 7 Variation in heat rate with cooling water temperature



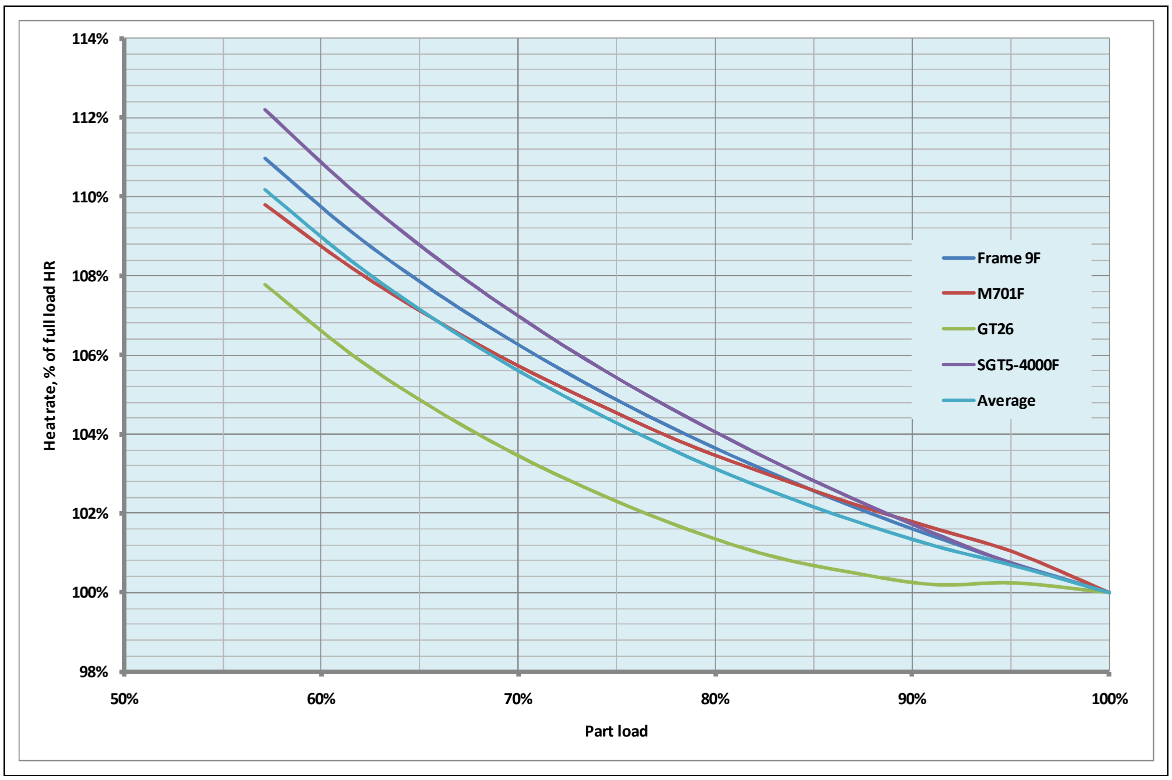
The use of fuel by the plant will reflect average operating conditions and hence the heat rate at the Reference Conditions has been applied. It is not appropriate to consider the Standing Capability Data criterion for capacity (i.e. at 32ºC) to also apply for the plant's heat rate. This differs from the treatment in the 2009-2010 review although the difference is immaterial (0.1%). This does have a small impact on the average part load factor as discussed below however.

Whenever the power plant is operated at less than the Maximum Continuous Rating (MCR) of the plant at the relevant site conditions, the heat rate is affected. The modelled variation in heat rate with the part load factor of the plant is shown in Table 10 and Figure 8.

Table 10 Variation of heat rate with part load (%)

Power	57%	62%	66%	70%	74%	79%	83%	87%	91%	95%	100%
Frame 9FB	111.0	109.1	107.6	106.2	105.0	104.0	103.0	102.2	101.4	100.7	100.0
M701F	109.8	108.2	106.9	105.7	104.7	103.7	103.0	102.2	101.6	101.0	100.0
GT26	107.8	106.0	104.6	103.4	102.4	101.6	100.9	100.5	100.2	100.2	100.0
SGT5-4000F	112.2	110.2	108.5	106.9	105.6	104.4	103.3	102.4	101.5	100.7	100.0
Average	**110.2**	**108.4**	**106.9**	**105.6**	**104.4**	**103.4**	**102.6**	**101.8**	**101.2**	**100.7**	**100.0**

Figure 8 Variation of heat rate at part load



Based on the actual historic performance Plant Factor (or Capacity Factor) of 74.9% (Section 3.7 below) and applying an outage rate (planned and unplanned) of 6.8% and with no economic shutdown time (for a base load plant), an average operating load of 80.4% is calculated.

Noting that the reported load factors are understood to be based on registered capacity (at 32ºCº) rather than the plant capacity at Reference Conditions, the apparent part load factor for the plant's performance is also slightly reduced since the registered capacity would only be 98.5% of the nominal capacity. The resulting overall part load factor is 79.2% for which the part-load factor for heat rate would be 3.3%.

An additional adjustment is made to reflect the natural gas used in starts through the year[21]. The gas usage for starts is estimated at 10 hours of full-load operating equivalent, or 0.1%.

In previous reviews an additional allowance on account of regulation service is added (+0.5%). It is not considered that the AGC requirement in Singapore is materially different from other jurisdictions where minor perturbations of output on account of AGC (for those units in the system providing AGC service) or on drop-control are part of normal operations for which no specific extra allowance is considered appropriate. Note that the impact of operating the plant at part-load on account of the need for regulation and contingency reserve ancillary services is already accounted for within the load factor correction. Since the part-load factor calculation incorporated no adjustment for economic outages whereas the calculations were based on actual operating history where some economic outages would have been likely, the part load factor heat rate correction is likely to already over-state the actual part-load heat rate correction.

An adjustment is applied for to account for the gas compressor auxiliary load.

The resulting overall heat rate calculated is shown in Table 11.

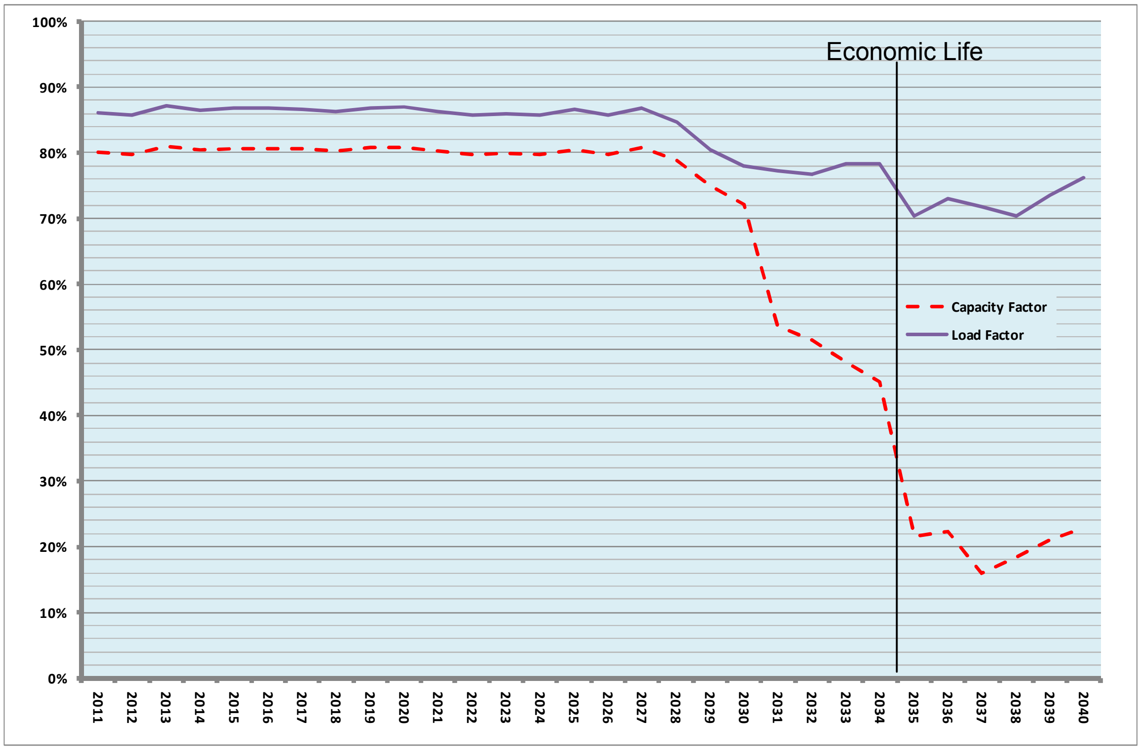
Table 11 Heat rate of new entrant CCGT units

Parameter/factor	Heat rate
Gross HR (clean-as-new, reference conditions)	6.865 GJ/MWh HHV
Net HR (clean-as-new, reference conditions) - after recognition of parasitic loads	+0.147 = 7.012 GJ/MWh HHV
Adjust for overall part load factor (+3.3%)	+0.231
Adjust for average degradation (+1.75%)	+0.126
Adjust for starts gas usage (+0.1%)	+0.007
Adjust for gas compressor impact	+0.019
Adjusted heat rate	7.395 GJ/MWh HHV
Net HR	**7,010 Btu/kWh HHV**

If the part load factor had been calculated based on the market modelling (as in previous reviews) instead of being calculated consistently with the (historic) Plant Factor/Capacity Factor, then the profile of the part load factor over the life of the proxy plant would have appeared as shown in Figure 9. The levelised average capacity factor and part load factor from this modelled data are 77.4% and 85.3% respectively. The adjustment for the overall part load factor in this case would be +2.3% instead of +3.3% and the resulting Net Heat Rate would have been lower.

[21] Based on 16 hot starts, 3 warm starts and 0.5 cold starts in an average year. These exclude starts due to economic shutdowns, the cost of which should be factored into the operator's decision to shut-down.

Figure 9 Capacity factor and part load factor from market modelling



3.5 Build Duration

Current expected build duration for this type of plants is **30 months**. This is unchanged from the 2009-2010 review and the mid-term 2010 review.

3.6 Economic Life

The technical life of this type of plant is considered to be approximately 30 years. However the economic modelling conducted on the Singapore market produces a shorter expected economic life of **24 years**. See Appendix A for details of the economic model. In the 2009-2010 review and the mid-term 2010 review, the economic life of the proxy plant was taken to be 20 years.

3.7 Plant Load Factor

The plant load factor of the new plant is determined to be the average historical plant load factor of the existing Class F plant (Senoko Energy's CCP 3 to 5, PowerSeraya's CCP 1 and 2 and Tuas Power Generation's CCP1 to 4) for the 12 months leading up to the base month. Station load has been subtracted when determining the plant load factor.

The average plant load factor for June 2009 to May 2010, as supplied by the EMA, is **74.9%** and checked to be achievable for 2011 and 2012. The plant factor in the 2009-2010 review and the mid-term 2010 review was 74%.

The impact of operating the plant at part-load conditions is discussed in Section 3.4.

There are some added benefits by way of reduced gas turbine maintenance costs produced by operating the plant at moderate loads (gas turbine maintenance is generally "on-condition" and the lower operating temperatures of part load conditions tend to reduce degradation of the turbine hot-section) however the difference is not quantifiable in this review.

3.8 Capital Cost

Capital cost includes (i) facility costs (ancillary buildings, demineralisation plant, sea water intake/outfall structures, constructing the jetty for emergency fuel unloading facility and gas receiving facilities) classified under land and site preparation cost in previous reviews, (ii) emergency fuel facilities classified under land and site preparation cost in previous reviews, (iii) civil works for the plans, erection and assembly, detailed engineering and start-up costs, and contractor soft costs classified under connection cost in previous reviews and (iv) discounted through life capital cost classified under miscellaneous cost in previous reviews.

The capital cost of a new entrant CCGT plant using current costs is assessed using the following method:

Using PA's understanding of the capital cost of CCGT units constructed recently elsewhere in the world, and discussions with Original Equipment Manufacturers (OEMs), PA assesses that the current cost of a "standard" single-unit "F" class CCGT unit is EUR650/kW or USD850/kW (based on net ISO output).

This is based on the most recent informal discussions and represents a reduction from the EUR700/kW or USD900/kW incorporated in earlier draft reports, which was based on the information that was available then from the discussion with the OEMs up to that time. Subsequent information obtained from informal discussions with three of the major OEM's suggest prices within the range of 600 EUR/kW to 700EUR/kW (775 USD/kW to 900 USD/kW) and this had moved the capital costs that had been previously estimated by PA Consulting from the mid-point of the range of estimates to the upper end of the range of estimates. Although the capital costs might revert quickly back to the previous values if the global outlook recovers quickly there is presently no justification for assuming the trend in costs for a plant procured today would be higher or lower than the mid-point price and hence the capital costs have been adjusted downwards to the current mid-point of the range of estimates. This is further supported in the latest release of the Gas Turbine World Handbook, it was indicated that “so far at least, utilities have not significantly delayed or cancelled planed projects, which means OEMs should not be as pressured to cut gas turbine prices as they did during 2009 – assuming the global economy continues to recover. Given these very recent market developments, Gas Turbine World has adjusted its pricing assessment, forecasting an approximate 9 to 10% overall decrease in prices for 2010. We expect to see this reflected in gas turbine shipment price levels during 2011 and 2012.”

This is on a turnkey, Engineering, Procurement and Construction (EPC), "inside-the-fence line", basis for natural gas firing, evaporative cooling tower condenser cooling, 1+1 single-shaft block. This standard unit would have an output of 423MW at ISO conditions. This equates to SGD505.5M using the exchange rates applicable of 1.8384 EUR/SGD. Note that because of a lack of firm market information there is a relatively high degree of uncertainty in this parameter. If sensitivity analyses were to be considered then we would expect the 90%ile confidence range to be ±EUR100/kW;

PA then calculates the capital cost of the same unit using the latest PEACE software. This produces a dissection of the EPC basis capital cost into the components and systems making up the plant. By comparing the EPC basis cost from PEACE with that of the current market EPC capital cost above, a scaling factor is calculated to scale PEACE output capital costs to current market costs;

The PEACE program is then used to calculate the cost of a unit relevant to this study, using the scaling factor calculated above. This allows adjustments to the scope to be made to reflect the local conditions.

This method differs from that applied in the 2009-2010 review. In the 2009-2010 review, the Gas Turbine World Handbook (2009 ed) quoted only the "equipment only" costs i.e. the cost of the primary generation equipment and the remaining costs that would need to be estimated include the balance of plant, civil/structural, electrical, installation, commissioning and contractor's costs (preliminaries, engineering, management, risk allowances and contractor's margin). The Power Island Equipment Only FOB costs applied in 2009 were averaged to USD547/kW from the 2009 Handbook. The 2010 Handbook has changed the form of quoting CCGT costs to "turnkey budget prices for total plant including balance of plant and construction". Despite this much larger scope, the price indicated for comparative plant has (according to the Handbook) reduced to under USD500/kW. This is not considered a realistic reflection of turnkey prices in the market as these figures are substantially lower as compared to turnkey prices indicated by recent contracts and discussions with the OEMs. A comparison of data presented in recent editions of the Handbook for relevant gas turbines is shown in Table 12. The various qualifications given in the Handbook should be considered when evaluating this data.[22]

Table 12 Gas Turbine World Handbook budget plant prices for CCGT units, USD/kW

Gas turbine unit for a single shaft CCGT block	Volume 26 2007-08 Equipment only, FOB	Volume 27 2009 Equipment only, FOB	Volume 28 2010 Turnkey
Frame 9FB	520	551	494
M701F	529	539	491
GT26	521	549	497
SGT5-4000F	521	550	497

The modifications applied to make the unit cost applicable to this study reflect different design features for the Singapore plant and that the plant required for this review is based on shared infrastructure within a multi-unit plant. A two-unit plant is assumed. The modifications applied are:

- Allowances are made for the capital cost of gas compression plant (2 train per unit);
- Civil costs are calculated on a two-unit station basis and then halved;
- Building and structures costs are calculated for a two unit station and then halved;
- The plant is based on a once-through cooling system with the civil costs added separately on a shared (two-unit) basis;
- Allowance for duel fuel systems for the gas turbines and fuel forwarding from the tanks;
- Allowance for a jetty and fuel unloading facilities is added separately on a shared (two-unit) basis; and
- Allowances for fuel tanks are added on a shared (two-unit) basis.

In calculating the costs of the civil component of the cooling system, the jetty/fuel unloading and the fuel tanks, the 2009 costs were applied, adjusted by the change in the BCA Index for commercial construction in Section 2.9. This method is consistent with the 2009 review.

[22] These are "bare bones" standard plant designs and exclude design options such as dual fuel and project specific requirements, are for sites with minimal transportation costs, site preparation and with non-union labour, and there can be a wide-range of prices for combined cycle plants depending on geographic location, site conditions, labour costs, OEM marketing strategies, currency valuations, order backlog and competitive situation.

The resulting EPC cost for the plant (excluding external connections) is **SGD550.9M per unit** as shown in Table 13. This cost is on an "overnight" basis[23].

Table 13 EPC capital cost summary (per unit) for 2010, with comparison against the 2009-2010 review and the mid-term 2010 review[24]

Project Cost Summary	2009-2010 review SGD k	Mid-term 2010 review SGD k	Current review SGD k	Comments
I Specialized Equipment	345,000	308,850	292,400	
II Other Equipment	47,100	62,650	9,668	
III Civil			29,106	Shared
IV Mechanical			41,306	
V Electrical Assembly & Wiring			9,546	
VI Buildings & Structures			13,217	Shared, except turbine hall
VII Contractor's Engineering & commissioning	7,000	6,850	19,866	
VIII Contractor's Soft & Miscellaneous Costs (including Contractor's contingencies, margins and preliminaries)	20,000	25,550	91,099	
Transport	6,900	6,350	Included	
Gas compressors			11,070	
Adjust for OT C/W system	6,700	7,450	6,676	Shared
Jetty & unloading	10,000	10,850	7,972	Shared
Fuel tanks	19,000	23,100	18,933	Shared
EPC equivalent capital cost excluding connections	**461,700**	**451,650**	**550,859**	

Note that there may be additional savings if both units of a two unit plant were procured at the same time. A small reduction in the costs of the second (and subsequent units if more than two are procured) which is expected to be of the order of 5% would result due to the sharing of transaction and engineering costs at both the contractor and owner level. Where the plant procurement is phased by more than (say) two years, these savings are less likely to result.

[23] That is, excluding Interest during Construction (IDC).

[24] 2009 values have been allocated to equivalent categories on an estimated basis

According to the load forecast supplied by the EMA (Appendix A.2.4), average load growth is projected to be less than 200MW/year in the next five years and hence it would be expected that additions of base-load plant in nominally 400MW blocks would be spaced two years apart or more, unless there are retirements from the market.

If the plant were not phased then consideration would be given to constructing the plant as a "2+1" block instead of two "1+1" blocks. Technical performance is very similar (including the amount of output lost when one gas turbine trips). The specific capital cost (SGD/MW) is typically materially lower with a "2+1" arrangement than for two "1+1" blocks. However, this depends on the load growth being sufficiently high to justify the additional capacity being constructed immediately after the first unit. This is not included in this analysis.

3.8.1 Through-life capital costs

Discounted through life capital cost was previously classified under miscellaneous cost for the previous reviews. These costs have been included under capital cost for the current review.

Capital costs of plant maintenance through the overhaul cycle of the gas turbine and steam turbine are included in Sections 3.12 and 3.13.

Additional capital costs are incurred through the project's life. Actual costs incurred vary considerably and are based on progressive assessments made of plant condition through the plant's life. Recommended estimates for this review are given in Table 14:

Table 14 Through-life capital expenditure (per unit)

Area	Time within project	Estimate, per unit	Discounted equivalent, SGDM/unit (pre-tax real WACC=6.37%), per unit
Distributed control system (DCS)	15 years	7 SGDM real	2.8
Gas turbine rotor	15 years (100,000 to 150,000 operating hours)	14 SGDM real	5.5
Total			**8.3**

The cost of the DCS upgrade depends on the level of obsolescence of related items such as field instrumentation and associated wiring.

In the 2009-2010 review and the mid-term 2010 review, KEMA reports a "Net upfront cost of lifetime extension" was allowed to extend the life of the plant to 24 years. For 2 units, SGD154.4M was allowed, which was discounted and an allowance made for residual value, to SGD7.4M/unit.

Towards the end of the notional technical life of the plant, if market studies indicated that the plant may still be economic, studies would be undertaken to evaluate extending the plant's life. The studies and the resulting costs and resulting life extensions are not included.

3.9 Land and Site Preparation Cost

The land and site preparation cost excludes (i) facility costs (ancillary buildings, demineralisation plant, sea water intake/outfall structures, constructing the jetty for emergency fuel unloading facility and gas receiving facilities) and (ii) emergency fuel facilities. These costs have been included under capital cost for the current review.

As for the 2009 analysis, the land cost is based on 12.5Ha of land and 200m of waterfront for a 2 unit plant.

JTC Corporation has advised a 30-year tenure prices for the land at Tuas View. The latest prices (1 Jun 2010)[25] for the Tuas View sites range from $168 to $211 per square metre for a 30-year lease. The waterfront fee is in the range of $594 to $1188 per meter run per year[26].

The annual cost of the waterfront fee is converted to a capital cost equivalent using a discount rate of 6.37% pre-tax real and 24 years.

Using the mid-range of the values indicated the land cost is SGD25.8M. On a shared basis between two units, the cost is SGD12.9M.

The land preparation cost allowed in 2009 was SGD1.5M (2 units). This is a relatively immaterial amount. This is escalated using the BCA Index for commercial construction given in Section 2.9 and divided between 2 units to SGD0.75M/unit.

Total cost of land and site preparation is thus **SGD13.65M/unit**.

The land and preparation cost for the 2009-2010 review and the mid-term 2010 review was SGD13.3M/unit and SGD12.65M/unit respectively

3.10 Connection Cost

Connection cost excludes civil works for the plans, erection and assembly, detailed engineering and start-up costs. These costs have been included under capital cost for the current review.

The electrical connection cost has been estimated using a "bottom-up" approach as shown in Table 15. This is based on connection of two units using the configuration shown in Figure 10.

Table 15 Electrical connection costs (2 units)

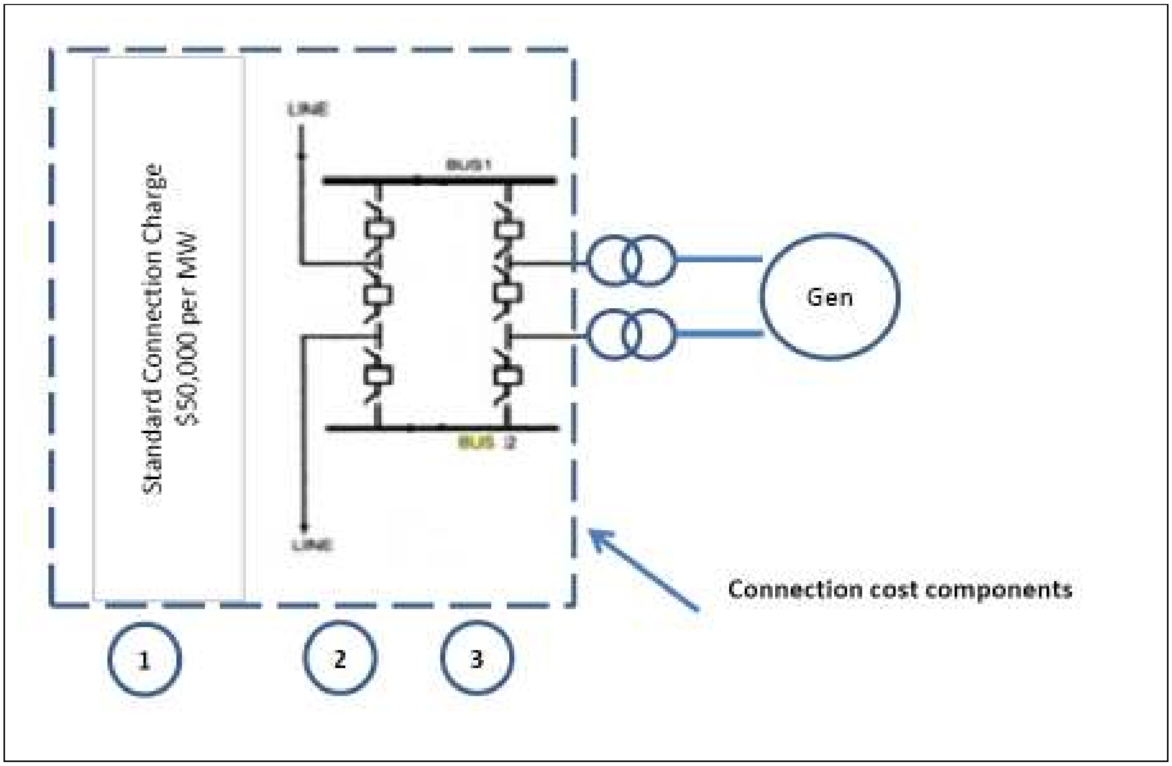
Items	Connection Cost Components	Cost (SGDM)		
1	Standard Connection Charge (to SPPG)	SGD50,000	per MW	38.1
2	Switchgear GIS (breaker and a half configuration) (Includes switch house but excludes gen transformer which is included with the power plant cost)	6	GIS	16.6
3	Cable (based on 2x1000MVA circuits of 1 km length) - underground in sand	4.25	per km	8.5
	Total			**63.2**

The connection cost for 2 units in the 2009-2010 review and the mid-term 2010 review was SGD68.2M.

[25] http://www.jtc.gov.sg/product/IndLLand/LongTenure/Pages/OLASPrice.aspx

[26] Email advice from JTC

Figure 10 Assumed electrical connection configuration (items per Table 15)



The cost for electrical connections is thus SGD31.6M per unit.

The gas connection costs are escalated from the 2009 report (using the BCA Index for commercial construction given in Section 2.9) to SGD13.3M or SGD6.65M per unit.

Total connection cost is thus **SGD38.25M/unit**.

3.11 Other Costs

Miscellaneous cost excludes discounted through life capital cost. These costs have been included under capital cost for the current review.

3.11.1 Owner's costs after financial closure

The Owner's costs incurred from Financial Closure to the Commercial Operation Date of the plant are typically allowed as percentage extra costs on the EPC basis plant costs.

PA recommends the following allowances as shown in Table 16:

Table 16 Owner's costs allowances

Area	Percentage of EPC + connection cost	Cost, per unit (SGDM)
Owners Engineering	3%	17.67
Owners "minor items"	3%	17.67
Initial spares	2%	11.78
Start-up costs	2%	11.78
Construction related insurance etc.	1%	5.89
Total		**64.8**

Note that the capital cost estimates are made at the 50th percentile of expected outcomes as is considered appropriate for this application. The EPC estimate includes the contingency and risk allowances, along with profit margins, normally included in the Contractor's EPC cost estimates. The extra contingency allowances normally included by the owner within investment decision making processes to reduce the risk of a cost over-run below 50% are not included.

Owner's engineering costs are the costs to the owner of in-house and external engineering and management services after financial closure, including inspections and monitoring of the works, contract administration and superintendency, project management and coordination between the EPC contractor, connection contractors and contractors providing minor services, witnessing of tests and management reporting.

Minor items include all the procurement costs to the owner outside of the primary plant EPC costs and the electricity and gas connections. This includes permits/licences/fees after Financial Closure, connections of other services, office fit-outs and the like. This also reflects any site specific optimisation or cost requirements of the plant above those of a "generic" standard plant covered in Section 3.8.

Start-up costs include the cost to the owner of bringing the plant to commercial operation (noting that the actual commissioning of the plant is within the plant EPC contractor's scope). The owner is typically responsible for fuels and consumables used during testing and commissioning, recruiting, training and holding staff prior to operations commencing, establishing systems and procedures.

Note that initial working capital, including initial working capital for liquid fuel inventory and for accounts receivable versus payable, are not included (these are an ongoing finance charge included in the fixed operating costs of the plant in Section 3.12).

3.11.2 Owner's costs prior to Financial Closure

At the time of Financial Closure, when the investment decision is being made, the costs accrued up to that time against the project are "sunk" and are sometimes not included in a new entrant cost estimate.

Nevertheless, the industry needs to fund the process of developing projects to bring a plant from initial conception up to financial closure. If these are to be added, the costs can be highly variable. The allowances should include both in-house and external costs to the owner/developer from concept onwards including all studies, approvals, negotiations, preparation of specifications, finance arranging, legal, due diligence processes with financiers etc. These would typically be over a 3 to 5 year period leading up to financial close. An example of typical allowances based on percentages of the EPC cost is shown in Table 17.

Table 17 Owner's costs allowances prior to Financial Closure

Area	Percentage of EPC + connection cost	Cost, per unit (SGDM)
Permits, licenses, fees	2%	11.78
Legal & financial advice and costs	2%	11.78
Owner's engineering and in-house costs	2%	11.78
Total		**35.3**

Permits, licences and fees primarily consist of gaining the environmental and planning consents for the plant.

Legal and financial advice is required for establishing the project vehicle, documenting agreements, preparing financial models and information memoranda for equity and debt sourcing, management approvals and due diligence processes.

Owner's engineering and in-house costs prior to financial closure include the costs of conceptual and preliminary designs and studies (such as optimisation studies), specifying the plant, tendering and negotiating the EPC plant contract, negotiating connection agreements, attending on the feasibility assessment and due diligence processes, management reporting and business case preparation, etc.

Project development on a project financed basis sometimes incurs extra transaction costs, such as swaptions for foreign exchange cover or for forward interest rate cover. These are highly project specific and not always necessary. No extra allowance is included.

3.12 Fixed Annual Running Cost

An assessment of the fixed annual cost of operating a CCGT station is shown in Table 18.

Note that we have included the gas turbine and steam turbine Long Term Service Agreement (LTSA) costs as variable costs rather than fixed costs, as LTSA's are normally expressed substantially as variable costs. The EMA Vesting Contract Procedures state that semi-variable maintenance costs should be included with the fixed costs amounts. If calculated correctly with the appropriate plant factor, the same vesting contract LRMC will result. Current LTSA costs for CCGT plants have been expressed as variable costs in this review and hence these costs are included in the variable cost section.

This method is different from that applied in 2009 which treated the LTSA costs as fixed costs. A comparison with the alternative treatment is given in Section 3.13.

Typically, an LTSA only covers the main turbine component. All of the balance of the plant including boilers, cooling system, electrical plant etc are maintained separately by the owner outside of the LTSA. The cost of this maintenance is typically considered to be a fixed cost, and is included in this section.

Table 18 Fixed annual operating cost allowance

Area	SGDM for 2 units
Manning	4.20
Allowance for head office services	2.52
Fixed maintenance and other fixed operations[27]	15.631
Starts impact on turbine maintenance	0.935
Distillate usage impact on turbine maintenance	0.0763
EMA license fee (fixed)	0.05
Working capital (see below)	13.521
Emergency fuel usage	1.497
Property Tax	1.037
Insurance	5.509
Total (for 2 units) per year	**44.976**

Costs per unit would thus be **SGD22.49M** per year.

Manning costs have been estimated based on 42 personnel covering 2 units at SGD100,000/person/year. The personnel include shift operators/technicians and shift supervision as well as day shift management, a share of trading/dispatch costs if this is undertaken at the station (versus head office), engineering, chemistry/environmental, trades supervision, trades and trades assistants, stores control, security, administrative and cleaning support. The cost per person is intended to cover direct and indirect costs.

Head office costs would be highly variable and depend on the structure of the business and the other activities the business engages in. Only head office support directly associated with power generation should be included as part of head office costs. The allowance for head office costs is a nominal allowance (60% of manning cost allowance) for services that might be provided by head-office that are relevant to the generation services of the plant. These would include (for example):

- Support services for generation such as trading etc;
- Corporate management and governance;
- Human Resources and management of group policies (such as OH&S, training etc);
- Accounting and legal costs at head office; and
- Corporate Social Responsibility costs.

[27] Calculated as 3% of the plant capital cost per year excluding the cost attributable to the gas turbine and steam turbine (which are included in the variable operating/maintenance costs below). These costs need to cover non-turbine maintenance, all other fixed costs including fixed charges of utilities and connections, service contracts, community service obligations etc.

In the previous reports, the manning and head office costs are bundled (with non-fuel working capital costs) and not dissected. For this review, the allocation of head office costs has been made by taking the previous (mid-term review) allowance of SGD6.8M for "manning, head office and working capital", escalating this based on CPI and deducting non-fuel working capital and the allowance for manning above. This leaves the amount of SGD2.52M/y for head office costs, or 60% of the manning cost allowance.

The starts impact on turbine maintenance costs accounts for the fact that some gas turbine OEM's add an Equivalent Operating hours (EOH) factor for starts and this impacts on the costs under the LTSA.

EOH costs are based on 2 EUR/CCGT-MWh at nominal full load. Allowing for part load adjustments the equivalent cost is EUR508.51/EOH. Note that the LTSA is based on the turbine only rather than maintenance of the whole plant. Based on 50 starts/unit and 10 EOH/start, the cost is SGD467,409/unit/year.

Additionally, the distillate usage (discussed below) also has an impact on turbine EOH consumption. Based on 1.5 EOH/hour when operating on distillate, the additional EOH consumption over natural gas fuel operation is 0.5 EOH/hour. This equates to an impact on maintenance of SGD38,161/unit/year.

Calculation of the working capital cost and the emergency fuel usage cost below requires an estimate of the costs of distillate and natural gas. PA monitors monthly Singapore HSFO and diesel prices from the OPEC Monthly Oil Market Report. Simultaneously, PA monitors Singapore pipeline gas prices, as published by the MSSL in its vesting contract price determinations. By performing a linear regression, we determine an estimated relationship between HSFO prices and gas prices. By projecting the long-term trend in real HSFO and diesel prices, we arrive at 2011 prices of 18.31 SGD/GJ and 23.53 SGD/GJ for HSFO and diesel, respectively. By applying the regression results, we calculate a gas price of 19.26 SGD/GJ.

Distillate stored and used as secondary fuel is based on the average Gasoil (0.5%S) Singapore Cargo Prices from March to May 2010, which is US$90.12/bbl[28]. A handling and delivery cost based on the allowance used in 2009 of USD5.50/bbl + CPI is added to give a delivered distillate cost of USD95.82/bbl, or SGD22.77/GJ. Applying the same relative costs differences between gas and distillate as found in the regression above produces an equivalent natural gas cost of SGD18.50/GJ.

Working capital costs are the annual costs of the financial facilities needed to fund working capital. This comprises two components:

- Emergency fuel inventory: 90 days (per 2 units), 9.1PJ at a distillate cost of SGD22.77/GJ and a pre-tax real WACC of 6.37% gives a working capital cost of SGD13.2411M/year; and
- Working capital against the cash cycle (timing of receipts from sales versus payments to suppliers) based on a net timing difference of 30 days and excluding fuel costs (based on the short settlement period in the market of 20 days from the time of generation). For two units the working capital requirement on this basis is SGD4.4M and the working capital cost (using a pre-tax real WACC of 6.37%) is SGD0.2794M/year.

Emergency fuel usage is a notional amount of emergency fuel usage for testing, tank turnover etc. Calculated as 1% of the annual fuel usage and using a cost based on the extra cost of distillate over natural gas (SGD22.77/GJ vs SGD18.50/GJ).

Property tax has been estimated based on 10% per year of an assumed Annual Value of 5% of the land, preparation and buildings/structures cost[29]. Note is also made of the IRAS circular regarding

[28] Platt's Oilgram Price Report

[29] Following http://www.business.gov.sg/EN/Government/TaxesNGST/TypesofTaxes/taxes_property.htm

property taxes on plant and machinery[30]. The value of certain fixed plant and machinery items must be included within the property valuation when calculating property taxes. However an appended list of exemptions exempts most of the principal plant items of a CCGT plant including turbines, generators, boilers, transformers, switchgear etc. To allow for the extra value of the portion of the plant that is included, 10% of the cost of the plant is included in the property tax valuation calculation (except where already included). The total value included for calculation of property tax is thus SGD207.4M (2 units).

Insurance has been estimated based on 0.5% of the capital cost. This is considered to cover property, plant and industrial risks but would not cover business interruption insurance or the cost of hedging against plant outages.

An assessment was made by PA on the impact of the EMA's proposed Automatic Penalty Policy, set out in EMA's decision paper "Review of Policy on Direct Supply of Electricity by Generating Sets to Onsite Loads" dated 5 July 2010, on the vesting price. The automatic penalty scheme is applicable for all Generation Registered Facilities (GRFs) that deviate from their dispatch schedule. The defaulting generator will be imposed with a penalty should the actual metered energy deviate by more than 10% from the scheduled energy. The penalty is calculated at a rate of 2 times the Value of Lost Load (VOLL), i.e. 2 x $5000/MWh = $10,000/MWh. The penalty collected will be returned to the market through the Monthly Energy Uplift Charge (MEUC). PA is of the view that the performance parameters of a penalty policy should reflect performance that the relevant plants are technically capable of achieving. In this case, any penalties incurred would be the result of economic trade-offs selected by the plant operator, or as a result of mis-operation of the plant. In either case it is not considered appropriate to add an allowance for an amount of annual penalties to the fixed annual cost allowances recovered via the vesting contracts.

A comparison with the values shown in the 2009-2010 review and the mid-term 2010 review is shown in Table 19.

Table 19 Fixed annual operating cost allowance comparison, SGD Millions for 2 units

Area	2009-2010 review	Mid-term 2010 review	Current Review
Manning, corporate overheads and working capital	6.9	6.8	7.0
Insurance, property tax, miscellaneous	11.0	10.8	9.2
Back-up fuel carrying cost	20.6	10.4	13.2
Maintenance (LTSA)	37.8	40.8	In variable costs
Maintenance (other)	5.8	5.7	15.6
Total (for 2 units) per year	**82.0**	**74.6**	**44.98**

[30] IRAS circular: "TAX GUIDE ON NON-ASSESSABLE PLANT AND MACHINERY COMPONENTS FOR PETROCHEMICAL AND POWER PLANTS", 16 Nov 2006.

3.13 Variable Non-Fuel Cost

It is assumed a Long Term Service Agreement (LTSA) would be sought for the first one to two overhaul cycles of the gas turbine plant (typically 6 to 12 years). These are typically structured on a "per operating hour" or "per MWh" basis and hence are largely variable costs.

An assessment of the variable, non-fuel, costs is given in Table 20.

Table 20 Variable non fuel costs

Area	SGD/MWh	Notes
Gas turbine	4.64	Based on approximately EUR2/MWh of total plant output, adjusted for part load factor
Steam turbine	0.5	
Balance of plant, chemicals, consumables	0.5	
Town Water	0.2	For a salt water cooled plant the town water costs are typically small. Based on 0.1t/MWh usage and a cost of 2 SGD/t.
EMC fees	0.3343	Based on EMC's Admin Fees of S$28.833 million for FY2010/2011[31], and a forecast wholesale volume of 43,121 GWh
PSO	0.2205	From EMC website[32] for FY2010-11
EMA license fee (variable)	0.155	A fee of $0.155/MWh applies.
Total	**6.55**	

Note the MWh in the above are those of the overall CCGT plant unit, not the individual turbine output.

If the alternative treatment of the LTSA had been adopted per the 2009 (2010 mid-term) review, the variable operating cost would reduce by approximately SGD5.1/MWh to SGD1.45/MWh and the fixed operating cost would increase by approximately SGD25.7M to approximately SGD70.3M (for 2 units)

A comparison with the values shown in the 2009-2010 review and the mid-term 2010 review is shown in Table 21.

Table 21 Variable operating cost allowance comparison, SGD/MWh

Area	2009-2010 review	Mid-term 2010 review	Current Review
LTSA (GT and ST)	In fixed costs	In fixed costs	5.14
EMC Fees	0.3661	0.31	0.33
PSO Fees	0.2104	0.22	0.22

[31] http://www.emcsg.com/n227.html

[32] http://www.emcsg.com/psobudgetandfees

Area	2009-2010 review	Mid-term 2010 review	Current Review
EMA Licence fee	0.0224	0.02	0.155
Consumables	0.4523	0.45	0.7
Total	**1.05**	**1.01**	**6.55**

Appendix A: Market Modelling

A simulation model of the Singapore electricity market was used to simulate the dispatch of the new CCGT plant over a 30-year technical life, in order to inform the determination of the plant's economic life. This appendix provides details of this modelling.

Note: This market modelling was **not** used to determine the plant's capacity factor, as the plant load factor this will be based on the historical plant load factors of existing CCGTs in Singapore i.e. Senoko Energy's CCP 3 to 5, PowerSeraya's CCP 1 and 2 and Tuas Power Generation's CCP1 to 4.

A.1 Description of the Model

The modelling was done using PA Consulting Group's proprietary WEMSIM model.

WEMSIM (Wholesale Electricity Market Simulation) is a state-of-the-art analytical dispatch planning and analysis tool that simulates the dispatch of thermal and hydro generation resources in a multi-regional transmission framework. WEMSIM is an optimization engine based on linear programming (LP). WEMSIM simultaneously optimizes generation dispatch and reserve provision.

WEMSIM is an extremely flexible modelling tool designed to model complex electricity markets. WEMSIM's economic and mathematical programming framework can be applied without the need for customization to analyze most existing and planned electricity market designs. It utilizes the most current optimization technology and does not depend on heuristics (sets of logical rules to determine dispatch, etc). WEMSIM's analytical capability and flexibility enable it to be used for many purposes, including:

- pool pricing analysis – regional or nodal and hourly or average pricing;
- market restructuring analysis;
- hydro resource management, dispatch, and valuation;
- revenue estimates and generation asset valuation;
- transmission constraint analysis and asset valuation; and
- impact assessment of alternative fuel contract structures.

WEMSIM is being used for modelling market-based dispatch and pricing for electricity markets in New Zealand, Australia, Southeast Asia, and Europe.

For Singapore, PA maintains an up-to-date database of input data on the Singapore electricity market. This has been successfully applied for assignments with multiple public and private sector clients.

A.2 Key Assumptions

In this section, we present the key input assumption that are germane to this application of the model.

A.2.1 Plant Capacities

The capacities of each generation plant in the model are presented in the following table. The new CCGT plant that is the subject of this report is called 'zNewCCGT' in the model.

The plants called 'Other_NewCCGT_1-4' are future new CCGT stations that are required to meet future load growth. It is assumed that these will be LNG-fired CCGTs.

Figure 11. Generation Plant Capacities

Generator	Unit Capacity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Environmental	35.5	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142
Island Power CCGT	400.0	0	0	800	800	800	800	800	800	800	800	800	800	800	800	800
Jurong_Diesel	90.0	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
Keppel Merlimau Cogen	245.0	490	490	490	490	490	490	490	490	490	490	490	490	490	490	490
Keppel Merlimau Expansion	450.0	0	0	450	900	900	900	900	900	900	900	900	900	900	900	900
Keppel Seghers Waste	22.0	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Other_NewCCGT_1	400.0	0	0	0	0	0	0	0	0	0	0	0	0	400	400	800
Other_NewCCGT_2	400.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other_NewCCGT_3	400.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other_NewCCGT_4	400.0	0	0	0	0	0	0	0	0	0	0	0	0	400	800	800
Pasir_Diesel	95.0	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
SembCorp_Cogen	392.5	785	785	785	785	785	785	785	785	785	785	785	785	785	785	785
SembCorp_Expansion	450.0	0	0	450	450	450	450	450	450	450	450	450	450	450	450	450
Senoko_CCGT	425.0	850	850	850	850	850	850	850	850	850	850	850	850	850	850	850
Senoko_CCGT_2	400.0	0	0	800	800	800	800	800	800	800	800	800	800	800	800	800
Senoko_Future_Repowers	400.0	0	0	0	0	0	0	0	0	0	0	364	364	364	364	364
Senoko_Repower_CCGT	365.0	1095	1095	1095	1095	1095	1095	1095	1095	1095	1095	1095	1095	1095	1095	1095
Senoko_Steam_2	250.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Senoko_Steam_3	250.0	500	500	365	365	365	365	365	365	365	365	0	0	0	0	0
Seraya_CCGT	366.0	732	732	732	732	732	732	732	732	732	732	732	732	732	732	732
Seraya_Cogen	370.0	740	740	740	740	740	740	740	740	740	740	740	740	740	740	740
Seraya_Future_Repowers	400.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seraya_Steam_1	250.0	750	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Seraya_Steam_2	232.7	698	698	698	698	698	698	698	698	698	698	698	698	698	698	698
Seraya_Steam_3	250.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_CCGT_1	360.0	720	720	720	720	720	720	720	720	720	720	720	720	720	720	720
Tuas_CCGT_2	360.0	720	720	720	720	720	720	720	720	720	720	720	720	720	720	720
Tuas_Future_Repowers	400.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_Steam	600.0	1200	1128	1128	1128	1128	1128	1128	1128	1128	1128	1128	1128	1128	1128	1128
Tuas_Tembusu	102.0	0	102	102	102	102	102	102	102	102	102	102	102	102	102	102
zNewCCGT	382.0	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
Total Capacity		**10,743**	**10,743**	**12,343**	**12,343**	**12,343**	**12,343**	**12,343**	**12,743**	**12,743**	**13,143**	**13,443**	**13,843**	**14,243**	**14,643**	**15,043**

Generator	Unit Capacity	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Environmental	35.5	142	142	142	142	142	142	142	142	142	142	142	142	142	142	142
Island Power CCGT	400.0	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Jurong_Diesel	90.0	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
Keppel Merlimau Cogen	245.0	490	490	490	490	490	490	490	490	490	490	490	0	0	0	0
Keppel Merlimau Expansion	450.0	900	900	900	900	900	900	900	900	900	900	900	900	900	900	900
Keppel Seghers Waste	22.0	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
Other_NewCCGT_1	400.0	800	800	800	800	800	1600	1600	1600	1600	1600	1600	2000	2000	2000	2000
Other_NewCCGT_2	400.0	400	800	800	800	800	1200	1200	1200	1200	1600	1600	1600	2000	2000	2000
Other_NewCCGT_3	400.0	0	0	0	400	800	800	800	800	1200	1200	1600	1600	1600	2000	2000
Other_NewCCGT_4	400.0	800	800	800	800	800	800	1200	1600	1600	1600	1600	2000	2000	2000	2400
Pasir_Diesel	95.0	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
SembCorp_Cogen	392.5	785	785	785	785	785	0	0	0	0	0	0	0	0	0	0
SembCorp_Expansion	450.0	450	450	450	450	450	450	450	450	450	450	450	450	450	450	450
Senoko_CCGT	425.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Senoko_CCGT_2	400.0	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Senoko_Future_Repowers	400.0	1200	1200	1200	1200	1200	1200	1200	1200	1200	2200	2200	2200	2200	2200	2200
Senoko_Repower_CCGT	365.0	1095	1095	1095	1095	1095	1095	1095	1095	1095	0	0	0	0	0	0
Senoko_Steam_2	250.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Senoko_Steam_3	250.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seraya_CCGT	366.0	732	732	732	732	732	732	732	0	0	0	0	0	0	0	0
Seraya_Cogen	370.0	740	740	740	740	740	740	740	740	740	740	740	740	740	740	740
Seraya_Future_Repowers	400.0	0	0	748	748	748	748	748	1400	1400	2180	2180	2180	2180	2180	2180
Seraya_Steam_1	250.0	750	750	0	0	0	0	0	0	0	0	0	0	0	0	0
Seraya_Steam_2	232.7	698	698	698	698	698	698	698	698	698	0	0	0	0	0	0
Seraya_Steam_3	250.0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_CCGT_1	360.0	720	720	720	720	720	720	0	0	0	0	0	0	0	0	0
Tuas_CCGT_2	360.0	720	720	720	720	720	720	720	720	720	720	0	0	0	0	0
Tuas_Future_Repowers	400.0	0	0	0	1128	1128	1128	1800	1800	1800	1800	2568	2568	2568	2568	2568
Tuas_Steam	600.0	1128	1128	1128	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_Tembusu	102.0	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
zNewCCGT	382.0	382	382	382	382	382	382	382	382	382	382	382	382	382	382	382
Total Capacity		**14,993**	**15,393**	**15,943**	**16,343**	**16,343**	**17,158**	**17,238**	**17,638**	**18,038**	**18,243**	**18,723**	**19,033**	**19,433**	**19,833**	**20,233**

Note:

- The capacity of 'Environmental' (The NEA incinerators) has been derated to account for typical actual generation.
- 'Senoko_Future_Repowers', 'Seraya_Future_Repowers', 'Tuas_Future_Repowers', represent future repowering projects that the 3 large generators can be expected to undertake to maintain their capacities when existing plant is due for retirement. They do not represent specific projects that have been announced.
- To be consistent with the current vesting contract price methodology, which assumes that the plant covers its own reserve cost, a cap has been placed on the generation of the new CCGT plant, to balance its allocated reserve cost with its reserve revenue.

A.2.2 Existing and New Plant Heat Rates

To provide a heat rate curve that varies with plant utilisation, hourly plant fuel use is calculated in the model as follows:

Fuel Use (GJ) = C x Unit Capacity (MW) + L x Generation (MWh)

The values of the parameters L and C are given below:

Table 22. Plant Fuel Use Factors

Type	Fuel Linear (L)	Fuel Constant Factor (C)
Existing CCGT	6.493	0.837
Current CCGT (Currently being built)	6.056	0.948
Next Generation CCGT (Built from 2018 onwards)	5.993	0.939
ST - Less Than 600MW	8.387	0.489
ST - 600MW or greater	8.265	0.544
OCGT	12.000	0.500

A.2.3 Plant Outage Rates

The following plant outage rates are based on actual historical performance of Singapore generators for 2004 - 2009, as published in MSCP reports.

Figure 12. Plant Outage Rates

Plant Type	Planned Outage Rate	Forced/Unplanned Outage Rate
ST	17.9%	2.5%
CCGT	5.8%	1.0%
OCGT	17.1%	2.2%

A.2.4 Demand

The EMA have provided the demand forecast for the modelling up to 2031. This forecast was extrapolated for the years 2032-2040. The EMA forecast was provided at the point of end use - i.e. the sum of residential and non-residential demand i.e. net of transmission losses, station loads as well as demand met by embedded generators. As WEMSIM models the transmission network but not the distribution network, both the peak and total demand values were adjusted to account for distribution system losses, by applying a factor derived from historical data from the EMC. The resulting demand forecast is given in Figure 13.

Figure 13. Demand Forecast

Year	EMA Forecast		Adjusted for Model	
	Total demand (GWh)	Peak Demand (MW)	Wholesale Demand (GWh)	Wholesale Peak (MW)
2011	42,257	6,740	44,793	7,145
2012	43,604	6,935	46,221	7,351
2013	44,994	7,176	47,695	7,607
2014	46,427	7,405	49,214	7,849
2015	47,906	7,641	50,782	8,100
2016	49,432	7,862	52,399	8,334
2017	51,006	8,135	54,068	8,623
2018	52,630	8,394	55,789	8,898
2019	54,306	8,661	57,566	9,181
2020	56,036	8,913	59,399	9,448
2021	57,821	9,222	61,292	9,776
2022	59,664	9,516	63,245	10,087
2023	61,566	9,819	65,261	10,408
2024	63,529	10,105	67,342	10,712
2025	65,555	10,456	69,490	11,084
2026	66,988	10,684	71,009	11,325
2027	68,454	10,918	72,563	11,573
2028	69,953	11,126	74,152	11,794
2029	71,486	11,401	75,777	12,085
2030	73,055	11,652	77,440	12,351
2031	74,660	11,908	79,141	12,623
2032	76,303	12,170	80,882	12,900
2033	77,981	12,438	82,662	13,184
2034	79,697	12,711	84,480	13,474
2035	81,450	12,991	86,339	13,771
2036	83,242	13,277	88,239	14,074
2037	85,073	13,569	90,180	14,383
2038	86,945	13,867	92,164	14,700
2039	88,858	14,172	94,191	15,023
2040	90,813	14,484	96,264	15,354
2041	92,810	14,803	98,381	15,691

A.3 Model Results

The key results of the WEMSIM model are as follows:

A.3.1 Generation

The generation for all generators is given below (in GWh):

Figure 14. Generation Results (in GWh)

Generator	Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Environmental	Other	976	980	976	979	972	981	972	976	981	980	985	982	978	976	970
Island Power CCGT	LNG	0	0	2,234	1,783	2,025	2,401	2,631	2,970	3,178	3,414	3,518	3,778	3,319	2,911	3,125
Jurong_Diesel	Diesel	6	20	0	0	0	0	1	3	4	6	13	16	8	14	11
Keppel Merlimau Cogen	PNG	3,976	3,934	3,138	2,681	2,790	2,854	2,970	3,034	3,178	3,262	3,512	3,578	3,476	3,362	3,438
Keppel Merlimau Expansion	LNG	0	0	3,685	7,298	7,303	7,337	7,317	7,308	7,312	7,303	7,342	7,325	7,293	7,329	7,349
Keppel Seghers Waste	Other	153	150	150	151	153	150	152	150	151	151	149	150	153	152	151
Other_NewCCGT_1	LNG	0	0	0	0	0	0	0	0	0	0	0	0	3,238	3,226	6,535
Other_NewCCGT_2	LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other_NewCCGT_3	LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other_NewCCGT_4	LNG	0	0	0	0	0	0	0	0	0	0	0	0	3,260	6,490	6,478
Pasir_Diesel	Diesel	36	57	0	0	0	1	11	11	18	23	38	63	41	31	33
SembCorp_Cogen	PNG	6,354	6,415	6,402	6,359	6,429	6,341	6,376	6,369	6,352	6,358	6,352	6,366	6,379	6,355	6,322
SembCorp_Expansion	PNG	0	0	3,701	3,716	3,702	3,683	3,673	3,652	3,662	3,680	3,657	3,697	3,630	3,665	3,698
Senoko_CCGT	PNG	6,469	6,514	4,846	4,736	4,916	5,121	5,295	5,511	5,712	5,895	5,641	5,798	5,248	5,132	4,824
Senoko_CCGT_2	PNG	0	0	6,510	6,483	6,548	6,534	6,530	6,520	6,492	6,481	6,470	6,497	6,525	6,484	6,496
Senoko_Future_Repowers	PNG/LNG	0	0	0	0	0	0	0	0	0	0	2,945	2,938	2,943	2,939	2,922
Senoko_Repower_CCGT	PNG	7,859	7,934	4,789	4,825	5,136	5,442	5,790	6,146	6,435	6,750	6,084	6,416	5,329	5,349	4,754
Senoko_Steam_2	Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Senoko_Steam_3	Fuel Oil	682	778	46	24	53	80	132	184	301	395	0	0	0	0	0
Seraya_CCGT	PNG	5,780	5,746	5,121	4,798	4,991	5,140	5,348	5,484	5,586	5,683	5,641	5,718	5,321	5,143	5,084
Seraya_Cogen	PNG	5,976	5,957	5,667	5,377	5,502	5,608	5,739	5,839	5,866	5,948	5,926	5,935	5,714	5,564	5,475
Seraya_Future_Repowers	PNG/LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seraya_Steam_1	Fuel Oil	249	303	2	1	3	6	34	52	81	110	185	275	198	156	152
Seraya_Steam_2	Fuel Oil	115	171	1	0	2	1	13	24	51	78	132	182	104	89	88
Seraya_Steam_3	Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_CCGT_1	PNG	2,119	2,194	112	75	125	171	379	546	842	1,061	1,073	1,346	902	816	776
Tuas_CCGT_2	PNG	2,564	2,726	262	184	306	409	683	925	1,217	1,425	1,458	1,746	1,227	1,143	1,121
Tuas_Future_Repowers	PNG/LNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_Steam	PNG	2,672	2,675	563	380	534	770	929	1,065	1,220	1,343	1,344	1,605	1,222	1,208	1,110
Tuas_Tembusu	Coal	0	703	714	692	690	711	692	702	700	708	704	704	714	697	695
zNewCCGT	LNG	2,671	2,663	2,703	2,685	2,693	2,692	2,691	2,680	2,694	2,698	2,678	2,661	2,665	2,659	2,687
Total (GWh)		**48,657**	**49,921**	**51,622**	**53,227**	**54,872**	**56,433**	**58,359**	**60,151**	**62,031**	**63,753**	**65,845**	**67,775**	**69,886**	**71,891**	**74,295**

Generator	Type	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Environmental	Other	969	970	976	985	988	974	980	976	976	978	980	984	990	978	975
Island Power CCGT	LNG	3,184	2,960	2,028	721	604	441	259	269	283	148	107	45	33	64	63
Jurong_Diesel	Diesel	9	7	8	7	8	2	2	2	4	3	1	1	3	2	3
Keppel Merlimau Cogen	PNG	3,382	3,253	2,794	1,863	1,812	1,608	1,196	871	826	160	19	0	0	0	0
Keppel Merlimau Expansion	LNG	7,337	7,322	7,280	6,980	6,841	6,381	5,042	4,134	3,932	2,195	2,178	1,726	1,447	1,779	1,440
Keppel Seghers Waste	Other	155	153	154	153	152	153	150	150	149	151	152	150	148	149	153
Other_NewCCGT_1	LNG	6,466	6,498	6,514	6,488	6,489	12,949	13,010	12,974	13,000	12,289	13,010	16,212	16,236	16,217	16,244
Other_NewCCGT_2	LNG	3,244	6,516	6,492	6,374	6,391	9,680	9,573	9,022	9,224	8,922	9,331	8,314	10,287	10,761	10,092
Other_NewCCGT_3	LNG	0	0	0	3,163	6,304	6,297	6,254	5,440	7,815	6,273	7,016	6,618	6,568	6,962	6,906
Other_NewCCGT_4	LNG	6,509	6,533	6,489	6,485	6,465	6,526	9,720	13,000	12,970	12,866	12,894	15,716	15,870	15,945	18,663
Pasir_Diesel	Diesel	27	16	20	21	20	11	6	6	8	9	9	2	9	13	8
SembCorp_Cogen	PNG	6,068	5,985	5,600	4,158	3,962	0	0	0	0	0	0	0	0	0	0
SembCorp_Expansion	PNG	3,706	3,698	3,681	3,415	3,325	2,610	3,003	1,934	1,821	982	1,279	1,079	1,017	1,171	1,048
Senoko_CCGT	PNG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Senoko_CCGT_2	PNG	6,271	6,156	5,900	6,120	6,203	5,076	5,223	5,234	5,408	3,277	3,485	2,993	3,064	3,349	3,391
Senoko_Future_Repowers	PNG/LNG	9,712	9,687	9,738	9,714	9,673	9,792	9,764	9,770	9,732	17,788	17,079	16,501	16,707	16,846	17,016
Senoko_Repower_CCGT	PNG	3,954	3,790	3,677	2,744	2,274	1,715	920	835	739	0	0	0	0	0	0
Senoko_Steam_2	Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Senoko_Steam_3	Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Seraya_CCGT	PNG	4,086	3,831	3,148	1,808	1,883	1,627	959	0	0	0	0	0	0	0	0
Seraya_Cogen	PNG	4,550	4,268	3,556	2,241	2,170	1,916	1,295	794	718	199	154	86	91	126	139
Seraya_Future_Repowers	PNG/LNG	0	0	6,059	6,061	6,057	6,040	6,052	11,277	11,247	17,803	17,790	17,845	17,812	17,788	17,799
Seraya_Steam_1	Fuel Oil	134	98	0	0	0	0	0	0	0	0	0	0	0	0	0
Seraya_Steam_2	Fuel Oil	73	59	57	34	47	20	23	23	21	0	0	0	0	0	0
Seraya_Steam_3	Fuel Oil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_CCGT_1	PNG	681	578	342	254	240	161	0	0	0	0	0	0	0	0	0
Tuas_CCGT_2	PNG	989	838	494	166	186	128	94	94	80	15	0	0	0	0	0
Tuas_Future_Repowers	PNG/LNG	0	0	0	7,640	7,373	6,185	8,442	7,313	7,127	4,584	4,905	4,590	4,548	4,725	4,735
Tuas_Steam	PNG	1,055	914	616	0	0	0	0	0	0	0	0	0	0	0	0
Tuas_Tembusu	Coal	707	701	704	696	710	698	695	708	693	720	708	698	705	713	700
zNewCCGT	LNG	2,663	2,695	2,630	2,499	2,407	1,786	1,717	1,607	1,505	719	744	533	612	705	763
Total (GWh)		**75,931**	**77,526**	**78,955**	**80,791**	**82,583**	**82,778**	**84,379**	**86,432**	**88,277**	**90,083**	**91,841**	**94,094**	**96,147**	**98,293**	**100,137**

A.3.2 Plant Capacity Factors

The plant capacity factor for all generators is given below (as a percentage of total capacity):

Figure 15. Plant Capacity Factor Results

Generator	Type	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Environmental	Other	78.7%	79.0%	78.7%	78.9%	78.4%	79.1%	78.4%	78.7%	79.1%	79.0%	79.4%	79.1%	78.8%	78.6%	78.2%
Island Power CCGT	LNG	-	-	32.0%	25.5%	29.0%	34.4%	37.6%	42.5%	45.5%	48.8%	50.3%	54.1%	47.5%	41.7%	44.7%
Jurong_Diesel	Diesel	0.4%	1.3%	0.0%	0.0%	0.0%	0.0%	0.1%	0.2%	0.2%	0.4%	0.8%	1.0%	0.5%	0.9%	0.7%
Keppel Merlimau Cogen	PNG	92.9%	91.9%	73.3%	62.6%	65.2%	66.7%	69.4%	70.9%	74.2%	76.2%	82.0%	83.6%	81.2%	78.5%	80.3%
Keppel Merlimau Expansion	LNG	-	-	93.7%	92.8%	92.9%	93.3%	93.1%	92.9%	93.0%	92.9%	93.4%	93.2%	92.8%	93.2%	93.5%
Keppel Seghers Waste	Other	79.6%	77.9%	78.0%	78.4%	79.5%	78.2%	79.3%	78.2%	78.3%	78.5%	77.5%	78.0%	79.5%	79.3%	78.5%
Other_NewCCGT_1	LNG	-	-	-	-	-	-	-	-	-	-	-	-	92.7%	92.3%	93.5%
Other_NewCCGT_2	LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other_NewCCGT_3	LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other_NewCCGT_4	LNG	-	-	-	-	-	-	-	-	-	-	-	-	93.3%	92.9%	92.7%
Pasir_Diesel	Diesel	2.2%	3.4%	0.0%	0.0%	0.0%	0.1%	0.7%	0.7%	1.1%	1.4%	2.3%	3.8%	2.5%	1.9%	2.0%
SembCorp_Cogen	PNG	92.7%	93.5%	93.4%	92.7%	93.7%	92.5%	93.0%	92.9%	92.6%	92.7%	92.6%	92.8%	93.0%	92.7%	92.2%
SembCorp_Expansion	PNG	-	-	94.1%	94.5%	94.2%	93.7%	93.4%	92.9%	93.1%	93.6%	93.0%	94.0%	92.3%	93.2%	94.1%
Senoko_CCGT	PNG	87.1%	87.7%	65.3%	63.8%	66.2%	69.0%	71.3%	74.2%	76.9%	79.4%	76.0%	78.1%	70.7%	69.1%	65.0%
Senoko_CCGT_2	PNG	-	-	93.2%	92.8%	93.7%	93.5%	93.4%	93.3%	92.9%	92.7%	92.6%	93.0%	93.4%	92.8%	92.9%
Senoko_Future_Repowers	PNG/LNG	-	-	-	-	-	-	-	-	-	-	92.6%	92.4%	92.6%	92.4%	91.9%
Senoko_Repower_CCGT	PNG	82.2%	82.9%	50.1%	50.4%	53.7%	56.9%	60.5%	64.3%	67.3%	70.6%	63.6%	67.1%	55.7%	55.9%	49.7%
Senoko_Steam_2	Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senoko_Steam_3	Fuel Oil	15.6%	17.8%	1.4%	0.8%	1.7%	2.5%	4.1%	5.8%	9.4%	12.4%	-	-	-	-	-
Seraya_CCGT	PNG	90.4%	89.9%	80.1%	75.0%	78.0%	80.4%	83.6%	85.8%	87.4%	88.9%	88.2%	89.4%	83.2%	80.4%	79.5%
Seraya_Cogen	PNG	92.4%	92.1%	87.7%	83.2%	85.1%	86.7%	88.8%	90.3%	90.7%	92.0%	91.7%	91.8%	88.4%	86.1%	84.7%
Seraya_Future_Repowers	PNG/LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Seraya_Steam_1	Fuel Oil	3.8%	4.6%	0.0%	0.0%	0.0%	0.1%	0.5%	0.8%	1.2%	1.7%	2.8%	4.2%	3.0%	2.4%	2.3%
Seraya_Steam_2	Fuel Oil	1.9%	2.8%	0.0%	0.0%	0.0%	0.0%	0.2%	0.4%	0.8%	1.3%	2.2%	3.0%	1.7%	1.5%	1.4%
Seraya_Steam_3	Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tuas_CCGT_1	PNG	33.7%	34.9%	1.8%	1.2%	2.0%	2.7%	6.0%	8.7%	13.4%	16.9%	17.1%	21.4%	14.3%	13.0%	12.3%
Tuas_CCGT_2	PNG	40.8%	43.3%	4.2%	2.9%	4.9%	6.5%	10.9%	14.7%	19.3%	22.7%	23.2%	27.8%	19.5%	18.2%	17.8%
Tuas_Future_Repowers	PNG/LNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tuas_Steam	PNG	25.5%	27.1%	5.7%	3.9%	5.4%	7.8%	9.4%	10.8%	12.4%	13.6%	13.6%	16.3%	12.4%	12.3%	11.3%
Tuas_Tembusu	Coal	-	78.9%	80.1%	77.6%	77.4%	79.8%	77.6%	78.7%	78.5%	79.5%	79.0%	79.0%	80.1%	78.3%	78.0%
zNewCCGT	LNG	80.0%	79.8%	81.0%	80.4%	80.7%	80.7%	80.6%	80.3%	80.7%	80.9%	80.2%	79.7%	79.9%	79.7%	80.5%

Generator	Type	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Environmental	Other	78.1%	78.2%	78.7%	79.4%	79.6%	78.5%	79.0%	78.6%	78.7%	78.8%	79.0%	79.3%	79.8%	78.9%	78.6%
Island Power CCGT	LNG	45.6%	42.4%	29.0%	10.3%	8.6%	6.3%	3.7%	3.8%	4.1%	2.1%	1.5%	0.6%	0.5%	0.9%	0.9%
Jurong_Diesel	Diesel	0.6%	0.4%	0.5%	0.5%	0.5%	0.1%	0.1%	0.1%	0.2%	0.2%	0.1%	0.1%	0.2%	0.1%	0.2%
Keppel Merlimau Cogen	PNG	79.0%	76.0%	65.3%	43.5%	42.3%	37.6%	27.9%	20.3%	19.3%	3.7%	0.4%	-	-	-	-
Keppel Merlimau Expansion	LNG	93.3%	93.1%	92.6%	88.8%	87.0%	81.2%	64.1%	52.6%	50.0%	27.9%	27.7%	22.0%	18.4%	22.6%	18.3%
Keppel Seghers Waste	Other	80.7%	79.4%	79.9%	79.7%	78.9%	79.7%	78.1%	78.2%	77.4%	78.6%	78.9%	78.2%	77.1%	77.4%	79.5%
Other_NewCCGT_1	LNG	92.5%	93.0%	93.2%	92.8%	92.8%	92.6%	93.1%	92.8%	93.0%	87.9%	93.1%	92.8%	92.9%	92.8%	93.0%
Other_NewCCGT_2	LNG	92.8%	93.2%	92.9%	91.2%	91.5%	92.3%	91.3%	86.1%	88.0%	63.8%	66.8%	59.5%	58.9%	61.6%	57.8%
Other_NewCCGT_3	LNG	-	-	-	90.5%	90.2%	90.1%	89.5%	77.8%	74.5%	59.8%	50.2%	47.4%	47.0%	39.8%	39.5%
Other_NewCCGT_4	LNG	93.1%	93.5%	92.9%	92.8%	92.5%	93.4%	92.7%	93.0%	92.8%	92.0%	92.2%	89.9%	90.8%	91.3%	89.0%
Pasir_Diesel	Diesel	1.6%	1.0%	1.2%	1.3%	1.2%	0.6%	0.4%	0.4%	0.5%	0.5%	0.5%	0.1%	0.5%	0.8%	0.5%
SembCorp_Cogen	PNG	88.5%	87.3%	81.7%	60.6%	57.8%	-	-	-	-	-	-	-	-	-	-
SembCorp_Expansion	PNG	94.3%	94.1%	93.6%	86.9%	84.6%	66.4%	76.4%	49.2%	46.3%	25.0%	32.5%	27.4%	25.9%	29.8%	26.7%
Senoko_CCGT	PNG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senoko_CCGT_2	PNG	89.7%	88.1%	84.4%	87.6%	88.8%	72.6%	74.7%	74.9%	77.4%	46.9%	49.9%	42.8%	43.8%	47.9%	48.5%
Senoko_Future_Repowers	PNG/LNG	92.6%	92.4%	92.9%	92.7%	92.3%	93.4%	93.1%	93.2%	92.8%	92.6%	88.9%	85.9%	86.9%	87.7%	88.5%
Senoko_Repower_CCGT	PNG	41.3%	39.6%	38.4%	28.7%	23.8%	17.9%	9.6%	8.7%	7.7%	-	-	-	-	-	-
Senoko_Steam_2	Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Senoko_Steam_3	Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Seraya_CCGT	PNG	63.9%	59.9%	49.2%	28.3%	29.4%	25.4%	15.0%	-	-	-	-	-	-	-	-
Seraya_Cogen	PNG	70.4%	66.0%	55.0%	34.7%	33.6%	29.6%	20.0%	12.3%	11.1%	3.1%	2.4%	1.3%	1.4%	1.9%	2.1%
Seraya_Future_Repowers	PNG/LNG	-	-	92.7%	92.8%	92.7%	92.4%	92.6%	92.2%	92.0%	93.5%	93.4%	93.7%	93.5%	93.4%	93.5%
Seraya_Steam_1	Fuel Oil	2.0%	1.5%	-	-	-	-	-	-	-	-	-	-	-	-	-
Seraya_Steam_2	Fuel Oil	1.2%	1.0%	0.9%	0.6%	0.8%	0.3%	0.4%	0.4%	0.3%	-	-	-	-	-	-
Seraya_Steam_3	Fuel Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tuas_CCGT_1	PNG	10.8%	9.2%	5.4%	4.0%	3.8%	2.6%	-	-	-	-	-	-	-	-	-
Tuas_CCGT_2	PNG	15.7%	13.3%	7.9%	2.6%	3.0%	2.0%	1.5%	1.5%	1.3%	0.2%	-	-	-	-	-
Tuas_Future_Repowers	PNG/LNG	-	-	-	77.5%	74.8%	62.8%	53.7%	46.5%	45.3%	29.2%	21.9%	20.5%	20.3%	21.1%	21.1%
Tuas_Steam	PNG	10.7%	9.3%	6.3%	-	-	-	-	-	-	-	-	-	-	-	-
Tuas_Tembusu	Coal	79.3%	78.6%	79.0%	78.2%	79.6%	78.3%	78.0%	79.4%	77.7%	80.8%	79.4%	78.3%	79.1%	80.0%	78.5%
zNewCCGT	LNG	79.8%	80.8%	78.8%	74.9%	72.1%	53.5%	51.4%	48.2%	45.1%	21.5%	22.3%	16.0%	18.3%	21.1%	22.9%

A.3.3 New CCGT Generation, Capacity Factor and Part Load Factor

The following table summarises the results for the new CCGT plant:

Figure 16. Summary of Results for New CCGT

Year	Hours Running	Generation (MWh)	Capacity Factor	Part Load Factor
2011	8124	2,670,657	80.0%	86.1%
2012	8124	2,663,438	79.8%	85.8%
2013	8124	2,702,917	81.0%	87.1%
2014	8124	2,684,620	80.4%	86.5%
2015	8124	2,693,004	80.7%	86.8%
2016	8124	2,691,601	80.7%	86.7%
2017	8124	2,690,655	80.6%	86.7%
2018	8124	2,680,150	80.3%	86.4%
2019	8124	2,694,322	80.7%	86.8%
2020	8124	2,698,161	80.9%	86.9%
2021	8124	2,677,839	80.2%	86.3%
2022	8124	2,661,298	79.7%	85.8%
2023	8124	2,665,386	79.9%	85.9%
2024	8124	2,659,006	79.7%	85.7%
2025	8124	2,687,349	80.5%	86.6%
2026	8124	2,662,751	79.8%	85.8%
2027	8124	2,695,151	80.8%	86.8%
2028	8124	2,629,575	78.8%	84.7%
2029	8124	2,498,861	74.9%	80.5%
2030	8088	2,407,020	72.1%	77.9%
2031	6051	1,786,161	53.5%	77.3%
2032	5863	1,716,665	51.4%	76.6%
2033	5368	1,607,171	48.2%	78.4%
2034	5031	1,504,851	45.1%	78.3%
2035	2671	718,773	21.5%	70.4%
2036	2667	744,134	22.3%	73.0%
2037	1944	532,670	16.0%	71.7%
2038	2279	611,928	18.3%	70.3%
2039	2508	705,418	21.1%	73.6%
2040	2621	763,441	22.9%	76.3%

Appendix B: Panel of Comparator Companies Considered against the Selection Criteria

In selecting the panel of comparator companies, PA started with a list of 361 publicly-listed companies classified as either "Electric Utilities" or "Independent Power Producers and Energy Traders". The first filter (removing companies with less than five years of available data) and the second filter (removing companies who had recently experienced financial distress) reduced the list by approximately 80%. The remaining four filters -- considering location of operations, sources of revenues, generation type and company credit rating -- were applied to the remaining companies to produce the panel of comparator companies. To be included in the panel, companies had to meet all six criteria. The selection process of companies is shown in the table below.

Scottish & Southern Energy plc	TransAlta Corp	Capital Power Income LP	Edison SpA	Allegheny Energy Inc	International Power plc
1. Availability of Data - Company must have data available for reporting years 2005 through to 2009.					
Yes	Yes	Yes	Yes	Yes	Yes
2. Financial Health - Company must be in good financial health, having not shown signs of financial distress for five reporting years.					
Yes	Yes	Yes	Yes	No. Company is the target of an announced merger.	Yes
3. Location of Operations - The majority of a company's generation assets must be located in economies that feature risk characteristics similar to that of Singapore.					
Yes. Over 96% of capacity is located in the UK. The remainder is located in Ireland (Source: 2009 SSE Annual Report)	Yes. All operations are located in either Canada, the US or Australia. (Source: 2009 TransAlta Annual Report)	Yes. All operations are located in either Canada or the US. (Source 2009 CCP Annual Report)	No. The majority of operations are located in Italy. (Source 2009 Edison Annual Report)	Yes. All operations are located in the US. (Source: Allegheny Energy website)	Yes. Over half of all operations are located in AAA rated European countries, North America or Australia (Source: 2009 International Power Annual Report)

Scottish & Southern Energy plc	TransAlta Corp	Capital Power Income LP	Edison SpA	Allegheny Energy Inc	International Power plc
4. Sources of Revenues - The majority of a company's revenues should come from non-regulated generation activities.					
Yes. 62% of revenues came from non-regulated generation activities in 2009. (Source: Capital IQ and 2009 SSE Annual Report)	Yes. 98% of revenues came from non-regulated generation activities in 2009. This includes long-term sale agreements. (Source: Capital IQ)	Yes. 100% of revenues came from non-regulated generation activities in 2009. This includes long-term sale agreements. (Source: Capital IQ)	Yes. 57% of revenues came from non-regulated generation activities in 2009. (Source: 2009 Edison Annual Report)	No. Only 47% of revenues came from non-regulated generation after elimination of intercompany sales. (Source: 2009 Allegheny Form 10K)	Yes. Over 90% of revenues came from non-regulated generation in 2009. (Source: 2009 International Power Annual Report)
5. Generation Type - The majority of a company's generation should be fossil fired.					
Yes. 79% of capacity was fossil fired in 2009. (Source 2009 SSE Annual Report)	Yes. 78% of capacity was fossil fired in 2009. (Source: 2009 TransAlta Annual Report)	Yes. 69% of capacity was fossil fired in 2009. (Source: 2009 CCP Annual Report)	Yes. 83% of capacity was fossil fired in 2009. (Source: 2009 Edison Annual Report)	Yes. 88% of capacity was fossil fired in 2009. (Source: 2009 Allegheny Form 10K)	Yes. 89% of capacity was fossil fired in 2009. (Source: 2009 International Power Annual Report)
6. Credit Rating - A company's credit rating must be of minimum investment grade (BBB- or higher).					
Yes. SEE has a credit rating A- as of 21 August 2009. (Source: S&P)	Yes. TransAlta has a credit rating BBB as of 6 February 2006. (Source: S&P)	Yes. CPP has a credit rating BBB+ as of 7 May 2007. (Source: S&P)	Yes. Edison has a credit rating of BBB+ as of 7 June 2004. (Source S&P)	Yes. Allegheny has a credit rating of BBB- as of 4 May 2007. (Source S&P)	No. International Power has a credit rating of BB as of 10 November 2009. (Source S&P)
Results of Selection Criteria - Companies who pass all criteria are judged suitable to form part of the comparator panel					
Passed all criteria. Selected to form part of the panel.	Passed all criteria. Selected to form part of the panel.	Passed all criteria. Selected to form part of the panel.	Failed criteria 3 - locations of operations. Excluded from panel.	Failed criteria 2 - financial health - and 4 - sources of revenues. Excluded from panel.	Failed criteria 6 - credit rating. Excluded from panel.

Appendix C: Bond Yield Data

The average yield to maturity values for various bonds and indices were used in the calculation of the financial parameters. This appendix lists the daily closing values from which the appropriate parameters were derived.

C.1 Risk Free Rate

Singapore Government **20 year Bond "CTSGD20Y" issued in 2007 and maturing in 2027 (Source: Bloomberg)**					
01/03/2010	3.36%	08/04/2010	3.41%	17/05/2010	2.96%
02/03/2010	3.36%	09/04/2010	3.40%	18/05/2010	3.04%
03/03/2010	3.35%	12/04/2010	3.43%	19/05/2010	3.05%
04/03/2010	3.36%	13/04/2010	3.41%	20/05/2010	3.11%
05/03/2010	3.36%	14/04/2010	3.39%	21/05/2010	3.12%
08/03/2010	3.38%	15/04/2010	3.35%	24/05/2010	3.14%
09/03/2010	3.36%	16/04/2010	3.34%	25/05/2010	3.06%
10/03/2010	3.37%	19/04/2010	3.33%	26/05/2010	3.11%
11/03/2010	3.38%	20/04/2010	3.37%	27/05/2010	3.21%
12/03/2010	3.37%	21/04/2010	3.39%	31/05/2010	3.20%
15/03/2010	3.35%	22/04/2010	3.37%	**Average Yield**	**3.31%**
16/03/2010	3.35%	23/04/2010	3.36%		
17/03/2010	3.35%	26/04/2010	3.36%		
18/03/2010	3.32%	27/04/2010	3.35%		
19/03/2010	3.35%	28/04/2010	3.33%		
22/03/2010	3.35%	29/04/2010	3.30%		
23/03/2010	3.35%	30/04/2010	3.30%		
24/03/2010	3.37%	03/05/2010	3.30%		
25/03/2010	3.38%	04/05/2010	3.31%		
26/03/2010	3.39%	05/05/2010	3.26%		
29/03/2010	3.43%	06/05/2010	3.23%		
30/03/2010	3.46%	07/05/2010	3.24%		
31/03/2010	3.45%	10/05/2010	3.29%		
01/04/2010	3.43%	11/05/2010	3.26%		
05/04/2010	3.49%	12/05/2010	3.21%		
06/04/2010	3.48%	13/05/2010	3.17%		
07/04/2010	3.44%	14/05/2010	3.07%		

C.2 Debt Premium

C.2.1 Bloomberg Fair Value US Utility Index

The Bloomberg Fair Value US Utility BBB- 20 year Index represents the average bond yields issued by utility companies having credit ratings of BBB- (Source: Bloomberg)					
01/03/2010	6.24%	12/04/2010	6.44%	26/05/2010	5.90%
02/03/2010	6.29%	13/04/2010	6.49%	27/05/2010	6.15%
03/03/2010	6.33%	14/04/2010	6.48%	28/05/2010	6.14%
04/03/2010	6.30%	15/04/2010	6.39%	31/05/2010	6.14%
05/03/2010	6.40%	16/04/2010	6.35%	**Average Yield**	**6.29%**
08/03/2010	6.45%	19/04/2010	6.39%		
09/03/2010	6.45%	20/04/2010	6.32%		
10/03/2010	6.39%	21/04/2010	6.31%		
11/03/2010	6.36%	22/04/2010	6.37%		
12/03/2010	6.29%	23/04/2010	6.37%		
15/03/2010	6.31%	26/04/2010	6.40%		
16/03/2010	6.30%	27/04/2010	6.36%		
17/03/2010	6.31%	28/04/2010	6.44%		
18/03/2010	6.33%	29/04/2010	6.39%		
19/03/2010	6.24%	30/04/2010	6.34%		
22/03/2010	6.26%	03/05/2010	6.34%		
23/03/2010	6.28%	04/05/2010	6.25%		
24/03/2010	6.42%	05/05/2010	6.17%		
25/03/2010	6.52%	06/05/2010	6.02%		
26/03/2010	6.52%	07/05/2010	6.09%		
29/03/2010	6.50%	10/05/2010	6.18%		
30/03/2010	6.46%	11/05/2010	6.19%		
31/03/2010	6.42%	12/05/2010	6.21%		
01/04/2010	6.48%	13/05/2010	6.17%		
02/04/2010	6.52%	14/05/2010	6.09%		
05/04/2010	6.51%	17/05/2010	6.19%		
06/04/2010	6.47%	18/05/2010	5.96%		
07/04/2010	6.47%	19/05/2010	5.97%		
08/04/2010	6.49%	20/05/2010	5.87%		
07/04/2010	6.47%	21/05/2010	5.96%		
08/04/2010	6.49%	24/05/2010	5.88%		
09/04/2010	6.49%	25/05/2010	5.88%		

C.2.2 Moody's Baa Utility Bond Index

The Moody's Baa Utility Bond Index represents the average bond yields issued by utility companies having credit ratings from Baa1 to Baa3 and a minimum maturity of 20 years (Source: Bloomberg)					
01/03/2010	6.20%	13/04/2010	6.17%	26/05/2010	6.01%
02/03/2010	6.21%	14/04/2010	6.22%	27/05/2010	6.17%
03/03/2010	6.21%	15/04/2010	6.22%	28/05/2010	6.16%
04/03/2010	6.17%	16/04/2010	6.17%	**Average Yield**	**6.13%**
05/03/2010	6.25%	19/04/2010	6.19%		
08/03/2010	6.26%	20/04/2010	6.16%		
09/03/2010	6.27%	21/04/2010	6.09%		
10/03/2010	6.27%	22/04/2010	6.11%		
11/03/2010	6.24%	23/04/2010	6.14%		
12/03/2010	6.21%	26/04/2010	6.14%		
15/03/2010	6.22%	27/04/2010	6.03%		
16/03/2010	6.17%	28/04/2010	6.10%		
17/03/2010	6.14%	29/04/2010	6.05%		
18/03/2010	6.16%	30/04/2010	5.98%		
19/03/2010	6.16%	03/05/2010	6.01%		
22/03/2010	6.12%	04/05/2010	5.92%		
23/03/2010	6.14%	05/05/2010	5.89%		
24/03/2010	6.26%	06/05/2010	5.71%		
25/03/2010	6.32%	07/05/2010	5.88%		
26/03/2010	6.30%	10/05/2010	6.01%		
29/03/2010	6.31%	11/05/2010	6.05%		
30/03/2010	6.30%	12/05/2010	6.10%		
31/03/2010	6.25%	13/05/2010	6.08%		
01/04/2010	6.26%	14/05/2010	5.95%		
02/04/2010	6.33%	17/05/2010	5.99%		
05/04/2010	6.37%	18/05/2010	5.93%		
06/04/2010	6.37%	19/05/2010	5.93%		
07/04/2010	6.26%	20/05/2010	5.90%		
08/04/2010	6.28%	21/05/2010	5.87%		
09/04/2010	6.26%	24/05/2010	5.93%		
12/04/2010	6.21%	25/05/2010	5.91%		

C.2.3 US Federal Reserve Treasury Bond

A 30 year US Federal Reserve Treasury Bond issued in 2000 and maturing 2030 (Source: Bloomberg)					
01/03/2010	4.40%	14/04/2010	4.56%	28/05/2010	4.03%
02/03/2010	4.40%	15/04/2010	4.54%	31/05/2010	4.02%
03/03/2010	4.42%	16/04/2010	4.49%	**Average Yield**	**4.37%**
04/03/2010	4.39%	19/04/2010	4.51%		
05/03/2010	4.48%	20/04/2010	4.50%		
08/03/2010	4.52%	21/04/2010	4.44%		
09/03/2010	4.51%	22/04/2010	4.46%		
10/03/2010	4.53%	23/04/2010	4.48%		
11/03/2010	4.51%	26/04/2010	4.49%		
12/03/2010	4.46%	27/04/2010	4.39%		
15/03/2010	4.47%	28/04/2010	4.44%		
16/03/2010	4.42%	29/04/2010	4.40%		
17/03/2010	4.40%	30/04/2010	4.33%		
18/03/2010	4.42%	03/05/2010	4.35%		
19/03/2010	4.40%	04/05/2010	4.23%		
22/03/2010	4.40%	05/05/2010	4.21%		
23/03/2010	4.43%	06/05/2010	4.02%		
24/03/2010	4.56%	07/05/2010	4.10%		
25/03/2010	4.59%	10/05/2010	4.22%		
26/03/2010	4.58%	11/05/2010	4.22%		
29/03/2010	4.59%	12/05/2010	4.28%		
30/03/2010	4.57%	13/05/2010	4.22%		
31/03/2010	4.54%	14/05/2010	4.14%		
01/04/2010	4.55%	17/05/2010	4.17%		
02/04/2010	4.63%	18/05/2010	4.04%		
05/04/2010	4.67%	19/05/2010	4.06%		
06/04/2010	4.66%	20/05/2010	3.90%		
07/04/2010	4.57%	21/05/2010	3.92%		
08/04/2010	4.58%	24/05/2010	3.91%		
09/04/2010	4.57%	25/05/2010	3.88%		
12/04/2010	4.52%	26/05/2010	3.91%		
13/04/2010	4.51%	27/05/2010	4.07%		

Appendix D: Financial Data of Comparator Companies

Financial Ratios

	Equity Beta[1]	D/ Market E[2]	Tax Rate[3]	Asset Beta[4]	S&P Credit Rating[5]
Simple Arithmetic Mean		**0.520**		**0.545**	
Scottish & Southern Energy plc	0.771	0.286	28.0%	0.639	A- (as of 04/19/04)
TransAlta Corp	0.815	0.629	29.0%	0.563	BBB (as of 02/06/09)
Capital Power Income LP	0.625	0.646	31.0%	0.432	BBB+ (as of 05/07/07)

5 yr Capital Structure of Comparator Companies

(in millions and local trading currencies taken at end of reporting year)

Scottish & Southern Energy plc *(LC: GBP)*	**2009**	**2008**	**2007**	**2006**	**2005**
Market Value of Equity	10,732	12,768	12,452	9,343	8,423
Book Value of Debt	5,396	3,921	2,279	2,215	1,681
Debt to Equity Ratio	0.503	0.307	0.183	0.237	0.200
5 yr Debt to Equity Ratio Average	0.286				

TransAlta Corp *(LC: CAD)*	**2009**	**2008**	**2007**	**2006**	**2005**
Market Value of Equity	5,070	3,797	6,797	4,896	4,692
Book Value of Debt	4,442	2,808	2,510	2,758	2,793
Debt to Equity Ratio	0.876	0.740	0.369	0.563	0.595
5 yr Debt to Equity Ratio Average	0.629				

Capital Power Income LP *(LC: CAD)*	**2009**	**2008**	**2007**	**2006**	**2005**
Market Value of Equity	922	843	1,195	1,307	1,636
Book Value of Debt	721	800	620	934	437
Debt to Equity Ratio	0.782	0.948	0.519	0.715	0.267
5 yr Debt to Equity Ratio Average	0.646				

1. Equity betas are adjusted equity betas as sourced from Bloomberg.
2. Debt to equity is calculated using the average debt to equity for the past five reporting years as sourced from Capital IQ.
3. Tax rates have been sourced from annual reports.
4. Asset Beta is calculated using the formula = β_{equity} / (1 + (1 - T_c) * D/E). Where β_{equity} is the adjusted equity beta, T_c is the corporate tax rate and D/E is the debt to market equity of the comparator.
5. Credit ratings are sourced from Standard and Poor's.

Appendix E: US Gas Plant Construction 2009/2010

Year	Plant Name	Planned Capacity (MW)[33]	Owner (Joint Owner)	Ownership	S&P Rating	Moody's Rating
2010	Buck CC	620	Duke Energy Corporation	100%	A-	Baa2
2010	Antelope Station	169	Golden Spread Electric Cooperative	100%	A	A3
2010	Middletown Peaking	200	NRG Energy, Inc (UIL Corporation)	50% (50%)	BB- (BBB)	(Baa3)
2009	Chouteau 2	540	Associated Electric Cooperative Inc.	100%	-	A2
2009	Delta Power Project	1,125	Pepco Holdings, Inc.	100%	BBB	Baa3
2009	Mill Creek Generating Unit	194	North Western Corporation	100%	BBB	-
2009	Hunlock Repowering	130	UGI Corporation	100%	-	-
2009	El Segundo Repowering	670	NRG Energy, Inc.	100%	BB-	-
2009	Cleveland CT	720	Southern Company	100%	A	-
2009	Coolidge Generating Station	575	TransCanada Corporation	100%	A-	Baa1
2009	Devon Peaking	200	NRG Energy, Inc (UIL Corporation)	50% (50%)	BB- (BBB)	(Baa3)

Source: SNL Financial

[33] Only plants with a planned capacity of greater than 100MW were included in the review.

Year	Plant Name	Additional Information on Arranged Off take Agreements and Plant Financing
2010	Buck CC	The Buck CC plant is planned to sell into a regulated market. It does not appear to be project financed.
2010	Antelope Station	The Antelope Station will provide the quick start backstop generation needed to allow greater integration of wind into Golden Spread's portfolio. It will also sell into non-regulated markets SPP and ERCOT. The 2009 company report explains the financing of the project as follows, "These assets were financed through cash generated from operations and constitute bondable additions under the Golden Spread indenture."
2010	Middletown Peaking	The Middletown Peaking plant has long term contracts in place. NRG's 2009 10-K states, "In a procurement process conducted by the Department of Public Utility Control, or DPUC, and finalized in 2008, GenConn Energy, or GenConn, a 50⁄50 joint venture of NRG and The United Illuminating Company, secured contracts in 2008 with Connecticut Light & Power, or CL&P, for the construction and operation of two 200 MW peaking facilities, at NRG's Devon and Middletown sites in Connecticut. The contracts, which are structured as contracts for differences for the operation of the new power plants, have a 30-year term and call for commercial operation of the Devon project by June 1, 2010, and the Middletown project by June 1, 2011." GenConn closed on $534 million of project financing related to this project. The project financing includes a seven-year project backed term loan and a five-year working capital facility which together total $291 million. In addition, NRG and United Illuminating have each closed an equity bridge loan of $121.5 million, which together total $243 million.
2009	Chouteau 2	The Chouteau 2 plant is planned to sell into a regulated market. On July 7 2009, Associated Electric Cooperative Inc received a $490 million loan guarantee in relation to its construction, though this was received after construction had begun.
2009	Delta Power Project	The Delta Power Project has a six year tolling agreement in place with Constellation (energy, capacity, and ancillary services). The plant is not project financed, as referenced in the 10-K of Conectiv Energy (who were at that time owned by Pepco Holdings), "Conectiv Energy is constructing a natural gas and oil-fired combined-cycle electricity generation plant in Peach Bottom Township, Pennsylvania (Delta Project). The total construction expenditures including capitalized interest for the Delta Project are expected to be $470 million, of which $178 million was expended in 2009, $62 million in 2008 and $63 million in 2007. Projected expenditures of $147 million in 2010 and $20 million in 2011 are included in Conectiv Energy's projected capital expenditures."
2009	Mill Creek Generating	The Mill Creek plant represents a regulated investment by NorthWestern to meet growing load obligations.

Year	Plant Name	Additional Information on Arranged Off take Agreements and Plant Financing
2009	Hunlock Repowering	The Hunlock plant, post repowering, is planned to sell the majority of its capacity into an unregulated spot market. It does not appear to be project financed, where the 2009 form 10k of UGI states, "2009 capital expenditures were financed in large part by capital contributions from UGI Energy Services' expenditures, principally relating to its Hunlock Station repowering project and an LNG storage expansion. In Fiscal 2010, projects are expected to be financed from capital contributions from UGI and bank borrowings. In addition, during Fiscal 2011 and Fiscal 2012, Energy Services expects to spend a total of approximately $90 million associated with these projects, an amount expected to be similarly financed."
2009	El Segundo Repowering	According to the 2009 NRG Form 10-K, "The El Segundo repowering project has been selected and contracted by a load-serving entity and is in the final stages of permitting. The project is planned to be in operation in the summer of 2013". This contract is for 80% of its capacity. With regards to financing, some uncertainty remains: "NRG currently intends to develop and finance the more capital intensive, solid fuel-fired projects included in the Repowering NRG program on a non-recourse or limited recourse basis through separate project financed entities and intends to seek additional investments in most of these projects from third parties... NRG may also decide to develop and finance some of the projects, such as smaller gas-fired and renewable projects, using corporate financial resources rather than non-recourse debt..."
2009	Cleveland CT	The Cleveland CT is planned to be a non-regulated merchant plant. It has long-term contracts in place with the North Carolina Electric Membership Corp (MCEMC) and North Carolina Municipal Power Agency Number 1 (NCMPA1). This is reflected in the owner's 2009 Form 10-K, "The Company has entered into long-term PPAs for 540 MWs of the generating capacity of the plant." 360 MW are contracted with NCEMC through 12/2035, 180 MW contracted with NCMPA1 through 12/2031. Only 720MW of the 1080MW planned are currently under construction. The project is not expected to feature project financing, as mentioned in the 2009 10-K, "The units are expected to begin commercial operation in 2012. Costs incurred through December 31, 2009 were $62.7 million. The total estimated construction cost is expected to be between $350 million and $400 million, which is included in the capital program estimates..."
2009	Coolidge Generating Station	The Coolidge Generating Station has in place a 20 yr PPA with Salt River Project for 100% of its output. It is not projected financed.
2009	Devon Peaking	Long-term contracts are in place for the Devon Peaking plant, as for the Middletown plant. Contract and financing details are described above in the notes on plant #3 (Middletown Peaking).

Appendix F: Technical Performance Analysis

Performance analysis of new entrant "F" class CCGT units has been undertaken using the GTPro and GTMaster software suite Version 20. Analyses have been made based on optimisation at the site average ambient and cooling water conditions. Representative performance parameters as calculated are shown in the following figures:

Figure 17 Performance analysis - Alstom "F" class CCGT, clean-as-new

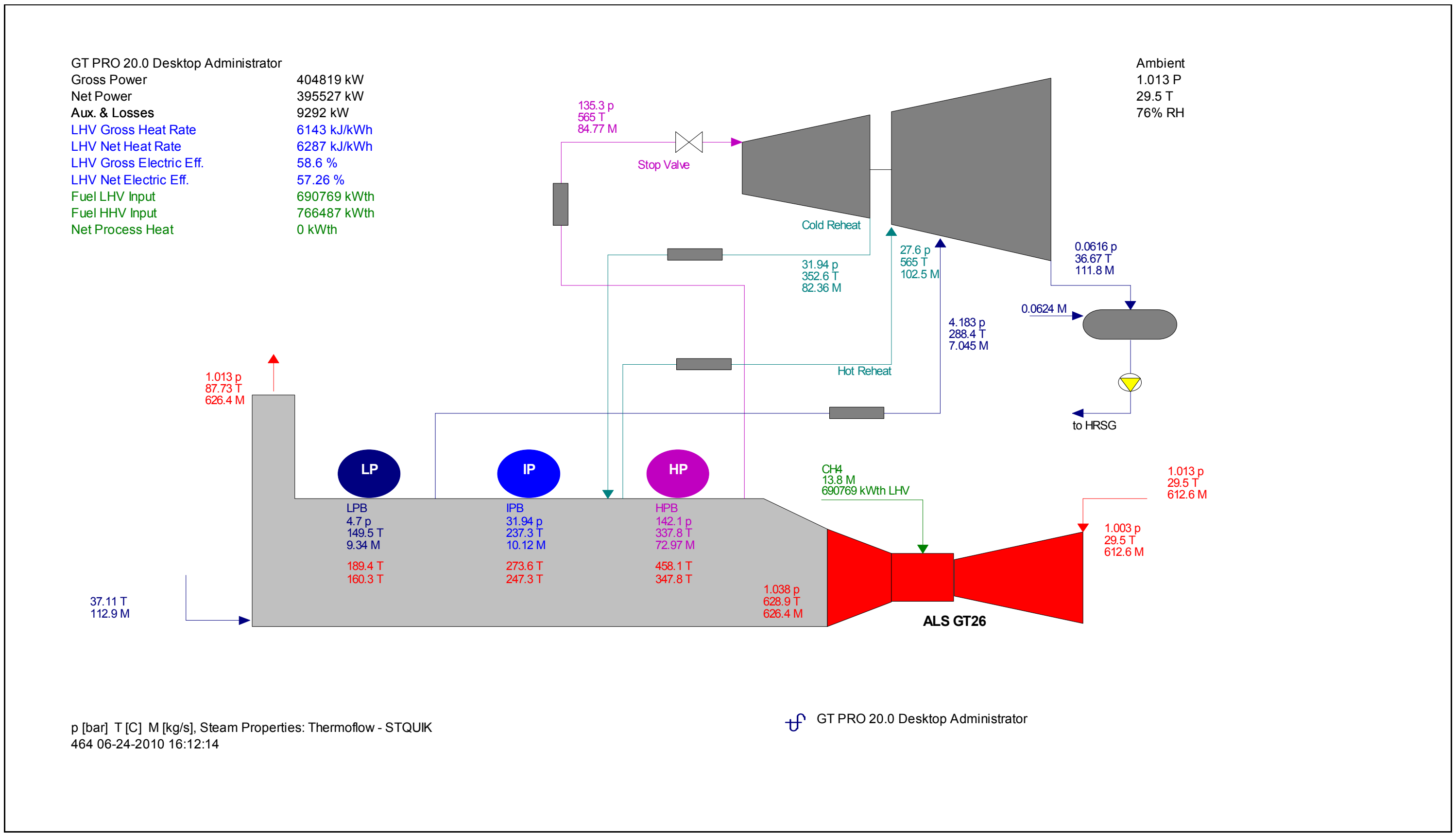


Figure 18 Performance analysis - GE "F" class CCGT, clean-as-new

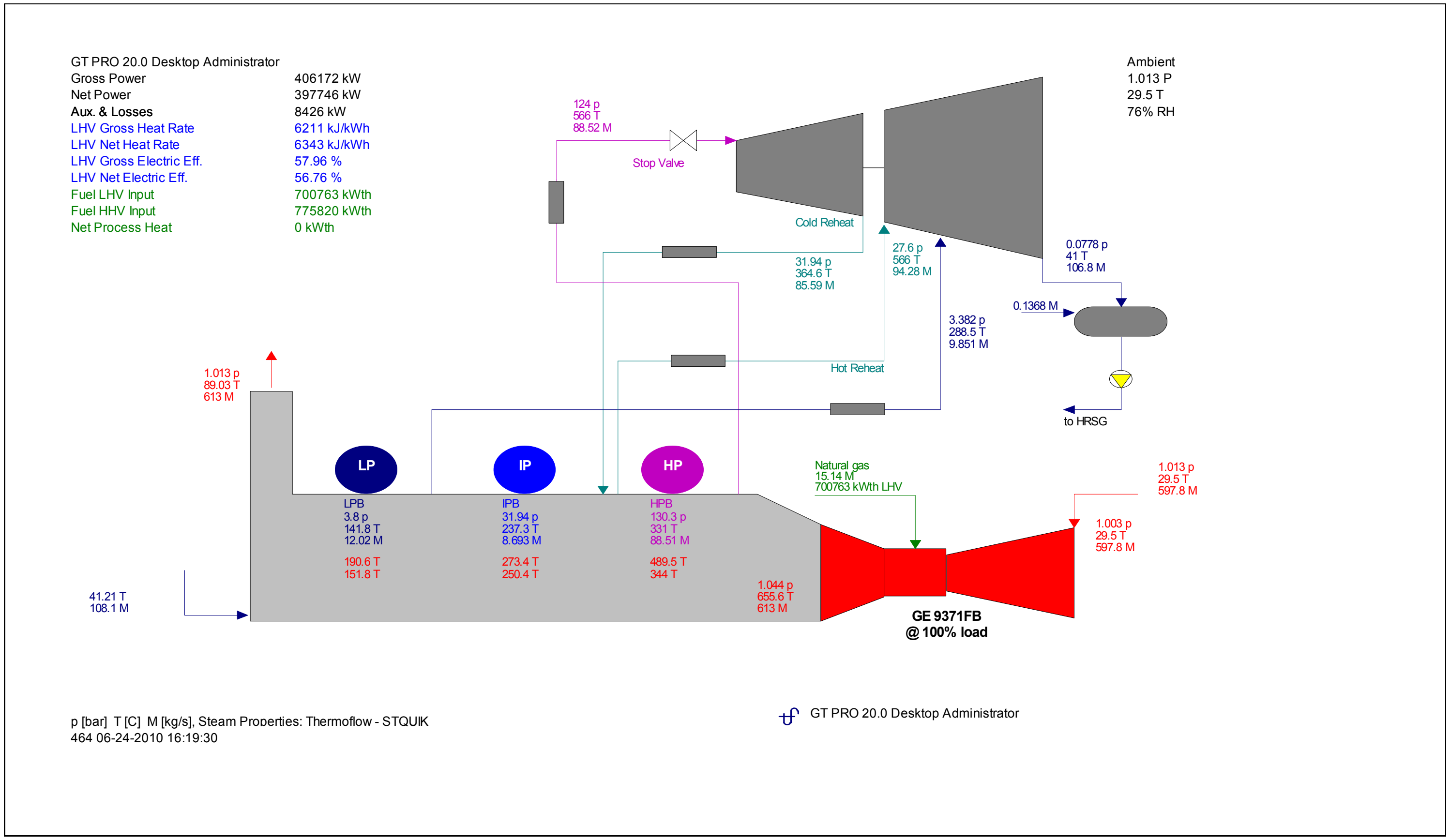


Figure 19 Performance analysis - Mitsubishi "F" class CCGT, clean-as-new

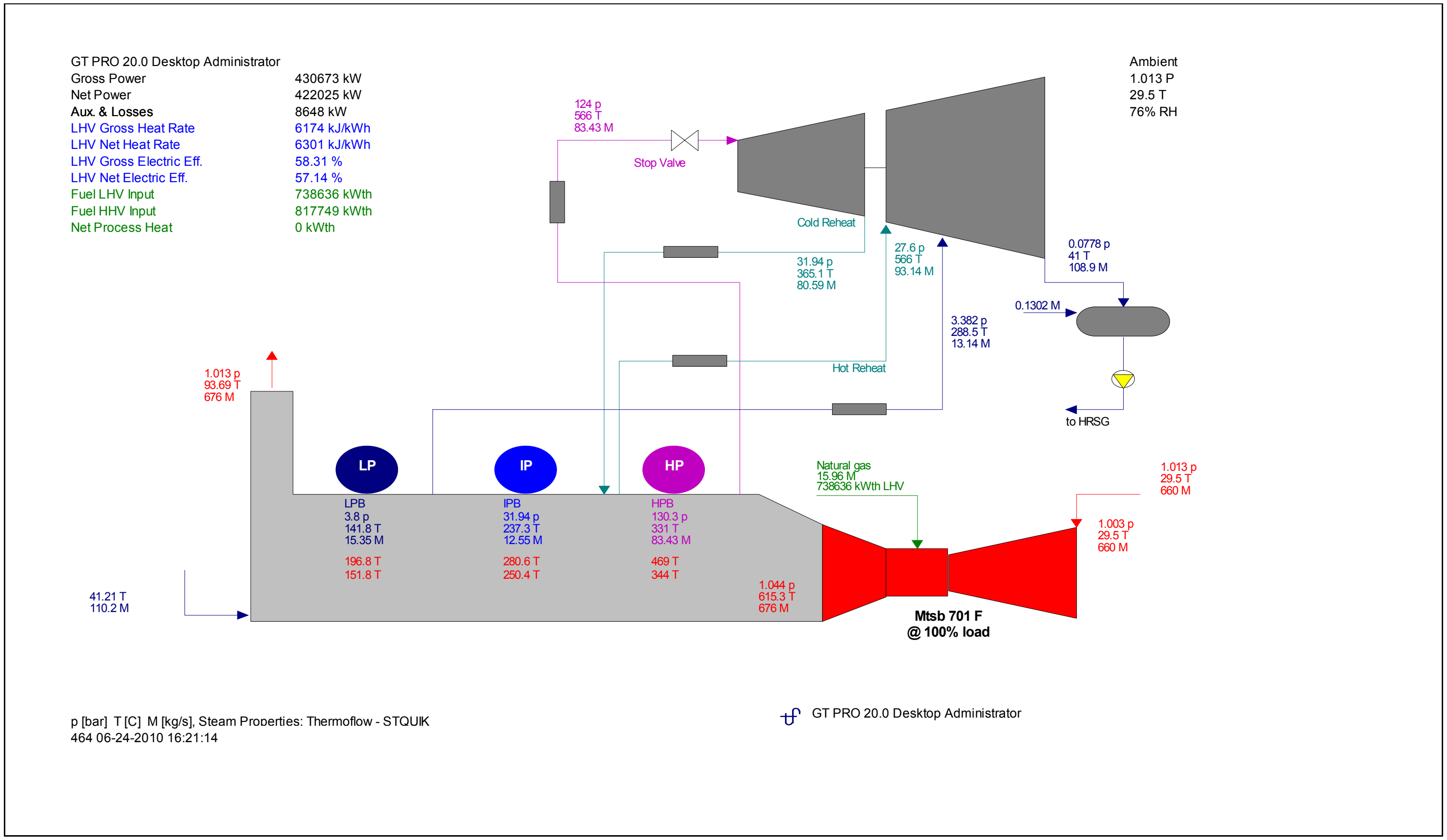
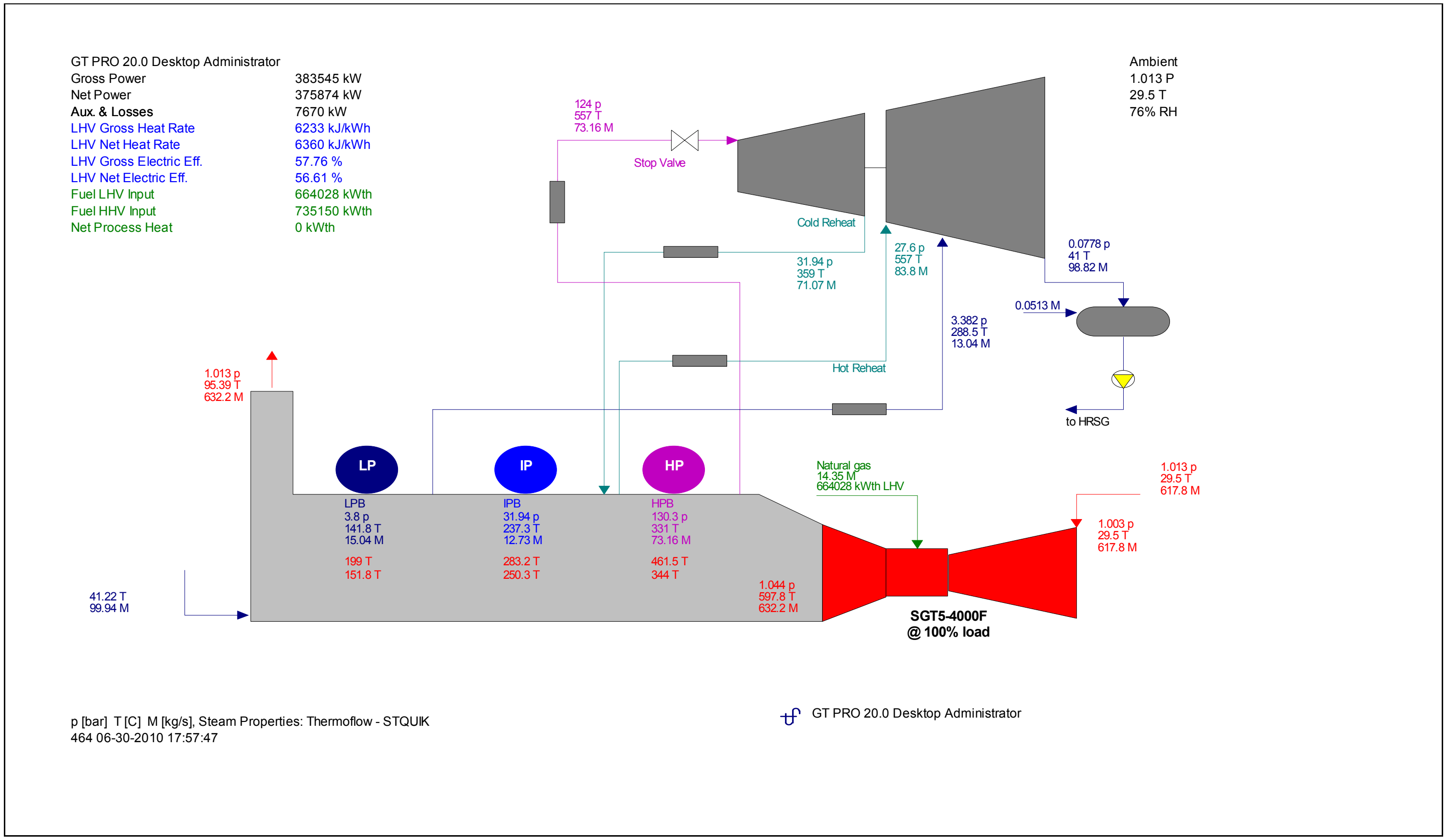


Figure 20 Performance analysis - Siemens "F" class CCGT, clean-as-new



Appendix G: Degradation

The degradation allowances in each year including non-recoverable and recoverable factors are shown below. The average degradation amounts, weighted by the discount factor for each year shown below, are 2.42% and 1.75% for power and heat rate degradation respectively.

Year	Non-recov: Power degr	Non-recov: HR degr	Recov - Power degr	Recov - HR degr	Total-Power degr	Total-HR degr	Factor-Power degr	Factor-HR degr	Disc factor (WACC = 6.37%)
1	0.1%	0.1%	1.0%	0.5%	1.1%	0.6%	98.9%	100.6%	1
2	0.6%	0.5%	1.0%	0.5%	1.6%	1.0%	98.4%	101.0%	0.940083
3	1.0%	0.9%	1.0%	0.5%	2.0%	1.4%	98.0%	101.4%	0.883756
4	1.4%	1.3%	1.0%	0.5%	2.4%	1.8%	97.6%	101.8%	0.830804
5	1.8%	1.6%	1.0%	0.5%	2.8%	2.1%	97.2%	102.1%	0.781025
6	2.0%	1.7%	1.0%	0.5%	3.0%	2.2%	97.0%	102.2%	0.734228
7	2.0%	1.8%	1.0%	0.5%	3.0%	2.3%	97.0%	102.3%	0.690235
8	1.0%	0.8%	1.0%	0.5%	2.0%	1.3%	98.0%	101.3%	0.648878
9	1.4%	1.2%	1.0%	0.5%	2.4%	1.7%	97.6%	101.7%	0.609999
10	1.7%	1.5%	1.0%	0.5%	2.7%	2.0%	97.3%	102.0%	0.57345
11	2.0%	1.7%	1.0%	0.5%	3.0%	2.2%	97.0%	102.2%	0.539091
12	2.0%	1.8%	1.0%	0.5%	3.0%	2.3%	97.0%	102.3%	0.50679
13	2.0%	1.8%	1.0%	0.5%	3.0%	2.3%	97.0%	102.3%	0.476425
14	1.2%	1.0%	1.0%	0.5%	2.2%	1.5%	97.8%	101.5%	0.447879
15	1.2%	1.0%	1.0%	0.5%	2.2%	1.5%	97.8%	101.5%	0.421043
16	1.6%	1.4%	1.0%	0.5%	2.6%	1.9%	97.4%	101.9%	0.395815
17	1.9%	1.7%	1.0%	0.5%	2.9%	2.2%	97.1%	102.2%	0.372099
18	2.0%	1.8%	1.0%	0.5%	3.0%	2.3%	97.0%	102.3%	0.349804
19	2.0%	1.8%	1.0%	0.5%	3.0%	2.3%	97.0%	102.3%	0.328845
20	1.7%	1.5%	1.0%	0.5%	2.7%	2.0%	97.3%	102.0%	0.309142
21	1.0%	0.9%	1.0%	0.5%	2.0%	1.4%	98.0%	101.4%	0.290619
22	1.4%	1.3%	1.0%	0.5%	2.4%	1.8%	97.6%	101.8%	0.273206
23	1.8%	1.6%	1.0%	0.5%	2.8%	2.1%	97.2%	102.1%	0.256836
24	2.0%	1.7%	1.0%	0.5%	3.0%	2.2%	97.0%	102.2%	0.241447
Wt. avg					2.42%	1.75%			

These allowances can be compared with the allowances in the previous reports. These are shown below. The data in the previous reports are based on the assumption of a "zero-hour" service occurring after Year 12. In the current analysis this is not assumed, instead a normal Major Overhaul service is assumed. In a normal Major Overhaul approximately $^{2}/_{3}$rds only of the degradation is recovered. However, degradation rates when new are much faster than degradation rates later in the cycle and the net effect is to bring forward the degradation profile by one year.

Year	Power	HR	Adjusted - Power	Adjusted - HR	Disc factor (WACC = 6.37%)
1	1%	0.65%	1%	0.65%	1
2	2.16%	1.38%	2.16%	1.38%	0.940083
3	2.48%	1.57%	2.48%	1.57%	0.883756
4	2.71%	1.70%	2.71%	1.70%	0.830804
5	2.86%	1.78%	2.86%	1.78%	0.781025
6	2.94%	1.83%	2.94%	1.83%	0.734228
7	3.02%	1.88%	3.02%	1.88%	0.690235
8	3.11%	1.92%	3.11%	1.92%	0.648878
9	3.19%	1.97%	3.19%	1.97%	0.609999
10	3.27%	2.02%	3.27%	2.02%	0.57345
11	3.36%	2.07%	3.36%	2.07%	0.539091
12	3.44%	2.11%	3.44%	2.11%	0.50679
13	1%	0.65%	2.16%	1.38%	0.476425
14	2.16%	1.38%	2.48%	1.57%	0.447879
15	2.48%	1.57%	2.71%	1.70%	0.421043
16	3%	1.70%	2.86%	1.78%	0.395815
17	2.86%	1.78%	2.94%	1.83%	0.372099
18	2.94%	1.83%	3.02%	1.88%	0.349804
19	3.02%	1.88%	3.11%	1.92%	0.328845
20	3.11%	1.92%	3.19%	1.97%	0.309142
21	3.19%	1.97%	3.27%	2.02%	0.290619
22	3.27%	2.02%	3.36%	2.07%	0.273206
23	3.36%	2.07%	3.44%	2.11%	0.256836
24	3.44%	2.11%	3.44%	2.11%	0.241447
Wt. average	2.7%	1.667%	2.752%	1.716%	

The degradation rates applied in the present analysis are not materially different from those of the earlier reports.

Appendix H: Approaches used to assess the Market Risk Premium

Approach	Resulting Market Risk Premium
Forward looking Dividend Discount Model	8.13%
Historical Premium Approach (Geometric Mean)	4.51%
Historical Premium Approach (Arithmetic Mean)	8.12%
"Volatility Adjusted" Approach (Geometric Mean)[34]	6.47%
"Volatility Adjusted" Approach (Arithmetic Mean)	9.10%
Local Benchmarks[35]	6.00%
UK Regulator	4.50% to 5.00%
Australian Regulator	6.50%

Sources: Bloomberg, Singapore Government Securities, Ibbotson, and Annual and Regulatory Reports

The resulting market risk premium of 7.0% was the midpoint of the identified range of possible values, 5% to 9%.

[34] The Volatility Adjusted approach is determined using the Relative Equity Market Standard Deviation method.

[35] Local benchmarks include Singapore listed companies SembCorp (6.00%), Keppel (6.00%) and CapitaLand (5.00%)

Appendix I: CPI Data

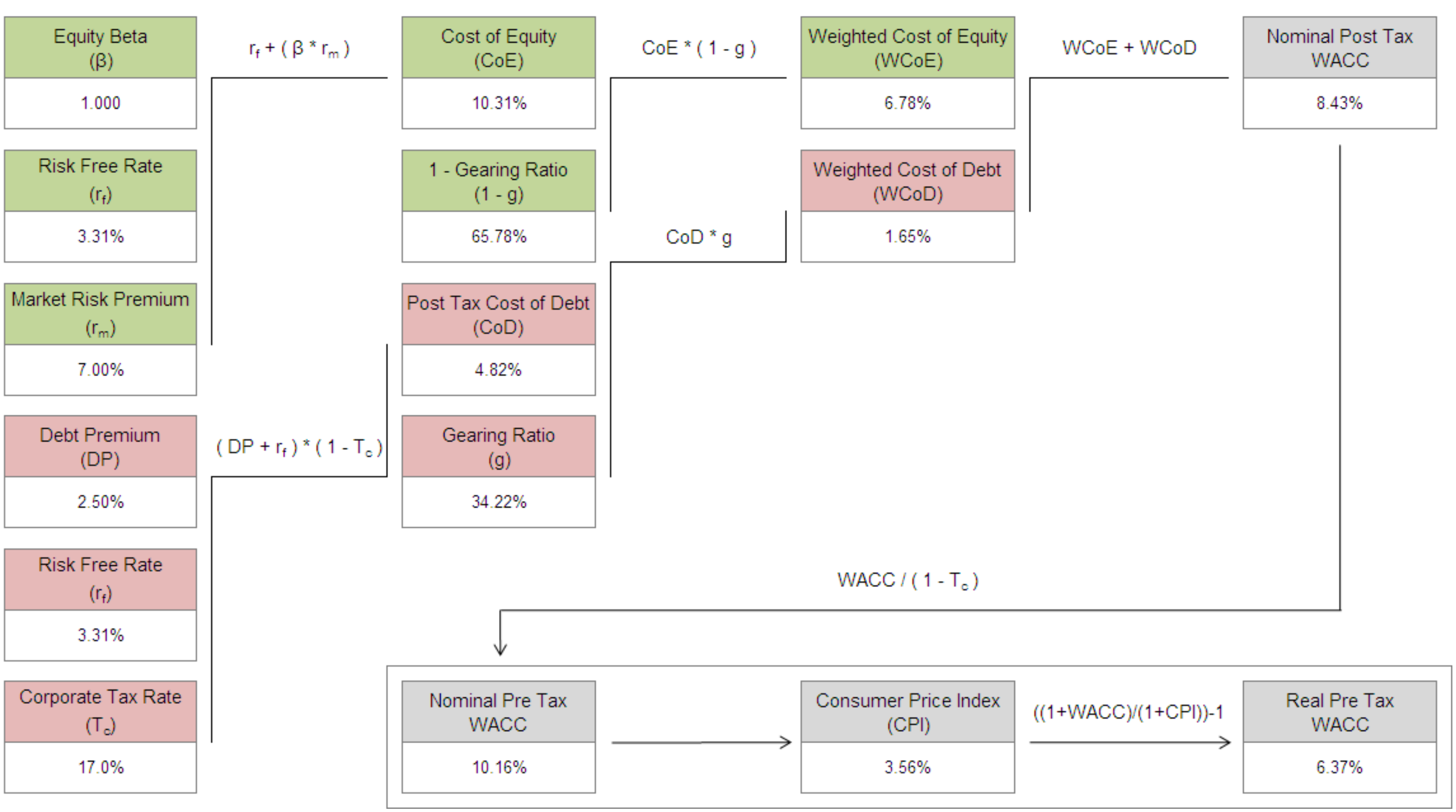
CPI indices have been sourced from monthly Singapore Department of Statistics News Releases (at http://www.singstat.gov.sg/stats/latestdata.html). The "All items" index for the months from Dec 2008 to May 2010 is shown below. The base date for the reported CPI index changed from Dec 2009 onwards and the indices prior to that time have been adjusted to the current base (Dec 2009=100).

Month	Index from Sing Stats (2004 = 100)	Index from Sing Stats (2009=100)	CPI index, base Dec 2009=100)	Year-on-year change
Dec-08	111.3		100.1	
Jan-09	111.2		100.0	
Feb-09	110.6		99.5	
Mar-09	110.2		99.1	
Apr-09	109		98.0	
May-09	109.7		98.7	
Jun-09	109.1		98.1	
Jul-09	110.4		99.3	
Aug-09	110.9		99.7	
Sep-09	110.7		99.6	
Oct-09	111.4		100.2	
Nov-09	111.8		100.5	
Dec-09	111.2	100	100	-0.09%
Jan-10		100.8	100.8	0.80%
Feb-10		101.2	101.2	1.75%
Mar-10		101.3	101.3	2.22%
Apr-10		102.2	102.2	4.26%
May-10		102.8	102.8	4.21%

The average year-on-year change for the months of March, April and May 2010 is 3.56%.

Appendix J: Summary of Pre and Post Tax WACC Calculation

WACC Calculation Tree



Appendix K: Change in WACC Resulting from the Inclusion of Non-Investment Grade Companies in the Comparator Panel

The criteria used in selecting the comparator panel for this review excluded companies with non-investment grade credit ratings. If the criteria were adjusted to allow non-investment grade companies, the panel would have included International Power and NRG, the only other companies that passed all other filters. The table below compares the financial parameters and WACC value under the existing panel versus the same metrics if the panel included these companies.

WACC Parameters

		Excluding Non-Investment Grade Companies	Including Non-Investment Grade Companies	%Change in Parameters Resulting from Inclusion of Non-Investment Grade Companies	Calculation Key
a	Risk-Free Rate (%)	3.31%	3.31%	-	
b	Corporate Tax Rate (%)	17.0%	17.0%	-	
c	Equity Beta	1.000	1.000	-	
d	Market Risk Premium (%)	7.0%	7.0%	-	
e	Median Credit Rating	BBB-	BBB-		
f	Debt Premium (%)	2.50%	2.50%	-	
g	Cost of Equity (%)	10.31%	10.31%	-	= a + (c * d)
h	Post Tax Cost of Debt (%)	4.82%	4.82%	-	= (a + f) * (1 - b)
i	Gearing	0.342	0.434	26.80%	
j	**Post-Tax WACC (%)**	**8.43%**	**7.93%**	**-5.97%**	= (g * (1 - i)) + (h * i)

Comparator Panel Including Non-Investment Grade Companies

	Asset Beta	Debt / Market E	Credit Rating
Simple Arithmetic Mean	**0.563**	**0.767**	
Median Credit Rating			**BBB**
Scottish & Southern Energy plc	0.633	0.286	A-
Capital Power Income LP	0.432	0.646	BBB+
TransAlta Corp	0.563	0.629	BBB
International Power plc	0.651	1.191	BB
NRG Energy Inc	0.535	1.081	BB-

Appendix L: Comparison with the Methodologies and Assumptions used in the Previous Review

WACC Parameters	Previous Review (2009 - 2010)	Proposed Review (2011 - 2012)	Comments
Risk-Free Rate (%)	3.55	3.31	Additional Criteria was used to determine the selection of comparator companies - Credit rating must be investment grade: companies rated below BBB- will be excluded. A company's debt premium will of course be impacted by its credit rating. Worldwide credit markets remained constrained - the resulting "flight to quality" will increase bond spreads and make access to debt difficult for non-investment grade companies. The debt premium used in the 2009 review was determined by benchmarking against the debt spread of 10-year utility bonds, sourced from the BondsOnline Group. This review has instead used the spread of 20-year utility bonds, represented by the average of the Bloomberg and Moody's utility indices over a risk-free government rate. The 20-year term of debt was chosen as that closest to the economic life of the plant. The Bloomberg and Moody's indices were chosen because these indices only include bonds whose minimum maturity is also 20 years.
Debt Premium (%)	5.5	2.5	
Cost of Debt (%)	9.1	5.8	
Market Risk Premium (%)	7	7	
Equity Beta	1.08	1.00	
Cost of Equity (%)	11.1	10.3	
Gearing	0.50	0.342	
Corporate Tax Rate (%)	18	17	
Post-Tax WACC (%) - Nominal Terms	**9.25**	**8.43**	

Technical Parameters	Previous Review (2009 - 2010)	Proposed Review (2011 - 2012)	Comments
Net Capacity of a new unit (MW)	359	381	
HHV Heat Rate (Btu/kWh)	7,085	7,010	
Build Duration (months)	30	30	
Economic Life (years)	20	24	
Plant Utilisation Factor (%)	74.0	74.9	Based on historical plant load factor from June 2009 to May 2010 (Senoko Energy's CCP 3 to 5, PowerSeraya's CCP 1 to 2 and Tuas Power Generation's CCP 1 to 4). Station load has been accounted for in the determination of the plant load factor.

Technical Parameters	Previous Review (2009 - 2010)	Proposed Review (2011 - 2012)	Comments
1. Capital Cost of a new unit (S$Million)	466.6	559.2	In the 2009 review, the Gas Turbine World Handbook was used to estimate the cost of the primary generation equipment. The Power Island Equipment Only FOB costs applied in 2009 were averaged to USD547/kW from the 2009 Handbook. The 2010 Handbook has changed the form of quoting CCGT costs to "turnkey budget prices for total plant including BOP and construction". Despite this much larger scope, the price indicated for comparative plant has reduced to under USD500/kW. This is not considered a realistic reflection of turnkey prices in the market.
- Comprising of EPC costs (S$Million)	459.2	550.9	Including 11.07M for gas compression
a. Single gaseous fuel plant (S$Million)	308.9	292.4	
b. Dual fuel hot switching capability (S$MM)	9.85	6.6	
c. Transport cost (S$Million)	6.35		Not separately dissected.
d. Facility Costs (S$Million)	31.15	35.6	Used to be under land, infrastructure & development cost for the 2009-2010 Review and now have been re-classified for comparability with the current review.
e. Emergency fuel facilities (S$Million)	23.1	18.9	
f. Civil works, erection & assembly, detailed engineering and start-up costs (S$Million)	79.8	197.4	
- Discounted through life capital cost (S$ Million)	7.4	8.3	

Technical Parameters	Previous Review (2009 - 2010)	Proposed Review (2011 - 2012)	Comments
2. Land, infrastructure & Development Cost (S$million)	66.5	152.0	
Land and Site Preparation Cost (S$million) - Land lease cost, water front fees & Land preparation	13.3	13.65	
a. Land Lease Cost and Water Front Fees (S$ Million)	12.55	12.9	
b. Land Preparation (S$ Million)	0.75	0.75	
Connection and Installation Cost (S$million) - Standard Connection Charge and cost of 230 kV switchgear	34.1	38.25	
Miscellaneous Cost (S$million)	19.1	100.1	
a. Owner's costs after financial closure (S$ Million)	19.1	64.8	
b. Owner's costs prior to Financial Closure (S$ Million)	-	35.3	Additional cost item included.

Technical Parameters	Previous Review (2009 - 2010)	Proposed Review (2011 - 2012)	Comments
3. Fixed Annual Running Cost (S$million/year/unit) - Manpower and overheads, carrying cost for back-up fuel and maintenance	41(22.1 if LTSA treatment were the same as for the current review)	22.49 (35.4 if LTSA treatment were the same as the previous review)	Fixed Annual Running cost and Variable non-fuel cost for the current review have been additionally shown on the same basis as the alternative LTSA treatment for comparability with the current review. Long Term Service Agreement (LTSA) costs for gas turbine and steam turbine have been reclassified from fixed annual running cost to variable non-fuel cost for the current review.
4. Variable Non-fuel Cost (S$/MWh) - EMC Charges, PSO Charges, Average Annual License Fees and Consumables	1.05 (9.17 if LTSA treatment were the same as for the current review)	6.55 (1.45 if LTSA treatment were the same as the previous review)	
Vesting Price ($/MWh)	176.1	177.8	Based on Gas Price of $17.219/GJ used to set the vesting price for Q2 2010
Vesting Price ($/MWh) - Non-Fuel Component	47.3	50.4	Non-fuel component for the previous review (2009 – 2010) have been adjusted by the indexes, DSPI and CPI used to set the vesting price for Q2 2010
Vesting Price ($/MWh) - Fuel Component	128.8	127.4	

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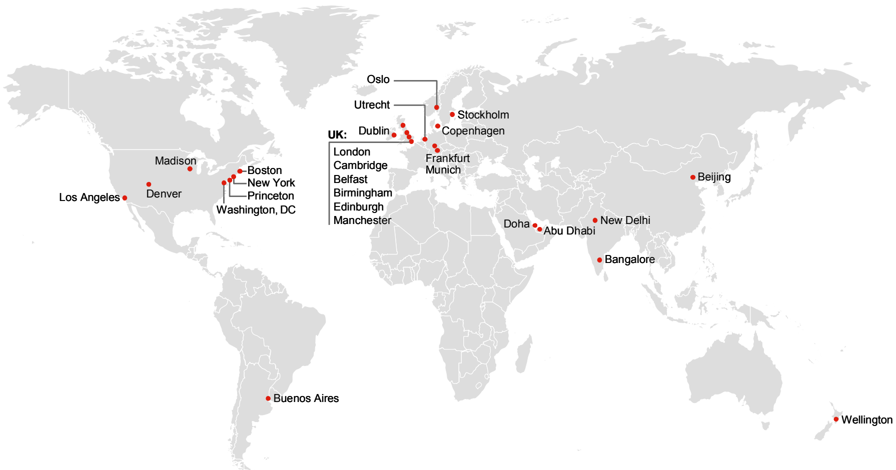

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