Parsons Brinckerhoff New Zealand Ltd

COST ESTIMATES FOR THERMAL PEAKING PLANT

"FINAL REPORT"

A report prepared for

Electricity Commission
Te Komihana Hiko

Version 2

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Report for the Benefit of Electricity Commission

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Limitations

This Report covers technical data relating to thermal generating plants and is based on the facts known to PB at the time of preparation. This Report does not purport to contain all relevant information for all plant. PB has made a number of assumptive statements throughout the Report, and the Report is accordingly subject to and qualified by those assumptions. This Report provides cost estimates for thermal peaking plant and is based on the information available in the public domain from previous investigations, specific plant and the facts known to PB at the time of preparation.

Parsons Brinckerhoff New Zealand Ltd.

Level 3, Revera House
48-54 Mulgrave Street
Wellington
Phone : 04 499 1000
Fax : 04 916 6514

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Appendices:

None.

Glossary of Terms

Term	Definition
Capex	Capital expenditure
EPC	Engineering Procurement Construction
MWh	mega watt hours (1,000,000 watt hours)
HV	High voltage
km	kilometre
kW	kilowatt
LRMC	Long Run Marginal Cost
LV	Low voltage
m	metres
M	million
MW	megawatt (1,000,000 watts)
MWh	Megawatt hour
NZEM	New Zealand Electricity Market
O&M	Operating and maintenance
SOO	Statement of Opportunities

Unless otherwise specified prices are in March 2008 real dollars

EXECUTIVE SUMMARY

Parsons Brinckerhoff New Zealand Ltd (PB) has been engaged to provide an estimate of the capital and O&M (operating and maintenance) costs associated with providing gas or liquid fuel turbine powered peaking plant in New Zealand. The review has included:

- The gathering and review of information available in the public domain on thermal peaking plant costs.
- The gathering and review of information internally available to Parson Brinckerhoff New Zealand Limited (PB) on thermal peaking plant costs.
- The completion of capital expenditure (Capex) and operating and maintenance expenditure (O&M) cost estimates for thermal peaking plant with nominal capacities of 40MW, 50MW, 100MW and 160MW.

The scope of the study included cost estimates for both liquid and gas fired peaking plant. The cost of gas compressors for gas fuelled engines and the cost of liquid fuel systems (tanks, pumps, unloading station, civil works etc.) are approximately the same for units of the target power ranges, and therefore the same capital cost estimate can be used for both cases. A summary of the cost estimates is provided in Table 1.

Table 1: Summary of thermal peaking plant cost estimates

Scheme	Engine type	Output (MW)	Capital cost ($/kW)	Fixed O&M ($/kW/Year)	Variable O&M ($/MWh/Year)
Gas fired peaking plant (40MW option)	GE Frame 6B (6581B)	42	1,227	14	6
Gas fired peaking plant (50MW option)	GE LM6000 PC Sprint	47	1,376	14	10
Gas fired peaking plant (100MW option)	GE 9171E W/I	128	916	14	6
Gas fired peaking plant (160MW option)	Siemens SGT5 2000E	168	787	12	5.5
Liquid fuel peaking plant (40MW option)	GE Frame 6B (6581B)	42	1,227	14	7.2
Liquid fuel peaking plant (50MW option)	GE LM6000 PC Sprint	47	1,376	14	14
Liquid fuel peaking plant (100MW option)	GE 9171E W/I	128	916	14	7.2
Liquid fuel peaking plant (160MW option)	Siemens SGT5 2000E	168	787	12	7

The variable O&M cost estimates for the liquid fuel peaking plant options is higher due to the reduced operating hour intervals between scheduled maintenance associated with operating an engine on liquid fuels.

1. INTRODUCTION

1.1 BACKGROUND

The Electricity Commission (Commission) has requested PB to provide an estimate of the capital and operating and maintenance (O&M) costs associated with delivering gas or liquid powered peaking capability in New Zealand.

1.2 REPORT OBJECTIVES AND SCOPE

Originally, capital and O&M cost estimates were required for peaking plant located in greenfield sites close to existing transmission connections. Six variants of peaking plant options were to be included in the cost estimation process. These options were identified as follows:

- 50MW gas fired peaking plant in Taranaki
- 100 MW gas fired peaking plant in Taranaki
- 50MW oil fired peaking plant near Auckland
- 100MW oil fired peaking plant near Auckland
- 50MW oil fired peaking plant in central South Island
- 100MW oil fired peaking plant in central South Island

A subsequent revision to the project scope included the 40MW and 160MW options of the liquid and gas fired plant.

No consideration has been given to possible transmission or consenting costs for the peaking plant options. Fuel costs have not been included in the O&M cost estimates.

1.3 STRUCTURE OF THE REPORT

This report has been structured into 3 sections, followed by references. A review of the report findings is included in the Executive Summary above.

• Section 1	Introduction, report objectives and scope.
• Section 2	Cost estimating methodology
• Section 3	Cost estimates for plant options

2. COST ESTIMATING METHODOLOGY

In order to achieve the report's objectives there were two main activities:

- Information gathering
- Cost estimation of the identified plant options

2.1 INFORMATION GATHERING

Cost estimates have been derived from local and international sources and from PB's in-house data including those of PB Power. A complete list of references is included at the end of this report. In order to identify thermal peaking plant cost estimates, PB has relied on:

- information and data available in the public domain; and
- in-house knowledge and experience.

Primary sizing of gas turbines and compilation of performance and cost data is undertaken using Thermoflow's GTPRO/PEACE software. Thermoflow supply a suite of engineering tools that are established and recognised throughout the power generation industry. For this review, PB has used GT PRO for gas turbine performance calculations and PEACE for building up a table of cost estimates. The suite of software used is revision 18 which contains performance and cost information updated as per March 2008.

The Thermoflow data was cross checked using prices derived from the Gas Turbine World (GTW) handbook for the year 2007 to 2008. This handbook, issued in February 2008, is recognised for use in obtaining basic application type data and if used correctly can be accurate to within ±10%.

As a final cross check, the costs have been correlated with actual costs from peaking power plant where PB has up to date and accurate data. This cost data, which is mainly from projects within Australia and New Zealand, has been used to normalise the results to ensure regional variations have been applied correctly.

Statement of Opportunities

The Electricity Commission (Commission) is required to publish a Statement of Opportunities (SOO) to meet the requirements outlined in Part F of the Electricity Governance (2003) Rules, which sets out possible future scenarios for electricity supply and demand. This is designed to show the opportunities that may be available for investment in both transmission upgrades and transmission alternatives.

During 2005, the Commission developed an initial SOO which was published in printed form in July 2005. As part of the work in developing this initial SOO, Parsons Brinckerhoff New Zealand Ltd (PB) completed reports for the Commission that, amongst other things examined the capital and O&M costs of gas-fired OCGTs and CCGTs in New Zealand.

2.2 COST ESTIMATION BASIS FOR THE SELECTED PLANT OPTIONS

PB formed its own cost estimating methodology for thermal peaking plant based on existing public domain information and in-house experience.

The cost estimates include allowances for investigation and design, project management and design supervision during construction, all construction activities, all equipment supply and installation, and all ancillary work associated with affected services (e.g. state highway and local authority roads and bridges). Transmission, consenting and fuel costs have been excluded.

All prices are based on rates and conditions applying at March 2008. The following sub-sections provide an outline of items and assumptions incorporated within the cost estimates.

The basis for the cost estimation makes the following assumptions:

- A new development on a greenfield site but close to existing infrastructure.
- A capacity factor of 2% combined with 30 starts per year.
- Power plant capacity considered as 40MW, 50MW, 100MW and 160MW.
- Capable of operating on gas and/or liquid fuel.
- Exclude land, legal and consenting costs.
- Exclude grid connection costs.

- Assume connection is possible to a nearby transmission line.
- Assume connection is possible to a nearby gas fuel line – for gas fuelled plant.
- Assume plant is located close to fuel supply for liquid fuelled plant.
- Assume to be contracted on a full engineering, procurement and construction (EPC) basis.

2.2.1 Capital cost estimation

PB has undertaken the following steps to build up and cross check the capital cost:

- Review gas turbine makes and models with the required capacity which are suitable for peaking duty and are currently available.
- Choose one from each power range and build up a table of capital costs using data from recognised and reliable sources.

2.2.2 Fixed and variable O&M costs

PB has undertaken the following steps to build up and cross check the O&M cost estimates:

- Make assumptions on the major operating factors affecting the level of O&M costs of the plant options selected given typical operating regimes.
- Build up a table of fixed and variable O&M costs based on the assumed operating regime of 2% capacity factor and 30 starts per year with an average duration of 6 hours operation.

3. PEAKING PLANT COST ESTIMATES

3.1 INITIAL ENGINE SELECTION

GTPRO was used to select the three most suitable engines within the target 40MW, 50MW, 100MW and 160MW power ranges. An initial high level costing exercise was undertaken to select the engine from each power range which had the lowest capital cost. The range around the target capacity was expanded until three suitable options were found.

The initial selection is as per the table below with the engine having the lowest cost in terms of $/kW being chosen for the detailed review. To ensure a consistent and lowest cost approach it has been assumed that a single engine is used in each of the power plants.

Table 3-1 : Engine makes and models considered

	kW(e)	US$/kW	Start up time
Nominal Capacity 40MWe			
GE Frame 6B DLN	42,100	931	~ 20 minutes
GE LM6000 PC	43,500	966	~ 10 minutes
GE LM6000 PD	42,750	1006	~ 10 minutes
Nominal Capacity 50MWe			
GE LM6000 PC Sprint	47,182	930	~ 10 minutes
Siemens SGT 800	47,000	949	~ 10 minutes
P&W FT8 Twin Pac 50	50,300	954	~ 10 minutes
Nominal Capacity 100MWe			
GE 9171E W/I	128,300	583	20-30 minutes
Alstom GT 11N2 (1)	113,580	679	20-30 minutes
GE LMS100PA Wet Cooled	98,487	871	20-30 minutes
Nominal Capacity 160MWe			
Siemens SGT5 2000E	167,700	550	20-30 minutes
GE Frame 9EC	172,980	560	20-30 minutes

Based on the table above the reference engine selected in each nominal capacity range are:

- 40MWe: GE Frame 6B @ 42.1MW
- 50MWe: GE LM6000 PC Sprint @ 47.18MW
- 100MWe GE Frame 9E @ 128.3MW

- 160MWe: Siemens SGT5 2000E (Formerly V94.2) @ 167.7MW

Note that costs in US$/kW used in the initial selection phase is the basic reference cost calculated by GTPRO. This is for a site located at an imaginary location in the US and is used as the starting point for calculating the actual cost based on local geographic and market conditions. The reference cost has been used to enable a direct comparison with GTW costs which are calculated on the same basis.

The initial selection, based on capital cost, is for industrial gas turbines in all the nominal power ranges except for the 50MW range where the most appropriate gas turbine is the aero derivative GE LM6000 PC.

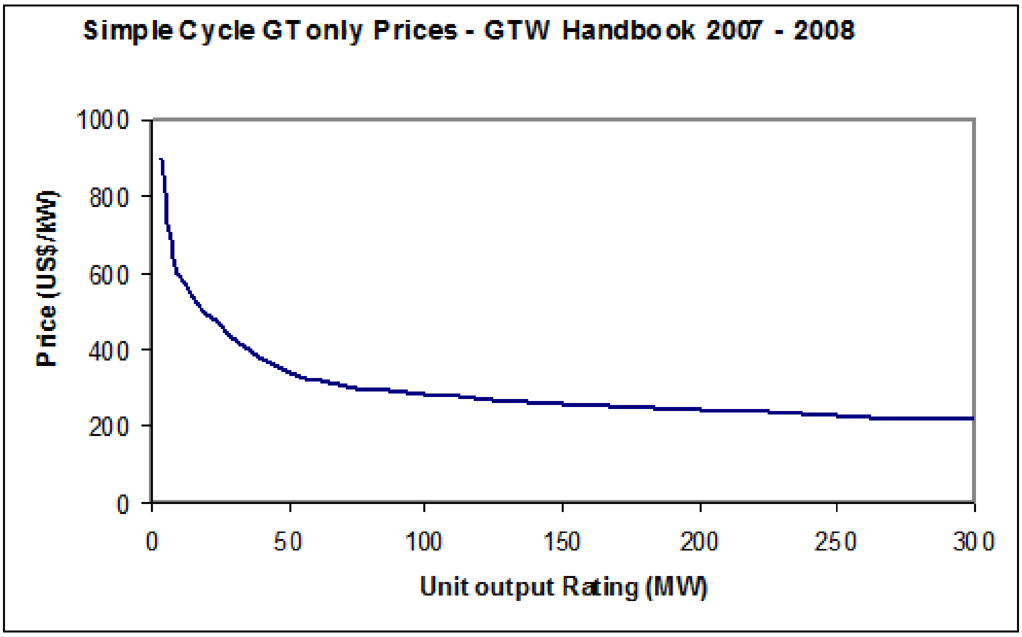
Gas turbines can usually be supplied with conventional (diffusion) type combustion utilising water or steam injection for NOx control or with DLE (pre-mix) type combustion which doesn't require any external water or steam. In general, conventional combustion systems are cheaper than DLN for peaking sets and therefore where an option exists the conventional system has been selected.

The choice of both aero derivative and large industrial gas turbines presents the opportunity to identify any cost differences between the two technologies.

Generally, power plant used in peaking or intermittent duty tends to comprise one or more engines of 40MW capacity or one engine at approximately 160MW capacity. For this reason there is more data available in the 40MW and 160MW categories and to a certain extent this data has been extrapolated to consolidate data available in the other power ranges of 50MW and 100MW. The reason for the 40MW and 160MW being normally selected is that duty requirements either point toward the fast starting and performance from aero-derivatives most of which are in the 25MW to 45MW range, or points toward the lower capital cost per MW that can be achieved using large industrial gas turbines. Above 160MW gas turbines tend to use more advanced technology that is not appropriate and not cost effective for peaking sets.

Costing gas turbines in the 40MW to 50MW is also a problem because it is close to the "knee point" of the GT only cost versus power output characteristic. As can be seen in Figure 3-1 the relationship between GT equipment only cost and power is not linear and a cost penalty is incurred if smaller engine sizes are selected. The issue when building up cost data is that small changes in power can result in large changes in cost and the possibility of increased uncertainty in the final calculation.

Figure 3-1 – GT only cost versus power output



3.1.1 Start up times

Aero derivatives, such as the LM6000, in the 45MW to 55MW range typically have the ability to start up and achieve full load within 10 minutes and potentially slightly quicker if required. Large Industrials such as the GE Frame engines and the Siemens SGT5 2000E normally take 20 to 30 minutes to achieve full load - some, but not all, offer fast start capability and the time drops to 10 to 15 minutes however this fast start capability causes higher than normal thermal stresses to the hot components and the manufacturers apply a maintenance penalty which can be expensive in terms of the impact on overall costs.

Start time is not usually an issue with peaking sets because they are often dispatched well in advance, although it is important to factor fuel used during starting and loading into the financial model to determine an overall heat rate. If it takes 30mins to start the plant and the generator is only dispatched for an hour then it will use a lot of gas without much reward. On projects where start time is important then the aero derivatives are clear winners because they are designed for rapid starting and loading.

3.2 GAS TURBINE WORLD HANDBOOK.

The cost data in the GTW handbook is intended to serve as a cost estimate for high level project planning and feasibility studies. The normal expectation is that the prices, which are for equipment only, are within ±5% of competitive bid prices for equipment FOB the manufacturers factory. Included in the price are the turbine, generator and major balance of plant such as gas compressors.

Normal practice for building up the major equipment price into an estimate of the total project price is to apply the following adjustments:

- Increase scope from equipment only to complete power island – multiply by 2.0
- Adjust for regional variations between mainland US and New Zealand – multiply by 1.38 (includes a factor for shipping costs)
- Adjust from multi contract to EPC contracting regime – multiply by 1.1
- Convert from US$ to NZ$ - assuming 1.25 currency exchange rate

The final result is generally considered to be accurate to within ±10% although in recent times there have been issues particularly in regions with high labour costs, where the results have been consistently lower. PB attempts to correct this using a regional adjustment based on careful correlation with prices from recent projects.

Table 3-2 : Engine prices sourced from the GTW Handbook

	Output	**GTW Price**	**Scope Build up**	**Regional Variation**	**EPC Contract**	**Convert to $NZ/kW**
Engine Type	**kW**	**US$/kW**	**(X 2)**	**(X 1.38)**	**(X 1.1)**	**(X 1.25)**
GE 6581B	42,100	305	610	842	926	1,160
LM6000 PC Sprint	47,182	375	750	1,035	1,138	1,423
GE 9171E W/I	128,300	231	462	638	701	877
Siemens SGT5 2000E	167,700	225	450	621	683	712

3.3 THERMOFLOW GTPRO/PEACE PRICES

The Thermoflow engineering tools has two discrete stages in developing and costing a power plant project.

> Step 1 is to use GTPRO to select an appropriate gas turbine based on technical and performance requirements.
>
> Step 2 is to use PEACE to build up a table of costs. PEACE can be configured to take account of shipping costs and regional variations with most adjustments pre-configured. However in the case of New Zealand based projects it is necessary to manually adjust the labour rate component to achieve a better match between US and NZ skilled labour rates.

The final stage is to convert from US dollars to NZ dollars using the prevailing conversion rate which has been assumed as 1.25.

Experience has shown that, particularly with GE products, PEACE can establish costs to a high order of accuracy sometimes within ±2% of firm EPC proposals. For this level of study, the accuracy should be considered in the region of ±10%. The results are as per Table 3-3:

Table 3-3 : Engine prices sourced using Thermoflow PEACE

	Output	Thermoflow price	Convert to $NZ/kW
Engine Type		**US$/kW**	**(X 1.25)**
GE 6581B	42,100	1,035	1,294
LM6000 PC Sprint	47,182	1,063	1,328
GE 9171E W/I	128,300	764	956
Siemens SGT5 2000E	167,700	690	863

3.4 PB COMPARISON OF GTW AND THERMOFLOW DERIVED PRICES.

With the exception of the SGT5 2000E gas turbine, the GTW and Thermoflow prices match within ±5% which is reasonable considering the current volatility in pricing and the assumptions used in building up the total costs. The exception is the SGT5 2000E where a 9.5% difference exists. In this case PB has cross checked the price with known data from other projects and thinks that the price range is correct despite the large difference. Under current market conditions larger than normal price fluctuations can be encountered on the most popular frame size engines.

PB has reviewed the other prices against current experience for peaking power plant within the Australia and New Zealand markets to determine whether further normalisation is required. The result of the review is that the prices appear to be about 10% higher than expected however this difference will be rapidly eroded by the increase in prices that have taken place over the last few months. No further adjustment to the price is therefore deemed necessary.

It is recommended to use the average price between the two results as the base capital cost estimate for the plant. Prices are therefore as per Table 3-4.

Table 3-4 : Recommended capital cost estimates for peaking plant

	Output	**Base Cost**
Engine Type		**$NZ/kW**
GE6581B	42,100	1,227
LM6000 PC Sprint	47,182	1,376
GE 9171E W/I	128,300	916
Siemens SGT5 2000E	167,700	787

The capital cost recommendations are based on the following assumptions:

- Complete facility required – no shared buildings or other key infrastructure.
- Equipment to be located in outdoor enclosures rather than buildings.
- Costs to purchase land excluded
- Costs for building consent excluded
- Costs to transport heavy equipment from nearest port to site excluded
- Cost is for single fuelled engines – refer below for dual fuel.
- Costs for connecting to the grid excluded

The capital cost build up has assumed that the gas turbines will be single fuel only. This means that they will be fitted with either a natural gas or a liquid fuel system but not both.

The cost of gas compressors for gas fuelled engines and the cost of liquid fuel system (tanks, pumps, unloading station, civil works etc.) are approximately the same for units of this power range therefore the above capital costs can be used for both cases.

In case a dual fuel system is required then the additional capital cost will be of the order $2M to $2.5M.

3.5 OPERATING AND MAINTENANCE COSTS

The selected engines include an aero derivative gas turbine (GE LM6000PC) and a large industrial gas turbine (GE Frame 9E). There is a basic difference in the maintenance regimes between aero derivative and large industrial gas turbines. Aeroderivatives are designed to start and stop regularly without penalty and are usually maintained on an operating hours only basis. Large industrial gas turbines are designed for long periods of continuous operation at steady load however can and often are set up to be run as peaking plant. Maintenance penalties are incurred each time the unit is started and in peaking duty, where many starts are involved, maintenance can be on a starts basis rather than hours.

In general, for base loaded sets, major maintenance on aero derivatives is more expensive than large industrials. The reason for this is that aero derivatives cannot usually be maintained in the field and also because the overall life of highly stressed components tends to be shorter. Maintenance costs are very dependant on the operating regime however it can be assumed that unless the number of predicted starts per year increases dramatically, it will still be more costly to maintain aero derivatives than large industrials.

There is also a difference between engines running on gas fuel and engines running on liquid fuel. The maintenance penalty for operating on liquid fuel can be a factor of 1.5 times the operating hours for gas fuel and this can have a long term impact if substantial liquid fuel operation is expected.

Operating and maintenance costs can therefore be subject to wide variation depending on the make and model of plant, the operating regime, and whether gas or liquid fuel is used.

There are also other less commonly known factors that can have an impact. Rapid starting, loading and stopping can have an impact as can operating above the normal rated turbine inlet temperature. These factors tend to be engine specific and are mainly discretionary modes of operation. They have been excluded from this review.

The following assumptions have been made when calculating the operating and maintenance costs:

- 2% capacity factor
- 30 starts per year (average 6 hours running per start)
- Ambient conditions referenced to ISO conditions (15°C, 60%RH, Sea level)
- Operating on either natural gas or light distillate.
- Fuel costs unknown therefore excluded from variable costs
- Standalone plant requiring its own O & M labour force.

In making an assessment of the fixed and variable O&M costs PB has not tried to build up a table of costs applicable to a particular engine or operating regime. PB has instead relied on data from its own in-house data base suitably adjusted to comply with the required parameters.

Table 3-5 identifies separate costs for aero derivative and industrial gas turbines. This is due to the slightly higher maintenance burden with aero derivative gas turbines.

Table 3-5 : Recommended O&M cost estimates for gas fuel peaking plant

		Aeroderivative Gas Turbine (LM6000 option)	**Industrial Gas Turbines** (Frame 6b and 9e option)	**Large Industrial Gas Turbines** (Siemens SGT5 2000E)
Fixed O&M	NZ$/kW/year	14	14	12
Variable O&M	NZ$/MWh/year	10	6	5.5

Note that an allowance has been made for the slightly different fixed and variable costs encountered between the medium and large industrial gas turbines.

For liquid fuel (oil) fired plant, PB has used the penalty factor of 1.2 on the gas fired plant option's variable O&M costs to account for the reduction in interval times between major maintenance. Running plant on liquid fuels decreases the number of operating hours between service intervals. These are included in Table 3-6.

Table 3-6 : Recommended O&M cost estimates for liquid fuel peaking plant

		Aeroderivative Gas Turbine (LM6000 option)	**Industrial Gas Turbine** (Frame 6b and 9e option)	**Large Industrial Gas Turbines** (Siemens SGT5 2000E)
Fixed O&M	NZ$/kW/year	14	14	12
Variable O&M	NZ$/MWh/year	12	7.2	7

The overall O&M costs for liquid fuelled plant are very sensitive to increases in operating hours and rapidly increase if annual operating hours assumptions increase. The costs are also very specific to the individual engines installed as each manufacturer specifies different maintenance requirements for their machines.

3.6 LOCATION FACTORS AFFECTING COST ESTIMATES

The scope of this report includes location specific cost estimation for the peaking plant including a gas fuelled peaking plant in Taranaki and liquid (oil) fuelled peaking plants in Auckland and Central South Island. The major location factors affecting overall capital cost would be the location of the peaking plant in proximity to the fuel supply and grid connection. Gas or liquid fuel transportation and transmission connection costs will have a direct and significant impact on the location and overall costs of thermal peaking plant.

Accurate cost estimation of location specific site requirements would also involve the following activities:

- Road widening or bridge strengthening requirements for plant component delivery
- Environmental and resource consenting issues
- Requirements for existing infrastructure such as grid connections, fuel

delivery arrangements and water supplies.

- Availability of skilled workforce
- Travel and accommodation requirements for staff

For high level estimation purposes a range of 10 – 20% of the total capital cost estimate for new thermal peaking plant should be allowed for location specific costs. A favourable location in terms of the factors that affect site specific costs will incur costs towards the lower end of the scale. For example, a Taranaki based gas fired peaking plant located near a major gas storage facility or existing gas pipeline will incur less cost due to the reduced gas transportation requirements. Similarly, a liquid fuel peaking plant located near an existing oil refinery will incur less cost relating to the transportation of the fuel.

Without specific site locations it is difficult to estimate the location related costs. For the purposes of this report, an assumption can be made that each of the plant options is located near to an existing fuel supply (gas facility or oil refinery) and also located close to an existing transmission connection point. Based on these assumptions, a value of 10% of the capital costs could be used to estimate the location specific costs. These are included in Table 3-7.

Table 3-7 : Recommended capital cost estimates for peaking plant including location specific costs

	Output	Base Cost	Location specific cost	Combined cost
Engine Type		**$NZ/kW**	**$NZ/kW**	**$NZ/kW**
GE6581B	42,100	1,227	123	1,450
LM6000 PC Sprint	47,182	1,376	138	1,514
GE 9171E W/I	128,300	916	92	1,008
Siemens SGT5 2000E	167,700	787	79	866

Regional O&M differences could exist in that there is a greater likelihood of skilled resource availability in Auckland and possibly Taranaki rather than central South Island. This would mean that that plant built near Auckland or existing developments in Taranaki would not be subjected to any quantifiable increase in labour costs. This however is not considered material for the level of estimation included in this report.

3.7 RECIPROCATING ENGINES

When evaluating power generation options for peaking power plant in the 40MW range it is also appropriate to consider reciprocating engines as the prime mover.

Reciprocating engine technology has advanced rapidly in recent years and it has achieved levels of reliability and efficiency that can make it competitive.

There are a number of other advantages in using reciprocating engines for peaking or intermittent duty power generation and the installed base is increasing rapidly even in areas where gas turbines had held strong market share.

A summary of the advantages of reciprocating engines relative to gas turbines is:

- Fast start and loading – 3 mins to synchronising, 7 mins to full load
- Better efficiency than open cycle GTs.
- Ambient temperatures up to approx 40°C have little impact on performance therefore in New Zealand rated power is available throughout the year.
- No maintenance penalty on the number of starts or loading cycles
- Usually no need for gas compressors
- Power plant construction times 30% to 50% of GT times
- Incremental expansion easy to accomplish
- High reliability – especially if operating on n+1 basis

The main disadvantage for reciprocating engines is that the lower power density means that over a certain capacity the physical size or quantity of equipment can become problematical.

Configuration

A 40MW power station would typically utilise multiple gas or diesel fuelled engines each having a power output of 5MW to 6MW which would result in a power station containing approximately 8 engines.

This number of engines gives flexibility in terms of the ability to only operate the number of engines required to meet the demand. It can also result in higher reliability because the impact of a single engine is much less than if a single engine of a larger frame size unit was utilised.

Reciprocating engines in the 5MW range will achieve operating efficiencies of between 40% and 45% depending on the type and technology. In terms of relative efficiency this is significantly better than open cycle gas turbines and slightly worse than the average combined cycle power station.

Construction Time

The reciprocating engine industry in general has lower lead times and the plant is easier to construct than gas turbine power stations which results in overall project build times which can be as little as 7 to 8 months. The modular approach also enables plant to be constructed and commissioned in a phased manner which can reduce lead times to first generation and also facilitate later expansion.

Costs

Detailed investigation into CAPEX and OPEX has not been carried out specifically for the purpose of this report however the following data is PBs understanding of the relative capital costs for reciprocating engines versus gas turbines is as per the table below:

Table 3-8 : Relative capital costs of various generation technologies

	Output	**Base Cost**
Engine Type	**kW**	**$NZ/kW**
Aero Derivative Gas Turbine	47,182	1,376
Small Industrial Gas Turbine	42,000	1,227
Diesel Fuel Recips 8 x 5.75MW	46,000	1,300
Gas Fuel Recips 8 x 5.75MW	46,000	1,480

On sites where liquid fuel is the primary fuel the breakeven point between an industrial gas turbine and a diesel engine is at approximately 2% capacity factor. Above 2% it can be more economical to use reciprocating engines. Note that this breakeven point considers initial investment costs as well as fixed and variable O&M.

On sites where gas fuel is the primary fuel the corresponding breakeven point is at approximately 5% capacity factor.

Sites greater than 50 MW the use of reciprocating engines becomes slightly problematical because of the number of engines required. The alternative is to utilise slow speed rather than medium speed reciprocating engines however these engines are really only suitable for continuous duty. PB is of the opinion that multiple 5MW reciprocating engines should be considered as a viable alternative to gas turbines upto 50MW total power station capacity.

3.8 MARKET TRENDS

The gas turbine market is extremely buoyant at the moment with the last 18 months seeing plant equipment price increases of 20% to 30% and the signs are that this trend will continue into the foreseeable future.

Many reasons have been put forward for the increase in turbine sales and prices, it seems to be impacted all frame sizes and in all markets. General opinion is that the market for power generation is cyclic and usually the geographic areas which are buoyant are balanced by those in decline. At the moment however, there is a big push to replace obsolete plant in the US and also the Asian markets are very strong.

The manufacturers cannot easily increase production therefore supply is limited and market forces are pushing up prices and increasing lead times. Manufacturers are also becoming very conservative in their approach and don’t see a need to take on projects which have high risk attached.

The price of materials has also increased recently and particularly steel and copper prices are having an effect.

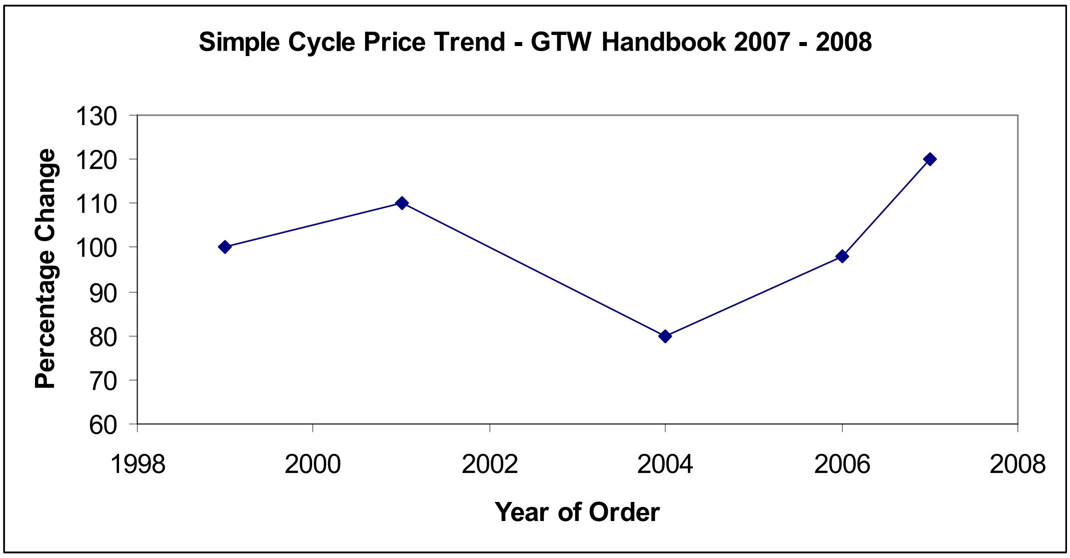
Predictions are that the market will remain buoyant until 2011, after that the demand for power generation will drop and also new technology will start to take market share away from gas turbines.

The current situation is that the manufacturer’s order books are full and lead times for open cycle power plant are increasing from 12 months to 24 or even 36 months. The manufacturers appetite is very low for taking on projects that are either complicated or contain significant risk and PB has recent experience where competitive tenders cannot be obtained for genuine projects.

This upward trend is problematic because prices are moving so quickly it is difficult to ensure the data being used is up to date and accurate. PB is using data that is only 3 months old yet there are signs that further increases have already taken place.

Figure 3-2 illustrates the upward price trend as described by Gas Turbine World magazine. The Thermoflow engineering software shows a slightly higher trend and this may be because the data is more recent and the trend is still increasing.

Figure 3-2 – Recent price trend for gas turbines



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