2011 NZ Generation Data Update

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Ministry of Economic Development

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Contents

List of tables

List of figures

Page number

Appendices

None.

Glossary

AF	Availability Factor
ASC	Advanced Supercritical Coal-fired. This technology is like conventional boiler and steam turbine technology, but operates at a much higher temperature and pressure, so is more efficient at generating electricity (has a lower Heat Rate). ASC technology needs to handle water and steam at very high temperatures and pressures. This requires special steel alloy tubes, pipes, valves and steam turbine components, which are more expensive than those required for a traditional boiler and steam turbine. In most electricity only applications, the lower on-going operating costs of the ASC technology (due to its higher efficiency), will outweigh the increased capital cost.
BCC	Binary Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDS	Centralised Data Set
CGPI	Capital Goods Price Index
E&M	Electrical and Mechanical
EA	Electricity Authority
EOH	Equivalent Operating Hours
EPC	Engineering, Procurement and Construction
FOM	Fixed Operations and Maintenance Costs
GEM	Generation Expansion Model
GJ	Gigajoules
Gross (and Net)	In this report, and consistent with general electricity industry practice, the terms “gross” and “net” are reserved for discriminating between electricity generation measured at the generator terminals (gross) and at the high voltage, transmission line side of the generator step-up transformer (net). Net generation is also commonly called “sent-out” and “dispatched” generation. The difference between the two is the electricity consumed in-house (auxiliary or parasitic load) and internal transformer losses.
GT	Gas Turbine

GW	Gigawatt
GWh	Gigawatt-hour
GXP	Grid Exit Point
Heat rate	A measure of the efficiency of the fuel-to-electricity conversion process in terms fuel quantity in energy terms consumed (burned) for each unit of electrical energy produced. The MED have defined this parameter as "*for each GJ of Fuel input how many useful (station export) GWh of electricity are generated*". Note that GJ/GWh = MJ/MWh = kJ/kWh, the latter being the more common units. Whenever heat rates are expressed they must be accompanied by the qualifications 'net' or 'gross' and 'HHV' or 'LHV", i.e ***Net** Heat Rate = 9180 kJ/kWh (**HHV**)*. MED have asked for the HHV heat rates to be provided in this report.
HFO	Heavy Fuel Oil
HHV	Higher Heating Value (HHV) or equivalently Gross Calorific Value (GCV) is a measure of the specific energy content for a fuel and is determined by bringing all the products of combustion back to the original pre-combustion temperature, and in particular, condensing any vapour produced. HHV are used to determine the actual amount of fuel that would need to be purchased to produce a MWh of electricity. This report only displays heat rates using HHV. To avoid confusion with Gross and Net generation output (inclusive or exclusive of parasitic load within a generation station), the term GCV is not used in this report.
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle. This technology allows coal to be used as fuel for the efficient combined cycle technology. The coal is first gasified and the resulting synthetic coal gas is used, instead of natural gas, in a combined cycle plant. IGCC has a higher capital cost than a natural gas combined cycle plant, owing to the extra components required for the coal gasification process.
kV	Kilovolt
LHV	Lower Heating Value (LHV) or equivalently Net Calorific Value (NCV) is a measure of the specific energy content for a fuel and is determined by subtracting the heat of vapourisation of the vapour produced in combustion of a fuel from the Higher Heating

	Value (HHV). LHV is not used in this report.
LNG	Liquefied Natural Gas
LRMC	Long Run Marginal Cost
MCR	Maximum Continuous Rating
MED	Ministry of Economic Development
MVA	Megavolt-Ampere
MW	Megawatt
MWh	Megawatt-hour
NCF	Net Capacity Factor
Net	In this report, and consistent with general electricity industry practice, the terms “gross” and “net” are reserved for discriminating between electricity generation measured at the generator terminals (gross) and at the high voltage, transmission line side of the generator step-up transformer (net). Net generation is also commonly called “sent-out” and “dispatched”. The difference between the two is the electricity consumed in-house (auxiliary or parasitic load) and internal transformer losses.
NOF	Net Output Factor
O&M	Operations and Maintenance
OCGT	Open Cycle Gas Turbine
ORC	Organic Rankine Cycle
SOO	Statement of Opportunities
ST	Steam Turbine
TJ	Terajoules
UCG	Underground Coal Gasification
VOM	Variable Operations and Maintenance Costs
WTG	Wind Turbine Generator

How to use this document

Parsons Brinckerhoff (PB) has been engaged by the Ministry of Economic Development (MED) to provide an update of technical and cost data for existing and potential future electricity generating plant in New Zealand. This reference document and data set is primarily intended to support energy supply scenario forecasting performed by MED.

The Generation Expansion Model (GEM) is a tool used for new generation build forecasts such as those previously produced and published by the Electricity Commission in the Statement of Opportunities work stream. As a result of the recent electricity market reforms, MED now has responsibility for maintaining information on the costs of new and existing generation in New Zealand. The reference information provided in this Report is a key input to the modelling performed using the GEM (a model maintained by the new Electricity Authority).

The reference data set provided within this Report which comprises technical and cost data estimates for generating plant with an operational capacity of greater than 10MW is split into three main categories or report sections:

- Existing NZ generating plant (Section 3);
- Proposed NZ generating plant (Section 4); and
- Future generic NZ generating plant (Section 5).

The proposed plant dataset (contained in Section 4) has been populated with specific projects that are in the public domain at the time of writing which have either applied for resource consent, have had consent granted or are currently under construction.

Section 5 provides guidance on possible future generic types of generating plant and estimates the technical and cost parameters required by the GEM. The analysis has been used to generate a list of possible future generic projects which is intended to represent the range of plant indicative of the future build options over the modelling timeframe (out to 2050), and provides the GEM with an option list to build and forecast future electricity supply scenarios. The list is not a view or opinion of what will actually be built over the modelling period or what type of plant has a greater probability of being built.

Absolute values are provided in this Report in response to the GEM data requirements. It is important to note that the cost estimates provided in this report are PB's opinion based on publically available information, currently available technology and other assumptions such as exchange rates and are the product of a concept or desktop level of estimation. This level of estimation accuracy supports the Report's objective to provide indicative estimates which help the MED establish the relativity of costs of generation between the different types of plant. This level of estimation for generating plant typically involves an accuracy range of +/- 30%, highlighting the importance of detailed investigations and studies when evaluating specific projects given that technical and cost parameters of power projects are extremely project-specific.

In addition to the data set in Sections 3 to 5, Sections 6, 7 and 8 provide some guidance on possible ranges of high level plant cost components, commentary around the future drivers of plant cost uncertainty and some additional information relating to the effects of load on thermal plant heat rates.

1. Introduction

1.1 Background

Parsons Brinckerhoff (PB) has been engaged by the Ministry of Economic Development (MED) to provide an update on technical and cost data for existing and potential future electricity generating plant in New Zealand. This data is primarily intended to support energy supply forecasting performed by MED.

The Generation Expansion Model (GEM) is the tool used for new generation build forecasts such as those previously produced and published by the Electricity Commission in the Statement of Opportunities work stream. As a result of the recent electricity market reforms, MED now has responsibility for maintaining information on the costs of new and existing generation in New Zealand. The information provided in this Report is a key input to the modelling performed using the GEM (a model maintained by the new Electricity Authority).

1.1.1 MED modelling

The input data included in this report is used in the GEM model and for estimating the Long Run Marginal Cost (LRMC) of new generation. The outputs of the GEM model include forecasts of new generation build by fuel/technology type. MED also uses the GEM outputs to forecast wholesale electricity prices (based on the LRMC of the new plant built).

The build schedule from the GEM and the forecast electricity prices are used to produce the MED publication titled New Zealand's Energy Outlook[1]. The Outlook provides a view on future energy demand and supply and is published on the MED's website. The Outlook is intended to inform and educate stakeholders (including policy makers) on some of the key trends and issues facing New Zealand's energy future.

MED also publishes an "LRMC interactive tool" on its website[2] which would use the information included in this report.

1.2 Project scope

A similar scope of review to the one included in this report was last undertaken as part of the 2005 Statement of Opportunities[3]. Since then updates to specific components of the data, such as thermal fuel and geothermal fuel costs have been undertaken on a more ad-hoc basis.

The scope of work for this report comprises three main tasks:

- Task 1 – A review and update of existing New Zealand generation plant information held by the MED;

[1] http://www.med.govt.nz/templates/StandardSummary____10186.aspx
[2] http://www.med.govt.nz/templates/MultipageDocumentTOC____45553.aspx
[3] http://www.ea.govt.nz/industry/ec-archive/soo/2005-soo/

- Task 2 – Provision of information on the specifications and cost estimates of potential future generating plant in New Zealand; and
- Task 3 – Additional discussion on aspects of the key drivers of future generating plant in New Zealand.

1.2.1 Task 1 – Existing plant information review

Information currently held by the MED on existing generating plant has been reviewed by PB. This has primarily involved validating/verifying the information with existing generating plant owners and with publicly available information such as that contained on generator websites or in company annual reports.

1.2.2 Task 2 – Possible future generation

The task involves providing information for possible future generating plant in New Zealand, with an estimated capacity of greater than 10 MW. Information has been provided for a number of publicly known projects including selected projects on the Electricity Authority's (EA) new generation update[4]. This regular release by the EA lists future proposed generation projects that have applied for resource consent, have resource consent or are under construction.

In addition to these known/publicly announced projects, PB has provided specifications and costs for a range of future generic generating plant. This includes details of how the categories of generic plant types have been selected and how the technical and cost data estimates have been generated.

This report also provides for each future proposed or future generic plant an estimated breakdown of capital costs into proportions that are foreign currency exposed and therefore best recorded in a foreign currency for modelling purposes and those which are not exposed to foreign currency movements.

In addition to plant data, cost estimates for fuel transmission, distribution, transport and logistics has been included in the analysis for the thermal plant.

1.2.3 Task 3 – Additional discussion

This task includes the following additional report discussions:

1. Uncertainty of costs: A commentary and analysis on the uncertainty of generating plant cost estimates presented in Task 1 and 2.

2. Heat rate as a function of plant capacity utilisation: For selected thermal plant analysed in Tasks 1 and 2, PB has estimated the heat rate (Higher Heating Value - HHV) based on an optimum operating range. For various sized projects of each thermal combustion technology, the report provides a spectrum of heat rates relative to a spectrum of capacity utilisations.

[4] http://www.ea.govt.nz/industry/modelling/long-term-generation-development/list-of-generation-projects/

3. Future uncertainty in costs of new generation: A general discussion on key drivers of uncertainty around future costs for selected generation types.

1.3 Project methodology

PB has used a variety of information sources to review the existing information and provide the estimates contained in this report. Reference sources include:

- Published studies, magazines, articles and reports by PB and others;
- Information from NZ generators, developers and owners of assets through consultation included as part of this project;
- Third party proprietary information sources to which PB has access such as GT Pro and Bloomberg Clean Energy Finance information portal; and
- PB in-house data, knowledge and experience.

1.3.1 PB opinion

Parsons Brinckerhoff is a leading provider of power generation related advice to developers, owners and operators of plant in New Zealand and abroad. PB has relied on its experience and knowledge to review and recommend the technical and cost specifications for generating plant provided in this report. Where possible PB has used publicly available and third party information to support the estimates provided.

Costs presented in this report represent PB's opinion on what is a "most likely" figure given current market conditions, publicly available information and available technology.

1.3.2 Consultation

The following companies have been consulted with the aim of improving the information base and reference dataset for analysis. We acknowledge with gratitude the cooperation we have received from these companies.

- Genesis Energy (www.genesisenergy.co.nz);
- Meridian Energy (www.meridianenergy.co.nz);
- Contact Energy (www.contactenergy.co.nz);
- TrustPower (www.trustpower.co.nz);
- Mighty River Power (www.mightyriverpower.co.nz); and
- Todd Energy (www.toddenergy.co.nz).

Any information provided as part of the consultation phase of this report has been reviewed by PB and included in this report where it has been used to inform our opinion. Some technical and specific cost data is commercially sensitive and confidential, and hence where possible, PB requested generic estimates and data ranges to inform the estimation process.

1.4 Limitations

1.4.1 Materiality/estimation accuracy

PB has provided a range of values for some of the data items included in the scope of work. The ranges provide an upper and lower bound for 'typical' values considered to be normally experienced given the information available today. Where possible and required, PB has also recommended absolute values for use in the MED's modelling.

For the cost estimates provided in this Report including plant capital and O&M cost values, PB has used a target 'concept' level of accuracy of +/-30%.

1.4.2 Conflicts of interest

PB is not aware of any conflicts of interest arising from or influencing the information contained within the report.

1.4.3 Other

Actual energy/fuel cost information is excluded from the scope of work for this report. We have not conducted any market modelling of future NZ supply scenarios as part of the analysis for this report. The focus of this report is on the current technical and cost parameters for generation plant in New Zealand and not an economic analysis or prediction of what plant will be built in the future.

1.5 Report structure

The remainder of this report contains the following sections:

- Section 2 – Definitions of key data items
- Section 3 – Existing plant data set
- Section 4 – Proposed plant data set
- Section 5 – Future generic plant data set
- Section 6 – Plant component cost breakdowns
- Section 7 – Thermal plant heat rate vs. utilisation
- Section 8 – Discussion of uncertainty in future plant costs

2. Definitions

The information data set provided by MED for PB to review contains a list of data items and values. To provide some background and a framework for the review, definitions of the more technical data items are included in this report section.

All costs included in this report are quoted in 2011 New Zealand Dollars (unless otherwise specified) and represent a 'most likely' cost given the high level of uncertainty of estimating at a 'concept' level.

Generally, data estimates provided in this report are averages for the project lifetime of the plant in accordance with the GEM information requirements and the nature of the modelling performed by MED.

2.1.1 Plant capacity

There are four commonly quoted capacity values for generation plant which are:

- Gross capacity (MW) – The total installed capacity or nameplate rating of the plant.
- Net capacity (MW) – This is equal to the gross capacity of the plant less any plant auxiliary loads (in MW), and represents the exportable capacity out to the Grid.
- Peak capacity (MW) – the maximum output that the unit or plant is able to produce at any one time. This may exceed the nameplate capacity in some instances.
- Operational capacity (MW) – long term average maximum capacity of the plant.

2.1.2 Operations and maintenance costs

These are the ongoing costs associated with the running of generating plant which exclude any capital costs but may include financing costs. The operations and maintenance (O&M) costs for generating plant have been split into two categories, fixed and variable.

2.1.2.1 Fixed O&M costs

These are O&M costs which do not vary with the level of generation and are generally influenced by or are proportionate to the size of plant (MW capacity). Theoretically these costs would still be incurred even if the plant was not generating (but still available to generate). Examples of fixed O&M costs include:

- Insurance;
- Landowner costs;
- Some maintenance costs;
- Grid/connection charges;
- Financing costs;
- Communications; and

- Corporate overheads/management time.

These costs are expressed on a $/kW/year basis.

2.1.2.2 Variable O&M costs

These are O&M costs which are impacted by the level of generation (MWh), i.e. as generation varies, so does the level of costs. Examples of common variable O&M costs are:

- Transmission charges;
- Royalties;
- Some maintenance costs (e.g. periodic maintenance checks based on generation); and
- Consumables.

These costs are expressed on a $/MWh basis.

Fuel costs are not included because GEM models these costs separately. For more information on fuel costs refer to MED's Energy Outlook.

2.1.3 Availability Factor

The Availability Factor (AF) is defined as the proportion of time that generating plant is available over the time period. Plant is generally unavailable due to two main types of event, planned and unplanned outages. For example, where a plant consists of one 100MW unit, and is available to generate for eight hours out of a ten hour time period (and hence unavailable for two hours due to either planned or unplanned outages or some combination of the two), the AF is 80%.

For this report which is concerned with average level of plant availability over its lifetime, PB has not considered the impact of de-ratings or the effects of individual unit unavailability unless specifically mentioned. Given the high level nature of the estimates it is not possible to tell for a plant with an 80% AF whether the whole plant was available for 80% of the time or if the plant comprised two units, whether one unit was available 60% of the time and the other 100%.

2.1.4 Net Output Factor

The Net Output Factor (NOF) is defined as the net actual generation (in MWh) divided by the product of the time period (in hours) when the plant is available and the operational capacity in (MW), and is a measure of the average loading in MW terms on the units over the period when the plant is available. For example, for a 100MW plant that generated 400 MWh over a 10 hour period, where the plant was available for only 8 of the 10 hours, the NOF is calculated as:

- 400MWh/(8 hours * 100MW) = 50%
- By way of comparison the Capacity Factor for the same example is 400MWh/(10 hours * 100MW) = 40%

The NOF can also be calculated by dividing the Capacity Factor by the Availability Factor. Note that it is not possible to tell whether a 50% NOF on a 100MW unit means that:

- The unit ran at 50MW for 100% of the time plant was available; or
- The unit ran at 100MW for 50% of the time plant was available; or
- Some other combination of loading regime.

For all existing plant PB has based the estimates on existing levels of generation, information provided by Generators and industry lifetime averages for the level of generation associated with the generic type of plant.

For all proposed or generic future plant, the NOF is based on an estimate of average annual generation over the life of the plant. Where possible, PB has provided references to publicly available information about the potential level of generation from the plant. Where none was available the estimate is generally based on a set of assumptions relating to the type of plant (technology), resource availability and anticipated plant role (e.g. baseload, intermediate, peaking).

2.1.5 Plant capital costs

Capital costs have been estimated for proposed and future generic plant. There are a number of factors which can materially influence the estimation of capital costs for generating plant, including the particular specified technical or commercial requirements, origin of the equipment sourced for the project, market conditions at the time of bidding and currency exchange rates applicable at the time of implementation.

Plant capital costs typically include:

- Mechanical (e.g. turbines, generators);
- Electrical (e.g. transformers, switchgear);
- Civil (e.g. buildings, dams, earthworks);
- Engineering design;
- Legal and financial costs including interest during construction; and
- Land and consenting costs.

Fuel delivery and lines connection costs are covered by a separate data item in this report.

Estimated plant capital costs included in the Report are expressed on a cost per kW basis, where the Gross capacity (MW) should be used for the calculation of total capital costs for a plant.

Plant capital costs have been quoted in two components:

- A NZD per kW component which represents that portion of the total plant capital cost which is denominated in the local currency, NZD; and
- A foreign currency per kW component, where the currency represents the dominant foreign currency for the supply of the non-NZD denominated plant costs e.g. USD, EUR, YEN.

To arrive at a total capital cost in NZD per kW, both components must be summed with the foreign currency denominated component converted at an assumed exchange rate.

To confirm the accuracy of the data set with the available reference information where no split of local and foreign component has been provided PB has used the following cross rates provided by MED, which represents a reference case for the conversion of foreign currencies to NZD:

- 1 NZD = 0.66 USD
- 1 NZD = 0.47 EUR
- 1 NZD = 0.38 GBP
- 1 NZD = 0.78 AUD
- 1 NZD = 72 JPY

These cross rates are intended to represent medium to long term average exchange rates consistent with the planning, development, financing and construction periods for generating plant and modelling timeframes involved with the GEM, and other forecasting performed by the MED. The use of medium to long-term exchange rates reduces the impact of short term foreign exchange volatility from skewing the reference case data estimates.

2.1.5.1 Land costs

Land that is acquired for the purposes of constructing generation assets is subject to restrictions which impact significantly on its value, these include:

- Treaty of Waitangi;
- Offer back obligations for land that has been compulsory acquired, and
- Use of conservation land or land used for recreational use and is not to be built on.

Given the accuracy level of plant capital cost estimates provided in this Report, land costs are assumed to be included in the values provided, although no specific land related acquisition costs have been estimated by PB.

2.1.5.2 Resource consents

Obtaining consents to build new or expand existing generation thermal, wind, geothermal or hydro generating plant can be time consuming and expensive. There is also a possibility that such consents may not be granted. Estimating the costs associated with obtaining resource consents is inherently difficult and therefore has the potential to vary considerably from actual project costs.

Given the concept accuracy level of plant capital cost estimates provided in this Report, consent related costs are assumed to be included in the values provided, although no specific consenting costs have been estimated by PB.

2.1.6 Project Lifetime

This is a generation technology dependant expected operational or engineering lifetime of a project. This is different from typical economic lifetime values which are typically shorter at 20 or 25 years, and are used for assessing the financial or commercial viability of generation projects.

It is the expected operational or engineering lifetime values of generation projects which are included in this report.

3. Existing NZ generation plant data

This report section provides the PB technical and cost estimates and describes the process used to review and update the GEM information for existing NZ generation plant. Each technology section (thermal, hydro, wind and geothermal) begins with a summary table of recommended values and then contains a description of the analysis completed for each main data item provided.

The process of reviewing and updating the GEM information on existing generation plant has relied on:

- Information provided by generators/developers, namely:
  - Contact Energy;
  - Genesis Energy;
  - Mighty River Power;
  - Meridian Energy;
  - TrustPower; and
  - Todd Energy
- Publicly available information including:
  - previous published reports (individually referenced);
  - internet searches including news media;
  - company annual reports;
- Information available to PB internally e.g. internal databases, which we have referenced;
- GT Pro and other commercially available technical/cost estimating software such as Bloomberg Clean Energy Finance.

3.1 Thermal

3.1.1 Summary

Table 3-1 summarises the PB recommendations for existing NZ thermal plant technical and cost data. The sections that follow below include any commentary considered necessary to understand the data provided for each technology/plant and any inconsistencies

Table 3-1 Existing NZ thermal plant data

Project name	Plant Tech	Energy Type	Subst.	Project lifetime	Capacity	AF	ULP	Baseload	Heat Rate (HHV)	VOM	FOM	FDC
				Years	*MW*	*%*	*%*	*Y/N*	*GJ/GWh*	*$/MWh*	*$'000/MW /year*	*$/GJ*
Southdown	CCGT	Gas	SWN	42	122	90	50	Y	7,400	4.3	35	1
Southdown E105	OCGT	Gas	SWN	42	45	80	100	N	10,600	8	16	1
Taranaki CC	CCGT	Gas	SFD	50	380	93	100	Y	7,400	4.3	35	1
Otahuhu B	CCGT	Gas	OTA	50	380	93	100	Y	7,400	4.3	35	1
Huntly unit 5 (e3p)	CCGT	Gas	HLY	50	385	93	100	Y	7,400	4.3	35	1
Huntly gas	ST	Gas	HLY	50	980	83	25	N	10,900	8.2	60	1
Huntly unit 6 (P40)	OCGT	Gas/diesel	HLY	42	44	87	100	N	10,525	8	16	1
Huntly coal units 1-4	ST	Coal	HLY	50	237	78	100	N	10,900	9.6	70	0.67
Kapuni	Cogen	Gas	KPA	42	20	85	100	N	-	4.3	35	1
Hawera	Cogen	Gas	HWA	42	68	85	100	N	-	4.3	35	1
Te Rapa	GT	Gas	TRC	42	45	85	100	N	10,600	4.2	30	1
Kinleith	Cogen	Various	KIN	50	38	80	100	N	-	8.2	60	1
Glenbrook	Cogen	Gas	GLN	50	112	80	100	N	-	8.2	60	0
Whirinaki	OCGT	Diesel	WHI	25	155	80	50	N	11,000	9.6	20	3
Stratford	OCGT	Gas	SFD	42	200	80	50	N	10,600	8	16	1
Edgecumbe	GT	Gas	EDG	42	10	80	100	N	-	4.2	30	2
Mangahewa	Recip	Gas	SFD	30	9.6	85	33	N	11,600	12.1	16	0

3.1.2 Plant

The following are the existing thermal generation plants nominated for review by the MED, according to the GEM naming convention:

- Southdown
- Taranaki CC
- Otahuhu B
- Huntly unit 5 (e3p)
- Huntly gas
- Huntly unit 6 (P40)
- Southdown E105
- Huntly coal unit 1
- Huntly coal unit 2
- Huntly coal unit 3
- Huntly coal unit 4
- Kapuni
- Hawera
- Te Rapa
- Kinleith
- Glenbrook
- Whirinaki

PB has added the following to the above list, as existing generation plants with a capacity of around or greater than 10 $MW_{electric}$.

- Stratford – the 200 MW gas-fired OCGT peaker recently commissioned by Contact Energy at its Stratford Power Station site
- Edgecumbe – the 10 MW gas-fired cogeneration plant owned by Todd Energy at Fonterra's Edgecumbe dairy factory
- Mangahewa – Todd Energy's 9.6 MW gas-fired reciprocation engine generation plant.

The following sections document PB's review and update, where necessary, of the MED's GEM information on existing generation.

3.1.3 Plant technology

3.1.3.1 Southdown

Mighty River Power's (MRP) web site describes Southdown as, "*a 175 MW natural gas-fuelled, co-generation station capable of producing 1400 GWh of electricity a year and up to 24 tonnes per hour of industrial use steam*."[5] Mighty River Power's web site lists the following equipment at Southdown:

- 3 x LM6000 Gas Turbines (GT) 45 MW each
- 1 x ABB VAX Steam Turbine (ST) 35 MW
- 4 x Generators:
  - 3 x Brush, 61.375 MVA 11.5kV @ pf 0.8 each
  - 1 x ABB, 42 MVA @ 11.5 kV

The GEM models the Southdown Power Station as two separate plants:

- Southdown – a 122 MW CCGT plant, and
- Southdown E105 – a 45 MW OCGT (see section 3.1.3.7 below).

This section concerns the 122 MW CCGT plant portion of the Southdown Power Station. This portion of the Southdown Power Station could be described as either:

- A Combined Cycle cogeneration plant, or
- A Combined Heat and Power Topping Cycle plant.

PB has previously described the Southdown plant as, "*a natural gas fuelled, 122 MW (net) combined cycle cogeneration plant. It comprises two, nominally 45 MW General Electric LM6000 PC aero derivative gas turbine generators, two heat recovery steam generators (HRSG) and one nominally 35 MW steam turbine. A low pressure (LP) steam turbine extraction provides approximately 24 t/h of process steam to industry (Carter Holt Harvey paper mill). Particular features of the plant are:*

- *The HRSGs are equipped for duct firing to provide steam to meet the cogeneration steam demand and to maximise generation from the steam turbine. The duct firing capability also enables a single LM6000/HRSG unit to provide some steam turbine generation and cogeneration steam with the second LM6000 out of service.*
- *There is no bypass stack between the gas turbine and the HRSG, however the HRSG are a once through design that can potentially be run dry to enable open cycle operation of the LM6000 should the steam turbine be out of service.*

The steam turbine condenser is a wet surface air cooled condenser (ACC). Its saturated outlet conditions provide the visible steam plume often observed at the Southdown facility."[6]

[5] http://www.mightyriverpower.co.nz/Generation/PowerStations/CoGeneration/Southdown/

[6] *Parsons Brinckerhoff, Thermal Power Station Advice, Report for Electricity Commission, July 2009*

The HRSGs are of the type designed by Innovative Steam Technologies (IST) and described as once through steam generators (OTSG). These are capable of running dry, or permitting the gas turbine to operate and generate power without producing steam. This enables the associated gas turbine generator to operate as if it were effectively an open cycle gas turbine (OCGT) generator.

The Southdown CCGT plant therefore appears to operate as either:

- A 2 x 45 MW OCGT peak load plant (i.e. 1 x 45 MW, or 2 x 45 MW)
- A 2 x 45 MW GT + 1 x 35 MW ST combined cycle plant, or
- A combined cycle cogeneration plant.

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Southdown and the data for the first six months of 2011 is plotted in Figure 3.1 below. The same data plotted as a duration curve is shown in Figure 3.2.

These show that for the first six months of 2011, Southdown generated (dispatched to the grid) on only 55% or 100 of the 181 days. It generated a total of 74,095 MWh for the 6 months, which approximately equivalent to a net capacity factor of only 9.7%.

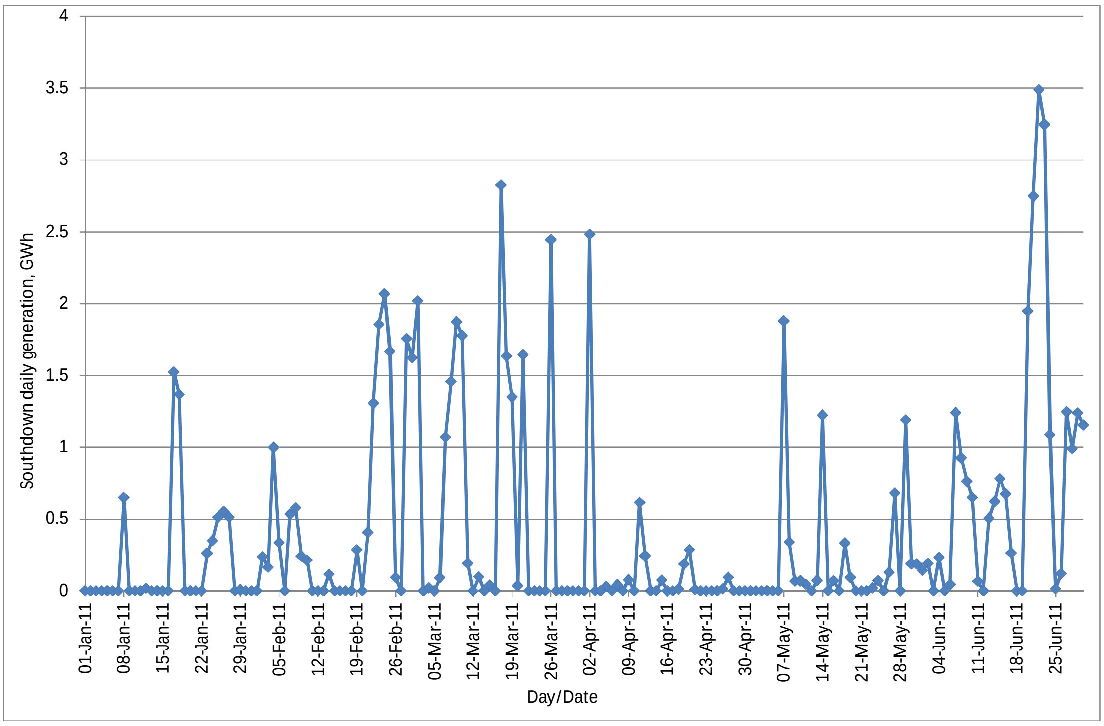


Figure 3.1 Southdown daily generation

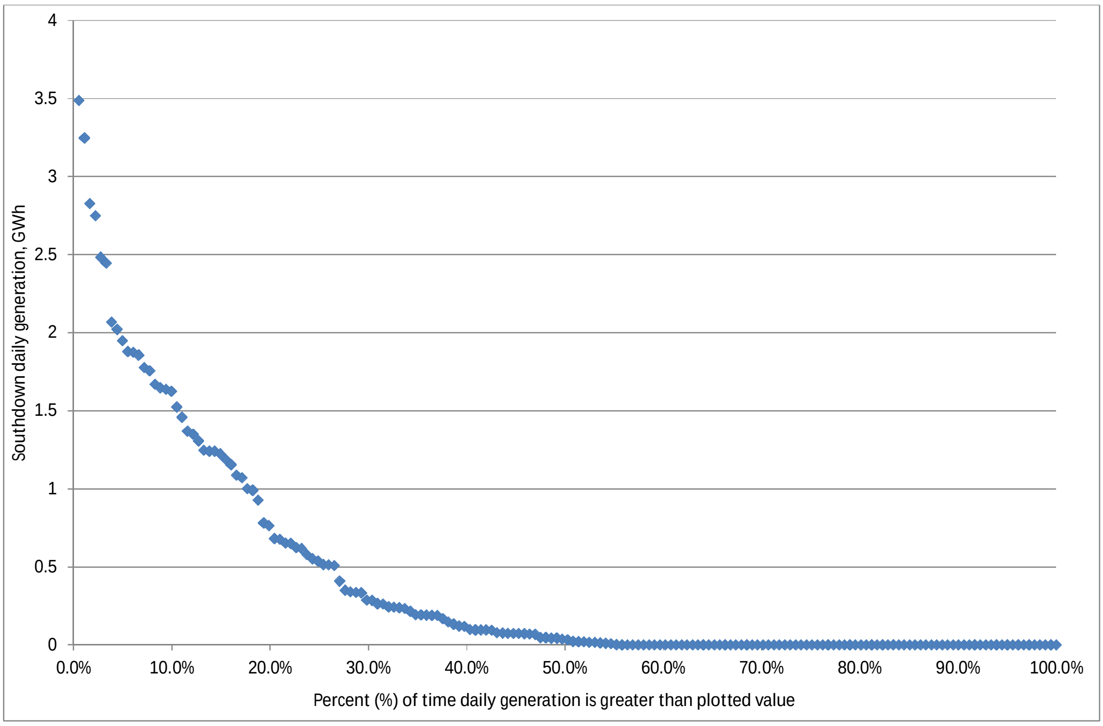


Figure 3.2 Southdown daily generation duration curve

Southdown has clearly operated as a peak load plant for the first six months of 2011, confirming the 2007 note against Southdown Technology in the GEM that the plant is "highly available at peak".

MED may like to consider modelling the Southdown plant as both a 2 x 45 MW OCGT peaker and also as a 125 MW CCGT base load cogeneration plant, although there is little evidence of the latter role over the first 6 months of 2011.

Southdown E105 is, "*a nominally 45 MW open cycle gas turbine installation using a General Electric LM6000 gas turbine. It is installed to provide peak load generation and also to provide synchronous condensing capacity (voltage support) to the national electricity grid.*

The E105 LM6000 gas turbine package was a surplus zero-time engine manufactured in 2001, and that has been converted to a specification with water injected NOx emission control. The gas turbine is also provided with SPRINT™ water injection to provide an additional peak generation capability of approximately 5 MW. Water injection increases the fuelled hour maintenance costs owing to increased erosion on the low pressure (LP) blading.

Synchronous condensing duty is enabled by a gearbox incorporating a clutch. The gas turbine is used to run the generator up to speed, the generator is synchronised to the grid, the clutch is then disengaged and gas turbine is shut down. The E105 installation is the first 50 Hz LM6000 to be provided with a clutched gearbox for synchronous condensing duty."6

The Electricity Authority's Centralised Dataset (CDS) does not record daily generation for Southdown E105 separately from the Southdown plant; generation from Southdown and Southdown E105 is combined.

3.1.3.2 Taranaki CC

Contact's web site describes the Taranaki Combined Cycle Power Station (TCC) as "*a large, efficient and modern plant, producing 380MW of electricity. It has one of the best fuel efficiencies of all of New Zealand's thermal stations at 56.7 per cent*."[7]

The plant is, "*a natural gas fuelled, 377 MW capacity (357 MW at commissioning), single shaft, combined cycle gas turbine plant (CCGT) using the Alstom GT26 gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability*."6

PB recommends using 380MW as the value used in the GEM.

3.1.3.3 Otahuhu B

Contact's web site describes the Otahuhu B Power Station as a, "*400MW power station*" and "*the largest of its kind in New Zealand and one of the most efficient in the world*."7

The Otahuhu B plant is, "*a natural gas fuelled, 404 MW capacity (380 MW at commissioning), single shaft, combined cycle gas turbine plant (CCGT) using the Siemens V94.3A(2) gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability, and using seawater make-up from the adjacent estuary*."6

3.1.3.4 Huntly Unit 5 (e3p)

Genesis' web site describes Huntly Unit 5 as, *"(formerly e3p; Energy Efficiency Enhancement Project)* " and "*a high-efficiency combined cycle generator consisting of four major components:*

- *250MW industrial gas turbine made by Mitsubishi Heavy Industries*
- *HRSG or heat-recovery steam generator*
- *135MW steam turbine*."[8]

The Huntly Unit 5 plant is, "*a natural gas fuelled, 385 MW capacity, single shaft, combined cycle gas turbine plant (CCGT) using a Mitsubishi 701F3 gas turbine. The steam turbine condenser is cooled by a wet-dry (hybrid) type cooling tower equipped with plume abatement capability*."6

3.1.3.5 Huntly gas

"Huntly gas" is the name used in GEM to describe the option of using natural gas fuel in Huntly Power Station units 1 – 4. Genesis' web site describes Huntly units 1 – 4 as a, *"1,000MW steam power plant*" and "*made up of four identical 250MW units, which consist of a boiler and a turbine. Fuel (either coal and/or gas) is burnt inside the boiler furnace*".8

The Huntly units 1 – 4 are, "*four identical 250 MW (gross), conventional, subcritical, Rankine cycle, thermal generation units (boiler and steam turbine). The units' boilers are dual fuelled*

[7] http://www.contactenergy.co.nz/web/shared/powerstations?vert=au
[8] http://www.genesisenergy.co.nz/genesis/index.cfm?12731B0F-B9CC-C9DD-ED2E-C346EA8DF685

and designed to burn natural gas and sub-bituminous coal. Heat rejection from the steam turbine condensers is to the Waikato River using once-through river water cooling."6

The technology for "Huntly gas" and "Huntly units 1 – 4" (see section 3.1.4.8 below) is identical. The boilers were designed from the outset to be dual fuelled with either coal and/or gas.

3.1.3.6 Huntly Unit 6 (P40)

Genesis' web site describes Huntly unit 6 as a, "*48MW Gas Turbine unit*" consisting "*of a General Electric gas turbine (LM6000), which drives a generator via a gearbox*".[8]

The Huntly unit 6 is, "*a dual fuelled, 48 MW capacity, open cycle gas turbine plant, designed to burn natural gas and diesel (distillate), using the General Electric LM6000 SprintTM aero derivative gas turbine*."6

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Huntly P40 and the data for the first six months of 2011 is plotted in Figure 3.3 below.

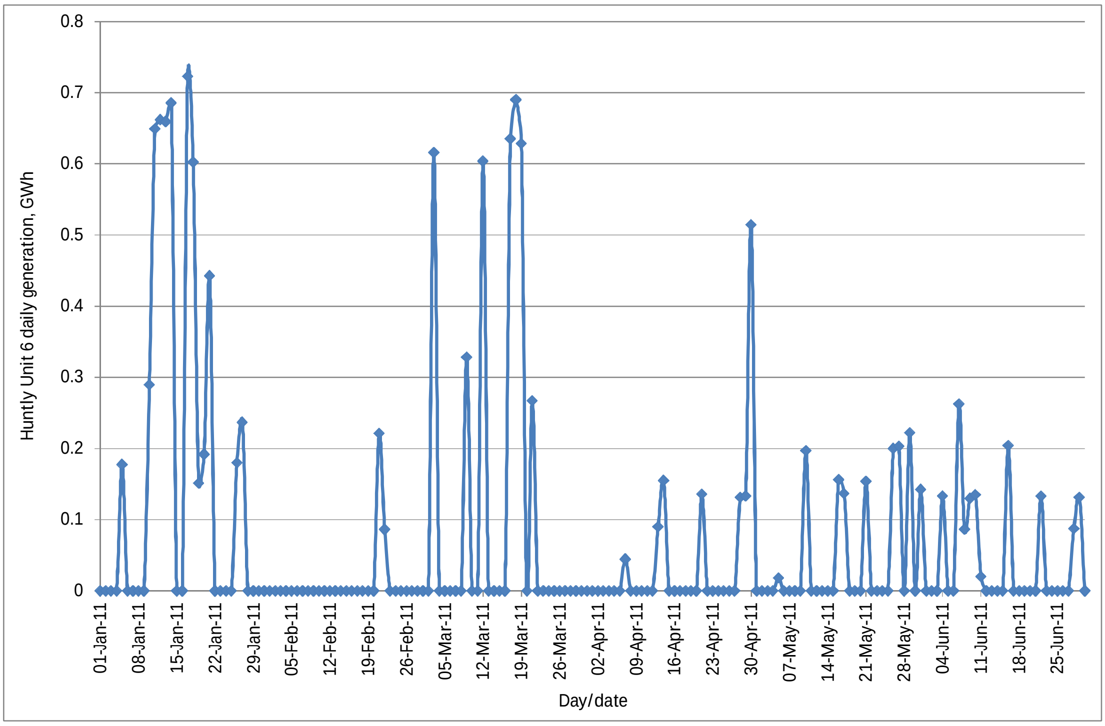


Figure 3.3 Huntly Unit 6 daily generation

The same data plotted as a duration curve is shown in Figure 3.4.

These show that for the first six months of 2011, Huntly Unit 6 generated (dispatched to the grid) on only 26.5% or 48 of the 181 days. It generated a total of 13,685 MWh for the 6 months, which is approximately equivalent to a net capacity factor of only 6.6%.

These are classic data and profiles of a peak load plant, showing that Huntly Unit 6 clearly operated in a peaking role for the first six months of 2011, consistent with the general understanding of its role and purpose.

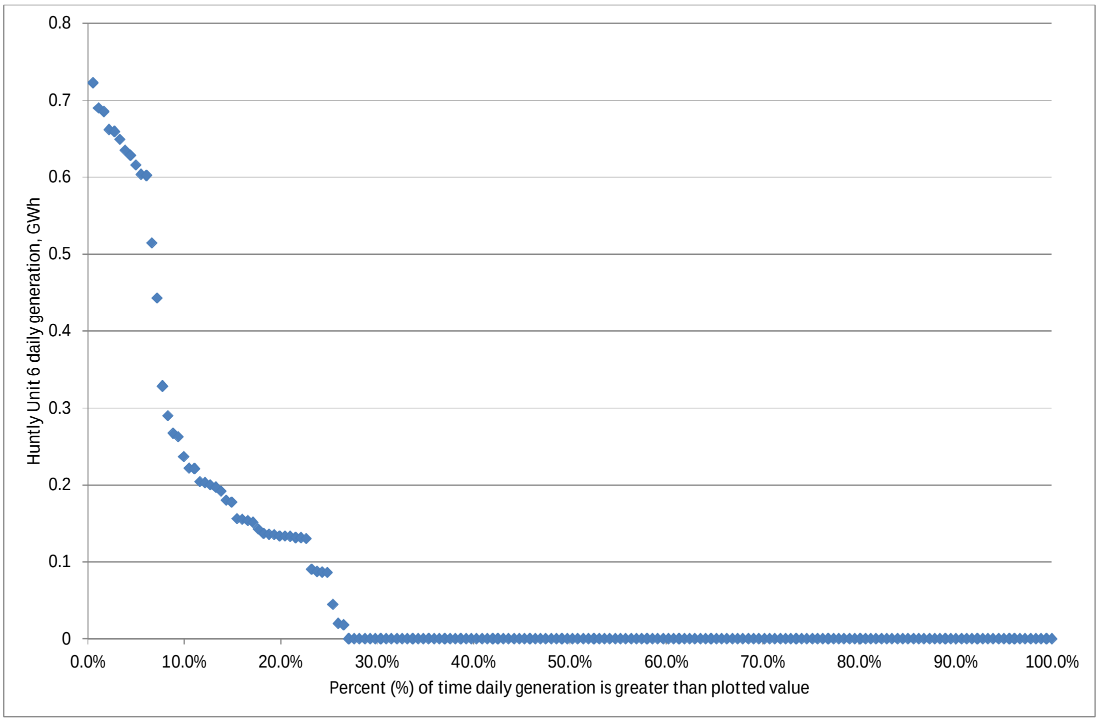


Figure 3.4 Huntly Unit 6 daily generation duration curve

3.1.3.7 Huntly coal units 1 - 4

Huntly Power Station units 1 – 4 are identical and are therefore covered together in this section. The technology description given in report section 3.1.3.5 above applies equally to Huntly coal units 1 – 4.

3.1.3.8 Kapuni

The Kapuni Co-generation Station is a 50:50 joint venture between Vector and Bay of Plenty Energy. Bay of Plenty energy is in turn a retail and generation company owned by Todd Energy.[9]

Todd Energy's web site describes the Kapuni co-generation plant as consisting of, *"two 10.5 MW Solar Mars turbines which are fuelled with treated Kapuni gas from Vector's gas treatment plant. Two steam turbines, in addition to two gas turbines, combine to produce approximately 25 MW of electricity.*

Waste heat steam from the gas turbines is used by Vector in their gas treatment process at Kapuni. This amounts to some 490,000 tonnes per annum. This steam is passed through a 1.5 MW back pressure steam turbine to achieve heat and pressure levels required by the factory and generate further electricity in the process.

Steam is also transported via a three kilometre insulated steam pipeline to Lactose at 34 bar. This steam is used in their dairy factory and final generation is undertaken via a 3 MW back pressure steam turbine located at the Lactose site.

[9] http://www.toddenergy.co.nz/kapuni-co-generation

Electricity is supplied to Lactose via a dedicated underground 11 kV ring main circuit owned by Bay of Plenty Energy."

"*The plant provides heat and power for local industry. The plant has a rated output of 25 MW and, of this, nearly 20 MW is exported to the national grid*."9

From PB's previous involvement in the development of this project, it is known that the gas turbines (GT) are Solar Mars 100 units as noted above, with associated heat recovery steam generators (HRSG). Also, one of the Solar Mars 100 GTs and the "1.5 MW back pressure steam turbine" noted above are connected to the same electric power generator.

This latter unit is therefore in effect a single-shaft combined cycle or CCGT cogeneration unit. However, the steam turbine, at around 1.5 MW is smaller than the typical 1/3 (around 5 MW) expected from a CCGT steam turbine. This is because the majority of the HRSGs nominal 45 t/h steam capacity is used for process and only 25 t/h goes to the CCGT steam turbine.

The other "3 MW back pressure steam turbine located at the Lactose site" noted above is separated from the GTs and their associated HRSGs and electric power generators on the Vector Kapuni gas treatment station site by a distance of approximately 3.5 km. This steam turbine is therefore physically independent from the GTs and their HRSGs, although dependent on them for its steam supply.

Both GT HRSGs fed their output steam into a common header which then supplies process heating steam directly and through the back pressure steam turbines.

Other pertinent features of the plant are:

- The GTs have bypass stacks, enabling them to generate without producing steam from their associated HRSGs, and enabling them to operate in a peaking role if required
- The HRSGs have fresh air/duct firing, enabling them to produce more steam then the GT exhaust would otherwise generate
- Both steam turbines draw steam from a common main and can therefore be supplied by either HRSG, although the steam turbine capacities are well below the HRSG capacities, and one steam turbine is physically connected (single shafted) to one GT generator
- The steam turbines are back pressure units and can therefore only operate when there is process steam demand
- The steam turbines can be bypassed through desuperheating/pressure reducing stations.

The Kapuni plant is therefore quite flexible in its ability to produce electricity and steam for processing heating in varying proportions.

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Kapuni and the data for the first six months of 2011 is plotted in Figure 3.5 below.

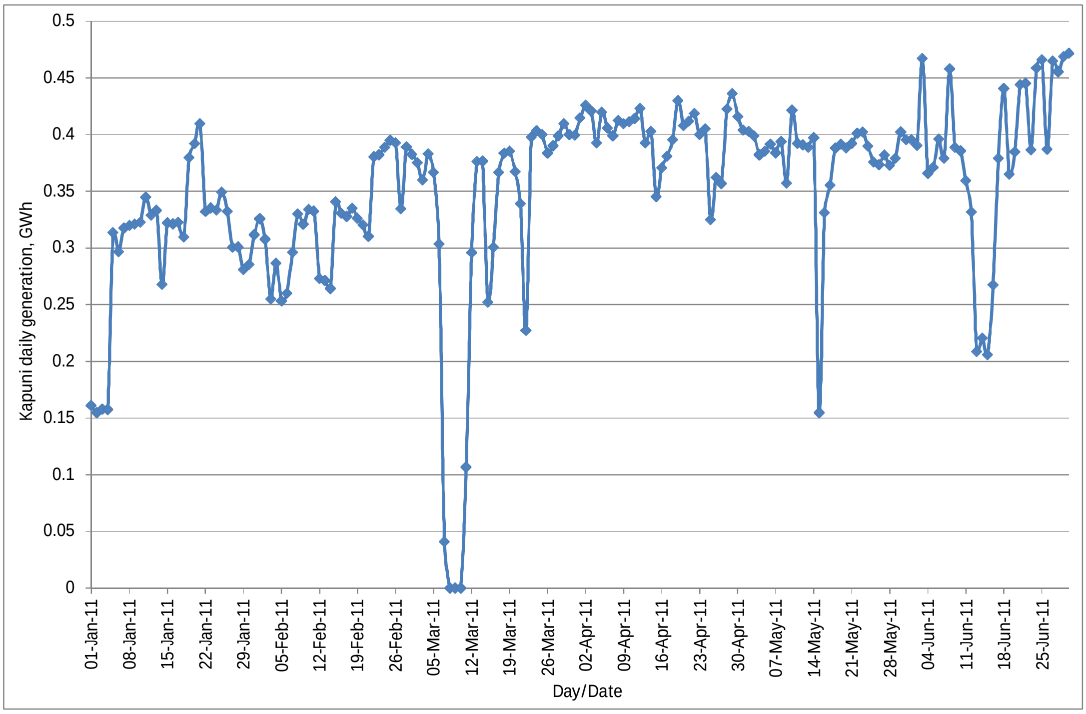


Figure 3.5 Kapuni daily generation

The same data plotted as a duration curve is shown in Figure 3.6 below.

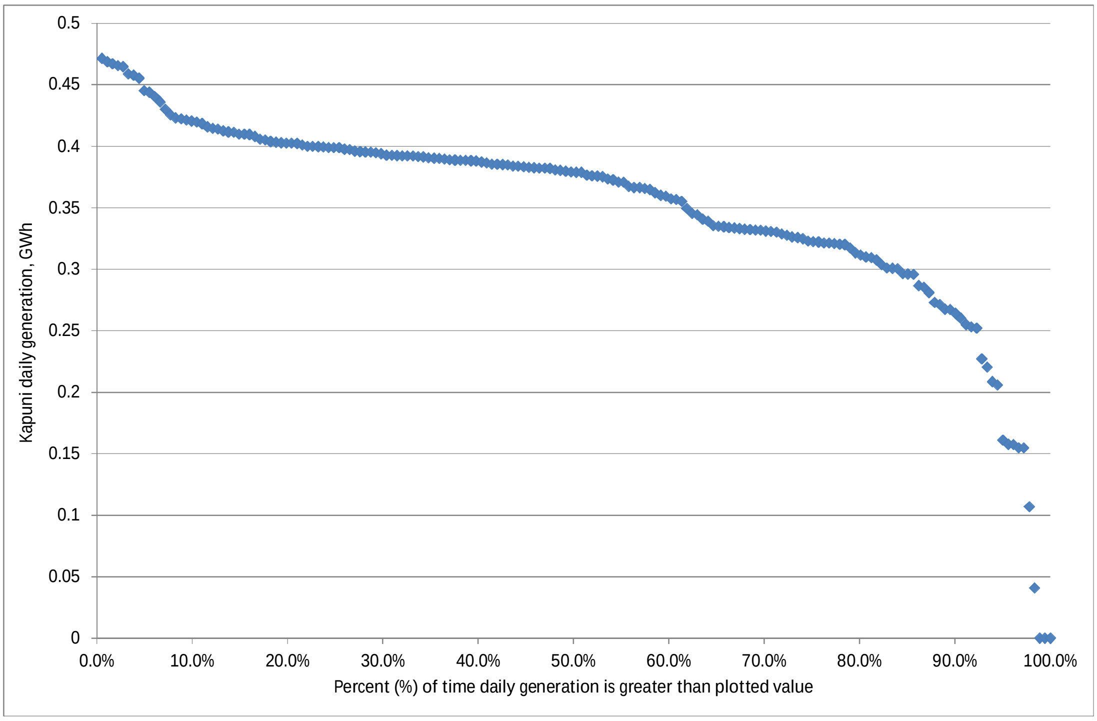


Figure 3.6 Kapuni daily generation duration curve

These show that for the first six months of 2011, Kapuni generated (dispatched to the grid) on 98% or 178 of the 181 days. It generated a total of 63,440 MWh for the 6 months, which is approximately equivalent to a net capacity factor of 73% (based on the 20 MW export capacity cited by Todd Energy on its web site).

In comparison to Southdown, Kapuni has clearly operated as a base load plant for the first six months of 2011.

3.1.3.9 Hawera

The owner's name for the Hawera cogeneration plant is the "Whareroa Co-generation Station. The plant is a 50:50 joint venture between Fonterra and Todd Energy.

Todd Energy's web site describes the Whareroa co-generation plant as, "*Four Solar Mars turbines drive generators to produce electricity, waste heat (exhaust heat) from the turbines is used in two John Thompson and two Innovative Steam Technologies manufactured Heat Recovery Steam Generators (HRSGs) to provide superheated high pressure steam with their electricity generation.*

Additional electricity is produced using a back pressure steam turbine and step down process where steam in a high pressure state not required for factory production is converted to a low pressure saturated state for other use in the factory.

During peak dairy periods additional steam is produced by supplementary firing in the HRSGs. Additional gas is fired in the waste heat stream scavenging the remaining oxygen to lift the heat output of the turbine waste heat step and thus allowing increased boiler steam production."

From PB's recent involvement with this plant, it is known that the gas turbines (GT) are Solar Mars 100 units as noted above.

Other pertinent features of the plant are:

- The GTs do not have bypass stacks, and therefore cannot run without passing their hot exhaust gases through their respective HRSGs.
- The "two Innovative Steam Technologies (IST) manufactured Heat Recovery Steam Generators (HRSGs)" are understood to be similar or of the same type as those installed at Southdown. These are described as once through steam generators (OTSG) and are capable of running dry, or permitting the gas turbine to operate and generate power without producing steam. This enables the associated GT generator to operate as if it were effectively an open cycle gas turbine (OCGT) peaking generator.
- The John Thompson (JT) HRSGs are supplementary fired, with duct burners, but are not equipped for fresh-air firing and are not designed to be run dry.

The Whareroa plant therefore has a degree of flexibility in its ability to produce electricity and steam for processing heating in varying proportions.

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Whareroa and the data for the first six months of 2011 is plotted in Figure 3.7 below.

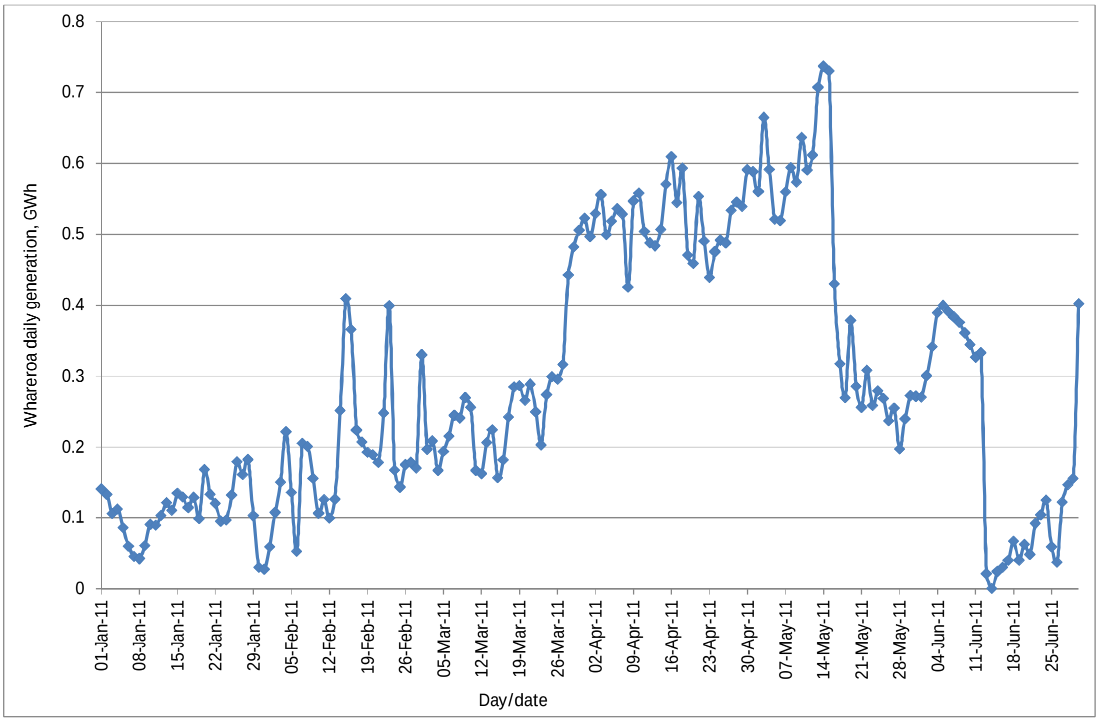


Figure 3.7 Whareroa daily generation

The same data plotted as a duration curve is shown in Figure 3.8 below.

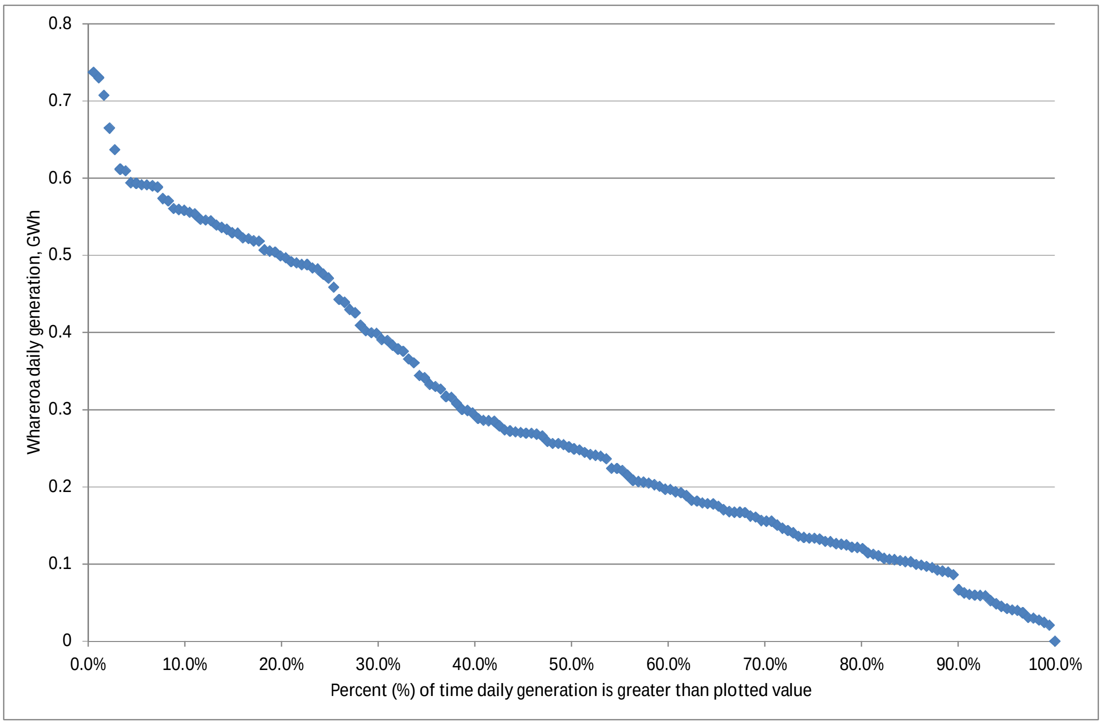


Figure 3.8 Whareroa daily generation duration curve

These show that for the first six months of 2011, Whareroa generated (dispatched to the grid) on 99% or 180 of the 181 days. It generated a total of 52,017 MWh for the 6 months, which is approximately equivalent to a net capacity factor of 17.6% (based on the 68 MW capacity cited by Todd Energy on its web site).

The duration curve profile shows that daily generation is highly variable. It is presumed that this is a consequence of load following the Fonterra milk processing process heating steam demand.

3.1.3.10 Te Rapa

There is little information on the Te Rapa cogeneration plant in the public domain. Contact Energy's (CE) web site simply notes that, "*The Te Rapa power station was commissioned in 1999 and is a cogeneration facility providing high quality steam and electricity to Fonterra's Te Rapa factory, one of the world's largest milk powder drying plants. Surplus electricity is directed back to the local area*."[10]

Wikipedia contains more information, advising that the Te Rapa cogeneration plant is "*a 45 MW cogeneration plant owned and operated by Contact Energy. It is located at the Fonterra dairy factory at Te Rapa near Hamilton in New Zealand.*

The plant is based on a gas turbine (a GE frame 6B) which can produce up to 45 MW of electricity. Hot exhaust gases from this gas turbine are ducted to a HRSG to raise steam. This HRSG has duct burners to increase steam output, which can be up to 180 tons of steam per hour. The plant was commissioned in 1999.

The cogeneration plant is designed for flexible operation, and can provide electricity to the dairy factory, export electricity to the local network or import electricity for use in the dairy factory. A common operating mode is 30 MW of electricity exported and 15 MW plus 120 tons per hour of steam provided to the dairy factory."[11]

Beca's web site notes that, "*As part of a major expansion project that would treble milk treatment to eight million litres per day, the Te Rapa dairy factory needed a lot more electricity and steam. Estimated final demand was 24MW of electricity and 180 ton/hour of steam, far outstripping the capacity of the installed coal boilers and 4MW of generation.*

Beca was commissioned by Contact Energy to draw up the technical specifications, assess and select bidders, and provide owner's Engineer services during the construction.

Contact Energy installed the 45MW gas turbine with a 170 tonne/hour heat recovery boiler."[12]

A CE, Thermal Electricity brochure is downloadable from CE's web site at http://www.contactenergy.co.nz/web/pdf/environmental/Thermal_brochure.pdf, and contains the following information, in particular:

- Generation capacity: 45 MW
- Gas turbine: General Electric Frame 6B
- Maximum steam output: 180 tonnes per hour

[10] http://www.contactenergy.co.nz/web/shared/powerstations?vert=au
[11] http://en.wikipedia.org/wiki/Te_Rapa_cogeneration
[12] http://www.beca.com/projects/power/power_generation/te_rapa_co_generation.aspx

- Te Rapa normally runs in cogeneration mode, providing roughly 15MW of electricity and steam to the Fonterra factory and 30MW of electricity back into the local electricity distribution network.
- The plant is fitted with a GT exhaust bypass, enabling the GT to operate as an electricity generator only, without producing steam
- There is no steam turbine associated with the Te Rapa cogeneration plant, however the 4 MW steam turbine generator noted in the Beca web site information may have been retained.

The Te Rapa plant therefore has little flexibility in its ability to produce electricity and steam for processing heating in varying proportions.

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Te Rapa and the data for the first six months of 2011 is plotted in Figure 3.9 below.

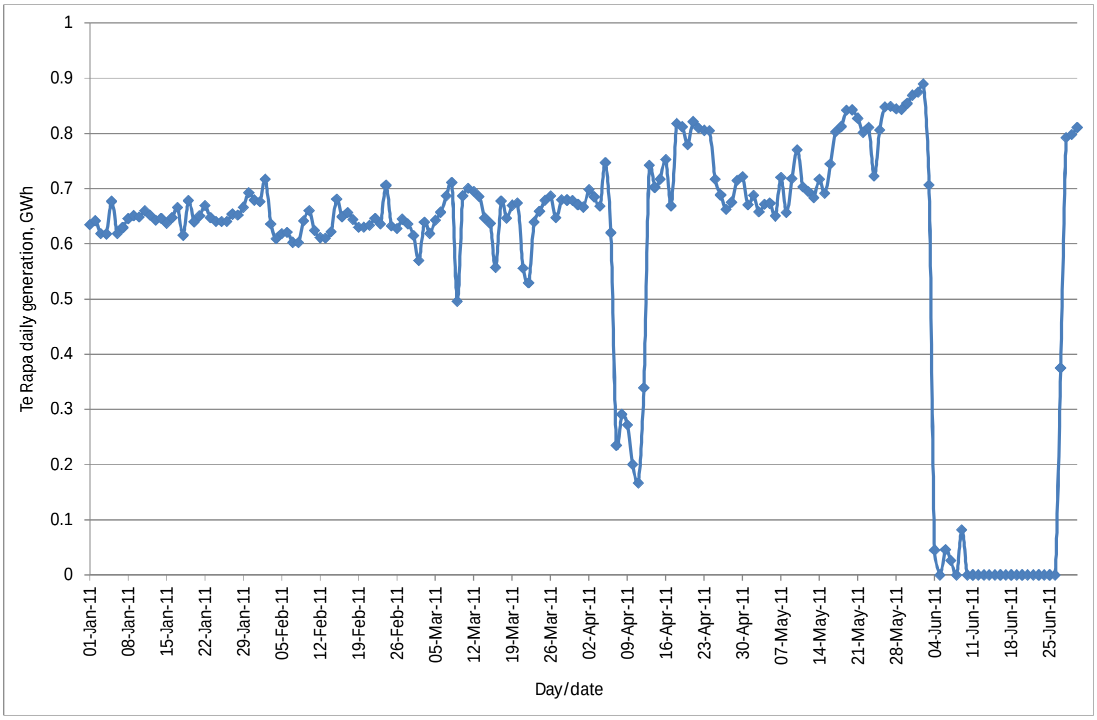


Figure 3.9 Te Rapa daily generation

The same data plotted as a duration curve is shown in Figure 3.10 below.

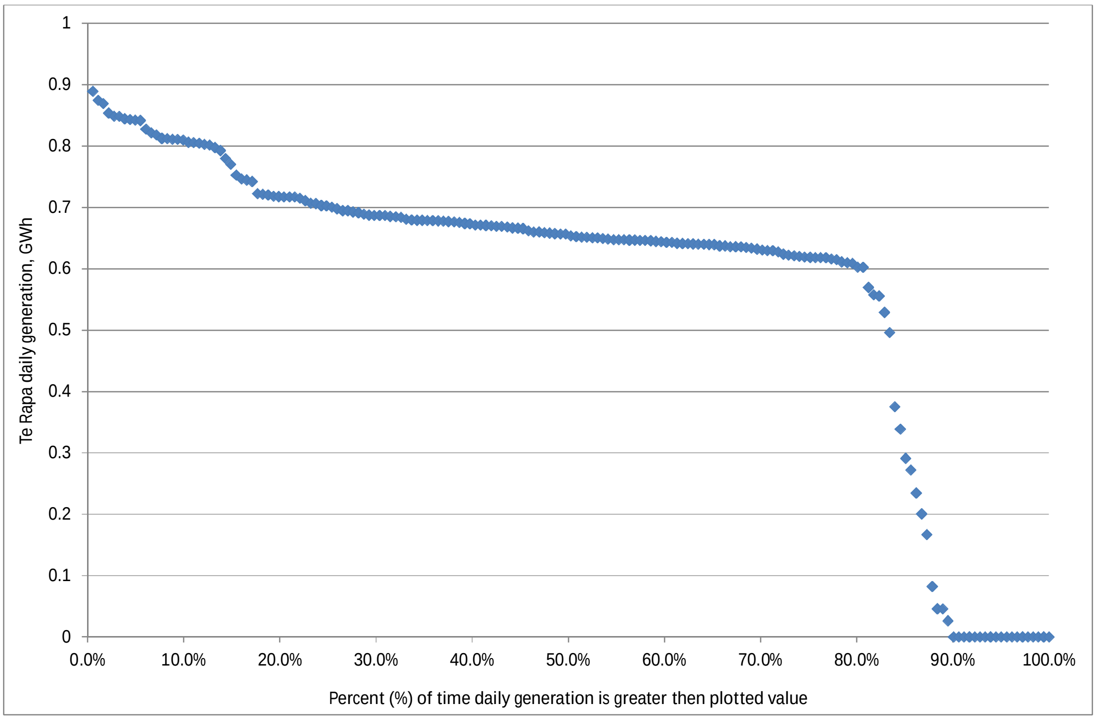


Figure 3.10 Te Rapa daily generation duration curve

These show that for the first six months of 2011, Te Rapa generated (dispatched to the grid) on 90% or 162 of the 181 days. It generated a total of 105,936 MWh for the 6 months, which is approximately equivalent to a net capacity factor of 54% (based on the 45 MW capacity cited by Contact Energy on its web site).

The duration curve profile shows a clear 'shoulder' and a significant portion of daily generation that varies only within a narrow range. It is presumed that this is a consequence of load following the Fonterra milk processing process heating steam demand. The lower daily generation values may indicate use of the GT in exhaust bypass mode for peaking.

3.1.3.11 Kinleith

The Kinleith Cogeneration Plant (Station) comprises a 39.6 MW extraction, back pressure steam turbine generator, which provides pressure let down for the Kinleith pulp and paper mill process heating steam demand. The steam is provided by two black liquor recovery boilers plus a third boiler, which was installed as part of the cogeneration project along with the steam turbine.

The primary fuel for the third or 'new' boiler is pinus radiata wood waste, including bark, chip fines and some sawdust. The secondary fuel is natural gas, and coal co-firing is also provided for.[13]

Genesis does not list the Kinleith Cogeneration Plant among its "Our generation sites" on its web site. However, a one-page excerpt titled "Physical Assets", from a larger document, is downloadable and records:

[13] *Nicholls B, Stark, P, Renewable Energy Cogeneration at the Kinleith Pulp and Paper Mill, presented at the 1999 FIEA Annual Conference on 22 June 1999*

"*This plant is located at the Carter Holt Harvey Pulp and Paper Plant at Kinleith, Tokoroa. It is fuelled by wood waste biomass supplemented as necessary with gas or coal. Biomass fuel is considered a renewable energy source because it can be replenished by planting more plantations. The fuel is burnt in a boiler to produce steam for a 40MW steam turbine and for process use*."[14]

Pertinent features of the cogeneration plant are:

- The steam turbine takes up to 477 t/h of steam, enabling it to generate up to 39.6 MW
- The three boilers providing steam to the steam turbine and downstream mill process heating steam demands have capacities of 190 t/h, 188 t/h and 180 t/h ('new', cogeneration project boiler)
- The steam turbine is an extraction, back pressure unit and therefore can only generate when the mill requires process heating steam
- The steam turbine can be bypassed by de-superheating and pressure reduction stations, so that the mill can continue to be supplied with steam if the steam turbine is not operating.
- The Kinleith plant therefore has little flexibility in its ability to produce electricity and steam for processing heating in varying proportions.

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Kinleith and the data for the first six months of 2011 is plotted in Figure 3.11 below.

The same data plotted as a duration curve is shown in Figure 3.12 below.

These show that for the first six months of 2011, Kinleith generated (dispatched to the grid) on 88% or 160 of the 181 days. It generated a total of 109,321 MWh for the 6 months, which is approximately equivalent to a net capacity factor of 63.6% (based on the 39.6 MW capacity cited by Nicholls et al).

The duration curve profile shows a clear and flat 'shoulder' at around 0.6587 GWh/day, which equates to generation at around 27.5 MW over the 24 hours. It is not known if this represents a load limitation on the steam turbine, or simply represents the process steam demand of the mill. This generator cannot be used for peaking.

[14] http://www.genesisenergy.co.nz/shadomx/apps/fms/fmsdownload.cfm?file_uuid=14B731BD-F227-0DC6-6FD8-DD2AD880849C&siteName=genesis

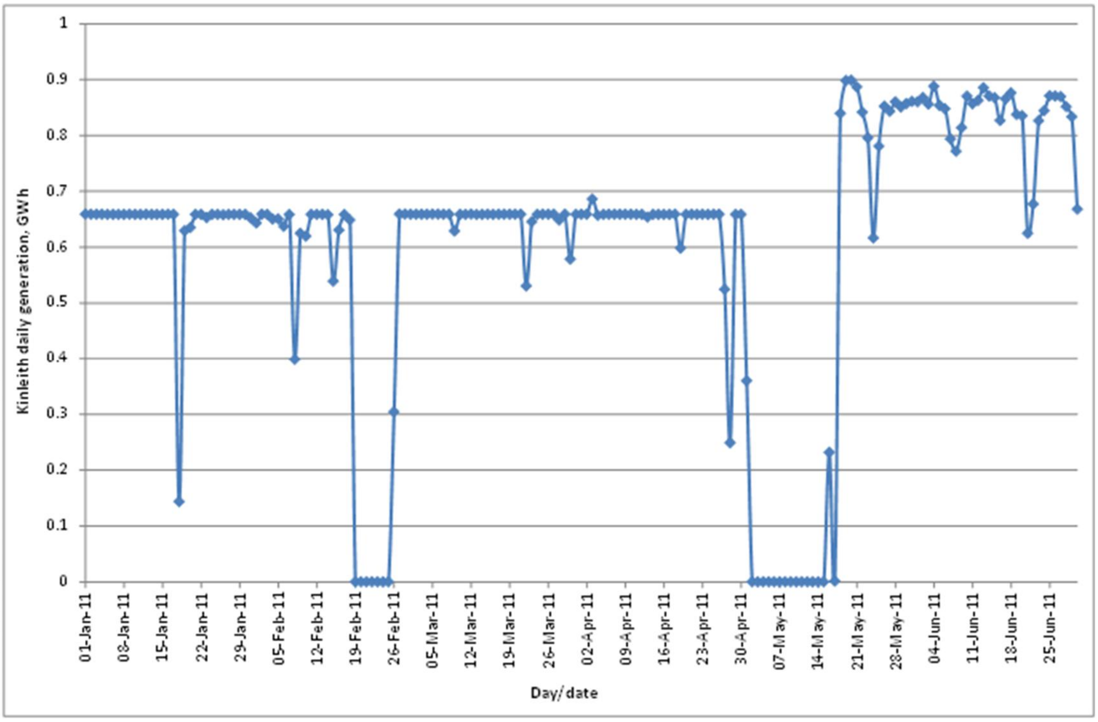


Figure 3.11 Kinleith daily generation

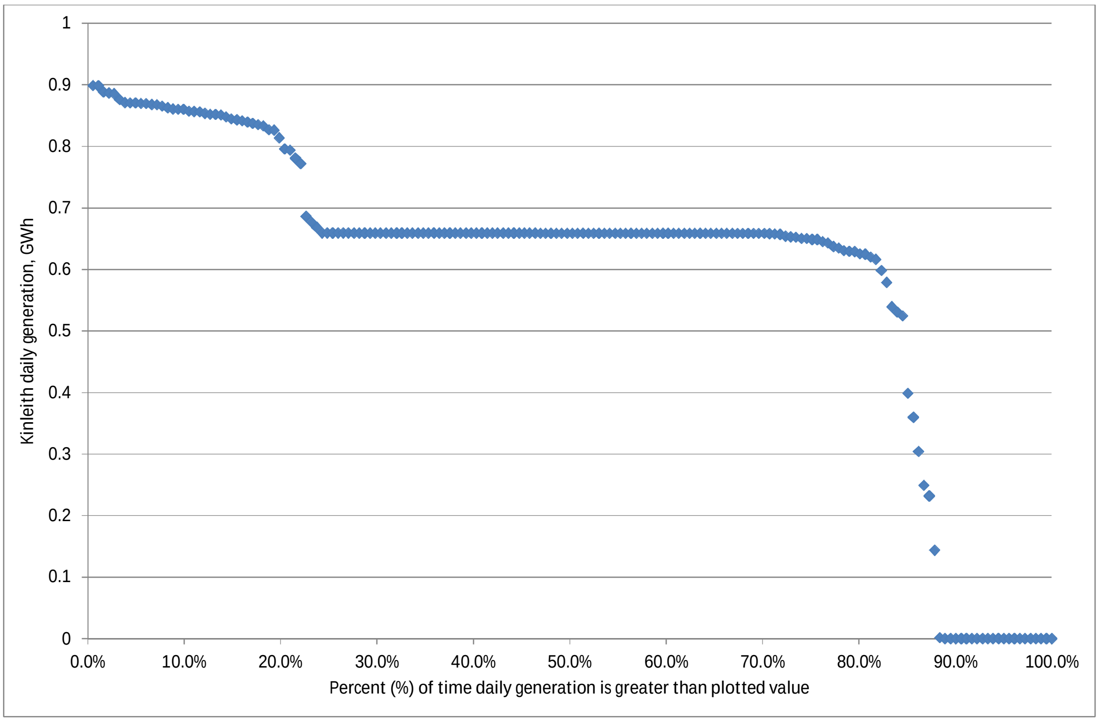


Figure 3.12 Kinleith daily generation duration curve

3.1.3.12 Glenbrook

The Glenbrook cogeneration plant is called “Glenbrook Power Station” by its owner, Alinta Energy. Alinta’s web site describes the plant as, “*112MW co-generation plant located at Glenbrook, south of Auckland, New Zealand.*

Glenbrook is fully integrated into the New Zealand Steel plant and is the core supplier of steam and electricity to that NZ Steel facility currently supplying around 60% of the electricity requirements."[15]

From past involvement with the Glenbrook cogeneration plant, PB understands that the cogeneration plant is an embedded, bottoming cycle, cogeneration plant on the site of, and integrated with, Bluescope Steel Limited's New Zealand steel plant (NZ Steel). The cogeneration plant produces electricity as a by-product of steel production, as well as producing steam for the host's steel making processes.

NZ Steel's steel making process at Glenbrook produces high temperature combustible gases, which provide energy for the cogeneration plant, from two sources:

Four multi hearth furnaces (MHF) produce an "off gas" at 450 – 1,000°C, which provides energy which is recovered in the MHF Cogeneration Plant. This comprises four waste heat boilers, two 18.8 MW condensing steam turbine generators, and conventional auxiliary plant.

Four Lurgi direct reduction rotary kilns produce an "off gas", at 800 – 1,200°C. The off-gas from the kilns contains up to 200 MW (thermal) of both fuel and thermal energy, which is recovered in the Kilns Cogeneration Plant. This comprises four boilers, a single 74 MW condensing steam turbine generator, and conventional auxiliary plant.

As an extension of the cogeneration development in 1997, a waste heat boiler (WHB) produces site process steam, utilising waste energy from the slab reheat furnace (SRF) at the Hot Rolling Mill.

The Glenbrook Power Station, comprising the MHF Cogeneration Plant, Kilns Cogeneration Plant and the SRF Waste Heat Boiler, is different from conventional power stations and cogeneration plants in the following ways:

- The inlet energy for the MHF cogeneration plant, except for times when surplus melter gas is used, is entirely sensible heat or thermal energy, with the inlet gases at up to 1,000°C. (Combustible gases are fired in MHF afterburners prior to entering the MHF boilers. The MHF boilers are "unfired");
- The inlet energy for the Kilns cogeneration plant is a combination of thermal energy (gases between 800°C and 1,200°C) and chemical energy (combustible gases, with carbon monoxide being the major component);
- The SRF waste heat boiler is unfired, using the thermal energy (up to 600°C) in the exhaust from the gas-fired slab reheat furnace;
- Part of the generated electricity (from the MHF cogen) is distributed to NZ Steel directly by connections to the steel plant's 11 kV system, with the bulk (from the Kilns cogen) connected by cable to the adjacent Transpower substation and the power is thence distributed back into the NZ Steel system;
- Operation of the Glenbrook Power Station plant is totally dependent on operation of the steelworks;

[15] http://alintaenergy.com/assets/generation/glenbrook/

- Under certain conditions of MHF and Kiln operation, there is opportunity for discretionary generation of up to approximately 14 MW by supplementary firing the Kilns Cogeneration Plant boilers with natural gas.

Apart from the opportunity for discretionary generation of up to approximately 14 MW, the Glenbrook plant has no flexibility in its ability to produce electricity and steam for processing heating in varying proportions.

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Glenbrook and the data for the first six months of 2011 is plotted in Figure 3.13 below.

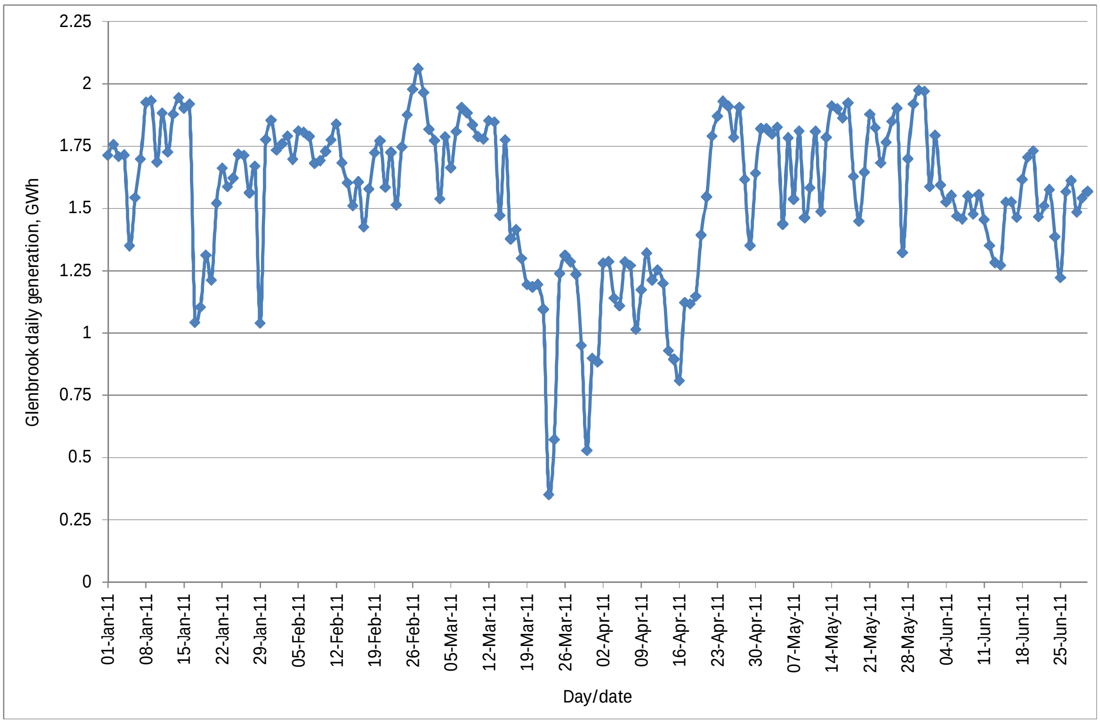


Figure 3.13 Glenbrook daily generation

The same data plotted as a duration curve is shown in Figure 3.14 below.

These show that for the first six months of 2011, Glenbrook generated (dispatched to the grid) on 100% of the 181 days. It generated a total of 282,414 MWh for the 6 months, which is approximately equivalent to a net capacity factor of 58.3% (based on the 111.6 MW capacity noted above (2 x 18.8 + 74 MW).

The duration curve profile shows variable generation between 1 and 2 GWh per day. The maximum of 2.06145 GWh in one day equates to generation at around 86 MW over the 24 hours. It is assumed that the variability represents the process steam demand of the steel mill.

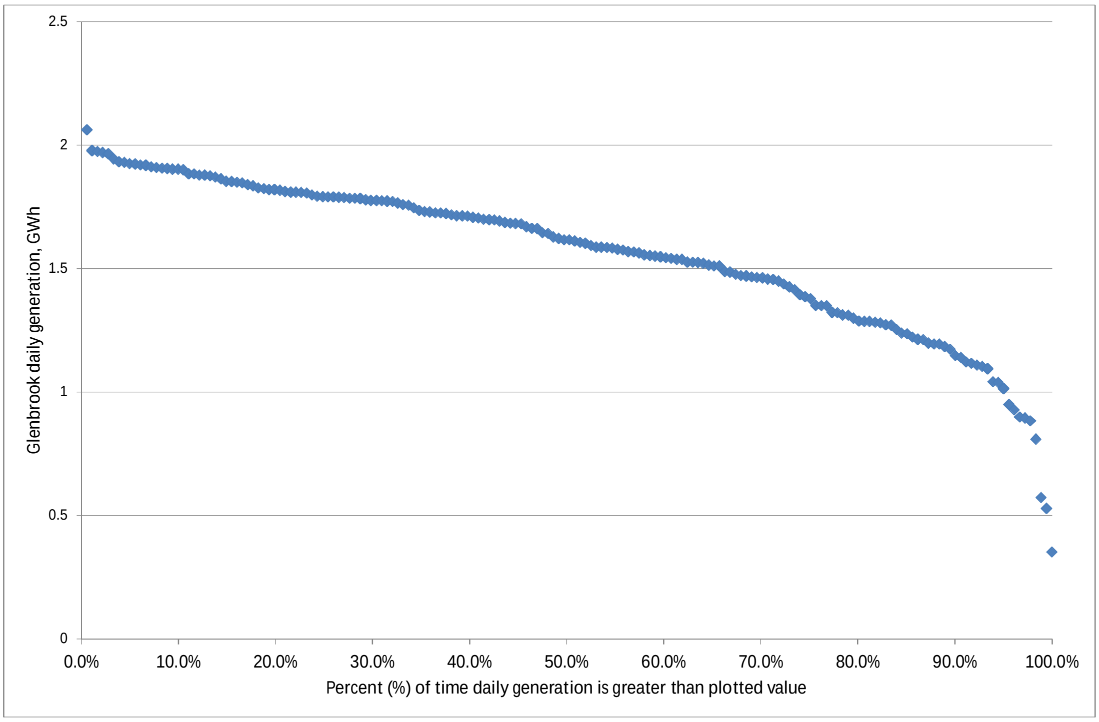


Figure 3.14 Glenbrook daily generation duration curve

3.1.3.13 Whirinaki

PB has previously described the Whirinaki plant as, "*a 155 MW, diesel fuelled, open cycle gas turbine power station using three Pratt & Whitney FT8 Twin Pac gas turbine generators. The FT8 gas turbine is an aero-derivative gas turbine derived from the Pratt & Whitney JT8D turbofan aircraft engine. In the TwinPac configuration, two FT8 aero-derivative gas turbines, each rated at around 26 MW are directly connected to each end of a centrally located synchronous generator.*

The gas turbines need water injection to control exhaust emissions to meet consent requirements. Four on-site staff manage the plant, which can also be operated remotely from Contact's Otahuhu Power Station.

A recent Sinclair Knight Mertz (SKM) report for the MED, "Whirinaki Power Station, Technical Information", December 2010, advises as follows.

"*The plant consists of 3 Pratt and Whitney Power Systems (PWPS) FT8-1 TwinPac gas turbine generator sets. Each set has two gas turbines which drive a common, centrally located Brush generator. It is possible to operate the generator using only one end at a time, but the power turbine of the non-operating end turns as there is no clutch between the turbines and the generator. Normally, however, both ends are used to meet a dispatch signal and the load is shared between each engine*."

The Electricity Authority's Centralised Dataset (CDS) records daily generation for Whirinaki and the data for the first six months of 2011 is plotted in Figure 3.15 below.

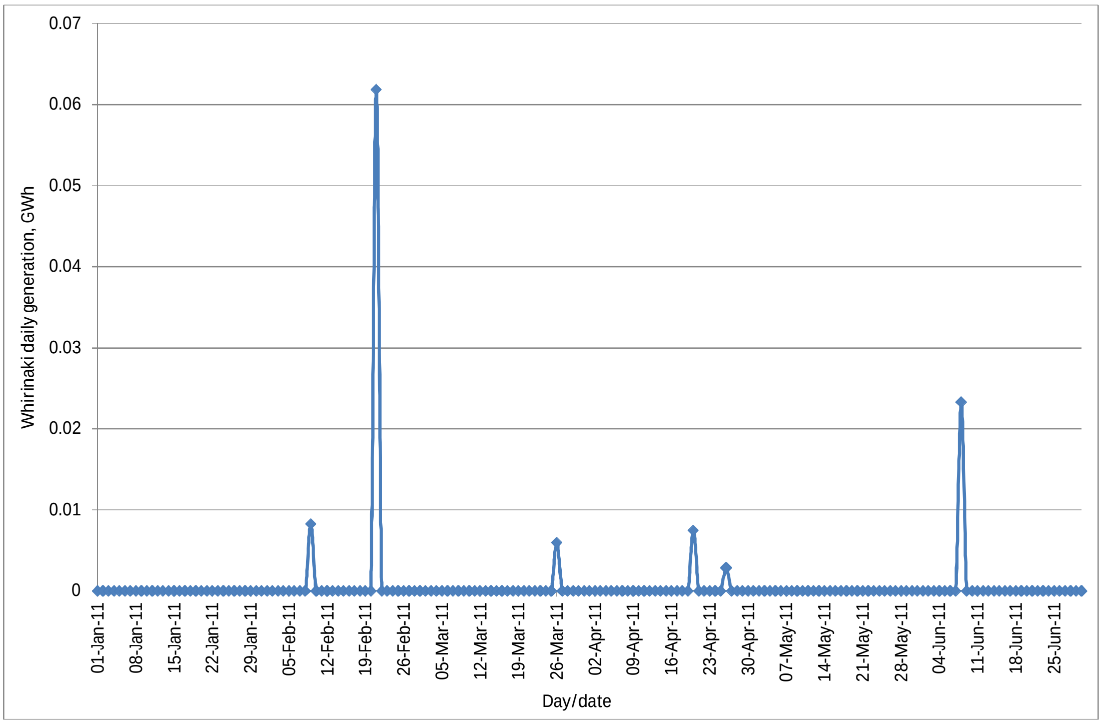


Figure 3.15 Whirinaki daily generation

The same data plotted as a duration curve is shown in Figure 3.16 below.

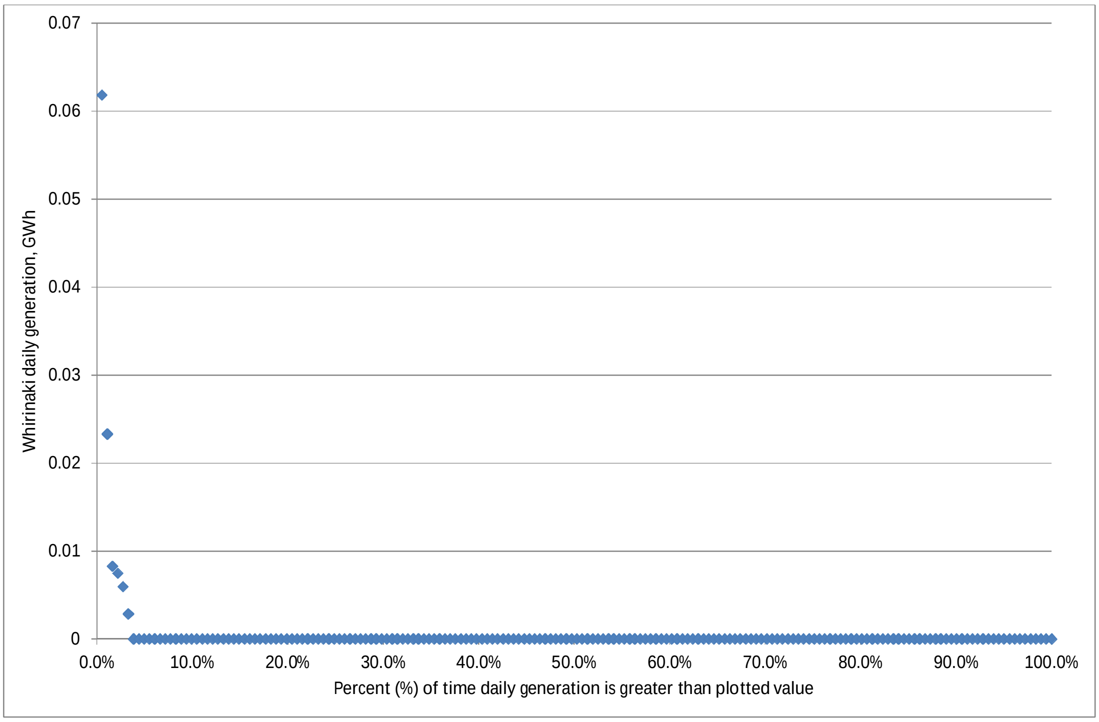


Figure 3.16 Whirinaki daily generation duration curve

These show that for the first six months of 2011, Whirinaki generated (dispatched to the grid) on only 3.3% or 6 of the 181 days. It generated a total of 10,965 MWh for the 6 months, which is approximately equivalent to a net capacity factor of 0.02% (based on the 155 MW capacity noted above.

3.1.3.14 Stratford

Contact Energy's web site describes Stratford as a 200 MW gas-fired peaking power station located at its Stratford power station in Taranaki, and commissioned in early 2011. "*When fully operational in late 2010, the two fast-start gas turbine peaking units will supply enough electricity for 200,000 average homes and can go from a cold start to full load in just 10 minutes.*

The two units are high efficiency LMS-100 gas turbine generators, the most efficient fast start technology available in Australasia.

The gas turbine peaking units have been installed on the site of Contact's former Stratford power station, adjacent to the company's existing Taranaki Combined Cycle (TCC) power station. Together, TCC and the two new peakers produce a total combined output of 580MW"[16].

Contact's web site further describes the LMS-100 as a "*fast start, high efficiency gas turbine developed especially for electricity generation. It brings together a heavy duty frame compressor and aeroderivative gas turbine technology, with an intercooler and power turbine. The LMS100 is the most efficient gas turbine generator on the market today, and the largest aeroderivative.*

The LMS100 produces approximately 100 MW at 46% LHV efficiency, depending on site ambient conditions."

In GEM terms the Stratford plant is an OCGT or gas peaker.

The Electricity Authority's Centralised Dataset (CDS) has so far recorded daily generation for "Taranaki CC + new turbines" and has not discriminated between Taranaki CC and Stratford.

3.1.3.15 Edgecumbe

Todd Energy's web site describes Edgecumbe as, "*wholly owned by Todd Energy via our retail/generation business, Bay of Plenty Energy*" and "*located in Edgecumbe in the Bay of Plenty at Fonterra's Edgecumbe dairy processing factory*."

"*The Station was commissioned in 1996*" and "*consists of two General Electric Corporation (GEC) Typhoons rated at 5 MW each. The plant produces up to 60 tonnes an hour of steam for use in the Fonterra milk processing plant"* (with supplementary firing), and an average annual generation of 60 GWh.[17]

In GEM terms, the Edgecumbe plant is a gas-fired GT cogeneration plant. It has no steam turbine generator.

The Electricity Authority's Centralised Dataset (CDS) has no recorded daily generation for "Bay Milk Edgecumbe", although it is listed as a generator.

[16] http://www.contactenergy.co.nz/web/ourprojects/gasturbinepeakingunits?vert=au
[17] http://www.toddenergy.co.nz/edgecumbe-co-generation

3.1.3.16 Mangahewa

Todd Energy's web site describes Mangahewa as, "*located at the McKee Production Station approximately 20 km SE of New Plymouth, some 12 km inland from the Methanex Motunui complex.*

Raw untreated gas from the recently drilled Mangahewa 3 well is being used to generate enough electricity to power about 10,000 houses annually" producing an average annual generation of 70 GWh.

The Mangahewa Generation plant comprises three packaged electricity generation units.

The units are driven by large internal combustion engines with the design tweaked so they can run on raw wellstream gas rather than pipeline gas. Each unit can generate up to 3.2 MW with the electricity exported to the local grid."

In GEM terms, the Mangahewa plant is a gas-fired internal combustion (IC) engine generator.

The Electricity Authority's Centralised Dataset (CDS) does not record Mangahewa as a generator.

3.1.4 Energy type

3.1.4.1 Southdown

Southdown is fuelled by natural gas. There are no diesel storage tanks on the site and it is therefore assumed that diesel fuel is not used as a back-up.

3.1.4.2 Taranaki CC

Taranaki CC is fuelled by natural gas.

3.1.4.3 Otahuhu B

Otahuhu B is fuelled by natural gas.

3.1.4.4 Huntly unit 5 (e3p)

Huntly Unit 5 is fuelled by natural gas.

3.1.4.5 Huntly gas

Huntly gas, or Huntly Power Station units 1 – 4, is fuelled by natural gas.

3.1.4.6 Huntly unit 6 (P40)

Huntly Unit 6 is dual fuelled with natural gas or diesel.

3.1.4.7 Southdown E105

Southdown is fuelled by natural gas. There are no diesel storage tanks on the site and it is therefore assumed that diesel fuel is not used as a back-up.

3.1.4.8 Huntly coal units 1 - 4

Huntly coal, or Huntly Power Station units 1 – 4, are fuelled with coal. It was reported in 2006 that, "*Genesis spokesman Richard Gordon said 1.2 million tonnes of coal a year would continue to be imported from Indonesia for Huntly, along with another million tonnes a year from Solid Energy's Waikato mines*."

The level of generation from coal is understood to have reduced following its displacement by the relatively new, natural gas fired, Huntly Unit 5 (e3p). While the level of generation from Huntly coal units 1 – 4 is recorded by the Electricity Authority's Centralised Dataset (CDS), the source of the coal cannot be determined.

3.1.4.9 Kapuni

Kapuni is fuelled by natural gas, namely "*treated Kapuni gas from Vector's gas treatment plant*." It is not known if liquid fuel (diesel) is available as a back-up.

3.1.4.10 Hawera

Hawera is fuelled by natural gas. It is not known if liquid fuel (diesel) is available as a back-up.

3.1.4.11 Te Rapa

Te Rapa is fuelled by natural gas. It is not known if liquid fuel (diesel) is available as a back-up.

3.1.4.12 Kinleith

Based on the paper cited earlier by Nicholls & Stark, Kinleith, that is the 40 MW steam turbine generator, is effectively fuelled by one or more of black liquor, wood waste, natural gas, and coal. The primary fuels are black liquor (two of three boilers only) and pinus radiata wood waste (one boiler only), including bark, chip fines and some sawdust. The secondary fuel for wood waste boiler only is natural gas, and coal co-firing is also provided for.

Note: 'Black liquor' is the spent cooking liquor from the Kraft pulp production process when digesting pulpwood into paper pulp by removing lignin, hemicelluloses and other extractives from the wood to free the cellulose fibres.

Based on boiler capacity, black liquor could provide 79% of the steam required by the steam turbine generator, with the balance made up by wood waste, natural gas, and coal. The actual proportions of the various fuels used are not known.

Black liquor and wood waste are by-product waste streams from the pulp and paper mill process, and are therefore zero cost fuels.

3.1.4.13 Glenbrook

The Glenbrook cogeneration plant relies on various off-gases and melter gas from upstream iron plant processes as the major energy supplies to the boilers that produce the steam for the steam turbine generators. These gases are supplied with high sensible heat (high temperature) as available, and have in effect, a zero cost.

As noted in section 3.1.3.13 above, under certain conditions of MHF and Kiln operation, there is opportunity for discretionary generation of up to approximately 14 MW by supplementary firing the Kilns Cogeneration Plant boilers with natural gas. It is not known to what extent this opportunity is taken.

3.1.4.14 Whirinaki

The SKM report for the MED, “Whirinaki Power Station, Technical Information”, December 2010, advises that the fuel for Whirinaki “*is normal diesel - sometimes referred to as AGO, or automotive gas oil.*

Fuel is supplied to the gas turbines from two 2 million litre tanks. (The fuel storage tanks and system belong to Contact Energy and are not amongst the Crown assets).”

3.1.4.15 Stratford

Stratford is fuelled by natural gas and is associated with Contact Energy’s underground gas storage facility at the depleted Ahuroa reservoir near Stratford. This facility is located close to Contact's Taranaki CC and the 200 MW Stratford peaker, and provides flexibility in Contact's natural gas supply, allowing Contact to take and store natural gas during off peak times, such as summer, and use it during peak times, like winter peaks.

Contact’s web site notes that, “*in conjunction with Origin Energy, Contact has installed a large injection compressor and drilled three injection/extraction wells.*

At this stage Contact is able to inject gas at up to 32 terajoules (TJ) per day and withdraw gas from the facility at rates of up to 45 TJ per day - enough to supply the two fast-start gas turbine peaking units at Stratford Power Station.”[18]

3.1.4.16 Edgecumbe

Edgecumbe is fuelled by natural gas. It is not known if liquid fuel (diesel) is available as a back-up.

3.1.4.17 Mangahewa

Managhewa is fuelled by “*raw wellstream gas rather than pipeline gas*”.

3.1.5 Substation

3.1.5.1 Southdown

Southdown is dispatched at 220 kV and the 11.5/220 kV transformers are part of the Southdown Power Station. The plant is connected to the Henderson-Otahuhu A (HEN-OTA-A) 220 kV transmission line via a Transpower substation adjacent to the Southdown Power Station, as shown in Figure 3.1.

The Transpower standard site abbreviation for the Southdown substation is SWN[19].

[18] http://www.contactenergy.co.nz/web/ourprojects/gasstoragefacility?vert=au
[19] *Transpower New Zealand Limited, Standard site abbreviations, TP.AG 10.11, Issue 29, Aug 2009*

3.1.5.2 Taranaki CC

Taranaki CC is located adjacent to the historical Stratford Power Station site, which in turn is located adjacent to the Transpower Stratford Substation.

The Transpower standard site abbreviation for Taranaki CC is SPL[19], based on the name of the original owner/developer, Stratford Power Limited. Contact Energy purchased Stratford Power Limited in 2003.

The Transpower standard site abbreviation for the Stratford substation is SFD[19].

3.1.5.3 Otahuhu B

Otahuhu B is located adjacent to the historical Otahuhu Power Station (Otahuhu Gas Turbine Station) site, which in turn is located adjacent to the Transpower Otahuhu Substation.

The Transpower standard site abbreviation for Otahuhu B is OTC[19] (Otahuhu Combined Cycle Plant).

The Transpower standard site abbreviation for the Otahuhu substation is OTA[19].

3.1.5.4 Huntly unit 5 (e3p)

Huntly Power Station units 1 – 6, including Huntly Unit 5 (e3p) are all connected to the Transpower Huntly substation.

The Transpower standard site abbreviation for the Huntly substation is HLY[19].

3.1.5.5 Huntly gas

As noted in section 3.1.5.4 Huntly Power Station units 1 – 6, including Huntly gas are all connected to the Transpower Huntly substation.

The Transpower standard site abbreviation for the Huntly substation is HLY[19].

3.1.5.6 Huntly unit 6 (P40)

As noted in section 3.1.5.4 Huntly Power Station units 1 – 6, including Huntly Unit 6 (P40) are all connected to the Transpower Huntly substation.

The Transpower standard site abbreviation for the Huntly substation is HLY[19].

3.1.5.7 Southdown E105

As noted in section 3.1.5.1, all the Southdown generating units, including Southdown E105 are connected to the Henderson-Otahuhu A (HEN-OTA-A) 220 kV transmission line via a Transpower substation adjacent to the Southdown Power Station, as shown in Figure 3.1.

The Transpower standard site abbreviation for the Southdown substation is SWN[19].

3.1.5.8 Huntly coal units 1 - 4

As noted in section 3.1.5.4 Huntly Power Station units 1 – 6, including Huntly coal units 1 - 4 are all connected to the Transpower Huntly substation.

The Transpower standard site abbreviation for the Huntly substation is HLY[19].

3.1.5.9 Kapuni

The Transpower standard site abbreviation for Kapuni is KPI[19] and the plant is electrically connected to the Transpower Opunake-Stratford A (OPK-SFD-A) double circuit 110 kV line via a deviation called the Kaponga Tee.

The Transpower standard site abbreviation for the Kaponga Tee deviation is KPA[19].

3.1.5.10 Hawera

Hawera (otherwise known as the Whareroa Co-generation Station) has a local substation/switching station named Whareroa, with the Transpower standard site abbreviation of WAA[19].

The Whareroa site is in turn understood to be connected to the Transpower's Wanganui-Stratford A (WGN-SFD-A) single circuit 110 kV line at the Hawera substation. The Transpower standard site abbreviation for the Hawera substation is HWA[19].

3.1.5.11 Te Rapa

The Transpower standard site abbreviation for the "Te Rapa Co-gen" power plant is TRC[19], however the plant is not connected directly to the Transpower system.

Contact Energy's Te Rapa cogeneration plant is embedded in the WEL Networks Ltd 33 kV system (network), and connected to the Pukete zone substation.[20] As shown in the following Figure 3.17, Pukete zone substation is also supplied from WEL Networks' Te Kowhai 'point of supply' at the Transpower Te Kowhai (TWH) substation.

[20] *ASSET MANAGEMENT PLAN, WEL NETWORKS LTD, Planning Period: 1 April 2010 to 31 March 2021, Disclosure Date: 14 December 2010*

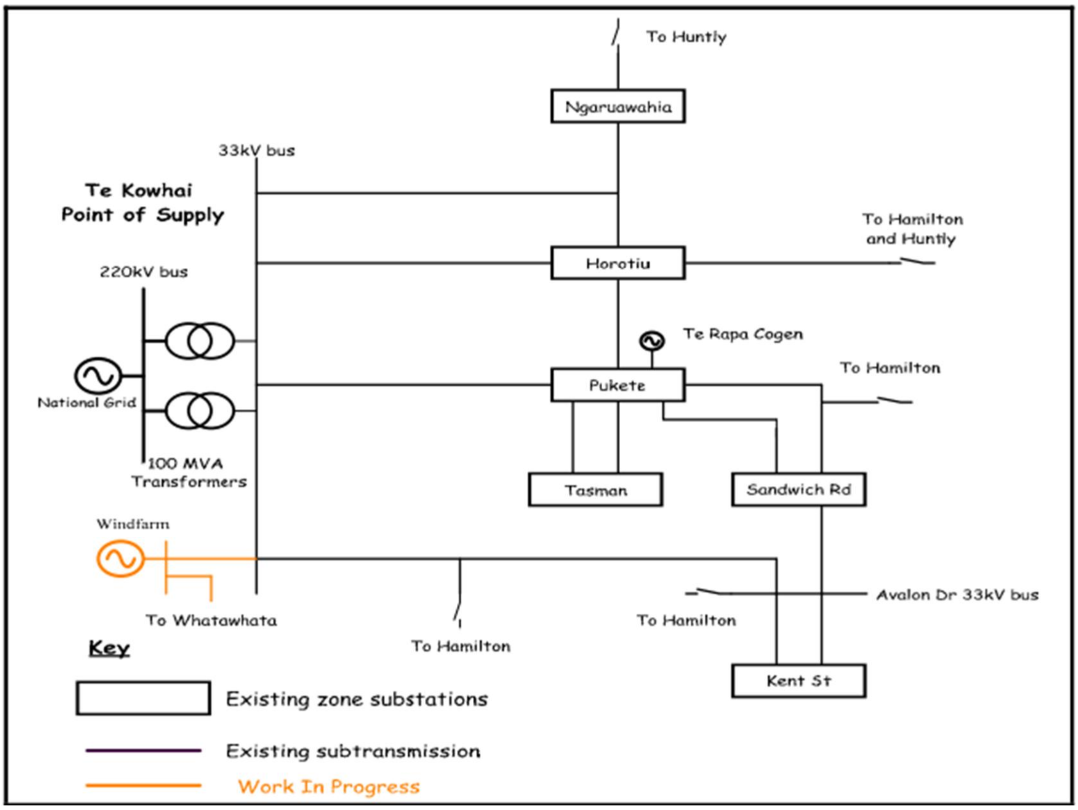


Figure 3.17 Te Rapa connection to WEL Networks Pukete zone substation[20]

3.1.5.12 Kinleith

The Kinleith cogeneration plant is also not connected directly to the Transpower system and it appears that Transpower does not record a standard site abbreviation for the plant.

The Kinleith cogeneration plant is embedded in the Powerco Limited 11 kV Kinleith pulp & paper mill system (network), and connected to that system. Powerco's Kinleith mill system is also supplied from the Powerco 'point of supply' at the Transpower Kinleith (KIN) substation.[19] [21]

3.1.5.13 Glenbrook

The Transpower standard site abbreviation for the Glenbrook cogeneration plant is NZS[19], based on an earlier owner's name, "Broken hill Proprietary NZ Steel Ltd (Glenbrook)" and the plant is electrically connected to the Transpower Glenbrook substation.

The Transpower standard site abbreviation for the Glenbrook substation is GLN[19].

3.1.5.14 Whirinaki

The SKM report for the MED, "Whirinaki Power Station, Technical Information", December 2010, advises that, "*power is generated at 11.5kV and transformed to 220kV before being exported to Transpower's Whirinaki substation*."

The Transpower standard site abbreviation for the Whirinaki substation is WHI[19].

[21] *Powerco Limited, 2011 Asset Management Plan, Information Disclosure for Electricity Networks, 2011 - 2021*

3.1.5.15 Stratford

Stratford is located on the historical Stratford Power Station site, which in turn is located adjacent to the Transpower Stratford Substation.

The Transpower standard site abbreviation for the Stratford, including both the power station and adjacent substation is SFD[19].

3.1.5.16 Edgecumbe

The Edgecumbe cogeneration plant is not connected directly to the Transpower system and it appears that Transpower does not record a standard site abbreviation for the plant.

The Edgecumbe cogeneration plant is embedded in the Horizon Energy Distribution Limited network system and is described as "*connected to site loads and to Plains substation*". Plains substation is a Horizon Energy 33 kV distribution asset.[22]

Horizon Energy's Plains Substation is in turn supplied from Transpower's Edgecumbe (EDG) substation.[19]

3.1.5.17 Mangahewa

The Mangahewa generation plant is also not connected directly to the Transpower system and it appears that Transpower does not record a standard site abbreviation for the plant.

The Managhewa generation plant is embedded in the Powerco Limited network system and the nearest Powerco substation is the McKee zone substation. Powerco describes the connections as, "*McKee Production station's 2MW generation is connected at 11kV and 9MW generation at 33kV*."[21]

The nearest Transpower Grid Exit Point substation is Transpower's Huirangi (HUI) substation, however the McKee zone substation is also interconnected to Transpower's Stratford (SFD) substation.

3.1.6 Project Lifetime

3.1.6.1 Introduction

These sections seek to determine how long each thermal generation plant can be reasonably expected to remain operational after commissioning. This subject was addressed in PB's report, "Thermal Power Station Advice, Report for the Electricity Commission", July 2009. That report noted that:

- Thermal power plant equipment design life is typically specified as 25 years operational life and 200,000 hours. A number of hot, warm and cold starts will also be specified. An equivalent operating hours (EOH) penalty will be associated with each start, stop or trip event.

- Thermal power plant operating life can be, and often is maintained well beyond the original design life with the replacement and refurbishment of equipment.

[22] *Horizon Energy, Asset management Plan 2011 - 2021*

- Worldwide it is observed that some coal fuelled steam and natural gas turbines are 40-50 years old and still in operation 20 years beyond the original nominal calendar design life.
- Whether thermal plants are refurbished, placed on standby or decommissioned before or at their design life remains primarily an economic decision for the owner. The economics of a unit are a function of market competitiveness, relating to potential net revenues versus the net costs which costs will include fuel, maintenance and capital costs. This decision is often difficult to make and the outcome is often based on reasons which are not always transparent to uninformed outside observation.
- Observed plant retirement decisions in US and Europe have generally been made to replace still operable but older less efficient plant which require significant capital expenditure for emissions related upgrades required for regulatory compliance with newer more efficient (heat rate <7000 kJ/kWh) and lower emissions units.

That report estimated decommissioning dates for each of the NZ thermal plant included in the scope of the study. The estimation of these dates was based on a set of assumptions around the original design life and operating regime of the plant. The results were summarised in Table 5.1 (page 48) of that report as reproduced below.

Table 5.1 Projected decommissioning dates of NZ thermal plant

Plant	***Commission-ing date***	***Design life*** *(Years)*	***Projected decomm. date***	***Refurb. date***	***Refurb. Capex*** *($/kW)*	***Projected decomm. date with mid-life refurb.***
Huntly PS - (Units 1 to 4)	*1982 - 1985*	*25*	*2020*	*2020*	*864*	*2035*
Huntly PS - CCGT	*2007*	*25 to 30*	*2037*	*2027*	*492*	*2057*
Huntly PS – OCGT	*2004*	*25*	*2029*	*2021*	*400*	*2046*
TCC	*1998*	*25 to 30*	*2028*	*2018*	*480*	*2048*
Ota B	*1999*	*25 to 30*	*2029*	*2019*	*480*	*2049*
New Plymouth	*1974 - 1976*	*25*	*n/a*	*n/a*	*n/a*	*n/a*
Southdown CCGT	*1998*	*25*	*2028*	*2018*	*480*	*2048*
Southdown E105	*2007*	*25*	*2032*	*2024*	*368*	*2049*
Whirinaki	*2004*	*25*	*2029*	*n/a*	*n/a*	*n/a*

This report will not replicate any other of the findings and discussion included in the 2009 Thermal Power Station Advice report, but will reply on its estimated decommissioning dates. Unless otherwise stated, the information below is sourced from the 2009 Thermal Power Station Advice report or PB in-house information.

3.1.6.2 Southdown

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2007, mid-life refurbishment of the unit would occur around 2024 and be likely to extend the life of the plant out to 2049.

The Project Lifetime is therefore 42 years.

3.1.6.3 Taranaki CC

Without mid-life refurbishment, plant of this nature should be able to operate beyond the original 25 year design life to at least 30 years of operation taking decommissioning to around 2028. Mid-life refurbishment of the unit would occur around 2018 and be likely to extend the life of the plant out to 2048.

Given that this plant was commissioned in 1998, the Project Lifetime is therefore 50 years.

3.1.6.4 Otahuhu B

Without mid-life refurbishment, plant of this nature, with regular maintenance, should be able to operate beyond the original design life to at least 30 years of operation and hence the projected decommissioning date would be 2029. If economic, a mid-life refurbishment of the unit would occur around 2019 and be likely to extend the operating life of the plant out to 2049.

Given that this plant was commissioned in 1999, the Project Lifetime is therefore 50 years.

3.1.6.5 Huntly unit 5 (e3p)

Without mid-life refurbishment, plant of this nature should be able to operate beyond the original design life to at least 30 years of operation to 2037. Mid-life refurbishment of the unit would occur around 2027 and be likely to extend the potential operating life of the plant out to 2057.

Given that this plant was commissioned in 2007, the Project Lifetime is therefore 50 years.

3.1.6.6 Huntly gas/coal units 1 - 4

Given that the main boiler plant was then approximately 25 years old, and had consumed approximately 75% of the design operating hours, a prediction of a further 10 years of reliable operation to 2020 was reasonable based on the assumption that regular scheduled maintenance is performed without the need for mid-life refurbishment. This was supported by the fact that gas was the predominant fuel up to 2002, resulting in less wear and tear on the main coal handling plant.

Extension of the life of the units beyond 2020 will be likely to require a significant refurbishment including the C&I upgrades over the next 10 years. Given the nature of the plant and observed lives of similar plant around the globe, as long as the economics allow refurbishments to be executed, there should be no technical reason why the plant could not continue to operate for another 25 years, doubling the original design life to 50 years, with a projected decommissioning date of 2035.

The Project Lifetime is therefore 50 years.

3.1.6.7 Huntly unit 6 (P40)

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2004, mid-life refurbishment of the unit would occur around 2021 and be likely to extend the life of the plant out to 2046.

The Project Lifetime is therefore 42 years.

3.1.6.8 Southdown E105

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2007, mid-life refurbishment of the unit would occur around 2024 and be likely to extend the life of the plant out to 2049.

The Project Lifetime is therefore 42 years.

3.1.6.9 Kapuni

The life of the cogeneration plants has not previously been estimated by PB. If the same principles applying to the other thermal power generators also apply to the cogeneration plants, then the same Project Lifetimes can be expected.

It is noted that cogeneration plants are generally dependent upon their process heating ‘hosts’. As long as the electricity price covers the cost of the fuel attributable to power, it seems likely therefore that the cogeneration plants will continue in operation as long as their hosts. The future life of the cogeneration hosts is indeterminate.

The Project Lifetime of Kapuni, a gas turbine based cogeneration plant is therefore considered to be 42 years.

3.1.6.10 Hawera

The Project Lifetime of Hawera is similarly considered to be 42 years.

3.1.6.11 Te Rapa

The Project Lifetime of Te Rapa is similarly considered to be 42 years.

3.1.6.12 Kinleith

The Project Lifetime of Kinleith, a boiler and steam turbine based cogeneration plant is similarly considered to be 50 years.

3.1.6.13 Glenbrook

The Project Lifetime of Glenbrook, a boiler and steam turbine based cogeneration plant is similarly considered to be 50 years.

3.1.6.14 Whirinaki

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. This suggests a decommissioning date of 2029.

Given that this plant was commissioned in 2004, the Project Lifetime is therefore 25 years.

3.1.6.15 Stratford

Without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Given the plant was commissioned in 2011, mid-life refurbishment of the unit would occur around 2028 and be likely to extend the life of the plant out to 2053.

The Project Lifetime of Stratford is therefore 42 years.

3.1.6.16 Edgecumbe

The Project Lifetime of Edgecumbe, a gas turbine based cogeneration plant is considered to be 42 years.

3.1.6.17 Mangahewa

Mangahewa uses internal combustion (IC) or reciprocating engines. PB has previously advised the Electricity Commission, in PB report, "Thermal Power Station Advice – Reciprocating Engines Study", November 2009 that, "*with proper maintenance, large engines have an operating life of 20 – 30 years*".

The Project Lifetime of Mangahewa is therefore estimated at 30 years.

3.1.7 Operational capacity

3.1.7.1 Introduction

These sections seek to determine the long term operational capacity of the thermal generation plants.

It is understood that the GEM uses what is otherwise referred to in the industry as "net capacity" as opposed to gross capacity. The difference between net and gross capacity is the auxiliary power demand, or 'house load' or 'parasitic load' and is the power consumed by the plant internally.

Such power is used to drive fuel delivery and preparation equipment (conveyors, crushers, feeders and pulverising mills for coal fired plant, and gas compressors for gas fired plant if required), and process equipment such as pumps and fans. It also includes power and lighting requirements, and electrical losses in transformers.

3.1.7.2 Southdown

The net capacity of the Southdown cogeneration plant is estimated as 122 MW.

3.1.7.3 Taranaki CC

The net capacity of the Taranaki CCGT plant is estimated as 380 MW.

3.1.7.4 Otahuhu B

The net capacity of the Otahuhu B CCGT plant is estimated as 380 MW.

3.1.7.5 Huntly Unit 5 (e3p)

In response to PB request, Genesis Energy has completed the MED data tables provided to it and returned the data tables as Excel spreadsheet file, “*MED data_Genesis existing (4)*”.

Genesis has not completed those rows of the data table that would involve the disclosure of information that is considered by Genesis to be confidential and commercially sensitive.

The long term operational net capacity of Huntly Unit 5 (e3p) is declared to be 385 MW. This is consistent with public domain data.

3.1.7.6 Huntly gas

Genesis Energy has declared the long term operational net capacity of Huntly units 1 – 4, firing natural gas, to be 245 MW. This is consistent with PB understanding for a unit with a gross capacity of 250 MW and around 2% auxiliary power demand.

3.1.7.7 Huntly Unit 6 (P40)

Genesis Energy has declared the long term operational net capacity of Huntly Unit 6 (P40) to be 40 - 48 MW. PB recommends that the median value is assumed for the GEM, 44 MW. This is consistent with public domain data.

3.1.7.8 Southdown E105

The net capacity of the Southdown E105 OCGT plant is estimated as 45 MW.

3.1.7.9 Huntly coal units 1 - 4

Genesis Energy has not declared the long term operational net capacity of Huntly units 1 – 4, firing coal. PB estimates this to be 237 MW on the basis of a gross capacity of 250 MW and around 5% auxiliary power demand when firing coal.

3.1.7.10 Kapuni

The net capacity of the Kapuni plant is estimated as 20 MW.

3.1.7.11 Hawera

The net capacity of the Hawera plant is estimated as 68 MW.

3.1.7.12 Te Rapa

The net capacity of the Te Rapa plant is estimated as 45 MW.

3.1.7.13 Kinleith

Genesis Energy has not declared the long term operational net capacity of Kinleith cogeneration plant. PB estimates this to be 38 MW on the basis of a gross capacity of 40 MW and around 5% auxiliary power demand.

3.1.7.14 Glenbrook

The net capacity of the Glenbrook plant is estimated as 112 MW

3.1.7.15 Whirinaki

The net capacity of the Whirinaki plant is estimated as 155 MW

3.1.7.16 Stratford

The net capacity of the Stratford plant is estimated as 200 MW

3.1.7.17 Edgecumbe

The net capacity of the Edgecumbe plant is estimated as 10 MW

3.1.7.18 Mangahewa

The net capacity of the Mangahewa plant is estimated as 9.6 MW

3.1.8 Availability Factor

3.1.8.1 Introduction

The MED and PB have defined “Availability Factor” as the “percentage of time plant is available to generate. That is, the proportion of its lifetime the plant is available to generate maximum capacity (given unlimited resource).

This definition is consistent with the use of the term “availability” in the industry.

3.1.8.2 Southdown

Given available information PB recommends a value of 90%.

3.1.8.3 Taranaki CC

Given available information PB recommends a value of 93%.

3.1.8.4 Otahuhu B

Given available information PB recommends a value of 93%.

3.1.8.5 Huntly Unit 5 (e3p)

Genesis Energy has declared the long term availability of Huntly Unit 5 (e3p) to be 90 – 95% depending on the type of maintenance outage in a particular year. PB recommends that the median value is assumed for the GEM, 93%.

3.1.8.6 Huntly gas

Genesis Energy has declared the availability of Huntly units 1 – 4, to be 60 – 90% depending on the type of maintenance outage in a particular year. The units presently have a Major Survey (overhaul) every four years.

Assuming 60% availability in the Major Survey year and 90% in the other three years results in an average long term availability of 83%. PB recommends this value for the GEM.

3.1.8.7 Huntly Unit 6 (P40)

Genesis Energy has declared the availability of Huntly Unit 6 (P40) to be 50 – 96% depending on the type of maintenance outage in a particular year. PB estimates that the lower availability of 50% will only occur every 5 years, resulting in a long term average availability of 87%.

3.1.8.8 Southdown E105

Given available information PB recommends a value of 80%.

3.1.8.9 Huntly coal units 1 - 4

PB estimates that the availability of Huntly units 1 – 4 when firing coal will be lower than when firing natural gas. This is because more auxiliary equipment is required for coal fuel delivery and preparation, and ash removal and disposal. Coal firing is also somewhat more onerous or ‘harder’ on the boiler than firing natural gas. The units would therefore be expected to have higher forced outage rates and more unplanned maintenance downtime when firing coal.

PB estimates an average long term availability of 78% for Huntly coal units 1 – 4.

3.1.8.10 Kapuni

Given available information PB recommends a value of 85%.

3.1.8.11 Hawera

Given available information PB recommends a value of 85%.

3.1.8.12 Te Rapa

Given available information PB recommends a value of 85%.

3.1.8.13 Kinleith

Genesis Energy has not declared the availability of Kinleith cogeneration plant. PB estimates this to be similar to Huntly Power Station, units 1 – 4 and recommends a value of 80% for the GEM.

3.1.8.14 Glenbrook

Given available information PB recommends a value of 80%.

3.1.8.15 Whirinaki

Given available information PB recommends a value of 80%.

3.1.8.16 Stratford

Given available information PB recommends a value of 80%.

3.1.8.17 Edgecumbe

Given available information PB recommends a value of 80%.

3.1.8.18 Mangahewa

Given available information PB recommends a value of 85%.

3.1.9 Unit largest proportion

This parameter is defined by MED as the "*largest proportion of a station output carried by a single unit*" and is expressed as a percentage. Such data can be presented in tabular form as follows.

Table 3-2 Unit largest proportions

Generator	Net operational capacity, MW	No. of units	Unit largest proportion
Southdown	122	2	50%
Taranaki CC	380	1	100%
Otahuhu B	380	1	100%
Huntly unit 5 (e3p)	385	1	100%
Huntly gas	980	4	25%
Huntly unit 6 (P40)	44	1	100%
Southdown E105	45	1	100%
Huntly coal units 1 - 4	237	4	100%
Kapuni	20	1	100%
Hawera	68	1	100%
Te Rapa	45	1	100%
Kinleith	38	1	100%
Glenbrook	112	1	100%
Whirinaki	155	2	50%
Stratford	200	2	50%
Edgecumbe	10	2	50%
Mangahewa	9.6	3	33%

3.1.10 Baseload

This parameter is simply a "yes/no" determination of "*whether the plant is designed to be operated near/or at full capacity most of the time*".

PB has taken the approach that all thermal generation plant that is not specifically designed and installed as peak load (peaker) plant, is designed to be operated at full capacity all of the time it is available.

Such data can be presented in tabular form as follows.

Table 3-3 Thermal plant operation

Generator	Design generator function	Baseload	Peaker	Comments
Southdown	cogenerator	YES	NO	Used as a peaker
Taranaki CC	generator	YES	NO	
Otahuhu B	generator	YES	NO	
Huntly unit 5 (e3p)	generator	YES	NO	
Huntly gas	generator	YES	NO	
Huntly unit 6 (P40)	generator	NO	YES	
Southdown E105	generator	NO	YES	
Huntly coal units 1 - 4	generator	YES	NO	
Kapuni	cogenerator	YES	NO	
Hawera	cogenerator	YES	NO	
Te Rapa	cogenerator	YES	NO	Has limited peaking capacity
Kinleith	cogenerator	YES	NO	
Glenbrook	cogenerator	YES	NO	Has limited peaking capacity
Whirinaki	generator	NO	YES	
Stratford	generator	NO	YES	
Edgecumbe	cogenerator	YES	NO	
Mangahewa	generator	YES	NO	

Note: all baseload plants have load following capability and, if operating in 'spinning reserve' mode at less than full capacity, can also pick up a share of peak loads.

It is not normal for conventional (boiler + steam turbine) technology to operate as a peaker because of the time taken for cold or warm starts (hours) and the cost of maintaining the unit in hot standby mode. A notable exception is the single 500 MW gas fired Newport D power station in Newport, Melbourne, Victoria, Australia.

This plant was modified specifically to enable it to maintain a hot standby condition and to enable it to start and ramp up to full load more rapidly than the original design provided for. It is understood the plant is able to virtually mimic an OCGT peaker plant.

3.1.11 Heat Rate

The MED have defined this parameter as "*for each GJ of Fuel input how many useful (station export) GWh of electricity are generated*". What is intended by MED here is a measure of the efficiency of conversion of fuel energy to electricity. The appropriate and common industry term for this is ***heat rate***. The term "higher heating value" is the term used synonymously with "gross calorific value" for the higher heating value of a fuel, expressed in energy/mass or volume terms, such as MJ/kg.

PB has relied on the generator owners for this data, and such data can be presented in tabular form as follows.

Table 3-4 Thermal plant heat rate

Generator	Design generator function	Heat rate, GJ/GWh	Comments
Southdown	cogenerator	7,400	
Taranaki CC	generator	7,400	
Otahuhu B	generator	7,400	
Huntly unit 5 (e3p)	generator	7,400	Median of given range
Huntly gas	generator	10,900	Median of given range
Huntly unit 6 (P40)	generator	10,525	Median of given range
Southdown E105	generator	10,600	
Huntly coal units 1 - 4	generator	10,900	Median of given range
Kapuni	cogenerator	-	
Hawera	cogenerator	-	
Te Rapa	cogenerator	10,600	
Kinleith	cogenerator	-	
Glenbrook	cogenerator	-	Indeterminate bottoming cycle (no fuel used)
Whirinaki	generator	11,000	
Stratford	generator	10,600	
Edgecumbe	cogenerator	11,500	
Mangahewa	generator	11,600	

The HHV heat rates expressed above can be assumed to reflect the operating regime of the particular plant. That is, they can be assumed to be long term averages and to include the depreciating (heat rate increase) effects of multiple startups (for peak load plant) and load following operation at less than full load or maximum continuous rating (MCR).

3.1.12 Variable O&M costs

3.1.12.1 Introduction

These are the non-fuel operational and maintenance costs that are dependent on plant output. Fuel cost is directly proportional to output but is treated separately by MED and is outside the scope of this report.

The variable O&M costs presently used in the GEM are those recommended by PB in its report to the Electricity Commission, “Thermal Power Station Advice - Fixed & Variable O&M Costs”, September 2009. These are as set out in the following table, copied from the Executive Summary of that report.

Table 3-5 NZ thermal plant O&M costs

Asset	Technology	Existing GEM values		PB recommendation[1]	
		Variable $/MWh	Fixed $/kW/year	Variable $/MWh	Fixed $/kW/year
Southdown	CCGT	4.3	50	4.25	35
TCC	CCGT	4.3	50	4.25	35
Otahuhu B	CCGT	4.3	50	4.25	35
Huntly unit 5 (E3P)	CCGT	4.25	50	4.25	35
Huntly unit 6 (P40)	OCGT	6.4	90	8	16
Southdown (E105)	OCGT	6.4	90	8	16
Huntly PS (Units 1-4)	ST (Coal)	9.6	60	9.6	70
Whirinaki	OCGT (liquid)	10	90	9.6	20

[1]*Values in 2009 New Zealand dollars.*

Note: the current GEM values are the "PB Recommendation" values in the above table. It is these values that this report seeks to review and either validate/verify or revise.

3.1.12.2 Definition

The PB report, "Thermal Power Station Advice - Fixed & Variable O&M Costs", September 2009, provided the following definition of variable O&M costs.

"*These costs, defined as $/MWh, refer to the incremental operations and maintenance costs incurred upon increasing the level of production by one unit. Variable O&M (VOM) costs will include minor unplanned maintenance, water usage, chemicals, limestone (where FGD is used), auxiliary energy use and ash disposal costs.*

Major maintenance costs for gas turbine plant can also be included in the VOM cost values. This is because maintenance is based on the equivalent operating hours of the plant as opposed to coal fuelled steam turbine plant where maintenance is periodic and treated as a fixed operating cost. Where the reference information allows, the report will indicate whether major maintenance has been included in the variable or fixed portion of gas turbine plant O&M costs.

Typically, gas fired plant has the lowest variable O&M costs and coal fuelled plant has the highest costs associated with the costs of ash disposal and requirements for flue gas desulphurisation (FGD)."

3.1.12.3 Validation data sources

PB had expected to rely on information provided by the generator owners to validate the GEM O&M cost data. However, the generator owners have advised that this information cannot be provided as it is considered commercially sensitive and confidential.

PB has therefore relied on the following public domain sources:

- Worley Parsons, "**AEMO Cost Data Forecast For the NEM, Review of Cost and Efficiency Curves**", 31 January 2011[23]. This report outlines the results of a review of the capital cost and efficiency curves provided by AEMO (Australian Energy Market Operator) used for modelling new entrants in the NEM. AEMO had sought an update of data

[23] http://www.aemo.com.au/planning/0419-0017.pdf

provided for NTNDP (National Transmission Network Development Plan) Modelling and Worley Parsons provided, among other things, cost curves relating 2009 industry figures to latest industry cost forecasts, plant efficiency updates and O&M cost updates.

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[24]. This report provides a summary and supporting documentation for Mott MacDonald's assessment of current and forward power generation costs for the main large scale technologies applicable in the UK. The work was commissioned by the Department of Energy and Climate Change and undertaken during October 2009 to March 2010.

- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[25]. The objective of the work leading to this report was to establish an up-to-date cost and performance database agreed by Australian stakeholders as supportable in the Australian context. The report also provides a levelised cost analysis of a basket of technologies in 2015 and 2030. This provides an agreed basis for comparing globally available power generation technologies and costs.

3.1.12.4 Worley Parsons January 2011

The Worley parsons report reviewed O&M costs for 39 existing and new entrant technologies. The revised O&M costs are published on the revised NTNDP Modelling Assumptions Input Spreadsheets[26]. PB confirmed by telephone that the spreadsheets were the latest versions, corresponding to the Worley parsons report.

The following Table 3-6 shows the variable operating costs recorded for the technologies applicable to the existing plant in the GEM as covered in this report. The Table 3-6 variable O&M costs converts to NZD as shown in Table 3-7.

Table 3-6 Worley Parsons variable O&M costs, AUD/MWh

Plant technology type	Fuel	Existing		New entrant	
		Range	Typical	Range	Typical
Subcritical pf	Black coal	1.19 - 3.00	1.19	-	-
Steam turbine	Natural gas	2.25 – 2.25	2.25	-	-
OCGT	Natural gas	2.26 – 9.98	9.61	-	2.50
CCGT	Natural gas	1.05 – 9.61	1.05	-	2.00
Cogen	Natural gas	0.00 – 2.40	0.00	-	-
Cogen	Steam	0.00 – 0.00	0.00	-	--
Cogen	Biomass (woodwaste)	2.25 – 2.25	2.25	-	-

The Worley Parsons median value variable O&M costs are significantly lower than previously estimated (in 2009) by PB for all technologies except for OCGT, where the Worley Parsons median value is higher. The reason for these differences is not presently known, but the

[24] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[25] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf
[26] http://wwww.aemo.com.au/planning/2010ntndp_cd/html/NTNDPdatabase.htm

higher variable O&M for the OCGT plants in Australia may be owing to the added cost of providing high quality demineralised water for GT compressor inlet cooling.

Table 3-7 Worley Parsons variable O&M costs, NZD/MWh

Plant technology type	Fuel	Existing		New entrant	
		Range	Typical	Range	Typical
Subcritical pf	Black coal	1.50 - 3.78	1.50	-	-
Steam turbine	Natural gas	2.84 – 2.84	2.84	-	-
OCGT	Natural gas	2.85 – 12.57	12.11	-	3.15
CCGT	Natural gas	1.32 – 12.11	1.32	-	2.52
Cogen	Natural gas	0.00 – 3.02	0.00	-	-
Cogen	Steam	0.00 – 0.00	0.00	-	--
Cogen	Biomass (woodwaste)	2.84 – 2.84	2.84	-	-

Note: the plant technology type described as “steam turbine” in Table 3-6 and Table 3-7 above is simply the natural gas fired “subcritical pf” technology, that is, the conventional boiler + steam turbine technology.

It appears counter-intuitive that gas fired “steam turbine” plant should have a higher variable operating cost than “subcritical pf”. However, this is understood to be owing to the low utilisation of the natural gas fired “steam turbine” plant. Three of the plants included, Newport and Torrens Island A & B are known to be used only for peaking or standby/reserve capacity.

3.1.12.5 Mott MacDonald June 2010

The Mott MacDonald report deals with only one technology relevant to this section of this report on existing thermal generators in New Zealand, and that is gas-fired CCGT. The variable operating cost, described as a technology input assumption, assumed for gas-fired CCGT was as follows:

- O&M variable fee, £/MWh: 1.8 – 2.5, with a “Medium” range value of 2.2 £/MWh

The above variable O&M cost converts to:

- O&M variable fee, NZ$/MWh: 3.50 – 4.90, with a “Medium” range value of 4.30 NZ$/MWh.

This is consistent with the current GEM value, and as recommended by PB in 2009.

3.1.12.6 EPRI/Worley Parsons February 2010

The EPRI/Worley Parsons report deals with two technologies relevant to this section of this report on existing thermal generators in New Zealand: gas-fired CCGT and supercritical pulverised coal (black coal) fired (boiler + steam turbine) power plant. All capital and O&M costs are presented as “overnight costs” expressed in June 2009 Australian dollars. The variable operating costs estimated were as follows:

- Pulverised coal-fired power plant: 4.6 AUD/MWh

- CCGT: 2.0 AUD/MWh.

The above variable O&M cost converts to:

- Pulverised coal-fired power plant: 5.80 NZ$/MWh
- CCGT: 2.50 NZ$/MWh.

These values are significantly lower than the current GEM value, or as recommended by PB in 2009. However, as might be expected, the values are consistent with the Worley Parsons January 2011 reported values.

3.1.12.7 Conclusions

Australian thermal generators appear to have significantly lower variable operating costs than previously (2009) estimated for New Zealand thermal generators. Investigation of the reasons for this are outside the scope of this study, but a significant contributor to the lower values in Australia is thought to be simply economies of scale. Australia has around 48 GW of thermal capacity (including reciprocating engines), compared to around 3 GW in New Zealand.

PB considers it unlikely that variable operating costs have fallen since 2009, and is not aware of any drivers that would be likely to have significantly increased variable operating costs over the past two years; this aspect however has not been studied.

Variable O&M (VOM) costs have therefore been estimated as follows:

- The 2009 values have been applied unchanged to the same, or like plant technologies
- “Huntly gas” has been estimated at 85% of “Huntly coal units 1 – 4” because it is considered logically intuitive that the same 250 MW unit running on natural gas would have a lower VOM than when running on coal, because gas firing requires no coal handling and preparation, and no ash handling and disposal.
- With the exception of Southdown, the CCGT cogeneration plants were not covered in 2009, however the VOM cost for Southdown was estimated the same as that for the CCGT generators in 2009. The CCGT cogeneration plants closely resemble CCGT generator plants and it seems reasonable to estimate their VOM costs at the same level.
- Te Rapa and Edgecumbe have no steam turbine or associated condenser cooling system and would therefore be expected to have a lower VOM cost than the CCGT cogenerators.
- Kinleith and Glenbrook are both ‘boiler + steam turbine’ cogeneration plants and the Australian data shows these to have (estimated) VOM costs the same as for the gas fired conventional ‘boiler + steam’ turbine plants. This approach has been taken, albeit with the ‘New Zealand’ values.
- Reciprocating engines (Mangahewa) were not covered in 2009 and the Australian values have been used, converted to New Zealand dollars at the prevailing exchange rate.
- Finally, to avoid the pretence of accuracy greater than actual, the values are rounded up to the nearest $0.10 (10 cents), e.g. $4.25/MWh values are rounded up to $4.30/MWh.

The following Table 3-8 records the results of the above approach. The dollar values are considered generally equivalent real 2011 New Zealand dollars.

Table 3-8 2011 GEM variable operating costs (VOM), NZD/MWh

Generator	Design generator function	Technology	VOM, NZ$/MWh	Comments
Southdown	cogenerator	CCGT	4.30	Was 4.25 in 2009
Taranaki CC	generator	CCGT	4.30	Was 4.25 in 2009
Otahuhu B	generator	CCGT	4.30	Was 4.25 in 2009
Huntly unit 5 (e3p)	generator	CCGT	4.30	Was 4.25 in 2009
Huntly gas	generator	Gas (steam)	8.20	85% of Huntly coal
Huntly unit 6 (P40)	generator	OCGT	8.00	No change from 2009
Southdown E105	generator	OCGT	8.00	No change from 2009
Huntly coal units 1 - 4	generator	Coal (steam)	9.60	No change from 2009
Kapuni	cogenerator	CCGT	4.30	Same as CCGT
Hawera	cogenerator	CCGT	4.30	Same as CCGT
Te Rapa	cogenerator	GT	4.20	No steam turbine
Kinleith	cogenerator	Biomass (steam)	8.20	Same as Huntly gas, as per Australian plants
Glenbrook	cogenerator	Offgas (steam)	8.20	Same as Huntly gas, as per Australian plants
Whirinaki	generator	OCGT (diesel)	9.60	No change from 2009
Stratford	generator	OCGT	8.00	No change from 2009
Edgecumbe	cogenerator	GT	4.20	No steam turbine
Mangahewa	generator	Recip	12.10	= AUD 9.61/MWh

The accuracy of the above and other costs estimates in this report is estimated to be ± 30% at best and could be up to ± 40%. The reasons for such apparently "inaccurate" estimates relate to the manner in which the estimates have been developed, and in particular PB's reliance on overseas data, as opposed to actual costs provided by the generator owners.

Given the level of accuracy inherent in the O&M cost estimates, PB considers it reasonable to assume that "the 2009 dollar values are considered generally equivalent to real 2011 New Zealand dollars" and hence no escalation of these values is required.

3.1.13 Fixed O&M costs

3.1.13.1 Introduction

These are the non-fuel operational and maintenance costs that are dependent on plant size.

The fixed O&M (FOM) costs presently used in the GEM are those recommended by PB in its report to the Electricity Commission, "Thermal Power Station Advice - Fixed & Variable O&M Costs", September 2009. These are as set out in section 3.1.12.1.

3.1.13.2 Definition

The PB report, "Thermal Power Station Advice - Fixed & Variable O&M Costs", September 2009, provided the following definition of fixed O&M costs.

"*These costs, defined as $/kW/year, typically include all fixed operating costs such as spares, major periodic maintenance, insurance, O&M fees, property taxes and leases and owner's costs such as wages. Fixed costs should not vary with changes in electricity generation levels*."

3.1.13.3 Validation data sources

PB had expected to rely on information provided by the generator owners to validate the GEM O&M cost data. However, the generator owners have advised that this information cannot be provided as it is considered commercially sensitive and confidential.

PB has therefore relied on the same public domain sources for FOM as it did for VOM in section 3.1.12.3.

3.1.13.4 Worley Parsons January 2011

Table 3-9 shows the fixed O&M costs recorded for the technologies applicable to the existing plant in the GEM as covered in this report, and Table 3-10 shows the NZ dollar conversions.

Table 3-9 Worley Parsons fixed O&M costs, AUD/kW/y

Plant technology type	Fuel	Existing		New entrant	
		Range	Mean or median	Range	Typical
Subcritical pf	Black coal	49 - 84	51.75	-	-
Steam turbine	Natural gas	40 – 40	40.00	-	-
OCGT	Natural gas	13 – 13	13.00	-	9.00
CCGT	Natural gas	25 – 31	31.00	-	14.00
Cogen	Natural gas	25 – 25	25.00	-	-
Cogen	Steam	25 – 25	25.00	-	--
Cogen	Biomass (woodwaste)	40 – 40	40.00	-	-

Table 3-10 Worley Parsons fixed O&M costs, NZD/kW/year

Plant technology type	Fuel	Existing		New entrant	
		Range	Mean or median	Range	Typical
Subcritical pf	Black coal	62 - 106	65.20	-	-
Steam turbine	Natural gas	50 – 50	50.40	-	-
OCGT	Natural gas	16 – 16	16.40	-	11.30
CCGT	Natural gas	32 – 39	39.10	-	17.60
Cogen	Natural gas	32 – 32	31.50	-	-
Cogen	Steam	32 – 32	31.50	-	--
Cogen	Biomass (woodwaste)	50 – 50	50.40	-	-

The Worley Parsons mean or median values for fixed O&M (FOM) costs correlate well with those previously estimated by PB in 2009, and the 2009 values are all within the Table 3-10 ranges.

3.1.13.5 Mott MacDonald June 2010

The Mott MacDonald report deals with only one technology relevant to this section of this report on existing thermal generators in New Zealand, and that is gas-fired CCGT. The fixed operating cost, described as a technology input assumption, assumed for gas-fired CCGT was as follows:

- O&M fixed fee, £/MW/y: 12,000 – 19,000, with a “Medium” range value of 15,000 £/MW/y.

The above fixed O&M cost converts to:

- O&M fixed fee, NZ$/MW/y: 23,400 – 37,000, with a “Medium” range value of 29,250 NZ$/MW/y.

This is somewhat lower than the current GEM value, as recommended by PB in 2009, and lower than the Worley Parsons range minimum.

3.1.13.6 EPRI/Worley Parsons February 2010

The EPRI/Worley Parsons report deals with two technologies relevant to this section of this report on existing thermal generators in New Zealand: gas-fired CCGT and supercritical pulverised coal (black coal) fired (boiler + steam turbine) power plant. All capital and O&M costs are presented as “overnight costs” expressed in June 2009 Australian dollars. The fixed operating costs estimated were as follows:

- Pulverised coal-fired power plant: 33,100 AUD/MW/y
- CCGT: 13,600 AUD/MW/y.

The above fixed O&M cost converts to:

- Pulverised coal-fired power plant: 41,700 NZ$/MW/y
- CCGT: 17,100 NZ$/MW/y.

These values are significantly lower than the current GEM value, or as recommended by PB in 2009. Unexpectedly, the values are also below the Worley Parsons January 2011 reported range minimum values.

3.1.13.7 Conclusions

The present GEM fixed O&M (FOM) cost values remain within the ranges published for similar Australian plants in the Worley Parsons January 2011 report. PB recommends that the present values are retained as there appear to be no compelling reasons to adjust them at this time. The following Table 3-11 records the results of this approach.

Fixed O&M (VOM) costs have been estimated as follows:

- The 2009 values have been applied unchanged (no escalation required for 2011 real dollars) to the same, or like plant technologies.

Table 3-11 2011 GEM fixed operating costs (FOM), NZD/kW/y

Generator	Design generator function	Technology	FOM, NZ$/kW/y	Comments
Southdown	cogenerator	CCGT	35	No change from 2009
Taranaki CC	generator	CCGT	35	No change from 2009
Otahuhu B	generator	CCGT	35	No change from 2009
Huntly unit 5 (e3p)	generator	CCGT	35	No change from 2009
Huntly gas	generator	Gas (steam)	60	85% of Huntly coal
Huntly unit 6 (P40)	generator	OCGT	16	No change from 2009
Southdown E105	generator	OCGT	16	No change from 2009
Huntly coal units 1 - 4	generator	Coal (steam)	70	No change from 2009
Kapuni	cogenerator	CCGT	35	Same as CCGT
Hawera	cogenerator	CCGT	35	Same as CCGT
Te Rapa	cogenerator	GT	30	No steam turbine
Kinleith	cogenerator	Biomass (steam)	60	Same as Huntly gas, as per Australian plants
Glenbrook	cogenerator	Offgas (steam)	60	Same as Huntly gas, as per Australian plants
Whirinaki	generator	OCGT (diesel)	20	No change from 2009
Stratford	generator	OCGT	16	No change from 2009
Edgecumbe	cogenerator	GT	30	No steam turbine
Mangahewa	generator	Recip	16	= AUD 13,000/MW/y

- "Huntly gas" has been estimated at 85% of "Huntly coal units 1 – 4" because it is considered logically intuitive that the same 250 MW unit running on natural gas would have a lower FOM than when running on coal, because gas firing requires no coal handling and preparation, and no ash handling and disposal. However, this assumes a permanent fuel switch from coal to gas such that coal and ash handling staff are no longer required. This is not valid for dual fuel operation, where the FOM would be the same for both coal and gas fuels.

- With the exception of Southdown, the CCGT cogeneration plants were not covered in 2009, however the FOM cost for Southdown was estimated the same as that for the CCGT generators in 2009. The CCGT cogeneration plants closely resemble CCGT generator plants and it seems reasonable to estimate their FOM costs at the same level.

- Te Rapa and Edgecumbe have no steam turbine or associated condenser cooling system and would therefore be expected to have a lower FOM cost than the CCGT cogenerators.

- Kinleith and Glenbrook are both 'boiler + steam turbine' cogeneration plants and the Australian data shows these to have (estimated) FOM costs the same as for the gas fired conventional 'boiler + steam' turbine plants. This approach has been taken, albeit with the 'New Zealand' values.

- Reciprocating engines (Mangahewa) were not covered in 2009 and the Australian values have been used, converted to New Zealand dollars at the prevailing exchange rate.

3.1.14 Fuel delivery costs

3.1.14.1 Introduction

PB's report, "Thermal Power Station Advice, Report for the Electricity Commission", July 2009 recorded the fuel prices assumed for the long run marginal cost (LRMC) calculations. These were reported under the heading, "generic assumptions" and included the note that "*the modelling . . . excludes fuel delivery costs*." This section reviews the cost of fuel transmission, distribution and/or transport logistics.

PB's most recent study of fuel costs for power generation that included fuel transport costs, is understood to be its report to the Electricity Commission, "Electricity Generation Database Statement Of Opportunities Update 2006", October 2006. The conclusions of that report are reproduced in the following sections for comparison.

With the exception of Kinleith, Glenbrook, and Mangahewa the thermal generators are all fuelled with one or more of three fuels:

- Natural gas
- Coal (Huntly coal units 1-4 only)
- Diesel (Whirinaki only)

Kinleith and Glenbrook are fuelled with by-product or waste streams from their cogeneration hosts and are considered to have a zero fuel cost and zero fuel delivery costs, as the fuels are produced on site.

Mangahewa is fuelled by raw wellstream gas rather than pipeline gas.

3.1.14.2 Natural gas

PB's Electricity Generation Database Statement of Opportunities Update 2006 report concluded with respect to gas transport costs as follows.

"*There is an additional cost for transporting gas north of Huntly after the gas leaves the Maui gas pipeline and is transported in the high pressure pipelines owned by Vector (formerly Natural Gas Corporation). In particular, Otahuhu B and Southdown pay for the transport of gas via Vector's transmission line from Rotokawa (the top end of the Maui gas pipeline) to Otahuhu.*

The gas transmission prices charged by Vector comprise three components:

1. *A "Capacity Reservation Charge" which reflects the asset costs (return and depreciation) of an optimal transmission system. These fees are calculated in $/GJ of reserved capacity. These are fixed charges, recovered whether or not the full Maximum Daily Quantity (MDQ) is used.*

2. *An "Overrun Charge" that applies to deliveries made in excess of reserved MDQ. These fees are set at a level to create incentives for customers to reserve MDQ as accurately as possible. The fees are avoidable by reserving sufficient capacity to meet short term peak*

requirements, or obtaining additional capacity entitlements through the secondary market; and

3. *A "Throughput Charge" that recovers all other operating costs. The same throughput fee applies to gas delivered anywhere on the system, for the calculation of the SRMC for each plant, Vector's posted price of $0.65/GJ for the "Throughput Charge", effective 1 October 2005, or the variable charge, has been included for those requiring gas to be transported through Vector's gas pipeline. From 1 October 2006 this charge increases to $0.78/GJ*."

3.1.14.3 Coal

Genesis Energy's Huntly units 1 – 4 is the only generator using coal fuel.

PB's Electricity Generation Database Statement of Opportunities Update 2006 report concluded with respect to coal transport costs as follows.

"*Present prices for Waikato coal from existing Huntly East and Rotowaro mines delivered to Huntly are estimated to be in the range of $85 to $114 per tonne or $3.85 to $5.16/GJ (prices indexed from report by Solid Energy et al, 2004). Actual prices are expected to be at the lower end of this range for coal under long term contract*." The transport portion of the cost is not declared.

"*A modern large truck and trailer unit can transport 25 to 30 tonnes on public roads (27 tonnes expected). The average hourly hire rate for a truck and trailer is in the range of $85 to $95 per hour. With allowances for loading, unloading and waiting time this equates to around 5 hours for a 200 km round trip from mine (or wharf for imported coal) to power station and back again or $2.25 per km (total cost/total distance). This equates to a cost of $16.67 per tonne*."

Coal imported from Indonesia for Huntly Power Station is discharged at the Port of Tauranga. The driving distance from Tauranga to Huntly is approximately 144 km (89 miles), giving a round trip of 288 km, with a round trip driving time of approximately 4 hours. Thus the above costs would still apply for the longer distance.

However, while imported Indonesian coal was initially transported to Huntly Power Station by truck, rail proved to be a lower cost option. In March 2004 it was announced that "*Tranz Rail will haul up to 1m tonnes of imported coal a year from the port of Tauranga to Huntly power station. It will start hauling the coal in December this year (2004) with each train carrying 1,500 tonnes from a new storage facility, which will be built at Mount Maunganui. This facility will have a storage capacity of 70,000 tonnes, making it one of the largest in the world, Tranz Rail said. The coal is at present being hauled by road. Tranz Rail will also construct 33 covered coal wagons for the contract at its workshops in Dunedin. Last year the port of Tauranga signed a 10-year agreement with Genesis Power to import coal for Huntly power station*."[27]

PB's estimate of the indicative cost of freight for coal from Tauranga to Huntly using rail transport is $14/tonne. Assuming a coal heating value of 21 MJ/kg, $14/t equates to $0.67/GJ.

3.1.14.4 Diesel

The Whirinaki OCGT plant is the only generator using diesel fuel.

[27] http://www.railexpress.com.au/archive/2004/Mar/18/tranz-rail-gets-power-station-coal-haul-contract

PB's Electricity Generation Database Statement of Opportunities Update 2006 report concluded with respect to diesel transport costs as follows.

"*At full capacity over 24 hours the Whirinaki plant will use approximately 1M litres of diesel per day. Whirinaki's fuel supply held is at two onsite tanks and two bulk storage tanks off-site near the Port of Napier. The onsite tanks will be kept nominally full and are able to hold approximately 4.3M litres of fuel. The two bulk storage tanks will be kept nominally full throughout winter and are able to hold approximately 19.5M litres of fuel*."

The cost of diesel for generation purposes is estimated to be NZ$1.45 per litre at October 2011, which is estimated to be made up of a purchase price of NZ1.34 per litre and a delivery cost of NZ$0.11 per litre. Based on an energy content of 37.1MJ per litre (net) the delivery cost equates to $2.97/GJ.

3.2 Hydro

3.2.1 Summary

Table 3-12 summarises the PB recommendations for the existing NZ hydro plant data for the GEM, which is publicly available for each region around New Zealand. Where this information is not publicly available or has not been provided through consultation with the generators, PB has provided recommendations based on arbitrary estimates and approximation techniques, as detailed through this report.

Table 3-12 PB recommendations: Existing NZ hydro plant data

Region	Substation	Project lifetime	Capacity	Availability Factor	Unit largest proportion	Baseload	Variable O&M cost	Fixed O&M costs
		Years	*MW*	*%*	*%*	*Y/N*	*$/MWh*	*$/kW/year*
Waikato	WKM	50	1,040	92.3	20	N	$0.86	$6.38
Bay of Plenty	TGA	50	165	92.3	50	N	$0.86	$6.38
Hawke's Bay	TUI	50	138	92.3	50	N	$0.86	$6.38
Taranaki	SFD	50	31	92.3	33	N	$0.86	$6.38
Bunnythorpe	TKU	50	360	92.3	33	N	$0.86	$6.38
Wellington	MHO	50	39	92.3	70	N	$0.86	$6.38
Nelson/ Marlborough	COB	50	32	92.3	31	N	$0.86	$6.38
Christchurch	CUL	50	69	92.3	10	N	$0.86	$6.38
Waitaki	WTK	50	1,739	92.3	17	N	$0.86	$6.38
Clutha	ROX	50	752	92.3	25	N	$0.86	$6.38
Waipori	BWK	50	84	92.3	33	N	$0.86	$6.38
Deep Stream	HWB	50	17	92.3	50	N	$0.86	$6.38
Fiordland	MAN	50	730	92.3	17	N	$0.86	$6.38

Note: The information provided in this table should only be used in conjunction with the information provided in the relevant sections contained within the body of this report.

3.2.2 Plant

The existing hydro power stations have been categorised by the regions within the GEM and are included as shown below in Table 3-13.

Table 3-13 Existing Hydro Plant Regional Capacity

Waikato Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Aratiatia	78 MW
Ohakuri	106 MW
Atiamuri	74 MW
Whakamaru	98 MW
Maraetai I	176 MW
Maraetai II	176 MW
Waipapa	54 MW
Arapuni	182 MW
Karapiro	96 MW
TOTAL	**1040 MW**
Bay of Plenty Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Lloyd Mandeno	16 MW
Ruahihi	20 MW
Matahina	80 MW
Wheao	24 MW
Aniwhenua	25 MW
TOTAL	**165 MW**
Hawke's Bay Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Tuai	60 MW
Piripaua	42 MW
Kaitawa	36MW
TOTAL	**138 MW**
Taranaki Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Patea	31 MW
TOTAL	**31 MW**
Bunnythorpe Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Tokaanu	240 MW
Rangipo	120 MW
TOTAL	**360 MW**

Wellington Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Mangahao (including Mini Hydro)	39 MW
TOTAL	**39 MW**

Nelson/Marlborough Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Cobb	32 MW
TOTAL	**32 MW**

Christchurch Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Coleridge	39 MW
Highbank	28 MW
Montalto (included as part of system)	2 MW
TOTAL	**69 MW**

Waitaki Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Aviemore	220 MW
Benmore	540 MW
Ohau A	264 MW
Ohau B	212 MW
Ohau C	212 MW
Tekapo A	26 MW
Tekapo B	160 MW
Waitaki	105 MW
TOTAL	**1739 MW**

Clutha Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Clyde	432 MW
Roxburgh	320 MW
TOTAL	**752 MW**

Waipori Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Waipori 1A	10 MW
Waipori 2A	58 MW
Waipori 3 (included as part of system)	8 MW
Waipori 4 (included as part of system)	8 MW
TOTAL	**84 MW**

Deep Stream Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Deep Stream	5 MW
Paerau	10 MW
Patearoa (included as part of system)	2 MW
TOTAL	**17 MW**
Fiordland Hydro Regional Capacity	
Existing Plant	**Rated Capacity**
Manapouri	730 MW
TOTAL	**730 MW**

3.2.3 Plant technology

3.2.3.1 Waikato Hydro

The Mighty River Power website describes the Waikato Hydro System as comprising of 39 turbines, with eight dams from Aratiatia to Karapiro, sited to allow water to flow directly from one station into the lake formed by the dam of the next station. Both Kaplan and Francis type turbines are utilised in the system. Figure 3.18 shows an overview of the Waikato Hydro System and the locations of the main hydro power plants.

Mighty River Power's website describes the water storage capacity of the system as "*The limited storage available in both Lake Taupo and the hydro lakes on the river mean that we are very reliant on regular rainfall to provide inflows to the system."*

The website describes the operation of the system as *"Modern forecasting techniques enable Mighty River Power to operate the Waikato hydro system efficiently by responding to weather patterns and instant changes in electricity demand. To do this we work closely with other agencies, sharing and analysing the most up-to-date weather data and information about river flows in the Waikato and the major tributaries feeding the catchment."* and *"Our nine hydro power stations along the Waikato River are complemented by our thermal plant at Southdown, which provides the flexibility to offset low hydro flows."*

The website also notes that *"In an average year the Waikato hydro electric power stations generate a combined total of 4,120GWh."* However, Mighty River Power's website specifies that for the 12 months to 30th June 2010 the hydro system generated 3730GWh.

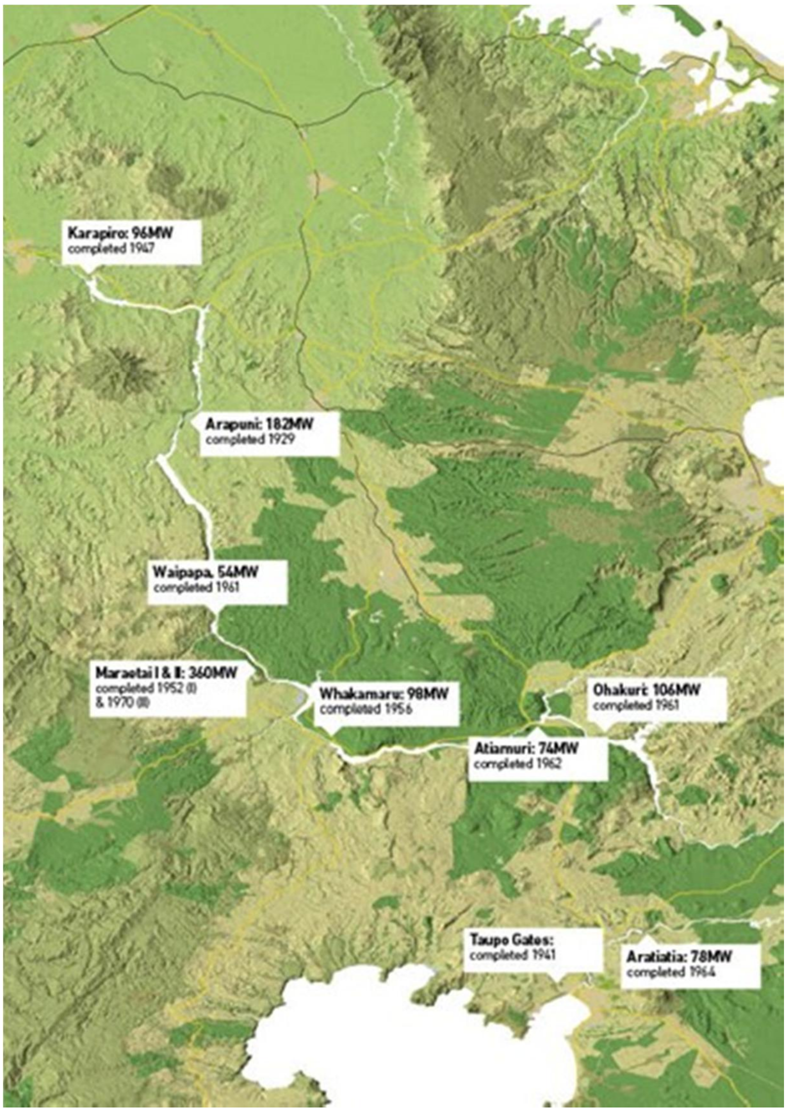


Figure 3.18 Waikato hydro system overview

3.2.3.2 Bay of Plenty Hydro

The majority of the Bay of Plenty's hydro generation is provided by the Kaimai Hydro Power Scheme, the Wheao and Flaxy Scheme, and the Matahina and Aniwhenua Power Stations. TrustPower's website provides the following overview of the hydro generation in the Bay of Plenty Region (refer to Figure 3.19 below).

Figure 3.19 TrustPower's hydro generation in the Bay of Plenty region

TrustPower's website has the following description of the Kaimai Hydro Power Scheme *"the scheme consists of the 0.3 MW Kaimai 5 Station on a diversion tunnel feeding Lake Mangaonui, the 16 MW Lloyd Mandeno Station, sited in the west bank of the Mangapapa River, the 5.6 MW Lower Mangapapa Station, and 4 km's further downstream, the 20 MW Ruahihi Station. The total annual output of the scheme is 167.8 GWh."*

The **Kaimai Hydro Power Scheme** has several dams with reservoirs providing water to the main generating units. The Lloyd Mandeno Station has a 29m earth dam across the Mangaonui valley (forming a 8.1 Ha surface area lake), the Lower Mangapapa Power Station has a 26m high concrete arch dam built across a narrow gorge in the Mangapapa River (that forms a lake extending upstream to the Lloyd Mandeno station) and the Ruahihi Power Station has a 26m high concrete arch dam across the lower Mangapapa River (forming Lake McLaren).

TrustPower's website has the following description of the **Wheao and Flaxy Scheme** *"Using water from the Rangitaiki River, supplemented with water from the Wheao River and Flaxy Creek, the scheme uses two generators at the Wheao Powerhouse delivering 12 MW each, with a further 2.1 MW of generation from a single induction generator at the Flaxy Powerhouse. Average yearly production from the scheme is 111 GWh."*

The website also has the following description of the **Matahina Power Station** *"With a 76-metre gross head of water behind its 86-metre high dam (the largest earth dam in the North Island), the Matahina scheme has two generators producing 80 MW to give an average annual output of 290 GWh."*

Todd Energy's website has the following description of the **Aniwhenua Power Station** *"The scheme involved the damming of the Rangitaiki River above the falls, forming a 255 hectare storage lake"*. The generation is provided by two 12.5 MW generators.

3.2.3.3 Hawke's Bay Hydro

The majority of the Hawke's Bay hydro generation is provided by the Waikaremoana Power Scheme, which is located between the Te Urewera National Park and Wairoa, along the Waikaretaheke River.

The Genesis Energy website describes the scheme as *"The scheme uses water from Lake Waikaremoana, Waikaretaheke River, Mangaone Stream and Kahuitangaroa Stream to generate electricity and incorporates three power stations: Kaitawa (36MW), Tuai (60MW) and Piripaua (42MW)."*

3.2.3.4 Taranaki Hydro

The majority of the Taranaki's hydro generation is provided by the Patea Power Station. TrustPower's website provides the following overview of the hydro generation in the Bay of Plenty Region (refer to Figure 3.20 below).

Figure 3.20 TrustPower's hydro generation in the Taranaki region

TrustPower's website has the following description of the Patea Power Station *"The scheme uses an 82-metre high compacted earth fill dam."* and *"This dam impounds Lake Rotorangi, which is the longest manmade lake in New Zealand".* The website also states that *"With three vertical Francis turbine and generator sets, the scheme has a total capacity of 30.7 MW and an average annual output of 118 GWh."*

3.2.3.5 Bunnythorpe/Central Hydro

The main hydro power generation in the Bunnythorpe / Central region is from the Tongariro Power Scheme, which is located on the central volcanic plateau south of Lake Taupo.

The Genesis Energy website has the following description of the scheme *"The scheme is operated to provide water to the Tokaanu (240MW) and Rangipo (120MW) power stations and uses a series of lakes, canals and tunnels to do so. Tokaanu Power Station is located on the slopes of Mount Tihia, near the township of Turangi, south of Taupo. Rangipo Power Station is situated underground in the Kaimanawa Forest Park, on the eastern side of the Tongariro Power Scheme."*

The website also states that *"The Tongariro Power Scheme typically contributes 1350 GWh (Gigawatt hours) per annum. - about 4% of the country's total electricity generation. The Tokaanu power station is also used as a frequency control station (controls the power system frequency) when required."*

Genesis Energy's website provides the following overview of the Tongariro Power Scheme (refer to Figure 3.21 below).

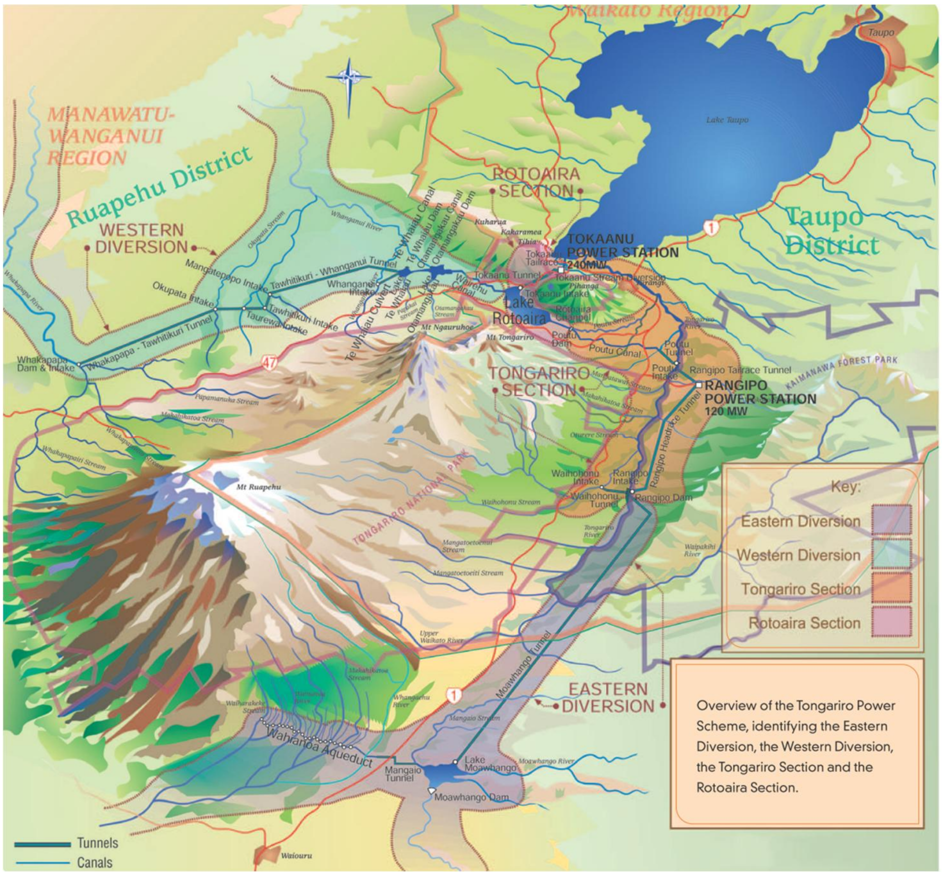


Figure 3.21 The Tongariro Power Scheme overview

3.2.3.6 Wellington Hydro

The majority of the hydro generation in the Wellington region is from the Mangahao Power Station, which is located near Levin.

Todd Energy's website has the following description of the Mangahao Power Station "*Water stored in the reservoirs formed by the two dams on the Mangahao River"* and *"The output from Mangahao was increased in 2004 with the addition of a mini-hydro station that produces an additional 10GWh of electricity per year - enough to power around 1,250 households or a town the size of Turangi. This output is on top of the 126GWh/year that is produced by the existing power station at Mangahao."*

3.2.3.7 Nelson/Marlborough Hydro

The majority of the hydro generation in the Nelson/Marlborough region is provided by the Cobb Power Station, which is located on the Cobb River, Northwest of Nelson City.

TrustPower's website has the following description of the Cobb Power Station *"There is a 13.7-metre range between the highest and lowest operational levels of the impounded water, which is 783-metres above sea level."* and *"The power station itself houses six single-runner Pelton type turbines, four 3 MW on single jet, and two 10 MW on double jets. A gross head of 595.9-metres, the greatest of any New Zealand power station, allows the generation of the full* *output of 32 MW from a water flow of only 7.25 cumecs. The facility produces an average annual output of 192 GWh."*

3.2.3.8 Christchurch Hydro

The majority of the hydro generation in the Christchurch region is provided by the Coleridge Power Station and the Highbank Power Scheme.

TrustPower's website mentions that the Coleridge Power Station has an installed capacity of 39 MW, with the *"energy production capability of the scheme has been boosted from 205 GWh/year to 270 GWh/year, with most of the gain being a direct result of more efficient use of the water resource."*

TrustPower's website describes the Highbank Power Scheme as *"Water for the station is collected from the Rangitata River by means of a 66 km long irrigation race, which provides water for use by farms in summer, when demand for electricity is lower. In winter, when electricity demand increases, and the demand for irrigation water reduces, the surplus water is used for power generation purposes".* The Montalto Scheme utilises *"the stepped flow of the Rangitata Diversion Race"* and *"The average annual output of the combined Highbank and Montalto Schemes is approximately 98GWh."*

3.2.3.9 Waitaki Hydro

The Meridian Energy website describes the Waitaki Power Scheme as *"The Waitaki hydro scheme consists of eight power stations from Lake Tekapo to Lake Waitaki. All eight are operated from a control centre in Twizel, which ensures that as much electricity as possible is generated from the water flowing from the Southern Alps out to the sea."*

Both Kaplan and Francis type turbines are utilised in the system. The following Figure 3.22 shows an overview of the Waikato Hydro System, the locations of the main hydro power plants and that on average the overall scheme annually generates a total of 7702 GWh.

Although shown in the Meridian publication in Figure 3.22 below, Tekapo A and B have since been sold to Genesis Energy in June 2011.

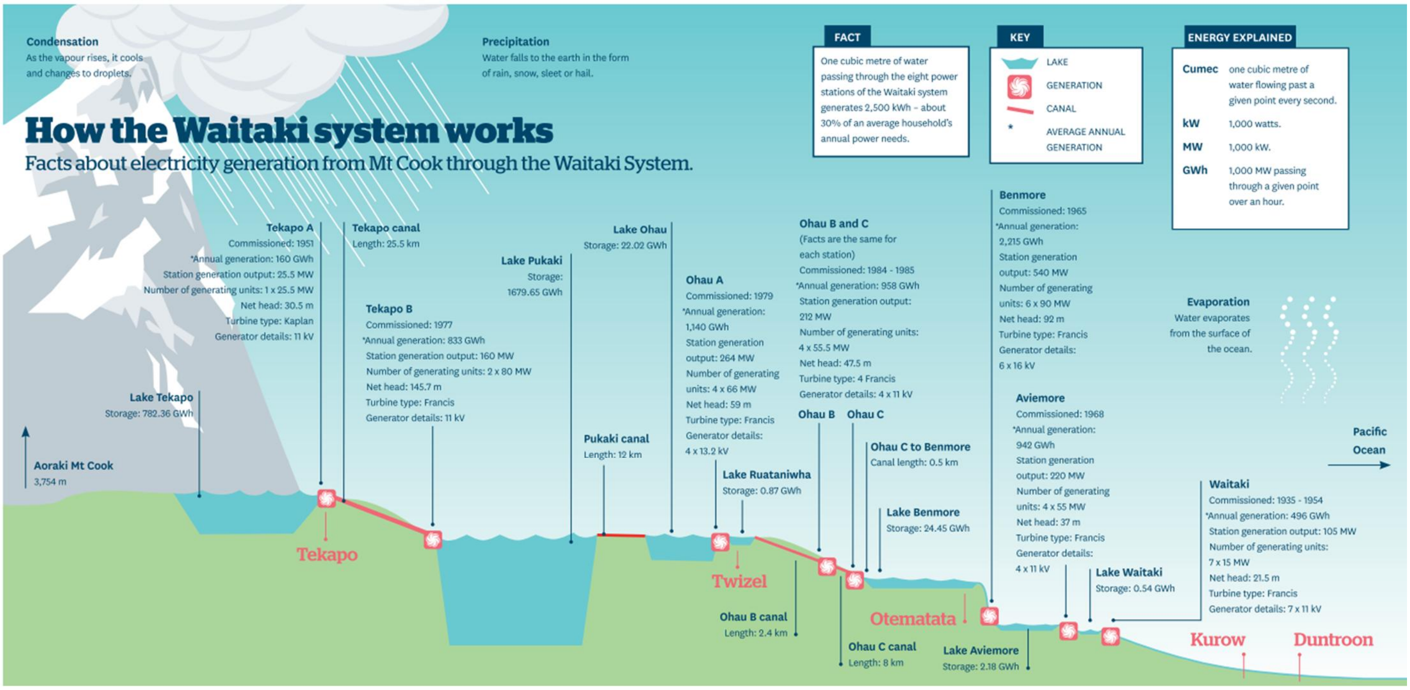


Figure 3.22 Waitaki Hydro System Overview

3.2.3.10 Clutha Hydro

The majority of the hydro generation in the Clutha region is provided by the Clutha Hydro Scheme, consisting of the Clutha and Roxburgh Power Stations. Contact Energy's website notes that the eight turbine 320 MW Roxburgh and four turbine 432 MW Clyde power stations on average annually generate a total of 3750 GWh.

Contact Energy's website describes the Roxburgh Power Station storage and operation as *"The Roxburgh Dam is powered with water from Lake Roxburgh, which has formed behind the dam. The Roxburgh Dam operates to strict environmental criteria. Contact is only allowed to change the level of the lake within a 1.8 metre range. This minimises the impact of varying lake levels on the surrounding environment."*

The website also describes the operation and storage of the Clyde Power Station as *"To minimise the environmental impact of the power station, Lake Dunstan operates in a narrow band from 193.5 to 194.5 metres above sea level. Lake Dunstan does not have a large amount of storage capacity, with the Clyde Power Station relying mainly on the run of the river for its generating power."*

3.2.3.11 Waipori Hydro

TrustPower's website describes the Waipori Hydro Scheme as *"the Waipori Hydro Scheme today consists of four generation stations. Waipori 1A delivers 10 MW, and Waipori 2A, 3 and 4 deliver 58 MW, 7.6 MW and 8 MW respectively. The scheme has a total average annual output of 192 GWh."*

The storage of the system is described on the website as *"The river's level plateau provides the perfect setting for the scheme's storage facility (Lake Mahinerangi) while the steep, narrow gorge provides the fall necessary for the water to drive the turbines."*

3.2.3.12 Deep Stream Hydro

The majority of the hydro generation in the Deep Stream region is provided by the Paerau Hydro Scheme, along with a smaller contribution from the Deep Stream Scheme.

The TrustPower website describes the Deep Stream Scheme as *"The Deep Stream Hydro Scheme channels water flowing from an existing Deep Stream Diversion, impounds that water in a storage reservoir, and then allows the water to be released through canals containing two 2.5 MW generating units to Lake Mahinerangi."*

The website also describes the Paerau Hydro scheme and its operation as *"The Paerau and Patearoa Power Stations were built within an irrigation scheme that impounds a winter watershed behind the Loganburn Dam, for release into the Taieri River during summer. The Power Stations use the run of river flows through winter, with the Paerau Station passing all irrigation flows through summer during which time the Patearoa Station is normally shut down."*

The website also states that *"Between them, the Paerau and Patearoa Stations produce an annual average output of 62 GWh."*

3.2.3.13 Fiordland Hydro

The majority of the hydro generation in the Fiordland region is provided by the Manapouri Power Station. Meridian Energy's website describes the Manapouri Power Station as *"the largest hydro power station in New Zealand, and is located on the edge of Lake Manapouri's West Arm in Fiordland National Park. Manapouri is an underground power station".*

The website mentions that the station has 7 Francis type turbines, each with a rated capacity of 121.5 MW of electricity.

3.2.4 Substation

3.2.4.1 Waikato Hydro

Mighty River Power's website describes the power generation of the system as *"All power in the Waikato system is generated at 11,000 volts. Most stations use transformers to step the voltage up to 220,000 volts for transmission onto the national grid. However, at Arapuni and Karapiro, the voltage is stepped up to 110,000 volts."*

The following Figure 3.23 from Transpower's website shows the connection of each of the main Waikato hydro power plants to the national grid.

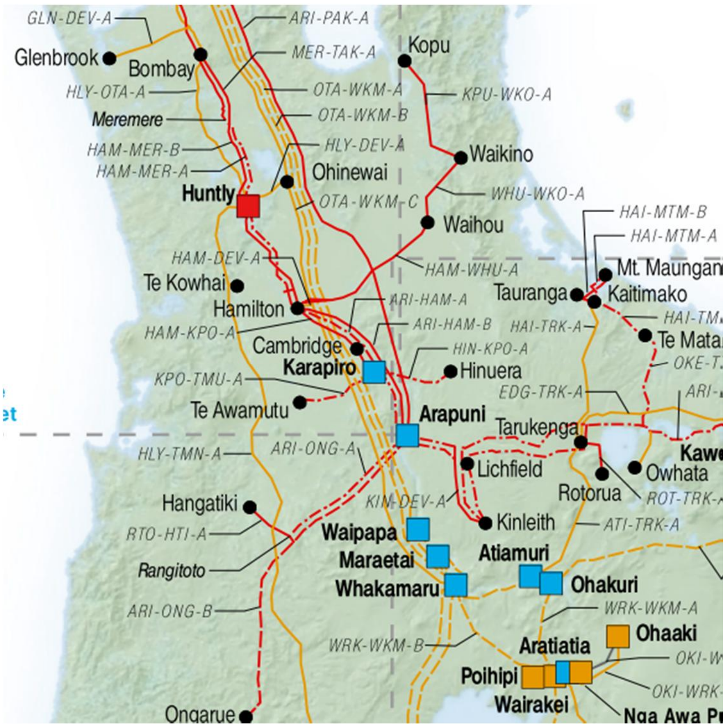


Figure 3.23 **Waikato hydro power stations shown on the Transpower national grid**

3.2.4.2 Bay of Plenty Hydro

The TrustPower website describes the power generation of the Lloyd Mandeno Power station as “there are two sets of turbines and generators, each producing 7,800kW at 11,000 volts”. The Todd Energy website also specifies that the Aniwhenua generator terminal voltage is 11,000 V.

The following Figure 3.24 from Transpower’s website shows the connection of the main Bay of Plenty hydro power plants to the national grid.

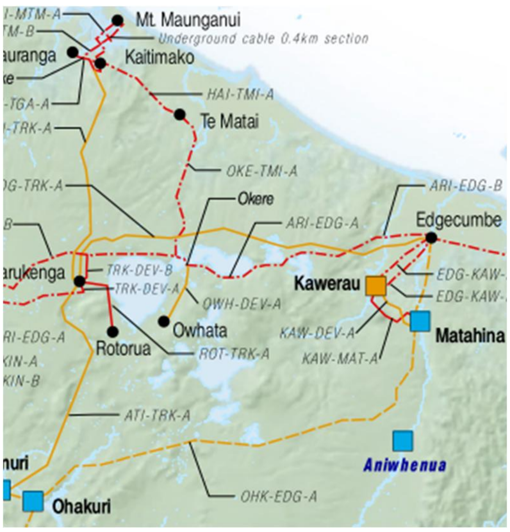


Figure 3.24 **Bay of Plenty hydro power stations shown on the Transpower national grid**

3.2.4.3 Hawke's Bay Hydro

The following Figure 3.25 from Transpower's website shows the connection of the lower north island main hydro power plants to the national grid.

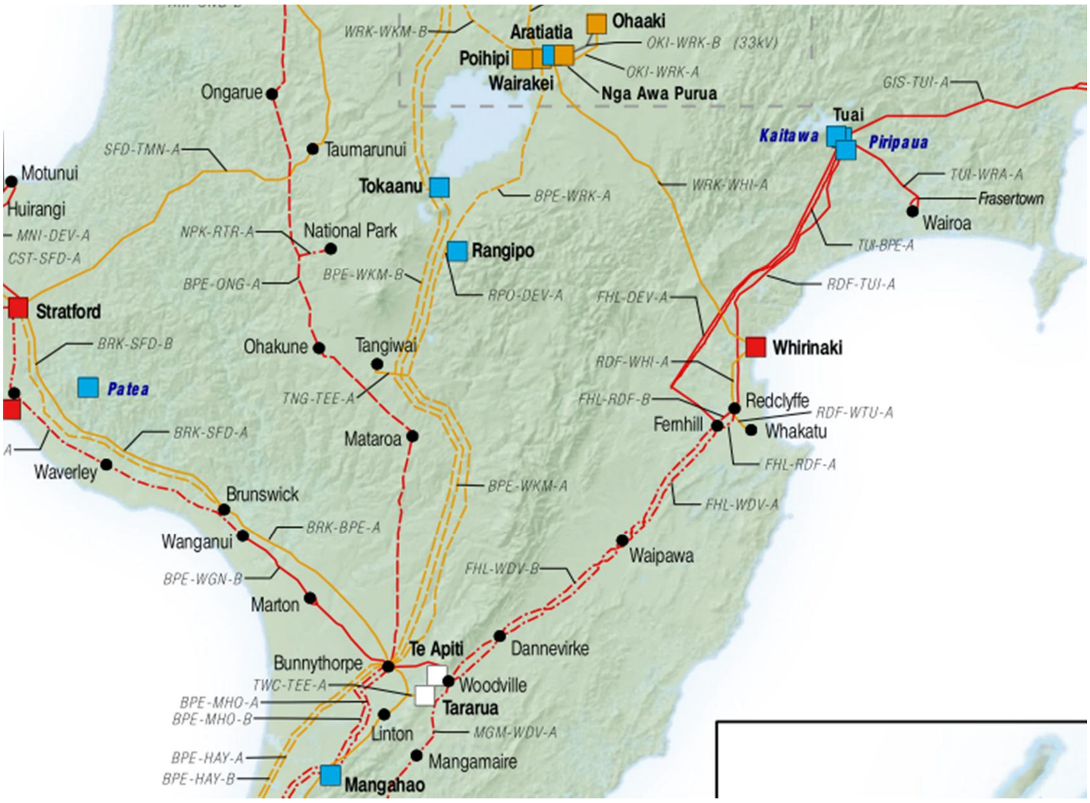


Figure 3.25 Lower North Island hydro power stations shown on the Transpower national grid

3.2.4.4 Taranaki Hydro

The main generating power plant in the Taranaki region (Patea) is shown in Figure 3.25 above, in relation to the national grid.

3.2.4.5 Bunnythorpe Hydro

The two main generating power plants in the Bunnythorpe region (Tokaanu and Rangipo, as part of the Tongariro Power Scheme) are shown in Figure 3.25 above, in relation to the national grid.

3.2.4.6 Wellington Hydro

The main generating power plant in the Wellington region (Mangahao) is shown in Figure 3.25 above, in relation to the national grid.

Todd Energy's website specifies that the Mangahao generator terminal voltage is 11,000 V.

3.2.4.7 Nelson/Marlborough Hydro

The following Figure 3.26 from Transpower's website shows the connection of the Cobb power station in the Nelson/Marlborough Region to the national grid.

Figure 3.26 Nelson/Marlborough hydro power stations shown on the Transpower national grid

3.2.4.8 Christchurch Hydro

The following Figure 3.27 from Transpower's website shows the connection of the Coleridge Power Station in the Christchurch Region to the national grid.

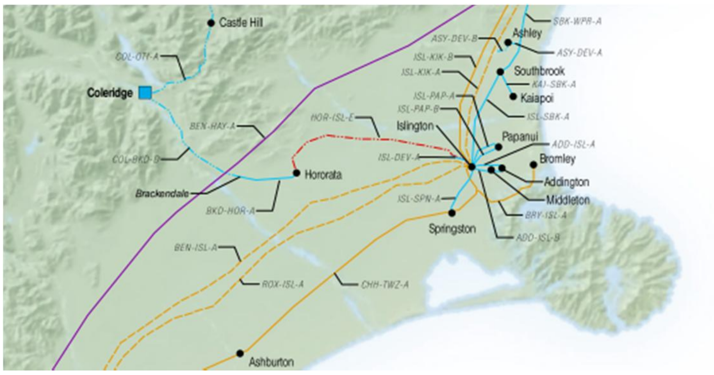


Figure 3.27 Christchurch hydro power stations shown on the Transpower national grid

TrustPower's website mentions the following upgrade to the Highbank scheme *"In 2002 the Highbank plant, with an installed capacity of 28 MW, underwent a substantial electrical and ancillary equipment upgrade including the total rebuild of the 11/66kV switchyard"*

3.2.4.9 Waitaki Hydro

The Figure 3.22 above shows the generator terminal voltages for each of the plants in the Waitaki Region. The following Figure 3.28 from Transpower's website shows the connection of the main hydro plants in the Waitaki system into the national grid.

Figure 3.28 Lower South Island hydro power stations shown on the Transpower national grid

3.2.4.10 Clutha Hydro

The main generating power plants in the Clutha System (Clyde and Roxburgh) are shown in Figure 3.28 above, in relation to the national grid.

3.2.4.11 Waipori Hydro

The Waipori system is shown in Figure 3.28 above, in relation to the national grid.

3.2.4.12 Fiordland Hydro

The Manapouri Power Plant is shown in Figure 3.28 above, in relation to the national grid.

3.2.5 Project lifetime

Provided adequate maintenance is carried out and the equipment is operated appropriately, hydro power plants can typically be expected to last at least 50 years at up to 100 years or more, with major refurbishment work carried out at 25-35 year intervals[28]. Ongoing equipment upgrades and overhauls can further extend project life, with the feasibility of each major equipment/plant replacement being assessed on a case by case basis. As mentioned by the International Energy Agency, Renewable Energy Essentials: Hydropower 2010 *"Many hydropower plants built 50 to 100 years ago are still operating today."*

[28] Discussed in *'Determining O&M Costs over the life of a hydro station, Charles T Wong, Hydro Review Dec 1990'*

Based on this information, PB's experience and the commissioning dates of existing schemes around New Zealand (listed in Table 3-13 below), this report considers that the expected lifetime of a small hydro power plants (10 – 50 MW) is approximately 50 years and the expected lifetime of large hydro power plants (>50 MW) is approximately 80 years.

The Table 3-14 below details the earliest and most recent plant commissioning dates for each region.

Table 3-14 Commissioning Dates of Existing Hydro Plants

Earliest and most recent commission dates of regional hydro power plants		
Region	**Plant**	**Year of Commissioning**
Waikato	Arapuni	1929
	Maraetai II	1970
Bay of Plenty	Matahina	1967
	Ruahihi	1983
Hawke's Bay	Tuai	1929
	Kaitawa	1948
Taranaki	Patea	1984
Bunnythorpe	Tokaanu	1973
	Rangipo	1983
Wellington	Mangahao	1924
Nelson/Marlborough	Cobb	1944
Christchurch	Coleridge	1914
	Montalto	1958
Waitaki	Waitaki	1935
	Ohau A & B	1985
Clutha	Roxburgh	1956
	Clyde	1992
Waipori	Original Waipori scheme	1907
Deep Stream	Paerau	1984
	Deep Stream	2008
Fiordland	Manapouri	1972

3.2.6 Operational capacity

The overall operational capacity of each region is provided as a total in Table 3.12 above. These regional totals consider plants with operational capacities greater than or equal to 10MW, from the main generating companies around New Zealand (Contact Energy, Genesis Energy, King Country Energy, Meridian Energy, Might River Power, Todd Energy and TrustPower).

3.2.7 Availability Factor

Plants are typically unavailable to generate due to planned and unplanned maintenance. Where this information has not been provided through consultation, the availability factor has been assumed to be 92.3% of the year. This is based on the median of the Plant Availability Factors published in the 2010 annual/interim reports of Meridian Energy and Genesis Energy.

Based on PB's experience, the Plant Availability Factor determined from the annual/interim reports are typical of what is currently expected on average over the lifetime of hydro plants in New Zealand.

Table 3-15 Existing Hydro Plant Availability Factor

Regional Availability Factor				
Region	**Capacity**	**Annual Power Generation**	**% of year estimated to be unavailable due to planned or unplanned maintenance**	**Availability Factor**
Waikato	1040 MW	4120 GWh	7.7%	92.3%
Comments/Capacity Restraints: In addition to the operational comments in Section 3.2.3.1 above, the website states *"In times of extreme rainfall, the Taupo Gates can be used to help reduce the severity of flooding in the lower Waikato. In dry conditions, the gates are used to conserve water in Lake Taupo while meeting generation and minimum flow requirements for the Waikato River."*				
Bay of Plenty	165 MW	699 GWh	7.7%	92.3%
Hawkes Bay	138 MW	442 GWh	7.7%	92.3%
Taranaki	31 MW	118 GWh	7.7%	92.3%
Bunnythorpe	360 MW	1,350 GWh	7.7%	92.3%
Wellington	39 MW	136 GWh	7.7%	92.3%
Nelson/Marlborough	32 MW	192 GWh	7.7%	92.3%
Christchurch	69 MW	368 GWh	7.7%	92.3%
Waitaki	1,739 MW	7,702 GWh	7.7%	92.3%
Clutha	752 MW	3,750 GWh	7.7%	92.3%
Waipori	84 MW	192 GWh	7.7%	92.3%
Deep Stream	17 MW	87 GWh	7.7%	92.3%
Fjordland	730 MW	5,100 GWh	7.7%	92.3%

3.2.8 Unit largest Proportion

The following Table 3-16 lists the capacity of the largest single hydro generator in each region.

Table 3-16 Unit largest Proportion for Existing Hydro Plants

Largest Single Generator Capacity			
Region	**Plant**	**Largest Generator Size**	**Percentage of Plant Capacity**
Waikato	Maraetai	36 MW	20%
Bay of Plenty	Matahina	40 MW	50%

Largest Single Generator Capacity			
Region	**Plant**	**Largest Generator Size**	**Percentage of Plant Capacity**
Hawke's Bay	Piripaua	21 MW	50%
Taranaki	Patea	10 MW	33%
Bunnythorpe	Rangipo	60 MW	50%
Wellington	Mangahao	26 MW	70%
Nelson/Marlborough	Cobb	10 MW	32%
Christchurch	Highbank	28 MW	100%
Waitaki	Benmore	90 MW	17%
Clutha	Clyde	108 MW	25%
Waipori	Waipori 2A	19 MW	33%
Deep Stream	Paerau	5 MW	50%
Fiordland	Manapouri	121.5 MW	16%

3.2.9 Baseload

Hydro power plants are not typically considered to provide base-load generation as they rely on rainfall in-flows to allow them to generate and megawatt output will vary. However, given the large storage reservoirs of some hydro generating plants, some generator units may at times be operated as baseload plant. The operating regime of the plant is dependent on many factors, including the commercial operating strategy of the generator, and hence for this report hydro power stations have been considered to not provide base-load.

3.2.10 Variable O&M costs

The operations and maintenance (O&M) costs of hydro power plants are dependent on each generators internal asset management strategy and systems for the plant. This information has been requested from the generators, and where this information has not been provided, the total O&M costs have been estimated using the following technique.

The proportion of O&M costs that are fixed and variable are likely to differ between generators. Where this information has not been provided by the generators, this report has considered the follow definitions of typical fixed and variable costs for hydro power plants.

The fixed O&M costs are costs that are not dependent on the number of hours of operation of the power plant. The following are considered to be typical fixed O&M costs[29]:

- Operation supervision and engineering
- Maintenance supervision and engineering
- Maintenance of structures

[29] *Based on PB's experience and "Estimation of Economic Parameters of U.S. Hydropower Resources, D.Hall, R.Hunt, K.Reeves, G.Carroll, June 2003"*

- Maintenance of reservoirs, dams, and waterways
- Maintenance of electric plant
- Maintenance of miscellaneous hydraulic plant
- Insurances and property taxes

The variable O&M costs are costs that depend on the number of hours of operation of the power plant. The following are considered to be typical variable O&M costs[29]:

- Increased operation supervision and engineering
- Hydraulic expenses
- Electric expenses
- Miscellaneous hydraulic power expenses

The report *'Determining O&M Costs over the life of a hydro station, Charles T Wong, Hydro Review Dec 1990'* analyses historical operating and maintenance costs from the U.S. Federal Energy Regulatory Commission and provides the following formula:

Operating and Maintenance Costs = 4.83 + 0.00239 x (plant age)² : in Canadian $/kW per annum (1987).

This formula has been used to predict future O&M costs over the life of existing plant. When this result is escalated using the Canadian Consumer Price Index and converted to New Zealand dollars per month, it results in a total O&M cost of NZ$873/MW per month for a new plant.

This cost does not include major capital expenditure, such as major plant overhauls and the report does not clarify whether operational administrative costs are included in the calculated cost.

The calculated O&M cost was compared to several industry guidelines and an alternative O&M cost estimate technique based on actual time data, with the estimated O&M costs varying by +/-50%. Considering this comparison and that operating costs typically do not go significantly under budget, the operating and maintenance costs can be considered to have a tolerance of +50%, -10%.

A report by the World Bank Group, '*Technical and Economic Assessment of Off-Grid, Mini-Grid and Grid Electrification Technologies Annexes, September 2006'* provides a table specifying the O&M costs of a large hydro plant. This report identifies both the fixed and variable costs, with the fixed cost making up 61% of the total O&M cost and the variable making up the remaining 39%. This ratio has been applied to the calculated total O&M costs for each of the hydro plants/regions (using an estimated average plant age for each region). For a new plant, this results in an estimated variable operating and maintenance cost of $340/MW per month.

This estimated variable O&M cost was converted to $0.00086kWh, using the estimated net output factor of 59% and availability factor of 92.3% to calculate the average number of hours of operation per year (refer to Section 4.2.8 and Section 4.2.7 for details on estimating the net output factor and availability factor respectively). Where a more accurate net output factor was available, this was for calculating the variable O&M costs.

3.2.11 Fixed O&M costs

The fixed operating and maintenance costs have been requested from the generators. Where this has not been provided, it has been determined using the technique detailed in Section 3.2.10 above. This technique results in an estimated fixed operating and maintenance cost of $532/MW per month for a new plant.

3.3 Wind

3.3.1 Summary

Table 3-17 summarises the PB recommendations for existing wind plant technical and cost data for use as inputs into MED modelling.

Table 3-17 PB recommendations: Existing NZ wind plant data

Project name	Plant technology	Substation	Project lifetime	Capacity (Gross)	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Variable O&M costs	Fixed O&M cost
			Years	*MW*	*%*	*%*	*%*	*y/n*	*$/MWh*	*$/kW/year*
Te Apiti	NEG Micon NM72 - 1.65MW	WDV	25	90.8	92	43	1.82	N	3	60
Te Rere Hau	Windflow S500 - 500kW	LTN	25	48.5	92	48	1.03	N	3	70
White Hill	Vestas V80 – 2.0MW	TWI	25	58	92	39	3.45	N	3	60
Te Uku	Siemens MM 82 VS – 2.3MW	HAM	25	64.4	92	48	3.57	N	3	60
Mahinerangi	Vestas V90 – 3.0MW	NMA	25	36	92	39	8.33	N	3	70
Tararua Stage 1 & 2	Vestas V47 – 660kW	LTN	25	67	92	48	0.97	N	3	60
Tararua 3	Vestas V90 - 3.0MW	WDV	25	94	92	48	3.23	N	3	60
West Wind	Siemens MM 82 VS – 2.3MW	WIL	25	142.6	92	43	1.61	N	3	60

3.3.2 Plant

The existing NZ wind farms included in the scope of this review are:

Table 3-18 Existing 10 – 100 MW wind farms

10 - 100MW		
Wind farm	**Developer / Owner**	**Capacity [MW]**
Te Apiti	Meridian Energy	90.8
Te Rere Hau	NZ Windfarms	48.5
White Hill	Meridian Energy	58
Te Uku	Meridian Energy	64.4
Mahinerangi	TrustPower	36

Table 3-19 Existing 101 – 200 MW wind farms

101 – 200 MW		
Wind farm	**Developer / Owner**	**Capacity [MW]**
Tararua	TrustPower	161
West Wind	Meridian	142.6

3.3.3 Plant technology

Table 3-20 lists the current technology installed in New Zealand. The majority (approximately 87.5%) of the wind turbine generators (WTGs) installed in NZ wind farms are European produced, the remaining are New Zealand produced by Windflow, based in Christchurch.

Table 3-20 Wind farm technology

Wind Farm	Plant technology
Te Apiti	NEG Micon NM72 - 1.65 MW
Te Rere Hau	Windflow S500 – 500 kW
White Hill	Vestas V80 – 2.0 MW
Te Uku	Siemens MM 82 VS – 2.3 MW
Mahinerangi	Vestas V90 – 3.0 MW
Tararua Stage 1 & 2	Vestas V47 – 660 kW
Tararua 3	Vestas V90 - 3.0 MW
West Wind	Siemens MM 82 VS – 2.3 MW

3.3.4 Substation

Each wind farm typically has their own substation which contains the protection (Static Var Compensators, etc), power regulation, step up transformer(s) and Supervisory Control and Data Acquisition (SCADA) system(s). The information required by MED for the GEM input relates to the connection from the wind farm transmission line into the grid operator's substation.

Table 3-21 Existing 10 – 100 MW wind farms

10 – 100 MW			
Wind farm	**Developer / Owner**	**Capacity [MW]**	**Substation**
Te Apiti	Meridian Energy	90.8	WDV
Te Rere Hau	NZ Windfarms	48.5	LTN
White Hill	Meridian Energy	58	TWI
Te Uku	Meridian Energy	64.4	HAM
Mahinerangi	TrustPower	36	NMA

Table 3-22 Existing 101 – 200 MW wind farms

101 – 200 MW			
Wind farm	**Developer / Owner**	**Capacity [MW]**	**Substation**
Tararua	TrustPower	161	LTN/WDV
West Wind	Meridian	142.6	WIL

3.3.5 Project lifetime

The International Electrotechnical Commission (IEC) 61400 certification requirements require a design life of twenty years for WTGs. Wind farm developers are starting to consider the possibility of a longer operational life (e.g. twenty five years) at some locations globally, but this is currently not the norm.

A recent report[30] on the projected costs of generating electricity by the IEA estimates an average project operational lifetime at 25 years for modelling wind plant.

WTGs located in New Zealand experience a comparatively high wind resource, high turbulence from complex terrain and close relative proximity to coastal climates which can shorten the mechanical life of some WTGs components such as blades and bearings. The primary effect of this is on O&M costs, where refurbishments and replacements are required more regularly.

For project financing of NZ wind farms, a project life of 20 years is commonly used, but realistically with adequate maintenance and refurbishment programs, wind farms should achieve an operational life of 25 years or more.

[30] *Projected Costs of Generating Electricity. 2010 edition. International Energy Agency*

PB recommends a value of 25 years for the operational life of wind plant in the GEM.

3.3.6 Operational capacity

PB has gathered the operational capacity data from generator websites and the New Zealand Wind Energy Association (NZWEA) website (http://windenergy.org.nz/nz-wind-farms/operating-wind-farms). PB has only considered wind farms with a capacity of 10MW or greater. The wind farms in Table 3-23 are not included in this study.

Table 3-23 Operational wind farms not included within this study

Wind farm	Developer / Owner	Location	Capacity [MW]
Brooklyn	Meridian	Wellington	0.225
Gebbies Pass	Windflow	Canterbury	0.5
Hau Nui	Genesis	Wairarapa	8.7
Horseshoe Bend	Pioneer Generation	Central Otago	2.25
Weld Cone	Energy3	Marlborough	0.75
Chatham Islands	CBD ENERGY / Chatham Islands Enterprise Trust	Chatham Islands	0.45
Lulworth	Energy 3	Marlborough	1.0

3.3.7 Availability factor

The availability factors commercially released by WTG manufacturers can typically exclude downtime associated with grid outages and climate related events. This is generally because of the contractual Service Level Agreements in place between the WTG Contractor and the Owner, defining the responsibilities associated with each type of downtime event and allocating the impacts of any lost revenue. For example:

- Grid downtime in the production period, defined as time when the WTG is not operational caused by grid conditions at the wind farm connection point being [outside specifications] or due to any restrictions in operation imposed by the system operator, e.g. with reference to the Grid Code

- Climate downtime in the production period, defined as time when the WTG is not operational caused by climatic conditions being [outside specifications], such time including subsequent initiation time for the WTG to commence operation after the climatic conditions having again become within specifications.

PB has experienced a typical warranted availability of between ninety to ninety three percent (90-93%) within the first year of operation. The first year of operation is considered as twelve months from the day of practical completion[31]. The following two to seven years of wind farm operation, depending upon the nature of agreement between the Contractor and the Owner, the warranted availability is commonly set at between ninety five to ninety seven percent (95-

[31] *Practical completion is the day that the WTGs have passed their reliability runs to prove their operational capability and handed over to the Owner.*

97%). From midlife, ten to thirteen years, PB would consider a ninety three percent (93%) average availability over the remainder of the operational life.

PB has assumed an annual average reduction of one percent (1%) to compensate for the grid and climactic downtime and has plotted the typical average availability of a wind farm considering existing in-house references in Figure 3.29.

Figure 3.29 Availability trend over a 25 year operational life

Using the data trend included in Figure 3.29, PB has estimated the average availability of WTGs over a 25 year operational life to be 92%. PB recommends that the GEM uses an average lifetime AF for all wind farms of 92% which PB considers is an applicable approach for all WTG technologies.

3.3.8 Net Output Factor

PB has defined two separate categories of wind resource using a wind map provided by NIWA (http://www.eeca.govt.nz/efficient-and-renewable-energy/renewable-energy/maps/wind). There are several regions with an average wind speed above 10 m/s at wind turbine hub height. NIWA's map shows wind resources over the entire country – mean annual wind speed is shown at a height of 10m above ground level (representing surface winds).

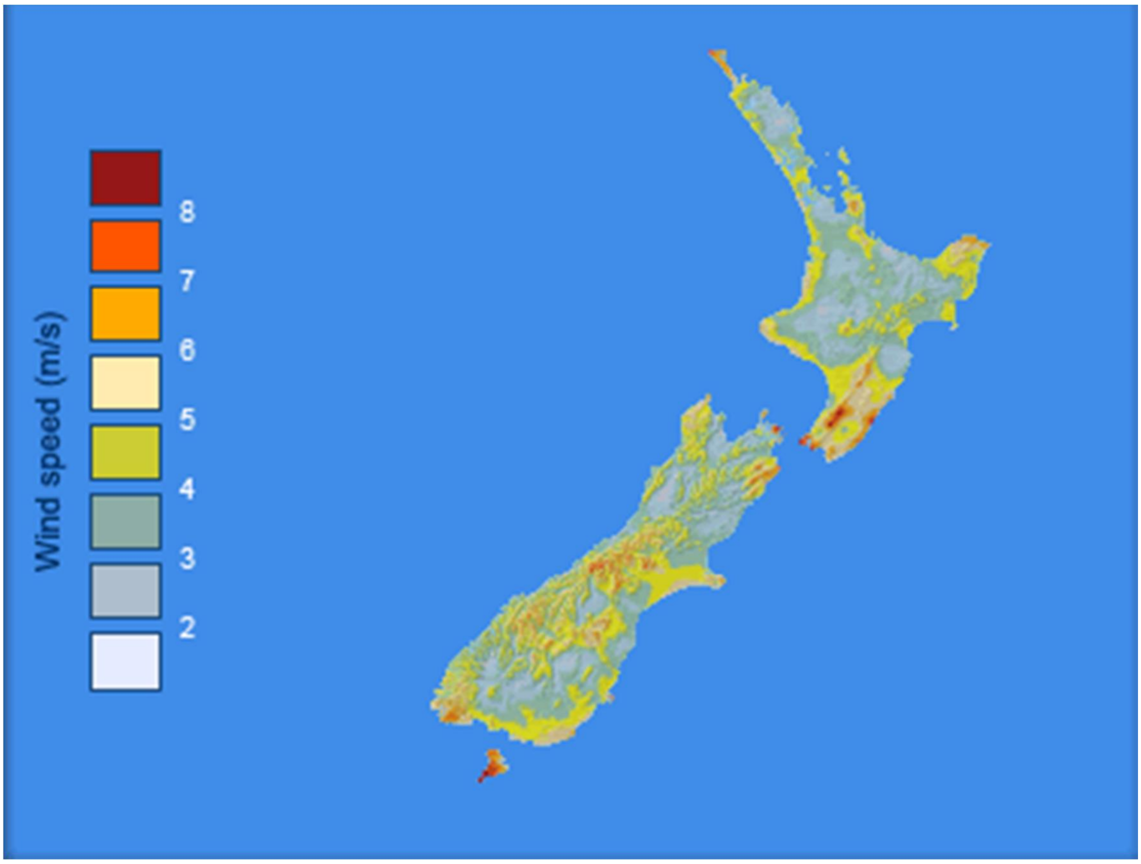


Figure 3.30 NIWA NZ wind map – median wind speed (m/s)

The total energy that would be produced by a wind turbine during a one-year period, assuming a certain distribution of wind speed probability density and assuming 100 per cent availability, is referred to as the potential Annual Energy Production (AEP). The capacity factor is defined as the ratio of actual average power to the rated power measured over a period of time (average power/rated power). The better the local wind conditions, the higher the capacity factor for the turbine at that site. The maximum potential capacity factor is illustrated in Figure 3.31 (referenced from http://www.windmeup.org/2007/09/understanding-capacity-factors_24.html which is a graph developed using IEC 61400) for an ideal WTG with assuming no losses.

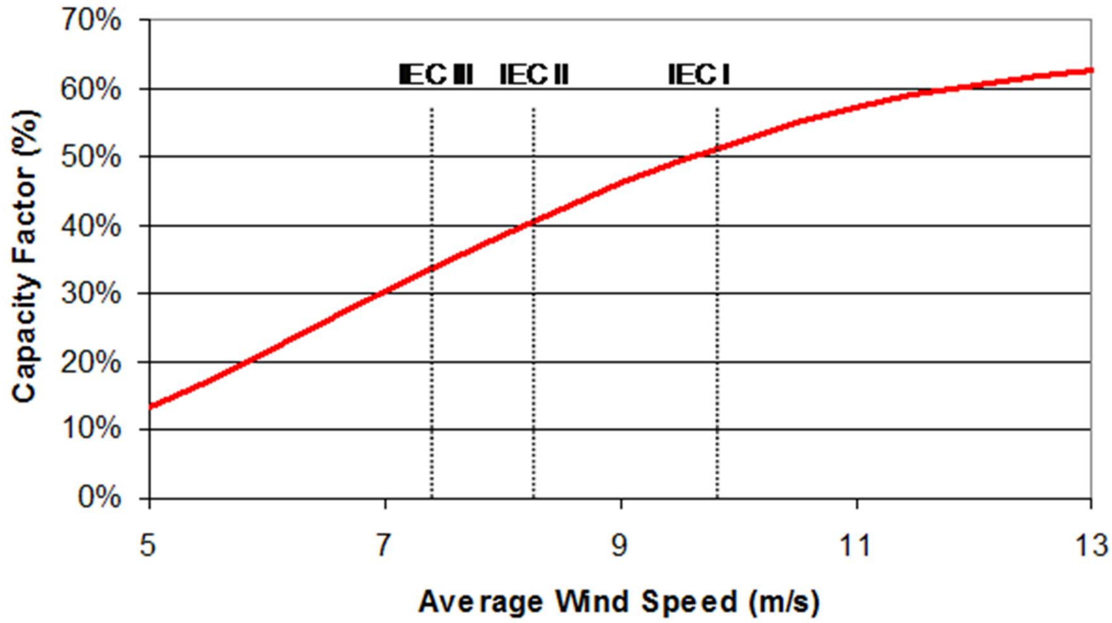


Figure 3.31 Maximum potential capacity factor

PB has used this graph as a litmus test with regard to IEC 61400 classifications and capacity factors associated with average wind speeds.

From analysis of wind farm owner provided generation figures (sourced from annual reports on generator websites), PB has back calculated the capacity factors for the following existing wind farms:

Table 3-24 Existing wind farms - actual generation and capacity factor

Wind farm	Annual generation [MWh]	Capacity factor [%]
Te Apiti	325,000	40.86
White Hill	183,000	36.02
Te Uku	240,000	42.54
Mahinerangi	105,000	33.30
Tararua Stage 1 & 2	258,012	43.96
Tararua 3	361,988	43.96
West Wind	497,000	39.79

PB also sourced the predicted generation figures and capacity factors from generator websites for the following wind farms:

Table 3-25 Proposed wind farms – estimated generation and capacity factor

Wind farm	Annual generation [MWh]	Capacity factor [%]
Mill Creek	265,000	43
Project Central Wind	420,000	39
Project Hayes	2,200,000	39

PB has applied these capacity factors to the NIWA map and defined three regional classifications of the wind resource and associated average lifetime capacity factors as shown in Table 3-26.

To calculate the NOF, PB has divided the NCF values by the average lifetime AF for wind farms (92%), estimated in Section 3.3.7:

Table 3-26 PB estimated average lifetime NOF for wind farms

Region	Estimated average NOF (%)
North Island	43
South Island	39
High wind areas (Tararua or direct equivalent)	48

3.3.9 Unit largest proportion

PB has calculated this by dividing the operational capacity (MW) of a single wind turbine unit by the total operational capacity (MW) of the wind farm e.g. for a wind farm consisting of twenty 2 MW turbines the ULP is 2MW divided by 40MW or 5%.

3.3.10 Baseload

Wind farms are currently unable to provide baseload generation.

3.3.11 O&M costs

In order to derive estimates for the average fixed and variable O&M costs for wind farms, PB has looked to provide a high level estimate for the total O&M costs and then provide a split into the variable and fixed components.

PB has reviewed a recent source of global benchmark figures for total operating expenditure (Opex) per MWh (refer to Table 3-27) as detailed within a report issued by Deloitte for the New Zealand Wind Energy Association (NZWEA) on the economics of wind development in New Zealand[32] (Deloitte Report). PB has verified these figures by comparing worked examples to an internal O&M cost database and other reports/articles available on the internet.

[32] *Economics of wind development in New Zealand Prepared for the NZ Wind Energy Association*

Table 3-27 Wind farm operating expenditure per MWh ($2010) - Global Benchmark

Opex per MWh ($2010)- Global Benchmark

COUNTRY	NZ		GERMANY	UK	USA
Currency	NZD	EUR	EUR	EUR	EUR
Low	10.0	5.2			
Average	16.0	8.3	22.5	20.1	16.4
High	22.0	11.4			

Source: Deloitte analysis, WindPower Monthly
1 NZD = 0.52 Euro

The Deloitte Report suggests a range of values from NZ$10 to NZ$22/MWh with a reference or average value of NZ$16/MWh. This appears low when compared to the international benchmarks in the same table which range from NZ$31.5/MWh to NZ$43.3/MWh (using 1 NZD = 0.52 EUR).

A previous report prepared by PB for the Electricity Commission as part of the 2006 SOO project concluded a value (2006 $) of $16/MWh:

> *"A figure of $13 per MWh for operating costs for wind generation was referenced during a wind energy conference in 2003 by TrustPower relating to Tararua stage I. This figure has been increased by 23% (to $16/MWh) to reflect current operating costs which again are influenced by the overseas component costs and variations in the exchange rate.*
>
> *The cost for full warranty contracts offered by wind turbine manufacturers is currently in the order of $25 per installed kW per year."*

A recent report for the International Energy Agency[33] (IEA) issued March 2011, observed ranges of annual total wind farm O&M costs from NZ$15/MWh to NZ$45/MWh for a cross-section of countries such as Denmark, Germany, Spain and the United States and a reference (average case) of $NZ28/MWh (€13/MWh).

Given the above references, and recent PB experience, we recommend increasing the Deloitte O&M cost range estimates by $4/MWh. This provides a range of $14 - $26/MWh for average total O&M costs over the project life.

PB considers the older WTGs to have a higher maintenance requirement than that of the newer and less mechanical (fewer moving parts) technology which also includes auto-lubrication, more advanced and better integrated condition monitoring which enables better maintenance planning and less unscheduled outages, this will affect where the O&M cost will sit within the benchmark range. The cost of O&M contracts offered by WTG manufacturers will vary due to contract length, exchange rates and market conditions at the time of procurement negotiations and maintenance philosophy. An example of the different types of OEM contract for that portion of the total O&M costs is as follows:

[33] *International Energy Agency (IEA) Wind's report – IEA Wind Task 26, Multi-national Case Study of the Financial Cost of Wind Energy (Work Package 1, Final Report) issued on 10 March 2011*

- An OEM may offer a 15 year Warranty and Operations and Maintenance (WOM) agreement and state that the WTG will be in a similar condition for the duration of the contract to that as when first installed – From PB's experience within Australia and New Zealand, O&M costs for this type of arrangement would sit at the top of the likely range ($19/MWh).
- From PB's experience, a standard 5 year WOM agreement within Australia and New Zealand would typically sit mid-range (around $16/MWh).

The Deloitte report goes on to provide a cost curve for total O&M costs as a function of wind farm size (MW capacity), as per Figure 3.32.

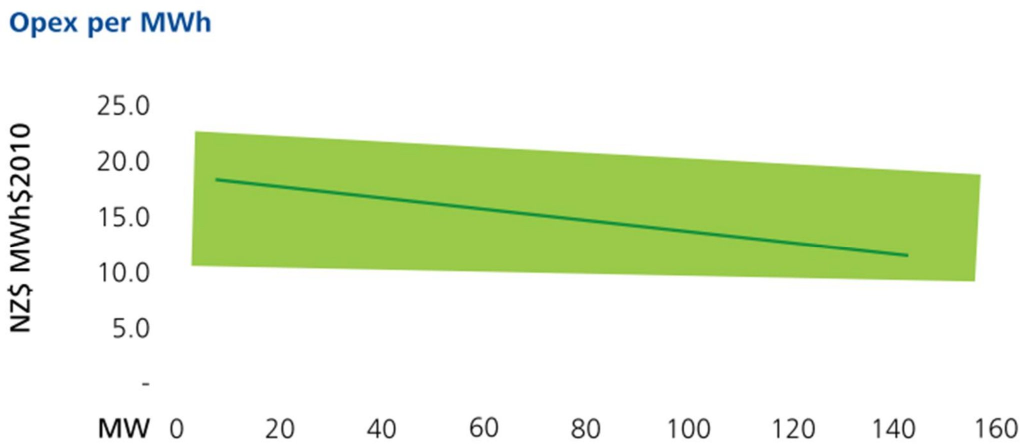


Figure 3.32 Deloitte analysis: NZ wind farm O&M cost per MWh

PB data suggests that the fixed O&M costs on a $/kW/year basis will decrease as the capacity of the wind farm increases as per Figure 3.32, whilst the variable O&M costs will typically remain more constant across different sizes of wind farm. On this basis, PB estimates the average lifetime total O&M costs for different size categories of wind farms as:

- 10 – 50 MW wind farm = $23/MWh
- 51 – 150 MW wind farm = $20/MWh
- > 151 MW wind farm = $17/MWh

PB has used an O&M cost breakdown of total O&M costs for the period between 1997 and 2001 based on German data from DEWI, a report from Wind Power Monthly[34], and typical PB modelling assumptions. To support the separation of total O&M costs into fixed and variable, PB has categorised wind farm O&M costs into the following components:

- Insurance
- Service and spare parts (scheduled maintenance including consumables)

[34] http://www.windpowermonthly.com/news/1010136/Breaking-down-cost-wind-turbine-maintenance/

- Miscellaneous (upkeep of roads, crane pads, easements, fencing, flora fauna, signage, public interface, etc.)
- Repairs (unscheduled maintenance including parts)
- Power from grid
- Administration
- Land rent

PB's experience within the industry and from research undertaken for this specific project indicates the average estimated breakdown for the total wind farm O&M costs over the life of a project as shown in Figure 3.33.

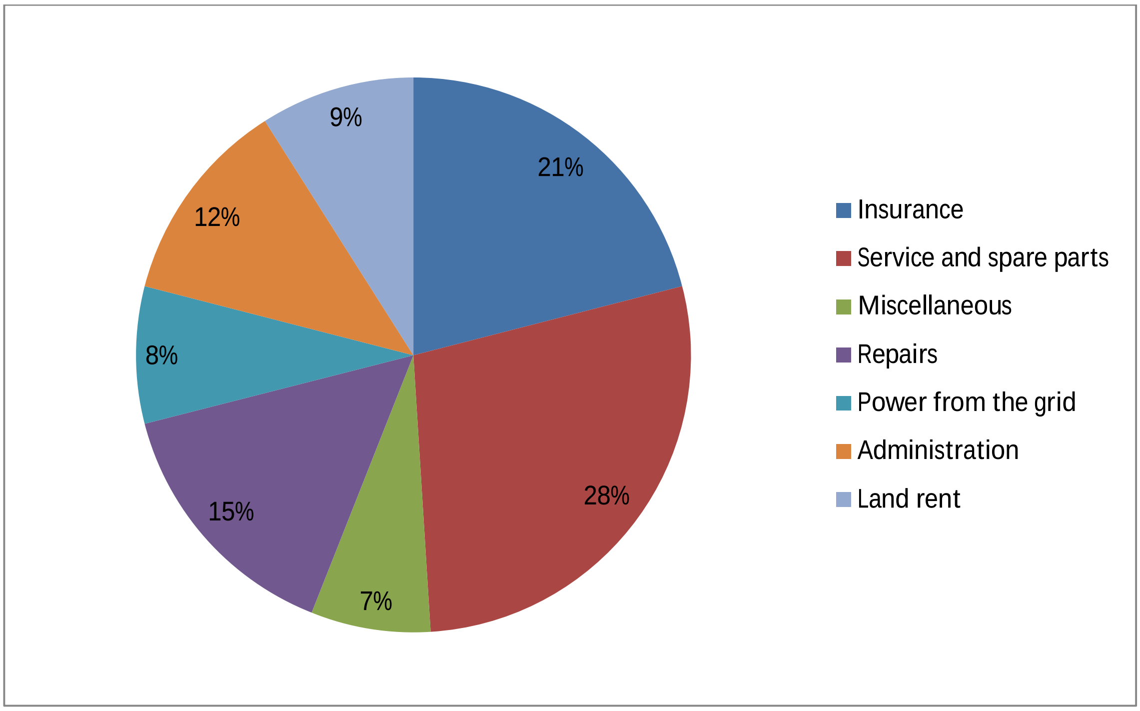


Figure 3.33 Estimated breakdown of wind farm O&M costs

To support our component breakdown, PB has also considered and evaluated reports from industry associations such as IEA, European Wind Energy Association (EWEA), and the British Wind Energy Association (BWEA).

3.3.11.1 Variable O&M Costs

PB has defined the variable O&M costs ($/MWh) incurred over the lifetime of the plant as those associated with repairs and maintenance not covered by the OEM (or third party) warranty and availability contract and includes costs associated with spares, labour, equipment/heavy plant and consumables.

PB has assumed a variable O&M cost of fifteen percent of the total O&M costs on average over the life of the wind farm. This component cost is a function of the level of generation and expressed as a dollar per MWh value. Given PB's recommendation of using $20/MWh for the average total O&M costs for wind plant, the average variable O&M cost over the life of the plant is estimated at $3/MWh.

PB has verified this value with industry benchmarks (included above) and PB in-house cost benchmarks and considers it to be appropriate for use in the GEM.

3.3.11.2 Fixed O&M costs

The fixed share of O&M expenditure ($/kW/year) typically includes all costs which are independent of how much the plant generates, and includes:

- Insurance
- Service and spare parts (scheduled maintenance)
- Miscellaneous (upkeep of roads, crane pads, easements, fencing, flora fauna, signage, public interface, etc.)
- Power from grid
- Administration
- Land rent

PB's definition of fixed O&M costs excludes any repair and maintenance costs not covered by OEM and 3rd party O&M contracts. PB has estimated the following fixed O&M costs using:

- An average wind farm capacity factor of 40%;
- Average variable O&M costs of $3/MWh; and
- Total O&M costs for the different size categories of wind farm defined above.

This provides estimated average fixed O&M costs over the life time of a wind farm:

- 10-50 MW wind farms = $70/kW/year
- 51 – 150 MW wind farms = $60/kW/year
- > 151 MW wind farms = $50/kW/year

3.4 Geothermal

3.4.1 Summary

Table 3-28 summarises the PB recommendations for existing NZ geothermal plant technical and cost data to be used in the GEM.

Table 3-28 PB recommendations - Existing NZ geothermal plant data

Project name	Plant technology	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Fixed O&M
			Years	*MW (Gross)*	*%*	*%*	*%*	*Y/N*	*$/kW/ year*
Wairakei	Conventional	WRK	50	157	92	92	20	Y	105
Wairakei Binary	ORC	WRK	40	15	95	97	100	Y	105
Ohaaki	Conventional	OKI	40	69	92	92	51	Y	105
Rotokawa	BCC	WRK	40	34	95	97	47	Y	105
Poihipi	Conventional	PPI	40	55	95	97	100	Y	105
Ngawha	ORC	KOE	40	25	95	97	48	Y	105
Kawerau Stage 1	Conventional	KAW	40	100	95	97	100	Y	105
Mokai	BCC	WKM	40	112	95	97	31	Y	105
Te Huka	ORC	WRK	40	25	95	97	100	Y	105
Tasman Mill	ORC	KAW	40	16	95	97	100	Y	105
Nga Awa Purua	Conventional	WRK	40	140	95	97	100	Y	105

3.4.2 Plant

The following are the existing geothermal generation plants nominated for review by MED, according the GEM naming convention.

- Wairakei
- Wairakei Binary
- Ohaaki
- Rotokawa
- Poihipi
- Ngawha
- Kawerau Stage 1
- Mokai
- Te Huka Binary (additional to existing GEM data set)
- Nga Awa Purua (additional to existing GEM data set)
- Tasman Mill (additional to the existing GEM data set)

3.4.3 Plant technology

3.4.3.1 Wairakei

Conventional condensing steam turbine comprising:

- Station A: 67.2 (6 x 11.2 MW low and intermediate pressure steam turbines)
- Station B: 90 MW (3 x 30 MW mixed pressure steam turbines)

3.4.3.2 Wairakei Binary

The plant is configured as a 15 MW Organic Rankine Cycle plant.

3.4.3.3 Ohaaki

Plant comprises a conventional condensing steam turbine but with a natural draft cooling tower. Although initially constructed to generate 104 MW, a decline in the steamfield has meant maximum net capacity is about 65 MW with an annual output of around 400 GWh per annum. Plant capacity is demonstrated[35] in Figure 3.34.

[35] *Information source: Data via the N.Z. Electricity Commission collection and Gnash, plotted via MatLab. Author Nicky McLean.*

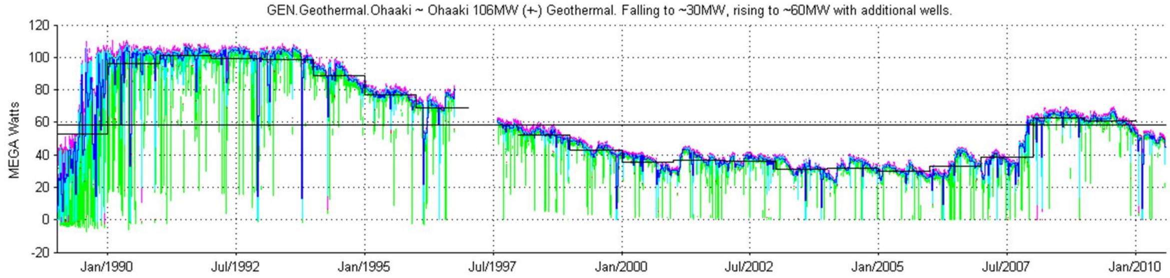


Figure 3.34 Ohaaki capacity (MW)

There are currently three turbines in operation. One smaller turbine runs off high pressure steam which then backfeeds into the main intermediate pressure system that feeds the two main units.

3.4.3.4 Rotokawa

Rotokawa is a Binary Combined Cycle power plant comprising of a back pressure steam turbine, and organic Rankine cycle units utilising the exhaust steam from the steam turbine and the hot brine flow.

A 14 MW backpressure turbine is utilised to drop the steam pressure to ~ 1.5 bar. This steam is condensed in two binary units of 5 MW output each. There is a third 5 MW binary unit utilising the hot brine flow.

In late 2002, a 20% expansion of Rotokawa was commissioned to further extend the operational improvements achieved in 2001 and capacity increased to 34MW.

3.4.3.5 Nga Awa Purua

This new 140 MW - geothermal power station at the Rotokawa geothermal resource is the second development by Mighty River Power in partnership with the Tauhara North No 2 Trust. It is close to the existing Rotokawa geothermal power station and connects into existing 220 kv transmission lines directly over the field.

The plant is a conventional geothermal single 140MW triple flash unit.

3.4.3.6 Poihipi

Poihipi is 1 x 55 MW conventional condensing steam turbine. Before being acquired by Contact Energy in 2000, it could not be fully loaded due to a shortfall of steam and averaged about 20MW of output.

However, as can be seen[36] in Figure 3.35, since Contact Energy acquired this asset, steam has been supplied from the Wairakei field and the plant has run at a much higher capacity.

[36] *Information source: Data via the N.Z. Electricity Commission collection and Gnash, plotted via MatLab. Author Nicky McLean.*

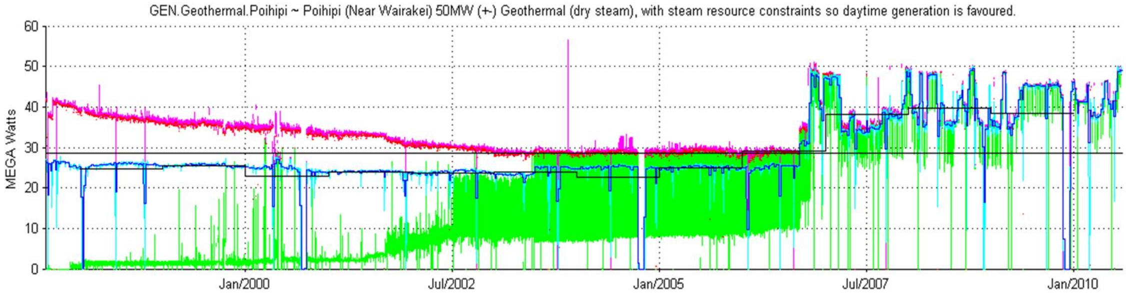


Figure 3.35 Poihipi generation (MW)

The plant produces around 350 GWh per annum, utilising geothermal steam from the Wairakei field, and is operated as part of the Wairakei Geothermal System.

3.4.3.7 Ngawha

The Ngawha plant is an Ormat built Organic Rankine Cycle type plant. The initial development was 10MW, but in 2007 a 15 MW unit was added. The total installed capacity is currently 25 MW.

Ngawha Power Station's output is fed into Top Energy's network and then connected to the National Grid, via Transpower's sub-station near Kaikohe.

3.4.3.8 Kawerau Stage 1

The Kawerau plant is a single unit, dual flash conventional geothermal power plant. Current generation capacity when fully operational is 100 MW. The Kawerau steam field also supplies steam for industrial use and some small scale generation.

3.4.3.9 Mokai

Mokai's generating plant consists of a main steam back pressure turbine and an Ormat Organic Rankine Cycle plant utilising the turbine exhaust steam and another unit utilising the hot brine.

The 55 MW Mokai power station was commissioned in February 2000 and is owned by the Tuaropaki Power Company. In 2005 a further 40MW was commissioned and in 2005 the Tuaropaki Power Company expanded the Mokai plant by a further 17 MW bringing the total operational capacity to 112 MW.

3.4.3.10 Te Huka Binary

Commissioned in 2010, the operational capacity of Te Huka geothermal power station (also known as Tauhara One) is 23 MW net output. Electricity is generated through a binary (Organic Rankine Cycle) process.

3.4.3.11 Tasman Mill

The energy demand of Norske Skog's Tasman pulp and paper mill is partly supplied by the embedded 16 MW (gross capacity) geothermal unit referred to as the TA3 turbine.

3.4.4 Substation

The transmission network connection points for the existing geothermal plant are:

- Wairakei – WRK (grid)
- Wairakei Binary - WRK (grid)
- Ohaaki – OKI (grid)
- Rotokawa – WRK (embedded)
- Nga Awa Purua – WRK (grid)
- Poihipi – PPI (grid)
- Ngawha – KOE (embedded)
- Kawerau Stage 1 – KAW (grid)
- Mokai – WKM (grid)
- Te Huka Binary – WRK (embedded)
- Tasman Mill – KAW (embedded)

3.4.5 Project lifetime

The economic project life of geothermal power plants is generally taken as 25 years, provided sufficient geothermal resource is available during the plant life and the plants are regularly maintained. However, generally geothermal plant exceed the design 'life' or project financing life of 25 years through refurbishment and replacements as demonstrated by existing NZ plant such as Wairakei which is now 50 years old. The question of when to decommission is usually an economic one or resource driven.

A 2010 report[37] by the IEA estimates average project operational lifetime at 40 years for geothermal plant.

For the purposes of modelling geothermal plant in the GEM, we have recommended an average operational project life of 40 years.

3.4.6 Operational capacity

The Gross capacity data has been derived from Generator web pages, public news sources and from Generator responses.

Where we have not been able to find the net capacity, this has been determined from the known gross installed capacity as follows:

- Conventional steam geothermal plant: net capacity=gross installed capacity x 0.94

[37] *Projected Costs of Generating Electricity. 2010 edition. International Energy Agency*

- Organic Rankine Cycle/Binary plant: net capacity=gross installed capacity x 0.92

Wairakei

Gross Capacity: 157.2 MW

Net Capacity:147.8 MW

Contact Energy has announced[38] that it plans to partially decommission approximately 50MW of plant capacity at Wairakei once the new Te Mihi geothermal plant is operational.

Wairakei Binary

Gross Capacity: 15 MW

Net Capacity:13.8 MW

Ohaaki

Gross Capacity: 114 MW

Net Capacity:65 MW (constrained by steam supply)

Rotokawa

Gross Capacity: 34 MW

Net Capacity:31.3 MW

Nga Awa Purua

Gross Capacity: 140 MW

Net Capacity:131.6MW

Poihipi

Gross Capacity: 55 MW

Net Capacity: 51.7 MW

Ngawha

Gross Capacity: 25 MW

Net Capacity: 23.0 MW

Kawerau Stage 1

Gross Capacity: 100 MW

Net Capacity: 94 MW

[38] http://www.contactenergy.co.nz/web/ourprojects/temihi

Mokai

Gross Capacity: 112 MW

Net Capacity: 103 MW

Te Huka Binary

Gross Capacity: 25 MW

Net Capacity: 23.0 MW

Tasman Mill

Gross Capacity: 16 MW

Net Capacity: 15 MW

3.4.7 Availability Factor

The average Availability Factor (AF) for geothermal power plants over their life is generally estimated as about 95%. This factor would be applicable to all existing NZ geothermal plant. This is supported by generator supplied information. Through consultation, MRP have provided an AF of 96% for their Rotokawa, Kawerau and proposed Ngatamariki plants.

The North American Reliability Council data for geothermal plants between 1990 and 1998 gives an average AF for all such plants as about 92%.

For older plant including Wairakei and Ohaaki PB recommends an AF of 92%, based upon North American Reliability Council data for older plants, and 95% for all other existing and proposed plant.

3.4.8 Net Output Factor

For all the existing geothermal plants, PB would estimate a Net Capacity Factor of between 90% and 95%, and therefore we recommend using an average lifetime NCF of 92.5%. This approximately equates to a Net Output Factor of 97% (using the recommended AF of 95%).

We would recommend an average lifetime Net Output Factor for all existing plants at 97%, except for older plants such as Wairakei and Ohaaki, where we have assumed 92% (assuming AF of 92% and NCF of 85%).

The Net Output Factor estimate of 97% for newer plants is supported by generator supplied information. For example, MRP have provided a Net Output Factor of 100% for their Rotokawa, Kawerau and planned Ngatamariki plants. The PB estimate is supported by PB experience and in-house data. Given the GEM value sought is an average over the life of the plant, it is reasonable to assume the plant does not always operate at 100% of capacity.

3.4.9 Unit largest proportion

The proportion of the station output from the largest unit is shown in Table 3-29. This data is from Generator web pages and public information sources.

Table 3-29 Unit largest proportion for existing NZ geothermal plant

Station	Capacity (MW)	Largest unit capacity (MW)	% of total capacity
Wairakei	157.2	30	19.1
Wairakei Binary	15	15	100
Ohaaki	114	58	51
Rotokawa	34	16	47
Ng Awa Purua	140	140	100
Poihipi	55	55	100
Ngawha	25	12	48
Kawerau Stage 1	100	100	100
Mokai	112	35	31
Te Huka Binary	25	25	100
Tasman Mill	16	16	100

3.4.10 Baseload

All existing geothermal plants are considered to operate as base load stations given the nature of the plant.

3.4.11 Fixed O&M costs

The primary determinant of geothermal plant O&M costs is the size (MW capacity) of the plant. Geothermal plant O&M costs mainly consist of O&M staff costs and equipment/spares acquisitions which would be required for regular scheduled maintenance and for major overhauls, almost all of which would be classified as 'fixed O&M costs' given they are independent of the level of generation. The only truly variable costs would be chemicals, lubricants and other maintenance disposables.

Under the above definition, variable O&M costs would be close to zero in $/MWh terms and not material considering the concept level of cost estimation used in this Report. For the GEM input estimates, PB has classified all geothermal O&M costs as fixed costs.

Given available references, we have split the estimate of fixed O&M costs into the power plant and steamfield components. The fixed O&M costs for both the power plant and steamfield have estimated based on the previous PB report SOO-Update-Final PB reference data.

The power plant fixed costs included are:

- 0.625 c/kWh (Kawerau proposed)
- 0.715 c/kWh (Tauhara proposed)

These are both for Binary Combined Cycle plant and are reasonably similar values even though the Kawerau project was 80MW and the Tauhara proposal only 15MW.

For all the existing and planned geothermal plants, PB recommends using a figure of 0.67c/kWh for the power plant component.

The steamfield O&M costs included in the previous PB report are:

- 0.445 c/kWh (Kawerau proposed)
- 0.625 c/kWh (Tauhara proposed)

For all the existing and planned geothermal plants, we would therefore use a figure of 0.535 c/kWh.

Therefore, we have assumed the total project O&M costs to be the sum of the plant and steam field costs which is 1.205 c/kWh. This is equivalent to $105/kW per annum. We have used this figure as the total project O&M cost for all existing and planned projects, irrespective of the technology type or size, as from our in-house records there is no clear indication of any significant differences between sizes or technology.

4. Future proposed NZ generating plant data

These sections describe the process used to review and update the GEM information on future proposed generating plant. The individual plant results are included in this section.

The process of reviewing and updating the GEM information on existing generation plant has relied on:

- Information provided by generators/developers (Genesis, MRP, Meridian, Contact and TrustPower)
- Publicly available information including:
  - previous reports (NZ and International)
  - internet searches
  - annual reports
- Information available to PB internally e.g. internal databases, which we can reference
- GT Pro and other commercially available technical/cost estimating software.

The sections that follow below include any commentary considered necessary to understanding the data provided for each technology/plant and any inconsistencies.

The list of projects included in the EA Generation Update – September 2011[39] has been used to create the list of plant covered in this report section. Where PB has identified alternatives, or where there are updates to the EA's list, these have been included.

4.1 Thermal

4.1.1 Summary

Table 4-1 summarises the PB recommendations for proposed NZ thermal plant technical and cost data for use in the GEM.

[39] http://www.ea.govt.nz/industry/modelling/long-term-generation-development/list-of-generation-projects/

Table 4-1 PB recommendations - Proposed NZ thermal plant data

Project name	Plant Technology	Energy Type	Substation	Project life.	Capacity	Availability factor	Unit largest proportion	Baseload	Heat rate	Variable O&M cost	Fixed O&M costs	Fuel del. charge	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
				Years	*MW*	*%*	*%*	*y/n*	*GJ/GWh*	*$/MWh*	*$/kW/y*	*$/GJ*	*$/kW*	*Currency /kW*		*$ million*
Belfast	Recip	Diesel	ISL	30	11.4	85	100	N	8,700	12.1	16	3	840	827	EUR	0.5
Bromley	Recip	Diesel	BRY	30	11.4	85	100	N	8,700	12.1	16	3	840	827	EUR	0.5
Otahuhu C	CCGT	Gas	OTA	50	388	93	100	Y	7,050	4.3	35	1	600	477	EUR	10
Rodney	CCGT	Gas	RDY	50	465	93	50	Y	7,768	4.3	35	1	632	502	EUR	10
Diesel 1	Recip	Diesel	MPE	30	9.9	85	50	N	9,000	12.1	16	3	612	942	USD	0.5
Todd Peaker	OCGT	Gas	MNI	42	99	87	50	N	10,500	8.00	16	1	385	472	USD	5
Cogen 1	Cogen	Gas	SWN	42	49.5	90	50	Y	9,300	4.3	35	1	780	772	USD	5
CCGT 1	CCGT	Gas	MNI	50	194	93	50	Y	8,300	4.3	35	1	660	653	USD	10

4.1.2 Plant

The following are the proposed thermal generation plants nominated for review by MED, according the GEM naming convention:

- Belfast;
- Bromley;
- Otahuhu C; and
- Rodney.

PB has added the following to the above list, as proposed generation plants with a capacity of around or greater than 10 $MW_{electric}$. These are taken from Transpower's Annual Security Assessment 2011[40].

- Diesel 1 - a 10 MW plant with no owner identified for confidentiality reasons. This is assumed by Transpower to be commissioned in time for the winter of 2011, and contributing an assumed 22 GWh to energy margins (potential GWh over Apr-Sep), and 10 MW to capacity margins. Transpower rate this project as having a "High" probability of proceeding. At the time of writing, PB is not aware if this has been commissioned or not.
- Todd Peaker – a peaking plant, assumed by Transpower to be commissioned in time for the winter of 2012. Transpower rate this project as having a "High" probability of proceeding. The owner is assumed to be Todd Energy. The estimated capacity of the plant is 100MW as per media reports[41].
- Cogen 1 - a 50 MW plant with no owner identified for confidentiality reasons. This is assumed by Transpower to be commissioned in time for the winter of 2013, and contributing an assumed 110 GWh to energy margins (potential GWh over Apr-Sep), and 38 MW to capacity margins. Transpower rate this project as having a "Medium" probability of proceeding.
- CCGT 1 - a 200 MW plant with no owner identified for confidentiality reasons. This is assumed by Transpower to be commissioned in time for the winter of 2014, and contributing an assumed 850 GWh to energy margins (potential GWh over Apr-Sep), and 194 MW to capacity margins. Transpower rate this project as having a "Low" probability of proceeding. The capacity of this plant rules it out as either of Otahuhu C or Rodney.

Note: the two plants named in Transpower's Annual Security Assessment 2011 as "CCGT 2" and "CCGT 3" are understood to be Genesis' proposed Rodney plant units, as the capacities (240 MW) match.

The following sections document PB's review and update, where necessary, of the MED's GEM information on proposed generation.

[40] *Transpower, Annual Security Assessment 2011, Prepared by the System Operator, January 2011*
[41] *http://www.nbr.co.nz/article/todd-build-100m-gas-fired-power-station-taranaki-135091*

4.1.3 Plant technology

4.1.3.1 Belfast

Orion New Zealand Limited's (Orion) Asset Management Plan (AMP), 1 April 2010 to 31 March 2020 notes that:

- "*This AMP now includes a provision of $0.6m for the development of the recently acquired Belfast site to potentially install diesel generation plant. This project was delayed from 2010 to 2011 due to a protracted consent process which delayed final issuing of land title to Orion*."
- "*We have gained resource consent to install a 10MW diesel generating set at Bromley and Belfast. Proceeding with either of these sites is subject to satisfactory negotiation of contractual arrangements with the Electricity Commission. As the Commission has advised that it does not wish to contract for any additional capacity at this time, this project is now on hold*."
- "*We have resource consents to install a total of 23MW of generation capacity split between sites at Bromley and Belfast. Justification for installing generation at these sites will require either a dry year reserve contract from the Electricity Commission or suitable market arrangements to reward us for relieving transmission constraints between Twizel and Christchurch*."
- "*During 2008, we purchased land for a future Belfast zone substation. We also hold a consent for 11.5MW of diesel generation at this site*. *We are also considering the Belfast site as the location for new generation plant, which would defer the investment of the Marshland zone substation and the planned 66/11kV 40MVA zone substation at Belfast*."[42]

In GEM terms, the proposed Belfast plant is a diesel fuelled internal combustion (IC) or reciprocating engine generator.

The Transpower Annual Security Assessment 2011 does not list Belfast as a potential new generation project.

4.1.3.2 Bromley

As for the Belfast plant, the proposed Bromley plant is a diesel fuelled internal combustion (IC) or reciprocating engine generator.

The Transpower Annual Security Assessment 2011 also does not list Bromley as a potential new generation project.

4.1.3.3 Otahuhu C

The National Infrastructure Unit of The Treasury, lists Otahuhu C in its National Infrastructure Plan - March 2010, Part 2 - Planned Investment, Introduction, Electricity generation, "Table 6: Planned investment in generation", with the following attributes:

- Fuel: Gas

[42] http://www.oriongroup.co.nz/publications-and-disclosures/asset-management-plan.aspx

- Capacity: 400 MW
- In-service date: 2015 - 2020
- Status: Consented.[43]

Other public domain sources advise:

- "*The power generator has a consented site adjacent to its Otahuhu-B CCGT earmarked as an expansion project called Otahuhu C, but says this has been deferred while it concentrates on other developments*."[44]
- "*Contact remains confident that the Otahuhu C station can be developed prior to 2010, although issues remain around: resolving fuel length and flexibility issues; and securing an imported fuel backstop*."[45]
- "*Contact Energy announcements about Otahuhu C refer to a deferral of Otahuhu C until after they have built their geothermal options around Taupo rather than Otahuhu C being cancelled*."[46]
- "*The proposed Otahuhu C plant would be a single-shaft CCGT with generation capacity of up to 400 MW. . . Otahuhu C would be run as a baseload generator . . . Otahuhu C would be located in Auckland, next to Otahuhu B . . . Contact currently holds the resource consents necessary for the construction and operation of the new plant. The air discharge, land use, and earthworks consents are valid until 2007; applications have been made to extend the air discharge and land use lapse dates to 2011. . . The biggest obstacle that the Otahuhu C project currently faces is the lack of certainty around the long term availability and pricing of gas fuel supply. Contact is confident that we will eventually be able to contract sufficient gas to supply this plant, either from indigenous fields or from the importation of LNG or CNG. However, without greater certainty than we currently have around the timing of these developments, Contact cannot proceed with this project*."[47]

From the above, PB understood that Otahuhu C will be similar if not near identical to the Otahuhu B CCGT plant. This is described in section 3.1.3.3 as a natural gas fuelled, single shaft, combined cycle gas turbine plant (CCGT). The plant is likely to have a capacity of around 400 MW and could be provided by Alstom (GT 26B), Siemens (V94.3A), Mitsubishi, or GE.

4.1.3.4 Rodney

Genesis Energy (trading name of Genesis Power Limited) plans to build a new combined cycle gas turbine (CCGT) plant at a site north-west of Auckland. Genesis describes the site

[43] http://www.infrastructure.govt.nz/plan/mar2010/16.htm
[44] *"Otahuhu makeover", Energy NZ No.8 Autumn 2009, http://www.contrafedpublishing.co.nz/Energy+NZ/Issue+8+Autumn+2009/Otahuhu+makeover.html*
[45] *Contact Energy, SOO – Scenarios, www.ea.govt.nz/document/7346/download/industry/ec.../gup-workshops*
[46] *Major Electricity Users' Group, Submission on proposed HVDC options, methodologies and assumptions, 22 June 2007, www.gridnewzealand.co.nz/f3698.../meug-submission-22-jun-07.pdf*
[47] *Contact Energy, Submission to Electricity Commission on Alternatives to Transpower's proposed Whakamaru-Otahuhu transmission upgrade, 13 July 2005*

as, "*encompassing approximately 48 ha of rural property at or adjacent to 526 Kaipara Coast Highway (State Highway 16) . . . mid-way between Helensville and Kaukapakapa*."[48]

Genesis has called the project, "Rodney Power Station" after its location in the Rodney district.

Genesis plans to construct, "*a nominal 480 megawatt ("MW") power station in two stages. Initially a nominal 240 MW combined cycle station will be installed with a subsequent project stage bringing the capacity to a nominal 480 MW*."[48]

Genesis describes the proposed Rodney Power Station as comprising, "*gas and steam turbines for the generation of electricity. Spent steam from the steam turbines will be condensed using air-cooled condensers (dry cooling). Other infrastructure requirements include accessory buildings (including control room, workshop, storage areas, office and administration facilities), facilities for the supply, treatment, storage and discharge of water, gas supply plant, a high voltage substation, and electricity transmission lines*."[48]

Genesis has also stated that the proposed Rodney project, "*will be in a modular form, which means that there would be two gas turbines enclosed in a building rather than one large single turbine. The development of the station would occur in stages with the initial stage of development providing a nominal 240MW. Subsequent stages could see the plant being expanded in the future*."[49]

4.1.3.5 Diesel 1

The proposed Diesel 1 plant is assumed to be a diesel fuelled internal combustion (IC) or reciprocating engine generator.

Apart from its location in the North Island, no other information is known about this proposed plant.

4.1.3.6 Todd Peaker

The only other information on the Todd Peaker plant, other than that quoted from the Transpower Annual Security Assessment 2011 in section 4.1.3.2 above, is a mention in the Hawkins Report, Winter 2011. It is noted in the Hawkins Report that Hawkins has joined with Transfield Worley to bid on the "*Todd Peaker gas-fired power station project*"[50].

Given that the project name includes "peaker", and the capacity is quoted in the media as 100 MW, it is reasonable to assume that the technology will be open cycle gas turbine (OCGT), and not reciprocating engines.

The largest aero-derivative gas turbines available are in 40 to 50 MW capacity range and the Todd peaking plant could consist of 2 machines like Genesis'; Huntly Unit 6 (P40) 48 MW OCGT plant, designed to burn natural gas and diesel (distillate), using the General Electric LM6000 SprintTM aero derivative gas turbine.

[48] *GENESIS ENERGY, RODNEY POWER STATION PROJECT (RodneyPowerStationProjectExecutiveSummary.pdf, 18 March 2008), downloaded from*
[49] *Genesis "Thermal" brochure (GED9821 Thermal Brochure FN_Art.pdf, July 2008), downloaded from*
[50] *Hawkins Report, Winter 2011, downloadable from http://www.hawkins.co.nz/assets/Uploads/Hawkins-Report-Winter-2011-5.5mb2.pdf*

4.1.3.7 Cogen 1

This plant is described as gas fuelled in the Transpower Annual Security Assessment 2011. Given this, and its 50 MW capacity, it seems likely that this would be a gas turbine based plant, similar to the cogeneration plants at Hawera, Kapuni and Edgecumbe.

Apart from its location in the North Island, no other information is known about this proposed plant.

4.1.3.8 CCGT 1

Apart from it being a CCGT plant and being located in the North Island, no other information is known about this proposed plant.

4.1.4 Energy type

4.1.4.1 Belfast

The proposed Belfast plant will be fuelled by diesel.

4.1.4.2 Bromley

The proposed Bromley plant will be fuelled by diesel.

4.1.4.3 Otahuhu C

The proposed Otahuhu C will be fuelled by natural gas.

4.1.4.4 Rodney

Rodney will be fuelled by natural gas and Genesis' Thermal brochure advises with respect to Rodney that, "*Natural gas generation would displace some higher-emitting coal-fired generation at Huntly*."

The following Figure 4.1 shows the location of the proposed Rodney plant (from the Genesis Thermal brochure) as a **red star**, relative to the natural gas transmission pipeline. It appears that a new lateral pipeline will be required to connect the proposed Rodney plant with the pipeline.

4.1.4.5 Diesel 1

The proposed Diesel 1 plant will be fuelled by diesel.

4.1.4.6 Todd Peaker

It is expected that the proposed Todd Peaker will be fuelled by natural gas but it is not known if it will be 'pipeline quality' gas.

4.1.4.7 Cogen 1

It is assumed that the proposed Cogen 1 plant will be fuelled by natural gas.

4.1.4.8 CCGT1

The fuel for the proposed CCGT1 is expected to be natural gas.

Figure 4.1 Excerpt from natural gas transmission pipeline map

4.1.5 Substation

4.1.5.1 Belfast

The proposed Belfast plant will be embedded in Orion's network, and located at a planned new 11 kV system Belfast zone substation. For modelling purposes the closest current GXP substation can be considered as Islington (ISL).

4.1.5.2 Bromley

The proposed Bromley plant will be embedded in Orion's network, and located at the Bromley substation.

The Bromley substation is a Transpower Grid Exit Point (GXP) and Transpower's standard site abbreviation for the Bromley substation is BRY[19].

4.1.5.3 Otahuhu C

Otahuhu C will be located adjacent to Otahuhu B, which is in turn located adjacent to the historical Otahuhu Power Station (Otahuhu Gas Turbine Station) site, which in turn is located adjacent to the Transpower Otahuhu Substation.

The Transpower standard site abbreviation for the Otahuhu substation is OTA[19].

4.1.5.4 Rodney

Section 4.1.3.4 above notes the need for "a high voltage substation, and electricity transmission lines" for the proposed Rodney plant.

It is assumed that the plant will be connected to the Henderson – Marsden – A (HEN-MDN-A) 220 kV transmission line, which passes near the site. This will require a short interconnecting transmission line.

It seems likely that the proposed Rodney plant will be connected to its own substation. Transpower has already allocated a standard site abbreviation for the Rodney plant, RDY[19].

4.1.5.5 Diesel 1

Apart from being in the North Island, the location of the proposed Diesel 1 plant and hence the interconnection point is not known. Since the GEM requires a value, PB recommends using Maungatapere (MPE) as a suitable estimate for the location.

4.1.5.6 Todd Peaker

Apart from being in the North Island, the location of the proposed Todd Peaker plant and hence the interconnection point is not known. Assuming the peaking plant will be located in the Taranaki region close to the gas transmission pipelines, Motonui (MNI) is a suitable proxy for the transmission connection point.

4.1.5.7 Cogen 1

Apart from being in the North Island, the location of the proposed Cogen 1 plant and hence the interconnection point is not known. PB recommends that the GEM uses the Southdown GXP (SWN) as a suitable proxy for the transmission connection point of this plant.

4.1.5.8 CCGT1

Apart from being in the North Island, the location of the proposed CCGT 1 plant and hence the interconnection point is not known. Assuming the plant will be located in the Taranaki region close to the gas transmission pipelines, Motonui (MNI) is a suitable proxy for the transmission connection point.

4.1.6 Commissioning date

4.1.6.1 Introduction

PB expected to be able to rely on the proposed generator project owners for this data and accordingly requested owners to specify the commissioning date, “where an approximate but reasonably likely commissioning date is known”.

Where the owners provided these dates, those have been relied on by PB. Where owners have not provided commissioning dates, PB has relied on dates estimated by Transpower in its Annual Security Assessment 2011. In the absence of either PB has estimated the dates.

4.1.6.2 Belfast

The proposed Belfast plant appears to be as yet uncommitted and neither Orion nor Transpower’s Annual Security Assessment 2011 has nominated a commissioning date. Belfast appears to be considered by Transpower to be outside its planning horizon (2019) or of lower than “Low” probability of proceeding.

PB estimates that this plant could be commissioned in 2017.

4.1.6.3 Bromley

The proposed Bromley plant appears to be as yet uncommitted and neither Orion nor Transpower's Annual Security Assessment 2011 has nominated a commissioning date. Bromley also appears to be considered by Transpower to be outside its planning horizon (2019) or of lower than "Low" probability of proceeding.

PB estimates that this plant could be commissioned in 2015.

4.1.6.4 Otahuhu C

The most recent public domain information quoting a commissioning date for Otahuhu C is The Treasury's National Infrastructure Plan - March 2010, which quoted an in-service date of 2015 – 2020.

PB has assumed a mid-range date and estimates that this plant will be commissioned in 2018.

Transpower's Annual Security Assessment 2011, list of potential new generation projects does not list Otahuhu C, either by name or anonymously by capacity (expected by PB to be >350 MW). Otahuhu C therefore appears to be considered by Transpower to be outside its planning horizon (2019) or of lower than "Low" probability of proceeding.

4.1.6.5 Rodney

Genesis Energy's response to the request for a commissioning date was, "to be confirmed".

The Genesis Energy Annual Report 2010 provided the following update on the status of the proposed Rodney plant:

"*Genesis Energy lodged resource consent applications with the Auckland Regional Council (ARC) and Rodney District Council in July 2007 for the proposed Rodney Power Station. Consents were obtained from the ARC in December 2008 and Genesis Energy appealed three conditions to the Environment Court in January 2009. The appeal was resolved through mediation with the ARC and a consent order from the Environment Court was issued in October 2009 resolving the appeal.*

An appeal lodged against the Vector pipeline designation for the Rodney Power Station project was heard in the Environment Court during the week commencing 19 April 2010. Genesis Energy was a party to the appeal and participated in the Environment Court hearing. The Environment Court ruled in favour of the gas pipeline designation on 18 June 2010.

Now that we have finalised all necessary approvals for the Rodney project, we are reviewing various development alternatives as well as long term fuel supplies to determine the optimum development timeframe for this project."[51]

Transpower's Annual Security Assessment 2011 lists two potential new CCGT projects, CCGT2 and CCGT3, with the same capacity as Rodney, 240 MW. PB has assumed that these are the Rodney development stages.

CCGT2 and CCGT3 are 240 MW plants, assumed by Transpower to be commissioned in time for the winters of 2016 and 2017 respectively. They each contribute an assumed 1,020 GWh

[51] *Genesis Energy Annual Report 2010 (Genesis-annual-report-fulldownload 2010.pdf), downloaded from http://genesisenergy.co.nz*

to energy margins (potential GWh over Apr-Sep), and 233 MW to capacity margins. Transpower rates both of these projects as having a “Low” probability of proceeding.

4.1.6.6 Diesel 1

Transpower’s Annual Security Assessment 2011 assumed Diesel 1 would be commissioned in time for the winter of 2011, in which case it may already be commissioned.

4.1.6.7 Todd Peaker

Transpower’s Annual Security Assessment 2011 assumes the Todd Peaker to be commissioned in time for the winter of 2012.

4.1.6.8 Cogen 1

Transpower’s Annual Security Assessment 2011 assumes Cogen 1 will be commissioned in time for the winter of 2013.

4.1.6.9 CCGT1

Transpower’s Annual Security Assessment 2011 assumes the CCGT 1 to be commissioned in time for the winter of 2014.

4.1.7 Project lifetime

4.1.7.1 Introduction

These sections seek to determine how long each proposed thermal generation plant can be reasonably expected to remain operational after commissioning. This subject was addressed in PB’s report, “Thermal Power Station Advice, Report for the Electricity Commission”, July 2009. That report estimated decommissioning dates for each of the NZ thermal plants included in the scope of the study. The estimation of these dates was based on a set of assumptions around the original design life and operating regime of the plant.

The following sections rely on the findings of the 2009 Thermal Power Station Advice report. When the phrase “PB previously estimated” is used below, the word “previously” refers to the 2009 Thermal Power Station Advice report.

4.1.7.2 Belfast

Diesel engine life was addressed briefly in PB’s report for the Electricity Commission, “Thermal Power Station Advice - Reciprocating Engines Study”, November 2009. In that report it is noted that, “*With proper maintenance, large engines have an operating life of 20 - 30 years, while smaller engines (<1 MW) tend to have shorter operating lives, of around 15 years*.”

On that basis, the Project Lifetime of the proposed Belfast diesel generator is estimated to be 30 years.

4.1.7.3 Bromley

As for Belfast above, the Project Lifetime of the proposed Bromley diesel generator is estimated to be 30 years.

4.1.7.4 Otahuhu C

PB has previously estimated project lifetimes of 50 years for CCGT plant, assuming a mid-life refurbishment "*would be completed to improve efficiency and extend the operating life of the plant, possibly through replacement of existing plant with improved current technology*." "*This is likely to occur around two-thirds of the way through the original design life and extend the technical operating life by 20 years*".

On that basis, and like Otahuhu B, the proposed Otahuhu C plant is expected to have a Project Lifetime of 50 years.

4.1.7.5 Rodney

Rodney is a proposed CCGT plant and like Otahuhu C, is expected to have a Project Lifetime of 50 years.

4.1.7.6 Diesel 1

As for Belfast and Bromley above, the project lifetime of the proposed Diesel 1 generator is estimated to be 30 years.

4.1.7.7 Todd Peaker

The proposed Todd Peaker is expected to be OCGT plant, and similar with respect to Project Lifetime expectations to Huntly Unit 6 (P40), Southdown E105 and Stratford.

PB previously estimated that without mid-life refurbishment plant of this nature should be able to operate to the original design life of 25 years of operation with regular maintenance. Mid-life refurbishment of such plant was estimated to be likely to extend the life of the plant by a further 17 years.

The estimated Project Lifetime for the proposed Todd Peaker is therefore 42 years.

4.1.7.8 Cogen 1

In sections 3.1.5.10, 3.1.5.11 and 3.1.5.17 the existing gas turbine based cogeneration plant fleet was estimated to have Project Lifetimes of 42 years.

The proposed Cogen 1 plant is similarly estimated to have a Project Lifetime of 42 years.

4.1.7.9 CCGT 1

CCGT 1 is a proposed CCGT plant and like Otahuhu C and Rodney, is expected to have a Project Lifetime of 50 years.

4.1.8 Operational capacity

4.1.8.1 Introduction

These sections seek to determine the long term operational capacity of the proposed thermal generation plants.

As noted in section 3.1.7, it is understood that the GEM uses what is otherwise referred to in the industry as "net capacity" as opposed to gross capacity.

PB has relied on the Otahuhu C and Rodney proposed generator owners for Operational Capacity data for those plants. Owner's for the other proposed generators are either not known, or were not approached to supply this data.

PB has therefore relied on the source that identified the existence of these latter plants, Transpower's Annual Security Assessment 2011. These are assumed to be gross capacity figures and PB has estimated the auxiliary power requirements and net capacity according to the typical characteristics of similar generation technologies.

The resulting data is presented in tabular form as follows.

4.1.8.2 Data

Table 4-2 Proposed generation net operational capacity

Generator	Type	Gross operational capacity, MW	Auxiliary power demand, %	Net operational capacity, MW	Comments
Belfast	Diesel	11.5	1	11.4	Gross from Orion AMP
Bromley	Diesel	11.5	1	11.4	Gross from Orion AMP
Otahuhu C	CCGT	400	3	388	Gross from public domain
Rodney	CCGT	480	3	465	Gross from Genesis
Diesel 1	Diesel	10	1	9.9	Gross from Transpower
Todd Peaker	OCGT	100	1	99	Gross from public domain
Cogen 1	GT cogen	50	2	49.5	Gross from Transpower
CCGT 1	CCGT	200	3	194	Gross from Transpower

4.1.9 Availability factor

PB has relied on the generator owners for this data, where it was provided by the owners. Where not provided, PB has estimated the availability based on similar existing generation technologies. The resulting data is presented in tabular form as follows.

Table 4-3 Proposed thermal plant - Availability Factor

Generator	Type	Availability Factor %	Comments
Belfast	Diesel	85	
Bromley	Diesel	85	
Otahuhu C	CCGT	93	As per Rodney
Rodney	CCGT	93	As advised by Genesis
Diesel 1	Diesel	85	
Todd Peaker	OCGT	87	As per Huntly Unit 6 (P40)
Cogen 1	GT cogen	90	
CCGT 1	CCGT	93	As per Rodney

4.1.10 Unit largest proportion

This parameter is defined by MED as the "*largest proportion of a station output carried by a single unit*" and is expressed as a percentage.

PB has relied on the generator owners for this data, where it was provided by the owners. Where not provided, PB has estimated the unit largest proportion. The basis of the estimate is recorded in the Table 4-4.

Table 4-4 Proposed thermal plant - Unit largest proportion

Generator	Type	Unit largest proportion, %	Comments
Belfast	Diesel	100	Orion AMP uses the singular to describe
Bromley	Diesel	100	Orion AMP uses the singular to describe
Otahuhu C	CCGT	100	Single shaft CCGT unit
Rodney	CCGT	50	As advised by Genesis
Diesel 1	Diesel	50	Two units assumed by PB for greater flexibility
Todd Peaker	OCGT	50	Two units assumed by PB for greater flexibility
Cogen 1	GT cogen	50	Two units assumed by PB for higher cogen reliability
CCGT 1	CCGT	50	Two units assumed by PB for greater flexibility

4.1.11 Baseload

This parameter is simply a "yes/no" determination of "*whether the plant is designed to be operated near/or at full capacity most of the time*".

As for the existing generation, PB has taken the approach that all thermal generation plant that is not specifically designed and installed as peak load (peaker) plant is designed to be operated at full capacity all the time it is available.

Table 4-5 Proposed thermal plant GEM role

Generator	Design generator function	Baseload	Peaker	Comments
Belfast	generator	NO	YES	
Bromley	generator	NO	YES	
Otahuhu C	generator	YES	NO	
Rodney	generator	YES	NO	
Diesel 1	generator	NO	YES	Assumed same as Belfast
Todd Peaker	generator	NO	YES	
Cogen 1	cogenerator	YES	NO	
CCGT 1	generator	YES	NO	

4.1.12 Heat rate

PB has relied on the proposed generator owners for this data, where it was provided by the owners. Where not provided by the owners PB has estimated the heat rate based on typical values for similar technologies.

Table 4-6 Proposed thermal plant heat rates

Generator	Design generator function	Nominal Size/ Technology	Heat rate, GJ/GWh	Comments
Belfast	Peaking generator	11.5 MW Recip	8,700	From PB report to Electricity Commission, “Thermal Power Station Advice - Reciprocating Engines Study”, November 2009
Bromley	Peaking generator	11.5 MW Recip	8,700	From PB report to Electricity Commission, “Thermal Power Station Advice - Reciprocating Engines Study”, November 2009
Otahuhu C	Baseload generator	400 MW CCGT	7,050	As per current (2010) GEM for Otahuhu B
Rodney	Baseload generator	480 MW CCGT	7,768	As advised by Genesis
Diesel 1	Peaking generator	2 x 5 MW Recip	9,000	From PB report to Electricity Commission, “Thermal Power Station Advice - Reciprocating Engines Study”, November 2009
Todd Peaker	Peaking generator	2 x 50 MW OCGT	10,500	PB estimate same as Huntly Unit 6 (P40), as advised by Genesis
Cogen 1	Baseload cogenerator	2 x 25 MW CCGT	9,300	As per current (2010) GEM for Hawera and Kapuni
CCGT 1	Baseload generator	2 x 100 MW CCGT	8,300	PB estimate based on Rolls Royce Trent 60 WLE CCGT (49% net efficiency, LHV = 43.6% HHV), rounded up to annual average

The HHV heat rates expressed above for baseload plant can be assumed to be the long term average heat rates applying at or around full load or maximum continuous rating (MCR). The heat rates expressed for the peaking plants can be assumed to be long term averages and to include the depreciating (heat rate increase) effects of multiple startups. Note that diesel and gas engine plant heat rates are not significantly affected by multiple startups and part load operation.

4.1.13 Variable O&M costs

Section 3.1.12 sets out PB’s rationale for estimating the variable O&M costs for the existing thermal generation plants, and provides, in Table 3-8, PB’s estimates for those plants.

Variable O&M costs for the proposed thermal generation are estimated by PB to be approximately the same as those for the existing plants, in present dollar value terms, and on the basis of ‘like for like’ technology.

The following Table 4-7 records the results of the above approach.

Table 4-7 2011 GEM variable operating costs (VOM), NZ$/MWh

Generator	Design generator function	Technology	VOM, NZ$/MWh	Comments
Belfast	generator	Recip	12.10	= AUD 9.61/MWh
Bromley	generator	Recip	12.10	= AUD 9.61/MWh
Otahuhu C	generator	CCGT	4.25	Was 4.25 in 2009
Rodney	generator	CCGT	4.25	Was 4.25 in 2009
Diesel 1	generator	Recip	12.10	= AUD 9.61/MWh
Todd Peaker	generator	OCGT	8.00	No change from 2009
Cogen 1	cogenerator	CCGT	4.25	Same as CCGT
CCGT 1	generator	CCGT	4.25	Was 4.25 in 2009

4.1.14 Fixed O&M costs

Section 3.1.13 sets out PB's rationale for estimating the fixed O&M costs for the existing thermal generation plants, and provides, in Table 3-11, PB's estimates for those plants.

Fixed O&M costs for the proposed thermal generation are estimated by PB to be approximately the same as those for the existing plants, in present dollar value terms, and on the basis of 'like for like' technology.

The following Table 4-8 records the results of the above approach.

Table 4-8 Proposed thermal plant fixed O&M costs

Generator	Design generator function	Technology	FOM, NZ$/kW/y	Comments
Belfast	generator	Recip	16	= AUD 13,000/MW/y
Bromley	generator	Recip	16	= AUD 13,000/MW/y
Otahuhu C	generator	CCGT	35	No change from 2009
Rodney	generator	CCGT	35	No change from 2009
Diesel 1	generator	Recip	16	= AUD 13,000/MW/y
Todd Peaker	generator	OCGT	16	No change from 2009
Cogen 1	cogenerator	CCGT	35	No change from 2009
CCGT 1	generator	CCGT	35	No change from 2009

4.1.15 Fuel delivery costs

Fuel delivery costs are discussed in section 3.1.14 and the cost estimating methodology in that section for existing generation also applies to the proposed generation.

4.1.16 Capital cost

4.1.16.1 Introduction

The GEM requires estimates of the capital cost of proposed generation in two components:

- The portion of the capital cost not exposed to foreign currency movements (in *NZD/kW*), and
- The capital cost exposed to foreign currency movements (in *Dominant foreign currency/kW*).

4.1.16.2 Current GEM data

The specific capital costs presently used in the GEM, as used by the Electricity Commission in its third and last Statement of Opportunities (SOO) prepared under part F of the Electricity Governance Rules (2010 Statement of Opportunities, September 2010), and as would apply to the planned generation, are as set out in the following Table 4-9.

The capital cost data in Table 4-9 is taken from the Excel workbook, "GEMinputdata_v1.5.10", downloaded from the Electricity Commission archive held on the Electricity Authority's web site, namely the 2010 Statement of Opportunities (SOO) archive.[52] These costs in USD and the conversion rate used in that file was 0.55 USD:NZD[53]. PB has converted the USD values back to NZD at that rate.

Table 4-9 Current (2010) GEM capital costs, NZ$/kW

Generator	Design generator function	Technology	Capex, NZ$/kW	Comments
Belfast	generator	Recip	-	No similar size plant in 2010 GEM
Bromley	generator	Recip	-	No similar size plant in 2010 GEM
Otahuhu C	generator	CCGT	1,091	Existing infrastructure used
Rodney	generator	CCGT	1,200	Built in two stages
Diesel 1	generator	Recip	-	No similar size plant in 2010 GEM
Todd Peaker	generator	OCGT	1,575	As per 50 MW OCGT Gaspk in GEM
Cogen 1	cogenerator	CCGT	1,636	As per 50 MW TkCogen in GEM
CCGT 1	generator	CCGT	1,200	Assumed same as Rodney

Note with respect to Table 4-9:

- The specific capital costs in the GEM Input Data spreadsheet are in a field titled, "Capital cost, foreign currency per kW", however the data in the field is understood to be the total specific capital cost.
- The current (2010) GEM lists six reciprocating/diesel engine generators, named Recipr1 – 6. They are all 40 MW, single unit plants, with capital costs of either $1,500/kW or

[52] http://www.ea.govt.nz/industry/ec-archive/soo/2010-soo
[53] *As advised by MED email, ST to NW, PB of 28 September 2011*

$2,000/kW. The 10 – 11.5 MW plants planned by Orion and others are significantly smaller.

4.1.16.3 Validation data sources

In developing its recommendations, PB has relied upon any information obtained through consultation with generators, PB in-house data and the same public domain sources as it did for the O&M costs, with the addition of the following sources:

- Worley Parsons, "**AEMO Cost Data Forecast For the NEM, Review of Cost and Efficiency Curves**", 31 January 2011[54]. This report outlines the results of a review of the capital cost and efficiency curves provided by AEMO (Australian Energy Market Operator) used for modelling new entrants in the NEM. AEMO had sought an update of data provided for NTNDP (National Transmission Network Development Plan) Modelling and Worley Parsons provided, among other things, cost curves relating 2009 industry figures to latest industry cost forecasts, plant efficiency updates and O&M cost updates.

- ACIL Tasman, for the Australian Department of Climate Change and Energy Efficiency (DCCEE), "**Modelling Greenhouse Gas Emissions from Stationary Energy Sources**, Electricity sector and direct combustion emissions over the period to 2029-30", 18 January 2011. ACIL Tasman was engaged to model greenhouse gas emissions from stationary energy sources to 2029-30 under a range of scenarios and sensitivities for an emissions projections exercise. The report includes a range of new entrant technology costs.[55]

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[56]. This report provides a summary and supporting documentation for Mott MacDonald's assessment of current and forward power generation costs for the main large scale technologies applicable in the UK. The work was commissioned by the Department of Energy and Climate Change and undertaken during October 2009 to March 2010.

- International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA), "**Projected Costs of Generating Electricity, 2010 Edition**" March 2010[57]. This report contains data on electricity generating costs for almost 200 power plants in 17 OECD member countries and 4 non-OECD countries. It presents the projected costs of generating electricity calculated according to common methodological rules on the basis of the data provided by participating countries and organisations.

- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[58]. The objective of the work leading to this report was to establish an up-to-date cost and performance database agreed by Australian stakeholders as supportable in the Australian context. The report also provides a levelised cost analysis of a basket of technologies in 2015 and 2030. This provides an agreed basis for comparing globally available power generation technologies and costs.

[54] http://www.aemo.com.au/planning/0419-0017.pdf
[55] http://www.climatechange.gov.au/publications/projections/~/media/publications/projections/acil-tasman-stationary-energy-modelling-pdf.pdf
[56] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[57] http://www.mit.edu/~jparsons/current%20downloads/Projected%20Costs%20of%20Electricity.pdf
[58] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf

- ACIL Tasman, for the Australian Department of Resources, Energy and Tourism (DRET), "**Carbon Capture and Storage Projections to 2050**", 26 June 2009. In this report, ACIL Tasman provides projections of the uptake of Carbon Capture and Storage (CCS) equipped plant over the period to 2050 in the Australian National Electricity Market (NEM). The report includes a range of new entrant technology costs.[59]

- Sinclair Knight Merz (SKM), for the Scottish Enterprise Energy Team, "**Energy Industry Market Forecasts 2008 – 2015, The Worldwide Thermal Power Generation Market**", January 2009[60]. This report looked at opportunities to supply equipment and services to the global thermal power generation market, in particular large plant, with typical unit sizes of greater than 300 MWe, which is generally coal-fired, gas-fired or nuclear.

4.1.16.4 Worley Parsons January 2011

The Worley parsons report reviewed specific capital costs for 21 new entrant generator technology/size options. The revised specific capital costs are published on the revised NTNDP Modelling Assumptions Input Spreadsheets[61]. PB confirmed by telephone that the spreadsheets were the latest versions, corresponding to the Worley Parsons report.

Table 4-10 shows the specific capital costs recorded for the technologies applicable to the planned plant in the GEM as covered in this report (reference values converted using 1 AUD:1.26 NZD).

Table 4-10 Worley Parsons specific capital costs, NZD/kW

Generator	Design generator function	Technology	Capex, NZ$/kW	Comments
Belfast	generator	Recip	-	No recip new entrants
Bromley	generator	Recip	-	No recip new entrants
Otahuhu C	generator	CCGT	1,896	Assumed 700 MW size
Rodney	generator	CCGT	1,896	Assumed 700 MW size
Diesel 1	generator	Recip	-	No recip new entrants
Todd Peaker	generator	OCGT	1,365	Assumed 160 MW
Cogen 1	cogenerator	CCGT	2,465	Assumed 50 MW size
CCGT 1	generator	CCGT	2,086	Assumed 300 MW size

The Worley Parsons specific capital costs are significantly higher (more than double in some cases) than the current (2010) data in the GEM. Potential reasons for these differences are:

- The total cost estimates for each technology include direct and indirect cost components.

- Indirect costs include development costs necessary to cover expenses prior to start of construction and all non EPC hard costs during construction. Specific development costs that are included are: Studies & Project Development, Site Acquisition, Legal Fees,

[59] http://www.ret.gov.au/resources/Documents/Programs/cst/ACIL%20-%20Carbon%20Capture%20and%20Storage%20Projections%20to%202050.pdf
[60] http://www.scottish-enterprise.com/~/media/SE/Resources/Documents/Sectors/Energy/energy-industry-reports/worldwide_thermal_power_generation_market_2008-2015.ashx
[61] http://wwww.aemo.com.au/planning/2010ntndp_cd/html/NTNDPdatabase.htm

Project Support Team, Development Approvals, Duties & Taxes, Operator Training, Commissioning Fuel, and Commissioning & Testing.

- A contingency is included to cover plant, materials and labour that are not fully defined and that would be expected to be spent during the construction stage.

4.1.16.5 ACIL Tasman/DCCEE January 2011

The ACIL/Tasman DCCEE report records new entrant specific capital costs for two technologies relevant to this section of this report on planned thermal generators in New Zealand: CCGT, and OCGT. The "Data source" is given as "ACIL Tasman" and the estimates as "real 2009-10 dollars. The specific capital costs estimated were as follows (reference values converted using 1 AUD:1.26 NZD):

- CCGT: AUD1,368/kW (NZ$1,724/kW)
- OCGT: AUD985/kW (NZ$1,241/kW).

These costs are lower than the Worley Parsons data.

4.1.16.6 Mott MacDonald June 2010

The Mott MacDonald report deals with only one technology relevant to this section of this report on planned thermal generators in New Zealand, and that is gas-fired CCGT. The specific capital cost, described as a technology input assumption, assumed for gas-fired CCGT was as shown in Table 4-11 below (reference values converted using 1 GBP = 1.95 NZD).

Table 4-11 Mott MacDonald specific capital costs, CCGT only

Capital cost components	£/kW	NZ$/kW
Pre-licensing costs, Technical and design	20 - 40	39 - 78
Regulatory + licence + public enquiry	15 - 35	29 - 68
EPC cost	593.8 – 687.5	1,158 – 1,341
Infrastructure cost	6.0 – 18.1	12 - 35
Total capital cost (excl. IDC)	**634.8 – 780.6**	**1,238 – 1,522**

The mid-range value is NZ$1,380/kW.

Note with respect to Table 4-11:

- Mott MacDonald estimated "Low", "Medium" and "High" specific capital costs for "1st of a Kind" and "Nth of a Kind" plants. The range values in Table 4-11 are the Low and High values for the "Nth of a Kind plant".
- Mott MacDonald also comment that, "*After a decade of cycling between $400 and $600 a kW* (NZ$488 – 745/kW) *installed EPC prices for CCGT increased sharply in 2007 and 2008 to peak at around $1,250/kW* (NZ$1,523/kW) *in Q3:2008. This peak reflected tender prices: no actual transactions were done at these prices. Prices have since fallen, with current prices now around $1,050/kW* (NZ$1,280/kW)" (reference values converted using 1 AUD:1.22 NZD).

The Mott MacDonald specific capital cost for CCGT plant at $1,522/kW (range highest) is 20% lower than the Worley Parsons $1,896/kW.

4.1.16.7 IEA/NEA March 2010

The IEA/NEA report `presents the main results of the work carried out in 2009 for calculating the costs of generating baseload electricity from fossil fuel thermal power stations and other technologies. The core of the study consists of individual country data on electricity generating costs. National currency units are converted to USD at average exchange rates for 2008.

All the technologies relevant to this section of this report on planned thermal generators in New Zealand are covered but with varying amounts of data. Specific capital costs are presented as "overnight costs" of electricity generating technologies in USD/kW. "Overnight costs" include pre-construction (owner's), construction (engineering, procurement and construction) and contingency costs, but exclude interest during construction (IDC). The results are as follows:

- CCGT: 24 data submissions were received from 14 countries. CCGT plants without CC(S) technology in the OECD area have overnight cost estimates ranging from as low as 635 USD/kW (in Korea) to 1,678 USD/kW (in Australia, with air cooled condenser), with a mean of 1,121 USD/kW (NZ$1,345/kW) and a median of 1,069 USD/kW.

- OCGT: one data submission was received from one country, from the Electricity Supply Association of Australia (ESAA). The overnight cost estimate was 742 USD/kW (NZ$890/kW).

- Diesel Reciprocating engine: one data submission only was received from one country, Mexico for an 83 MW HFO (heavy fuel oil) engine. The overnight cost estimate was 1,817 USD/kW (NZ$2,180/kW).

- CCGT cogeneration, gas fired: 7 data submissions were received from 5 countries. Overnight cost estimates ranged from 788 USD/kW to 1,949 USD/kW, with a mean of 1,462 USD/kW (NZ$1,754/kW) and a median of 1,442 USD/kW.

The IEA/NEA report also makes the following comments on power plant cost trends over the past decade:

- "*The period from 2004 to 2008 saw an unprecedented level of inflation of power plant costs, covering all construction materials, but especially main mechanical components, electrical assembly and wiring, and other mechanical equipment. In this period, cost rises of at least 50% were observed in many locations. Inflation had an impact on different technologies to different degrees, but all have been affected. Since mid 2008, the global crisis has lessened these inflation pressures, although prices for many components have been slow to drop. Depending on when precisely cost estimates have been performed, the outcomes may vary quite widely even for the same technology in the same location.*" [Chapter 1, page 31]

- "*A cursory look at recent trends delineates a marked power plant cost increase since the middle of the decade, owing to the escalation in the prices of hydrocarbons, commodities and bulk materials. Although the higher prices of raw materials led to roughly similar generation cost escalation for all generating technologies, the competitive margin of capital-intensive technologies, in particular nuclear and wind, has been particularly* *affected. This inflationary trajectory was reversed after reaching a peak in August 2008*". [section 6.3.4, page 136]

- "*According to the IHS CERA Power Capital Cost Index (PCCI), which tracks the costs of coal, gas, nuclear and wind power plants in North America, the construction costs for power plants have grown by 217% between 2000 and the beginning of 2009 (IHS CERA, 2009). The cost increases are not uniform for all plant types, but especially affect the capital-intensive ones such as coal, nuclear and wind. Whether power plant costs will remain that high is an open question. In the first quarter of 2009, IHS CERA cites a drop of 6% in the investment costs of coal power plants, mainly related to reduced labour costs and declining ancillary equipment costs.*

- *Since the first quarter of 2008, the fall in construction costs was largely limited to nuclear power plants, but in the final quarter of 2008 and into 2009, the downward trend has spread to non-nuclear plants as well, driven primarily by lower prices for steel, copper and hydrocarbons. The decline has been amplified by the easing power supply and demand balance, as industrial power demand fell in line with the economic downturn*." [section 6.3.4, page 137]

4.1.16.8 EPRI/Worley Parsons February 2010

The EPRI/Worley Parsons report deals with two technologies relevant to this section of this report on planned thermal generators in New Zealand: gas-fired CCGT and OCGT power plant. All capital costs are presented as "overnight costs" expressed in June 2009 Australian dollars. The specific capital costs estimated were as follows:

- CCGT: AUD1,173/kW (NZ$1,478/kW)

- OCGT: AUD801/kW (NZ$1,009/kW).

The EPRI/Worley Parsons report notes with respect to its capital cost estimates that:

- Capital costs include the interconnection substation (to a single point connection), but not the switchyard and associated transmission lines.

- Capital costs exclude a railroad spur or cooling water intake structures due to the assumptions that these plants are mine mouth and utilise dry-cooling, thus negating the need for rail connections or cooling water intake structures.

- Capital costs do not include tariffs that may be charged for importing equipment to Australia, but the costs do include shipping charges for this equipment.

- Contingencies for all fossil technologies have been included.

- The estimates carry an accuracy of +/-30%, consistent with the screening study level of information available for the various study power technologies.

- Capital Costs are presented at the Total Plant Cost (TPC) level. TPC includes:

  - equipment (complete with initial chemical and catalyst loadings);

  - materials;

  - labour (direct and indirect);

- engineering and construction management;
- contingencies (process and project); and
- an allowance for project specific costs.

- Owner's costs are excluded from TPC estimates. These include but are not limited to land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, allowance for funds-used-during construction, legal fees, owner's engineering, pre-production costs, initial inventories, furnishings, and owner's contingency.

- The site is characterised as Australia and is considered to be Seismic Zone 1, relatively level and free from hazardous materials, archaeological artefacts, or excessive rock. Soil conditions are considered adequate for spread footing foundations. The soil bearing capability is assumed adequate such that piling is not needed to support the foundation loads.

The above illustrate the many factors that give rise to variations between capital cost estimates, and especially between estimates prepared by different parties for differing purposes.

4.1.16.9 ACIL Tasman/DRET June 2009

The ACIL/Tasman DRET report records new entrant specific capital costs for two technologies relevant to this section of this report on planned thermal generators in New Zealand: CCGT, and OCGT. The CCGT technology includes an air-cooled condenser (AC) as this is expected to be the norm in Australia. The "Data source" is given as "ACIL Tasman analysis". The specific capital costs estimated, described as "real 2009 $'kW installed", were as follows:

- CCGT: AUD1,237/kW (NZ$1,559/kW)
- OCGT: AUD889/kW (NZ$1,120/kW).

These costs are lower than the Worley Parsons data.

4.1.16.10 SKM/Scottish Enterprise January 2009

The SKM/Scottish Enterprise report gathered and compared data collated from various sources on capital costs, and reported the results shown in the following Table 4-12. The following comments are made by SKM/Scottish Enterprise on the estimates:

- "*The capital cost of building a typical plant is usually considered to be the EPC contract costs. The capital costs are sensitive to the following factors:*
  - *Site-specific requirements relating to supporting infrastructure*
  - *The duration of construction of the project*
  - *Market influence of major equipment manufacturers*
  - *Price variations due to equipment supply and demand in*
  - *"Soft costs" such as development, financing and legal fees*.

Table 4-12 SKM/Scottish Enterprise capital cost analysis[60]

			Capital cost per kW								
Source			IEA, NEA & OECD[1]	OECD[2]	PB Power[3]	IEA[4]	IEA (China)[6]	ERIRAS (Russia)[7]	WEC[5]	IEA, NEA &OECD[1]	IEA, DGEMP[8]
Year			2005	2005	2006	2006	2007	2007	2007	2015 forecast	2015 forecast
Technology type	Unit size (MW)	Efficiency (%)	USD	USD	USD	USD	USD	USD	USD	USD	USD
Coal Subcritical	200-400	30-36	1,350	1,000-1,500	1,067	1,200-1,400	500-600	1050-1200	750	1,350	1,276
Coal Supercritical	330-800	41-45			1,200		600-900	960-1130	1,000		
Gas CCGT	400-800	49-55	570	500-1,000	594	550-650		450-800		627	569
Nuclear	1150		2,250		1,834[b]	2000-2,500	1,500-1,800			2,718	1,633
IGCC		45-55		1,000-2,500	1,747	1,400-1,600	1,100 -1,400	1400 -1800	1,500		

INFORMATION SOURCES:

1	IEA, p33, http://www.iea.org/Textbase/Papers/2008/CHP_Report.pdf IEA sources , including IEA ,NEA (Nuclear Energy Agency) and OECD report, Projected Costs of Generating Electricity (IEA 2005 Update)
2	2005 OECD comparative study, http://www.world-nuclear.org/info/inf02.html [a] Nuclear overnight construction costs ranged from US$ 1000/kW in Czech Republic to $2500/kW in Japan, and averaged $1500/kW.
3	PB Power report "Powering the Nation", published in March 2006. A summary document is available as a free download in pdf format. http://www.pbworld.co.uk/index.php?doc=528. All prices in Pounds sterling converted to USD, using exchange rate of 1.74
4	IEA, World Energy Outlook 2006, International Energy Agency (IEA), p145 The Economics of New Power Plants
5	World Energy Council, Survey of Energy Resources 2007, http://www.worldenergy.org/publications/survey_of_energy_resources_2007/coal/631.asp
6	IEA, World Energy Outlook 2007, International Energy Agency (IEA), China and India Insights, p345 Coal-Based Power Generation Technology in China and p352-3 Power Generation Economics
7	Energy Research Institute Russian Academy of Sciences, 3rd international forum, RUSSIAN POWER, Investing into the Russian power generation companies. Alexei Makarov, Fedor Veselov, http://www.eriras.ru/papers/2007/makarovveseloveng.pdf
8	Energy Policies of IEA Countries, France 2004 review, http://www.iea.org/textbase/nppdf/free/2004/france.pdf, p129 In December 2003, DGEMP – DIDEME within the Ministry of Economy, Finance and Industry released a study on the costs of the generation of electricity from different generating technologies, "Coûts de référence de la production électrique". All capital cost assumptions include equipment, construction, design, development and interest during construction.

- *There is significant variance in the capital costs of plants built in developed nations and transition nations. For example the capital cost building a subcritical coal fired plant in China can be up to half the cost of building a similar plant in Europe or Japan.*

- *The cost of building power stations has increased significantly over the past few years, particularly in OECD countries. This is largely due to increase in the cost of materials, high energy prices, rising labour costs and supply chain constraints.*

- *Recently there have been sharp increases in construction costs of new power plants, particularly in OECD countries. For non-OECD countries, less cost data are available; therefore it is difficult to draw conclusions on the extent of the increases experienced there. According to the IEA, the sharpest increases have been in the United States, where the construction cost of a new supercritical coal plant has doubled over a few years.*

- *Similar trends are evident in other OECD countries; the main causes of higher costs are as follows:*

    - *Increase in demand: outside the OECD, strong growth in electricity demand is pushing up orders for new plant in addition to the need for new plant in OECD countries due to shrinking reserve margins.*

    - *Increases in the cost of materials: metal prices such as steel, Al, and Cu have substantially increased since 2003/2004 and the prices of some special steels used in power plant manufacturing have increased even faster. Cement prices are also reported to have gone up.*

- *Increase in energy costs: high energy prices affect the manufacturing and transportation cost of power plant equipment and components.*
- *Tight manufacturing capacity: power plant manufacturer are not able to fulfil orders quickly due to lack of capacity and a shortage of skilled engineers. Many manufacturers claim that their order books are full for the next three to five years.*
- *Increases in labour costs: rising labour costs, particularly in non-OECD countries and a shortage of EPC contractors in some regions is pushing up total project costs*."

If the SKM/Scottish Enterprise China and Russian data is ignored, the specific capital cost estimates remaining for "Gas CCGT" range from US$500 – 1,000/kW.

Using an exchange rate of 1 USD = 1.2 NZD, the above specific capital cost range converts to NZ$600 – 1,200/kW, with a mid-range value of NZ$900/kW.

4.1.16.11 Summary

Table 4-13 summarises the validation data extracted by PB from the above sources. In some cases the data in a source report is dated earlier than the date of its report, therefore both the report date and the dollar value date is given. Where a range was given in the source data, the higher of the mean, median or midrange value is recorded below.

Table 4-13 Validation specific capital cost data summary, NZD/kW

Report source/author		GEM	Worley Parsons	ACIL Tasman/ DCCEE	Mott MacDon.	IEA/NEA	EPRI/ Worley Parsons	ACIL Tasman/ DRET
Report date		2010	January 2011	January 2011	June 2010	March 2010	February 2010	June 2009
Dollar date/time value		Not known	"Real 2009-10"	"Real 2009-10"	2009	2009	June 2009	"Real 2009"
Generator	Function/ technology	NZ$/kW	NZ$/kW	NZ$/kW	NZ$/kW	NZ$/kW	NZ$/kW	NZ$/kW
Belfast	Gen recip	No data	No data	No data	No data	2,180	No data	No data
Bromley	Gen recip	No data	No data	No data	No data	2,180	No data	No data
Otahuhu C	Gen CCGT	1,091	1,896	1,724	1,380	1,345	1,478	1,559
Rodney	Gen CCGT	1,200	1,896	1,724	1,380	1,345	1,478	1,559
Diesel 1	Gen recip	No data	No data	No data	No data	2,180	No data	No data
ToddPeaker	Gen OCGT	1,575	1,365	1,241	No data	890	1,009	1,120
Cogen 1	Cog CCGT	1,636	2,465	No data	No data	1,754	No data	No data
CCGT 1	Gen CCGT	1,200	2,086	1,724	1,380	1,345	1,478	1,559

Note that the SKM/Scottish Enterprise data has been excluded from the above table because it was considered to be out of date. Although the report is dated January 2009, the data sources are dated from 2003 to 2007.

4.1.16.12 Conclusions

- Regardless of the inaccuracies involved in using specific capital cost estimates developed by others, for other countries and in other currencies, it appears that with the exception of OCGT plant, capital costs for thermal power plant have increased since the current (2010) GEM data was adopted.
- Of the seven public domain sources PB has relied on for specific capital costs, four were prepared for Australian government clients and estimated the cost of thermal power plant in Australia. Of the remaining three, the SKM/Scottish Enterprise data has been excluded as noted above, and the Mott MacDonald data is focussed on UK generation costs. Only the IEA/NEA report includes data from multiple countries.
- The IEA/NEA report suggests that specific capital costs, at least for CCGT generators, are highest in Australia. Reasons for this may be the use of the more expensive air cooling and air-cooled condensers, the higher cost of water supply infrastructure in a relatively dry climate. Remoteness could also be a factor.
- There appear to be grounds therefore, for not adopting the highest of the Australian specific capital costs.

4.1.16.13 Way forward

The challenge to deriving specific capital cost estimates (NZD and foreign currency components) from public domain data is dealing with the variability. The reasons for such variability have been discussed earlier in this section of this report and a further ‘variability’ is added by the currency exchange conversions that reference data may have assumed.

The approach PB has taken is to:

- Firstly resolve the variability issue for one technology only. The gas fired CCGT technology was chosen as, according to the IEA/NEA report, “*In the last decade, gas-fired power generation has accounted for around 80% of OECD area incremental power generation*”. That in itself does not resolve the variability as the CCGT data in that report alone varied widely.
- Secondly, estimate the specific capital costs for the other technologies based on the average cost differential between the technologies.

The data for the CCGT technology in Table 4-14 can be plotted as a ‘duration curve’ as follows in Figure 4.2.

The highest values are for Australian CCGT generators and it was noted previously that there appeared to be grounds for not adopting those values for New Zealand CCGT generators. A value toward the high end of the remaining data is also close to the 50 percentile value and is considered a reasonable choice.

PB has therefore chosen a specific capital cost value for the CCGT generator technology of NZ$1,500/kW. Such a value also avoids the pretence of accuracy by quoting to the nearest dollar/kW.

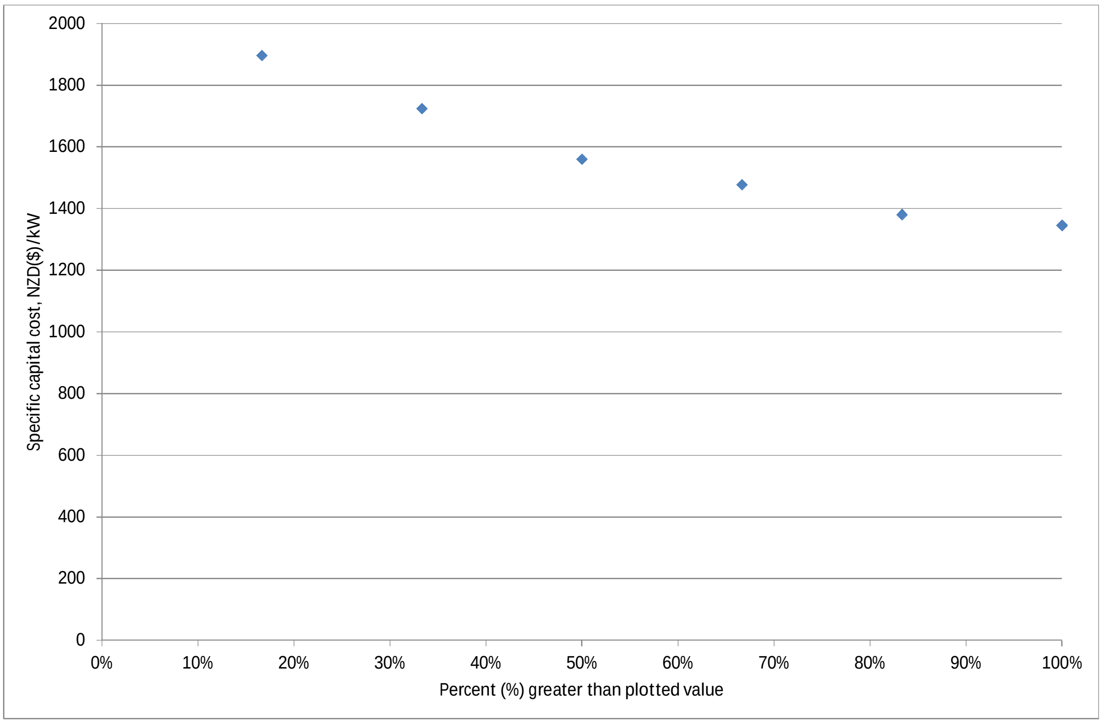


Figure 4.2 CCGT summary specific capital costs data 'duration curve'

The specific capital cost chosen of NZ$1,500/kW is assumed to apply to the modern, large-scale single shaft machines and multiples of the same, such as the planned Otahuhu C generator. This value is close to the NZ$1,478/kW (AUD1,173/kW) estimated by EPRI/Worley Parsons and the EPRI/Worley Parsons report appears to have adopted a robust cost estimating methodology.

Specific total capital costs (NZD and foreign components) for the other technologies based on the average cost differential between the technologies are as follows:

- Rodney: multiple smaller units are normally more costly and this is reflected in the current (2010) GEM data, with the planned Rodney generator estimated at NZ$660/kW compared to Otahuhu C at NZ$600/kW. If a proportional differential (10%) is applied to the NZ$1,500/kW, the Rodney specific capital cost would be NZ$1,650/kW. This appears excessive and PB recommends a 5% differential, giving a cost (rounded up) of NZ$1,580/kW.

- CCGT 1: this a assumed to be a two 100 MW units and would be expected to suffer a cost penalty as a result of its size compared to a nominally 400 MW, single-shaft unit, and as a result of it being the first and only unit of the plant. PB considers that a 10% differential may apply, resulting in a specific capital cost of NZ$1,650.

- Todd Peaker: this is assumed to consist of a 2 x 50 MW unit OCGT generator and would also be expected to suffer a small cost penalty as a result of its size. The OCGT specific capital costs in Table 4-14 are on average 70% of the CCGT costs. This is contrary to the current (2010) GEM data, which has the OCGT generators 44% more costly than the CCGT generators. PB recommends the 70% factor, with an additional 5% cost penalty. The result is a specific capital cost of NZ$1,100/kW.

- Cogen 1: this is a 50 MW, assumed two unit, CCGT cogeneration generator. The CCGT cogenerator specific capital costs in Table 4-14 are on average 130% of the CCGT costs.

The current (2010) GEM data has the CCGT cogenerator specific capital costs at 150% of the CCGT costs. PB considers the 130% factor more realistic, resulting in a specific capital cost of NZ$1,950/kW.

- Belfast & Bromley: these are 10 – 11.5 MW, assumed single unit, low speed diesel generators. There is only one data source for reciprocating engine/diesel generator costs in Table 4-14, the IEA/NEA report. The specific capital cost for the diesel generator in the IEA/NEA report is 160% of the CCGT cost, and when this factor is applied to the chosen specific capital cost value for the CCGT generator technology of NZ$1,500/kW, the result is a specific capital cost of NZ$2,400/kW for the diesel generators.

- Diesel 1: this is assumed to be a two-unit, 2 x 5 MW, medium speed, diesel generator. The medium speed engine generator is understood to have a lower capital cost, around 85%, than the low speed engine generator. This results in a specific capital cost of NZ$2,040/kW.

4.1.16.14 Data

Table 4-14 compares the proposed specific capital costs estimated above with the current (2010) GEM costs.

Table 4-14 Proposed (2011) GEM capital costs, NZ$/kW

Generator	Design generator function	Nominal Size/ Technology	2010 GEM NZ$/kW	Proposed GEM NZ$/kW	Comments
Belfast	Peaking generator	11.5 MW Recip	-	2,600	Not previously estimated
Bromley	Peaking generator	11.5 MW Recip	-	2,600	Not previously estimated
Otahuhu C	Baseload generator	400 MW CCGT	1,091	1,600	47% increase
Rodney	Baseload generator	480 MW CCGT	1,200	1,700	42% increase
Diesel 1	Peaking generator	2 x 5 MW Recip	-	2,040	Not previously estimated
Todd Peaker	Peaking generator	2 x 50 MW OCGT	1,575	1,100	30% decrease
Cogen 1	Baseload cogenerator	2 x 25 MW CCGT	1,636	1,950	19% increase
CCGT 1	Baseload generator	2 x 100 MW CCGT	1,200	1,650	38% increase

In most cases estimated specific capital costs have increased by 19 – 47%. This is less than indicated by the comment in the IEA/NEA report, namely, "*the construction costs for power plants have grown by 217% between 2000 and the beginning of 2009*". This shows that the effects of that increase were largely taken into account in the current (2010) GEM data (likely dated 2009).

The most likely reasons for the increase in specific capital costs are:

- The historical use of EPC contract cost data for plant costs, which exclude owner's costs. This has the effect of discounting the historical costs.

- The historical use of currency conversions only to adopt other-country cost estimates. The EPRI/Worley Parsons report in particular uses “Labour Productivity”, “Crew Rate” and “Material Cost” factors in addition to “Currency Exchange Rate” to adjust North American cost estimates to an Australian context.
- Foreign currency exchange rate variations over time.

No cost data has been received from the planned thermal generation owners. This would have provided an additional validation of the above PB estimates.

The specific capital costs for the reciprocating/diesel engine generators in Table 4-15 are consistent with the ranges expressed in PB’s report to the Electricity Commission, “Thermal Power Station Advice - Reciprocating Engines Study”, November 2009, where the total (installed) capital cost of reciprocating engine gensets, in 2009 New Zealand dollars, is estimated to be:

- High speed: NZ$1,200 – 1,800/kW
- Medium speed: NZ$1,500 – 2,400/kW
- Low speed: NZ$2,100 – 2,500/kW.

To verify the relative proportions of the capital cost that are exposed (imported or of foreign origin) and not exposed (domestic origin) to foreign currency movements, PB has based its analysis on three sources:

- PB’s report to the Electricity Commission, “**Thermal Power Station Advice - Reciprocating Engines Study**”, November 2009. This report provided a breakdown of the total installed cost for a small, high speed, 500 kW genset and estimated that 60 – 75% of the capital value would comprise imported equipment, which would include the engine-generator module.

- Mott MacDonald, “**UK Electricity Generation Costs Update**”, June 2010[62]. This report provides a summary and supporting documentation for Mott MacDonald’s assessment of current and forward power generation costs for the main large scale technologies applicable in the UK. This report provided the breakdown of total capital cost shown in Table 4-12 for a gas-fired CCGT plant.

- Sinclair Knight Merz (SKM), for the Scottish Enterprise Energy Team, “**Energy Industry Market Forecasts 2008 – 2015, The Worldwide Thermal Power Generation Market**”, January 2009[63]. This report provided a breakdown of the EPC cost only into specific cost areas based on Thermoflow’s Plant Engineering and Cost Estimator (PEACE) for a gas-fired CCGT plant. It also provided a breakdown of the greater of those ‘specific cost areas, namely “Equipment Procurement” into engineering disciplines.

PB replicated the cost breakdown given in the above references in an Excel spreadsheet in percentage terms, for two technologies:

- Gas-fired CCGT plant
- 400 MW subcritical coal-fired plant.

[62] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[63] http://www.scottish-enterprise.com/~/media/SE/Resources/Documents/Sectors/Energy/energy-industry-reports/worldwide_thermal_power_generation_market_2008-2015.ashx

PB then estimated the relative proportions of domestic and foreign (exposed to foreign currency movements) for each breakdown item. The overall split, in percentage terms was then calculated, giving the following results:

- Gas-fired CCGT plant: 39% domestic, 61% foreign
- 400 MW subcritical coal-fired plant: 55% domestic, 45% foreign.

The difference is mainly owing to the higher proportion of civil/structural cost in the coal-fired plant. For that breakdown item PB has assumed a domestic/foreign split of 70/30 for the CCGT plant and 60/40 for the coal-fired plant on the basis that the larger and heavier above ground support structures required for coal-fired plant require imported structural steel members.

To confirm the capital cost domestic/foreign split for the other generator technologies, PB has assumed:

- As above, larger and heavier above ground support structures lead to higher proportions of imported structural steel members. Conversely, smaller and lighter above ground support structures lead to lower proportions of imported structural steel members.
- OCGT and reciprocating engine/diesel generating plants, because they tend to utilise modular construction and require relative lightweight buildings and support structures, will tend to have higher proportions of imported equipment than gas-fired CCGT plant.

Table 4-15 sets out the resulting domestic/foreign split derived from the PB recommended capital cost component (NZD and foreign currency) estimates using the MED reference exchange rates. To avoid the pretence of accuracy the values are rounded up or down to the nearest 5%.

Table 4-15 Proposed domestic/foreign capital cost split, %

Generator	Design generator function	Nominal Size/ Technology	Domestic, %	Foreign, %	Comments
Belfast	Peaking generator	11.5 MW Recip	35	65	Modular construction
Bromley	Peaking generator	11.5 MW Recip	35	65	Modular construction
Otahuhu C	Baseload generator	400 MW CCGT	40	60	Base case, calculated at 39/61
Rodney	Baseload generator	480 MW CCGT	40	60	Assumed same as Otahuhu C
Diesel 1	Peaking generator	2 x 5 MW Recip	30	70	Small, lightweight, skid mounted units
Todd Peaker	Peaking generator	2 x 50 MW OCGT	35	65	Modular construction
Cogen 1	Baseload cogenerator	2 x 25 MW CCGT	40	60	Assumed same as Otahuhu C
CCGT 1	Baseload generator	2 x 100 MW CCGT	40	60	Assumed same as Otahuhu C

4.1.17 Dominant foreign currency

4.1.17.1 Introduction

The dominant foreign currency will depend on which country or countries the major equipment is sourced from. This is not readily determined because there are competing OEMs (original equipment manufacturers) located in different countries for all the planned thermal generator technologies. For example, the single shaft GT/ST/generator units comprising the existing gas-fired CCGT plants in New Zealand were sourced as follows:

- Taranaki combined cycle plant: Alstom (previously ABB Power Generation) GT26 from Baden, Switzerland and assumed denominated in Swiss Francs (CHF), now Euros (EUR)
- Otahuhu B combined cycle plant: Siemens V94.3A from Germany and assumed denominated in German Marks (DEM), now Euros (EUR)
- Huntly Unit 5 combined cycle plant: Mitsubishi Heavy Industries from Japan and assumed denominated in Japanese Yen (JPY).

There are is also a competing CCGT OEM in the USA, GE.

This situation applies to all the planned generators.

4.1.17.2 Methodology

The following assumptions have been made by PB in order to determine the dominant foreign currency:

- Otahuhu C will be based on a Siemens machine, similar to Otahuhu B, from Germany and the dominant currency will therefore be Euros (EUR).
- Caterpillar Solar, Pratt & Whitney and GE gas turbines are understood to comprise the remaining gas turbine fleet in New Zealand. These are all sourced from the US. Rolls Royce (UK) gas turbines were installed at Otahuhu A gas turbine station. The Todd Peaker, Cogen 1 and CCGT 1 are assumed to be supplied out of the US and the dominant currency will therefore be US Dollars (USD).
- Wartsila is a significant supplier of diesel engines and is the assumed OEM for the larger Belfast and Bromley generators. The dominant currency is therefore assumed to be Euros (EUR).
- Caterpillar is also a significant supplier of diesel engines and is the assumed OEM for the smaller Diesel 1 units. The dominant currency is therefore assumed to be US Dollars (USD).

4.1.17.3 Data

Table 4-16 sets out the resulting dominant foreign currencies estimated by PB using the above methodology.

Table 4-16 Proposed dominant foreign currency

Generator	Design generator function	Nominal Size/ Technology	Assume OEM	Dominant foreign currency
Belfast	Peaking generator	11.5 MW Recip	Wartsila	EUR
Bromley	Peaking generator	11.5 MW Recip	Wartsila	EUR
Otahuhu C	Baseload generator	400 MW CCGT	Siemens	EUR
Rodney	Baseload generator	480 MW CCGT	Alstom	EUR
Diesel 1	Peaking generator	2 x 5 MW Recip	Cater-pillar	USD
Todd Peaker	Peaking generator	2 x 50 MW OCGT	GE	USD
Cogen 1	Baseload cogenerator	2 x 25 MW CCGT	Solar	USD
CCGT 1	Baseload generator	2 x 100 MW CCGT	GE	USD

4.1.18 Lines connection cost

4.1.18.1 Introduction

In order to estimate the lines connection cost, it is necessary to know the proximity of the plant to the distribution or transmission network connection point. For the planned thermal generators the locations are known for four plants (Belfast, Bromley, Otahuhu C, & Rodney), and not known for four of the plants (Diesel 1, Todd Peaker, Cogen 1 & CCGT 1.

For the known locations, three of the plants are located in or adjacent to existing Orion and Transpower substations.

Rodney location is known and it was noted in section 4.1.5.4 that it was assumed that the plant will be connected to the Henderson – Marsden – A (HEN-MDN-A) 220 kV transmission line, which passes near the site. This was assumed to require a short interconnecting transmission line. However, on further review of the site description published by Genesis, and inspection of the area using 'Google maps', it appears that Genesis has chosen a site adjacent to the transmission line and, therefore that the connection will be very short.

4.1.18.2 Unknown location assumptions

For the proposed generators where the exact location is unknown (but where a possible representative transmission connection node has been estimated), PB has made the following assumptions:

- Diesel 1: this is assumed to be a two-unit, 2 x 5 MW, medium speed, diesel generator. At that size, this generator can reasonably be assumed to be embedded in a local distribution network and probably located at or adjacent to an existing distribution or zone substation. This would be a situation no different to the planned Belfast and Bromley generators.

- Todd Peaker: this is a 2 x 50 MW OCGT plant and likely to be located at either a convenient gas supply point, a convenient transmission connection, or a combination of both.

- Cogen 1: this is a 50 MW, assumed single unit, CCGT cogeneration generator. This will be located at the site of the cogeneration heat load (steam consumer) host, and is also likely to be located at either a convenient gas supply point, a convenient transmission connection, or a combination of both.

- CCGT 1: this is a 200 MW, assumed two unit, CCGT generator. This will also likely to be located at either a convenient gas supply point, a convenient transmission connection, or a combination of both.

4.1.18.3 Data

Table 4-17 sets out the resulting lines connection costs estimated by PB on the basis of the above assumptions.

Table 4-17 Proposed lines connection costs

Generator	Design generator function	Nominal Size/ Technology	Lines connection cost, NZ$ M	Comments
Belfast	Peaking generator	11.5 MW Recip	0.5	Embedded in local zone substation
Bromley	Peaking generator	11.5 MW Recip	0.5	Embedded in local zone substation
Otahuhu C	Baseload generator	400 MW CCGT	10	Adjacent to Otahuhu substation
Rodney	Baseload generator	480 MW CCGT	10	Adjacent to 220 kV transmission line
Diesel 1	Peaking generator	2 x 5 MW Recip	0.5	Embedded in local zone substation
Todd Peaker	Peaking generator	2 x 50 MW OCGT	5	Close proximity to transmission line/Transpower substation.
Cogen 1	Baseload cogenerator	2 x 25 MW CCGT	5	Close proximity to transmission line/Transpower substation.
CCGT 1	Baseload generator	2 x 100 MW CCGT	10	Close proximity to transmission line/Transpower substation.

4.2 Hydro

4.2.1 Summary

Table 4-18 summarises the proposed hydro plant data, publically available at the time of writing for each region around New Zealand. Where this information is not available or has not been provided by the generators, PB has provided recommendations based on arbitrary estimates and approximation techniques, as detailed through this report.

Table 4-18 PB recommendations: Proposed NZ hydro plant data

Project name	Plant Tech	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Variable O&M costs	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
			Years	MW	%	%	%	Y/N	$/MWh	$/kW/year	NZD/kW	€/kW	Currency	NZD million
Wairau	HydRR	BLN	80	72	92.3%	71%	17%	N	$0.70	$6.38	$3,516[64]	€306	EUR	$10[65]
Lake Pukaki	HydPK	TWZ	50	35	92.3%	59%	100%	N	$0.86	$6.38	$2,451[66]	€363	EUR	$4[64]
North Bank	HydPK	WTK	80	260	92.3%	60%	50%	N	$0.84	$6.38	$3,536[64]	€226	EUR	$14[65]
Rakaia	HydRR	ASB	50	16	92.3%	59%	50%	N	$0.86	$6.38	$4,025[66]	€436	EUR	$6[65]
Arnold	HydPK	DOB	50	46	92.3%	59%	50%	N	$0.85	$6.38	$3,407[64]	€340	EUR	$6[65]
Mokihinui	HydRR	IGH	80	100	92.3%	49%	33%	N	$1.02	$6.38	$2,457[64]	€283	EUR	$15[65]
Stockton Mine	HydRR	WMG	50	35	92.3%	62%	50%	N	$0.80	$6.38	$3,016[64]	€363	EUR	$6[65]
Stockton Plateau	HydRR	WMG	50	50	92.3%	59%	50%	N	$0.86	$6.38	$3,370[64]	€333	EUR	$6[65]
Hawea	HydPK	CML	50	17	92.3%	51%	50%	N	$0.86	$6.38	$1,518[64]	€430	EUR	$13[65]

Note: The information provided in this table should only be used in conjunction with the information provided in the relevant sections contained within the body of this report.

[64] *Estimate, based on publically available project cost estimates, refer to GEM input data spreadsheet for references.*
[65] *Estimate, based on estimated lines connection costs (refer to Section 4.2.16 for details). Project specific information used where available, otherwise generic information within this report used (refer to GEM input data spreadsheet for project specific data references).*
[66] *Estimate, based on total capital costs of generic hydro plants, excluding pre-development costs (refer to Section 5.2.13.4). Project specific information used where available, otherwise generic information within this report used (refer to GEM input data spreadsheet for project specific data references).*

4.2.2 Plant

Table 4-20 lists the proposed hydro power generation projects around New Zealand that are greater than or equal to 10 MW capacity and have either applied for resource consent, have received resource consent or are under construction. The information in this table has been sourced from http://www.ea.govt.nz/industry/modelling/long-term-generation-development/list-of-generation-projects/ unless otherwise stated.

Table 4-19 Proposed NZ hydro projects

Current proposed NZ hydro projects				
Region	**Project Name**	**Capacity**	**Owner**	**Status / Comments**
Marlborough	Wairau	72 MW	TrustPower (TP)	Consented – TP's website states that the *"Environment Court hearing concluded in May 2010 and in November 2010 the Environment Court confirmed the resource consents for the scheme"*
Canterbury	Lake Pukaki	35 MW	Meridian Energy (ME)	Consented, 15 June 2011 – ME's website states that *"Meridian today welcomed the decision by ECan and the Mackenzie District Council to issue resource consents for its Pukaki Hydro project."*
Canterbury	North Bank Tunnel	260 MW	Meridian Energy	Applied for consent
Canterbury	Rakaia River	16 MW	Ashburton Com. Water Trust	Consented
West Coast	Arnold (Dobson)	46 MW	TrustPower	Consented
West Coast	Mokihinui	85 MW	Meridian Energy	Consent under appeal
West Coast	Stockton Mine	35 MW	Solid Energy (SE)	Consent under appeal – 1 Oct 2010, SE's website mentions that *"Solid Energy was not successful with its application in June 2010 to gain consents for an alternative hydro-electricity proposal and has appealed that decision."*
West Coast	Stockton Plateau	50 MW	Hydro Developments	Consented
Otago	Hawea Control Gates	17 MW	Contact Energy	Consented

4.2.3 Plant technology

4.2.3.1 Mokau

The King County Energy website mentions that *"it will no longer pursue the resource consents required for the proposed 9.6MW hydro-generation scheme along the Mokau River",* 28 June 2011. This report has not considered the Mokau scheme further.

4.2.3.2 Wairau Hydro

TrustPower's website describes the Wairau Valley Hydroelectric Power System as a *"72MW scheme"* and *"The scheme will take water from the Wairau River above the existing Branch River station, and pass it through a 49 kilometre canal system and six power stations, including the existing Branch River hydro scheme, before returning to the Wairau River. The scheme is expected to cost approximately $280 - $320 million and produce enough power for around 47,000 homes."*

The layout and storage of the system is described in *'The Assessment of Environmental Effects Report, June 2005'* as *"The Scheme builds on the existing Branch HEPS, and expands it with the addition of a new Intake on the Wairau River and 6 new Power Stations downstream of the existing Scheme. The new Intake will feed into the existing Branch HEPS between the Argyle and Wairau Power Stations, increasing the inflow to the Head Pond that currently feeds the existing Wairau Power Station. A new Power Station (PS1A) will be constructed immediately adjacent to the existing Wairau Power Station to cater for the increased flows. The generation flows from PS1A and the existing Wairau Power Station will be discharged to the same tailrace, and will subsequently be conveyed (predominately via canal with short sections of pipe) to the 5 new stations."* , where the Branch HEPS refers to the Branch Hydroelectric Power Scheme.

The report also describes the operation of the scheme as *"The Scheme is not configured as a 'peaking' facility ('peaking' means maximising generation during peak demand periods). In this respect, the limited storage capacity available within the Canal and reservoirs means that the Scheme can only regulate inflows/discharges on a daily basis. As such, the daily volume discharged from the Scheme will be similar to the volume abstracted."*

The report also specifies that the total gross head available for the new power stations is 232.5 m.

4.2.3.3 Pukaki Hydro

Meridian Energy's website describes the Pukaki Hydro Scheme as a *"new hydro electricity power station which utilises the existing head between Lake Pukaki and the Pukaki-Ohau Canal for hydro electricity generation."*
The website also mentions that *"The proposal is to construct a new, small powerhouse, close to the existing canal inlet structure with the capability to generate up to 35MW."*

The storage and operation of the scheme is described in the website as *"Lake Pukaki is controlled and operated to remain between 518.00 and 532.50 metres above mean sea level. Meridian also has consent to take water at a maximum rate of 560 cubic metres per second through Gate 18 into the Pukaki-Ohau Canal. The proposed Pukaki Hydro Scheme would operate within these parameters and existing consents would remain unaltered."*

Figure 4.3 is from the Meridian Energy website and shows the site of the proposed scheme.

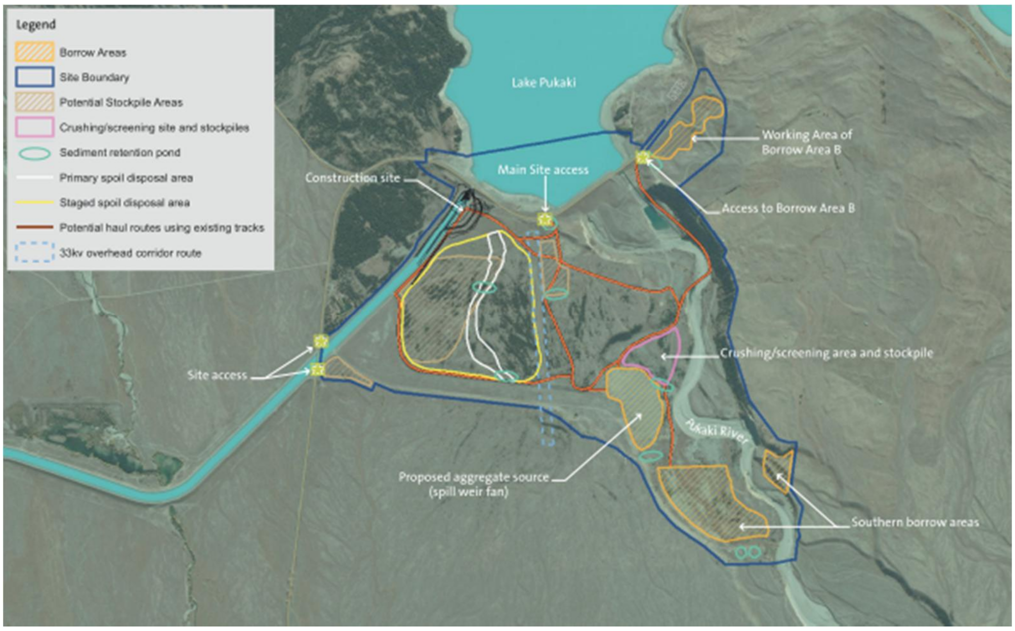


Figure 4.3 Proposed Pukaki (Gate 18) Hydro Scheme Layout

4.2.3.4 North Bank Tunnel Hydro

Meridian Energy's website describes the North Bank Tunnel Concept as *"a hydro generation proposal taking water from Lake Waitaki and discharging it back into the Waitaki River about 34km downstream near Stonewall." and "Over this distance the river drops about 125 metres and it is this elevation drop, or head, that would be utilised by the tunnel concept to generate electricity."*

The website has the following description of the operation of the system, *"A monthly flow regime is proposed for the Waitaki River based on the variable, seasonal in stream and out of stream values and the electricity demand cycle."*

The website mentions the following about the potential power generation *"The net gain would be between 1100 and 1400 gigawatt-hours per year."*

The website also mentions that estimated capacity of the North Bank Tunnel Scheme is *"approximately 260 MW (depending mainly on the final optimum tunnel diameter chosen)".*

4.2.3.5 Rakaia River Hydro

The website http://www.scoop.co.nz/stories/AK0905/S00383.htm describes the Rakaia River Hydro Scheme as *"The Rakaia Terrace hydro scheme proposes to take up to 40 cubic metres of water per second (cumecs) from Highbank and discharge it at Barrhill."*

An article in The Press website on 29/05/2009 *'Consent granted for Plains hydro scheme'* also mentions that *"Consents for the scheme, which will produce up 16 mega-watts of electricity for the district, have been issued until 2035."*

4.2.3.6 Arnold Hydro

TrustPower's website has the flowing description of the Arnold Power Scheme, *"Arnold Hydroelectric Power Scheme is a planned 46 MW scheme"* and *"The scheme will divert a proportion of the flow from the Arnold River, via a canal beginning at the location of the existing dam, to a storage pond. The power station will draw water from the storage pond, generate electricity through turbines and then return the water to the Arnold River via canals and a flow regulation pond located on Killeen Island."*

The website also mentions that *"The scheme is estimated to cost around $180 – 200 million."*

The *'Hydro Electric Power Scheme Arnold River, Volume 1: Assessment of Environmental Effects (March 2006)'* specifies that the Gross head of the new power station is 55.5 m and that *"Annual generation is projected to be 220 GWh per annum."*

The report also mentions that *"The Scheme is designed to allow peaking operation. This means more electricity can be generated when it is demanded. This is done by passing a higher flow water through a turbine to generate electricity. For this reason the Scheme includes a single storage pond which is designed to provide some short term regulation of flows."*

4.2.3.7 Mokihinui Hydro

The Meridian Energy website has the following description of the Mokihinui Hydro Project, *"The Mokihinui Hydro Project would generate up to 100 MW"* and *"Meridian plans to construct an 85m high dam, power station and substation in the Mokihinui Gorge, about 3km upstream of Seddonville. The development will create a 340 hectare "ribbon lake" extending 14 kilometres eastwards"*

The website also mentions that "Mokihinui Hydro Project will generate between 370 and 420 GWh of renewable electricity a year"

4.2.3.8 Stockton Mine Hydro

The Solid Energy website describes the Stockton Hydro scheme as *"Creating 176 Gigawatt hours (GWh) of renewable electricity and improving the ability of Solid Energy to manage the effects of water runoff from the mining areas at Stockton."*

The website also provides the following information on the scheme:

- 176 GWh of renewable energy
- 35 megawatts of peak generation capacity
- 575 m of head to drive turbines
- The mean flow diverted through the scheme is only 4.3 m³/s which is approximately 15% of the mean Ngakawau River flow.

4.2.3.9 Stockton Plateau Hydro

Hydro Developments Ltd's website has the following description about the project *"The Stockton Plateau Hydro Project will generate electricity by diverting drainage from the Stockton Plateau through a series of reservoirs, tunnels and power stations to an ocean outfall. The outfall will consist of a submarine tunnel connected to a diffuser built into the sea bed."*

The website also has the following description *"The project will generate in the order of 240 GWh of renewable energy per year. The drop of more than 555m between the highest reservoir and ocean outfall means that large amounts of electricity can be generated from the relatively small volumes of water that will be diverted from the main river system (4 - 8 cubic metres per second)."* and *"the Project is expected to provide a continuous (24/7) base load in the order of 25MW.".* The website also mentions that *"The Project has the potential to double the baseload output to around 50MW for short periods during and following heavy rainfall.".*

4.2.3.10 Hawea Control Gates Hydro

The Contact Energy website has the following description about the Hawea Control Gates project and its status *"Contact holds resource consents for the installation of a generating plant within the existing Hawea Dam, which would harness water released from the dam into the Hawea River. At a capacity of up to 17 megawatts, this plant has the potential to generate enough clean, renewable electricity to power around 8,000 homes per year."*

4.2.4 Substation

As hydro power plants are often located in remote areas, when new plants are built, they typically require a new substation to be built adjacent to the new plant. A transmission line is also required to be constructed to connect the substation with the national grid. The exception to this is where the hydro plant has been built nearby to an existing substation that has adequate capacity for the additional generation.

This report assumes that each new hydro power plant will require a new substation, unless details of a suitable adjacent substation have been provided by the generators as part of the hydro scheme project proposal.

Refer to Section 4.2.16.2 for details on estimating the substation costs.

4.2.5 Project lifetime

The proposed hydro power plants are expected to have an operational life of around 50 years for plants ≤ 50 MW and 80 years for plants > 50 MW. Refer to Section 3.2.5 for further details on the lifetime of hydro power plants.

4.2.6 Operational capacity

The operational capacity of each of the proposed schemes is listed in Table 4-20 above. The list above only considers proposed plants with operational capacities greater than or equal to 10 MW. These capacities were obtained from publically available sources, such as internet news articles, and the main generator companies (Contact Energy, Meridian Energy and TrustPower) were requested to confirm these capacities.

4.2.7 Availability Factor

The estimated availability factor for each of the proposed plants has been requested from the generators. Where this information is not available, is it assumed to be 92.3%. Refer to Section 3.2.7 for details on this estimated availability factor.

4.2.8 Net Output Factor

The net output factor (NOF) is project specific as it depends on many factors, such as; the availability factor, water storage capacity, local precipitation rates, inflows into the hydro scheme and the operational strategy of the generator. The water available to generate electricity is very site specific and hence it can vary widely between different locations.

Using the estimated availability factor above, with published annual generation outputs of existing schemes around New Zealand (refer to Section 3.2), the net output factor was calculated and varied significantly between plants/schemes, for example the Waipori scheme had a NOF of 29% and Tekapo A had a NOF of 78%. Each hydro scheme should be considered on a case-by-case basis to determine a more accurate net output factor.

The estimated Net Output Factor for each of the proposed plants has been requested from the generators. Where this information is not available, is has been determined using the following technique.

The net output factor was calculated from the plant capacity, estimated availability factor (above) and the estimated annual power generation of each of the proposed schemes. The net output factor from each proposed scheme was averaged to determine an overall estimated net output factor of 59%.

This was compared to the 2010 interim/annual reports and websites of Meridian Energy and Might River Power which specify the annual power generation from each hydro generator. The average net output factor from each generator was averaged to determine an overall estimated net output factor of 56%.

Where the net output factor has not been provided by the generators, it has been assumed to be 59%, as the annual outputs of the proposed schemes are likely to be representative of what is anticipated over the life of the proposed schemes.

4.2.9 Unit largest proportion

Table 4-20 lists the estimated capacity of the largest single hydro generator for each proposed plant. These capacities were obtained from publically available sources, such as internet news articles, and the main generator companies (Contact Energy, Meridian Energy and TrustPower) were requested to confirm these capacities.

Where values were not known, PB has estimated based on a possible plant configuration given available information and PB experience with similar type of plant.

Table 4-20 Unit largest Proportion for proposed NZ hydro plants

Largest Single Generator Capacity			
Region	**Plant**	**Largest Generator Size**	**Percentage of Plant Capacity**
Marlborough	Wairau	12 MW	17% (estimated)
Canterbury	Lake Pukaki	35 MW	100% (estimated)
Canterbury	North Bank Tunnel	130 MW	50%
Canterbury	Rakaia River	8 MW	50% (estimated)
West Coast	Arnold (Dobson)	23 MW	50%
West Coast	Mokihinui	33 MW	33%
West Coast	Stockton Mine	17.5 MW	50%
West Coast	Stockton Plateau	25 MW	50% (estimated)
Otago	Hawea Control Gates	8.5 MW	50%

4.2.10 Baseload

The proposed hydro power plants are not considered to generate base-load. Refer to Section 3.2.9 for details.

4.2.11 Variable O&M costs

The variable operation and maintenance costs have been based on $340/MW per month for a new plant. Refer to Section 3.2.10 for details on determining operating and maintenance costs. Where the generators have provided more detailed operating and maintenance costs, this information has been included in the proposed hydro plant data.

4.2.12 Fixed O&M costs

The fixed operation and maintenance costs have been based on $532/MW per month for a new plant. Refer to Section 3.2.11 for details on determining operating and maintenance costs. Where the generators have provided more detailed operating and maintenance costs, this information has been included in the proposed hydro plant data.

4.2.13 Capital cost (NZD component)

The following Table 4-21 lists the estimated total capital costs of each of the proposed hydro power station projects.

Where the published project costs are prior to 2011, these costs have been escalated by using the Civil Construction Capital Good Price Index (CGPI) published by Statistics New Zealand. The CGPI is published quarterly and the yearly average for each year was used for determining the escalation.

These costs have been assumed be total project costs, including all costs such as land acquisition, contractor margins and owner costs. However they have been assumed to not include pre-development costs, such as resource consent approvals (refer to Section 5.2.13.3 for details on pre-development costs).

The project cost estimates in Table 4-21 below are comparable to the cost estimates in the report *'Transmission to enable renewables potential NZ hydro schemes, Parsons Brinckerhoff Associates, June 2008',* which has the 2008 project cost estimates for the Wairau project of $330M (+20%, -10%), Arnold $ 223M (+20%, -10%), North Bank Tunnel $974M (+50%, -10%) with 25% tunnel lining and the Mokihinui $304M (30%, -20%). Escalating these prices to 2011 costs, using the civil construction CGPI, provides estimated project costs of $362M, $245M, $1069M and $334M respectively.

Table 4-21 Total capital costs for proposed NZ hydro plants

Proposed Hydro Capital Cost			
Plant	**Project Cost $Mil NZD (Date)**	**2011 Project Cost $Mil NZD**	**Source**
Wairau	$300M (2011)	$300M	2011 TrustPower website: estimate costs to be $280M - $320M
Lake Pukaki	$113M (estimated)	$113M (estimated)	Calculated in accordance with Section 5.2.13, using published information as referenced in GEM input data spreadsheet
North Bank Tunnel	$1,000M (2009)	$1,044M	2009 Timaru Herald website: estimate cost to be $1 Billion
Rakaia River	$79M (estimated)	$79M (estimated)	Calculated in accordance with Section 5.2.13, using published information as referenced in GEM input data spreadsheet
Arnold (Dobson)	$190M (2011)	$190M	2011 TrustPower website estimate costs to be $180M - $200M
Mokihinui	$300M (2010)	$306M	2010 The National Business Review Website estimate costs to be $300M
Stockton Mine	$130M (2010)	$133M	2010 TVNZ Website Business news article (9/2/2010)
Stockton Plateau	$200M (2010)	$204M	2010 TVNZ Website Business news article (9/2/2010)
Hawea Control Gates	$30M (2004)	$40M	2004 Contact Energy Website estimate costs to be $30M

The capital costs shown in Table 4-18 represent the portion of total project capital costs which is typically denominated in NZD currency. The portion of total project capitals costs (in $/kW) which is denominated in a foreign currency has been deducted. This foreign currency component is covered in the following report section 4.2.14.

4.2.14 Capital cost foreign component

Typically the main foreign currency cost component of large hydro plants are the electrical and mechanical (E&M) powerhouse equipment. Other major costs, such as the civil construction, engineering, project management and environmental mitigation are typically sourced locally, in New Zealand dollars. Based on PB's experience, the most probable region/country to provide the majority of the E&M equipment would be Europe and hence the foreign currency is mostly likely to be the Euro (€).

An estimate of the foreign currency component of the project has been requested from the generators, but where this has not been provided, it has been based on the following technique.

The article *'Estimating E&M powerhouse costs, Cesar Adolfo Alvarado-Ancieta, Water Power and Dam Construction, February 2009'* provides the following equation to estimate the cost of the E&M equipment, based on 81 hydro projects in 32 countries.

E&M Cost = 1.1948 x (Installed Capacity in MW)$^{0.7634}$: In Million $USD, 12/2008.

The calculated costs have been converted[67] to New Zealand dollars and escalated to 2011 costs, based on the Statistics New Zealand Plant, Machinery and Equipment, Capital Goods Price Index.

This report for estimating E&M costs specifies that the costs are for powerhouses only and include the '*turbines, governors, valves, cooling and drainage water systems, cranes, workshops, generators, transformers, earthing systems, control equipment, telecommunication systems (including remote central control room) and auxiliary systems (including draft tube gates, heating and ventilation, domestic water and installation).'*.

As a small proportion of the E&M equipment may be provide locally, based on PB's experience, it has been assumed that 90% of the calculated E&M cost have been used as the foreign currency component of the proposed hydro plant capital cost. The proportion of the E&M cost that is in foreign currency can vary significantly depending on how much of the design and construction work is sourced locally.

4.2.15 Dominant foreign currency

As discussed above, the most probable region/country to provide the majority of the E&M equipment would be Europe and hence the majority of the foreign currency is mostly likely to be the Euro (€). However, the dominant foreign currency will depend on where the E&M equipment is sourced from and the equipment may also be sourced from other regions around the world, such as North America or Asia.

4.2.16 Lines connection cost

The line connection costs to connect the proposed hydro power plants to the national grid include both the substation costs and the transmission line costs.

The substation size and associated costs are dependent on many factors, such as the number of bays and ratings of the transformers. For an accurate substation cost, the project specific

[67] *Using an exchange rate of 1 NZD = 0.66 USD, and 1 NZD = 0.47 EUR*

substation design should be considered. Similarly, the transmission line voltage and associated transmission line costs should also be considered on a case by case basis as they are very site / project specific and depend on many factors, such as the distance to the grid, terrain, amount of redundancy required and the voltage and capacity of grid at the connection point.

The transmission line connection cost for each proposed project has been requested from the generators. Where this has not been provided, an estimated connection cost has been determined using the following technique.

4.2.16.1 Estimation of transmission line costs

The report *'Optimised Deprival Valuation of Transpower's Fixed Assets, 30 June 2006'* provides estimated costs per kilometre for transmission lines. The transmission costs in the report have a wide range of costs, depending on the type of tower, number of circuits, line capacity and the terrain.

The following Table 4-22 provides approximate upper and lower transmission line cost estimates, which have been escalated from the 2006 costs provided in Transpower's report, using the civil construction CGPI. Also included in the table is the median cost for each transmission voltage, which has been used as an arbitrary typical valve for estimating transmission costs when other information is not available to better estimate the costs.

Table 4-22 Estimated transmission line costs

Substation assumptions			
Transmission Voltage	**Estimated Minimum Cost (NZD per km)**	**Estimated Median Cost (NZD per km)**	**Estimated Maximum Cost (NZD per km)**
33	$44,000 Single Conductor Pole, Flat Terrain	$70,000 Hill Terrain	$108,000 Double Conductor Pole, Mountainous Terrain
66	$49,000 Single Conductor Pole, Flat Terrain	$107,000 Hill Terrain	$464,000 Double Conductor Steel Tower, High Capacity, Mountainous Terrain
110	$61,000 Single Conductor Pole, Flat Terrain	$164,000 Hill Terrain	$473,000 Double Conductor Steel Tower, High Capacity, Mountainous Terrain
220	$158,000 Single Conductor Steel Tower, Flat Terrain	$272,000 Hill Terrain	$528,000 Double Conductor Steel Tower, High Capacity, Mountainous Terrain

Please note that these cost ranges are estimates only and other factors, such as land access or river crossings, may further increase these costs.

4.2.16.2 Estimation of substation costs

The report *'Optimised Deprival Valuation of Transpower's Fixed Assets, 30 June 2006'* provides a table outlining the site establishment costs for various substation size categories. Table 4-23 is an extract from this report showing the different size categories

Table 4-23 Transpower's substation size categories

Major	accommodating on average 14x220kV, 19x110kV, 15x33kV bays, roadways, buildings (60000 sq m)	3,184.75	3	Y
Medium	accommodating on average 6x220kV, 6x110kV, 15x33kV bays, roadways, buildings etc. (26,000 sq m)	1,203.07	25	Y
Small	15x33kV bays, roadways and buildings (10,000 sq m)	1,072.82	41	Y

The report also provides Transpower's proposed 'building blocks' to establish sub-station replacement costs. This information is used to establish the estimated substation costs, using the information assumed in Table 4-24 and the following technique.

Table 4-24 Assumptions for estimated substation costs

Substation Assumptions						
Hydro plant output	**Substation size**	**Assumed transmission voltage**	**Number of generators**	**Generator voltage**	**Number of substation bays**	**Number of busbars**
10MW – 100MW	Small	110 kV	2	11 kV	4	Single
100MW – 300MW	Medium	220 kV	3	11 kV	5	Dual
> 300MW	Medium	220 kV	4	11 kV	6	Dual

The 220 kV and 110 kV transformer costs were estimated by using the range of costs in Transpower's report and establishing a linear relationship between the transformer MVA and costs. The power station generators were assumed to be approximately 85% of the rating of the transformers to allow for varying power factors and a spare capacity margin.

The transformers and switch gear costs were escalated using the Plant Machinery and Equipment CGPI, with the remainder of the sub-station costs escalated using the Civil Construction CGPI.

The following Table 4-25 provides estimates for determining approximate sub-station costs for the hydro power plants.

Table 4-25 Substation cost estimates

Generic hydro categories – substation cost estimates		
Unit Output	**Substation Costs (exc. Transformer) $1,000's NZD**	**Transformer Costs (per unit) $1,000's NZD**
10MW – 100MW	$3,530	Cost = 15.90 * (MW) + 619
100MW – 300MW	$5,585	Cost = 20.28 * (MW) + 921
> 300MW	$6,015	Cost = 20.28 * (MW) + 921

As with the estimated transmission line costs, the substation costs can vary significantly depending on many project specific factors, such as the number of substation bays, number of generating units or whether the substation is indoor, outdoor or underground. Transpower's report provides the various building blocks to estimate the sub-station costs and is available at http://www.transpower.co.nz/odv-2006. The appendix from this report should be referenced to provide an estimated range of costs for each part of the sub-station, with the site establishment and building costs approximately escalated to 2011 costs using the 2011: 2006 Civil CGPI (with an approximate ratio of 1.19), and the electrical switchgear and transformers escalated to 2011 costs using the 2011: 2006 Plant, Machinery and Equipment CGPI (with an approximate ratio of 1.07).

4.3 Wind

4.3.1 Summary

Table 4-26 summarises the PB recommendations for proposed NZ wind plant technical and cost data for use in the GEM.

Table 4-26 PB recommendations: Proposed NZ wind plant data

Project name	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Variable O&M costs	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
		Years	*MW*	*%*	*%*	*%*	*y/n*	*$/MWh*	*$/kW/year*	*NZD/kW*	*EUR/kW*	*Currency*	*$m*
Awhitu	SWN	25	18	92	43	16.7	N	3	70	910	1,370	EUR	3.2
Titiokura	ROX	25	48	92	43	6.3	N	3	70	910	1,370	EUR	8.4
Taumatatotara	HTI	25	54	92	43	5.6	N	3	60	910	1,370	EUR	9.5
Taharoa	HTI	25	54	92	48	5.6	N	3	60	910	1,370	EUR	9.5
Long Gully	CPK	25	12.5	92	43	4.0	N	3	70	2,975	280	EUR	2.2
Mill Creek	WIL	25	67	92	48	4.5	N	3	60	910	1,370	EUR	11.7
Mt Cass	WPR	25	69	92	39	4.3	N	3	60	910	1,370	EUR	12.1
Hurunui	WPR	25	78	92	39	3.8	N	3	60	910	1,370	EUR	13.7
Project Central Wind	MAT	25	120	92	43	2.5	N	3	60	780	1,180	EUR	14.4
Waitahora	DVK	25	156	92	43	1.9	N	3	50	780	1,180	EUR	18.7
Mahinerangi Stage 2	NMA	25	164	92	39	1.8	N	3	50	780	1,180	EUR	19.7
Turitea	LTN	25	183	92	48	1.6	N	3	50	780	1,180	EUR	22.0
Puketoi	BPE	25	159	92	43	1.9	N	3	50	780	1,180	EUR	19.1
Hawkes Bay	FHL	25	225	92	43	1.3	N	3	50	780	1,180	EUR	27.0
Kaiwera Downs	NMA	25	240	92	39	1.3	N	3	50	780	1,180	EUR	28.8
Project Hayes	ROX	25	630	92	43	0.5	N	3	50	728	1,100	EUR	52.9
Hauauru ma raki	HLY	25	504	92	48	0.6	N	3	50	728	1,100	EUR	42.3
Castle Hill	MST	25	600	92	43	0.5	N	3	50	728	1,100	EUR	50.4

4.3.2 Plant

The list of proposed NZ wind plant was sourced from the EA reference table[68] of projects currently under construction, consented or applied for consent, updated as at September 2011.

Table 4-27 Proposed 10 – 100 MW wind farms

10 – 100MW		
Wind farm	**Developer / Owner**	**Capacity [>MW]**
Awhitu	Awhitu Windfarms Ltd	18
Titiokura	Unison/Roaring 40s	48
Taumatatotara	Ventus Energy	54
Taharoa	Taharoa C and PowerCoast	54
Long Gully	Windflow Technology Ltd	12.5
Mill Creek	Meridian Energy	67
Mt Cass	MainPower	69
Hurunui	Meridian Energy	78

Table 4-28 Proposed 101 – 200 MW wind farms

101 – 200MW		
Wind farm	**Developer / Owner**	**Capacity [MW]**
Project Central Wind	Meridian Energy	120
Waitahora	Contact Energy	156
Mahinerangi Stage 2	TrustPower	164
Turitea	Mighty River Power	183
Puketoi	Mighty River Power	159

Table 4-29 Proposed 201 – 300 MW wind farms

201 – 300MW		
Wind farm	**Developer / Owner**	**Capacity [MW]**
Hawkes Bay	Meridian Energy	225
Kaiwera Downs	TrustPower	240

Table 4-30 Proposed >301 MW wind farms

> 301MW		
Name of wind farm	**Developer / Owner**	**Capacity [MW]**
Project Hayes	Meridian Energy	630
Hauauru ma raki	Contact Energy	504
Castle Hill	Genesis Energy	858

The same methodology used to estimate the GEM technical and cost specifications of the existing NZ wind farms (covered in Section 3.3) has been used to provide the data points for

[68] Source: http://www.ea.govt.nz/industry/modelling/long-term-generation-development/list-of-generation-projects/

the proposed plant. Where a different methodology has been applied, this has been explained.

4.3.3 Substation

The connection point for the proposed wind farms has been estimated based on the proposed location of the plant and closest transmission substation.

4.3.4 Project lifetime

Average project lifetime for a NZ wind farm is estimated as 25 years. This is explained in more detail in Section 3.3.5.

4.3.5 Operational capacity

The operational capacity of proposed projects has been verified using publicly available information, primarily generator websites and media releases.

4.3.6 Availability Factor

Average lifetime availability factor for proposed future wind farms is estimated at 92%, as included in Section 3.3.7.

4.3.7 Net Output Factor

Each proposed wind farm has been classified by PB as being located in either the North Island, South Island or a specific high wind area (such as the Tararua ranges), and attributed the relevant NOF as calculated in Section 3.3.8.

4.3.8 Unit largest proportion

PB has calculated this by dividing the operational capacity (MW) of a single wind turbine unit by the total operational capacity (MW) of the wind farm e.g. for a wind farm consisting of twenty 2 MW turbines the ULP is 2 MW divided by 40 MW or 5%.

4.3.9 Baseload

Wind farms are currently unable to provide baseload generation. Research is being undertaken as to how the energy produced outside of peak demands can be stored to enable a baseload. Storage methods such as; underground cave pressurisation, hydrogen cells, and water pumping have been researched. PB suggests that the GEM does not consider wind to provide baseload generation until a robust and proven system is introduced in the future.

4.3.10 O&M costs

PB has used the same methodology as used for estimating the variable and fixed O&M costs for the existing wind farms, covered in Section 3.3.11.

4.3.11 Capital cost (NZD component)

The following sources of information have been used to generate the recommended capital costs (NZD and foreign currency denominated) of proposed NZ wind farms:

- Deloitte Report[69]
- Cost data supplied by Meridian[70] on their website
- Generator web pages for existing and future wind farms
- Newspaper announcements
- Extracts from the Bloomberg Clean Energy Finance dataset
- PB in-house wind farm cost data base

The capital costs below have largely been produced from a PB in-house cost data base for Australian, New Zealand, and international wind projects, but have also been compared with any commercially available records including from available generator web pages.

PB reviewed the high level capital cost drivers included in the Worley Parsons report[71] which are:

- Capital – the ability to obtain funds and the cost of those;
- Commodities – the influence of commodity prices on fabricated items;
- Social – the general acceptance of wind and affects on such projects;
- Remoteness – additional costs required if projects were more remote;
- Opportunity – the premium that could be extracted for wind energy;
- Carbon price – the affect that a carbon price would have on wind projects; and
- Grid – extra costs associated with grid constraints and penetration.

In consideration of the above cost drivers, New Zealand's geographical location with regard to global importation, remoteness and accessibility to the high class site positions within complex wind resource areas (ridge lines, coastal areas, etc.), typical road operational capacities (gradients, cambers, turning radius, width, low bridges, overhanging foliage, etc.) and low number of ports capable to receive the major capital components (blades, nacelle, towers, etc.), foreign exchange rates and other such influential parameters, PB is of the opinion costs will be slightly higher per kW in New Zealand than that of Europe and America where resources are more readily available.

PB's costing assumptions are based on all typical capitalised project components including; WTGs, BoP, project management, insurances, land costs, approval costs, Engineering Procurement and Commissioning (EPC) premium and development costs.

[69] *Economics of wind development in New Zealand prepared for the NZ Wind Energy Association. 2011. Deloitte.*
[70] *Meridian Energy Annual Report for year ending 30 June 2010*
[71] *AEMO Cost Data Forecast For the NEM – Review of Cost and Efficiency Curves, 31 January 2011*

PB referenced the median projected capital costs for three Meridian proposed wind farms (Mill Creek, Project Central Wind and Project Hayes) which were provided on the Generator's website. PB placed this data into a graph (refer to Figure 4.4) and compared them to our in-house modelling figures.

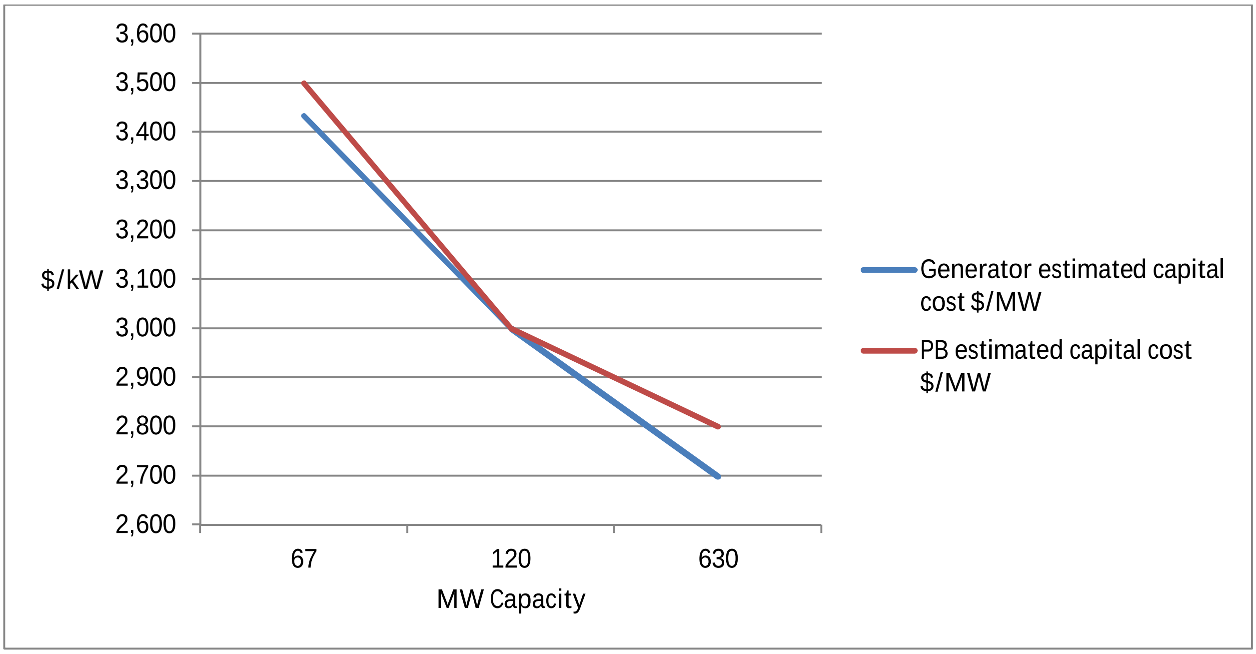


Figure 4.4 Wind farm capital cost curve comparison

The figures proposed were similar, although PB's model did appear to be more conservative than the Meridian's figures[72].

PB considers the following to be the major components of wind farm CAPEX:

- WTG supply, transportation and installation;
- Balance of plant (including civil, electrical installation, consultancy); and
- Grid/distribution connection.

[72] *Source: http://www.meridianenergy.co.nz/assets/Company/Annual-reports/2010/MeridianEnergyAnnualReportforyearending30June2010.pdf*

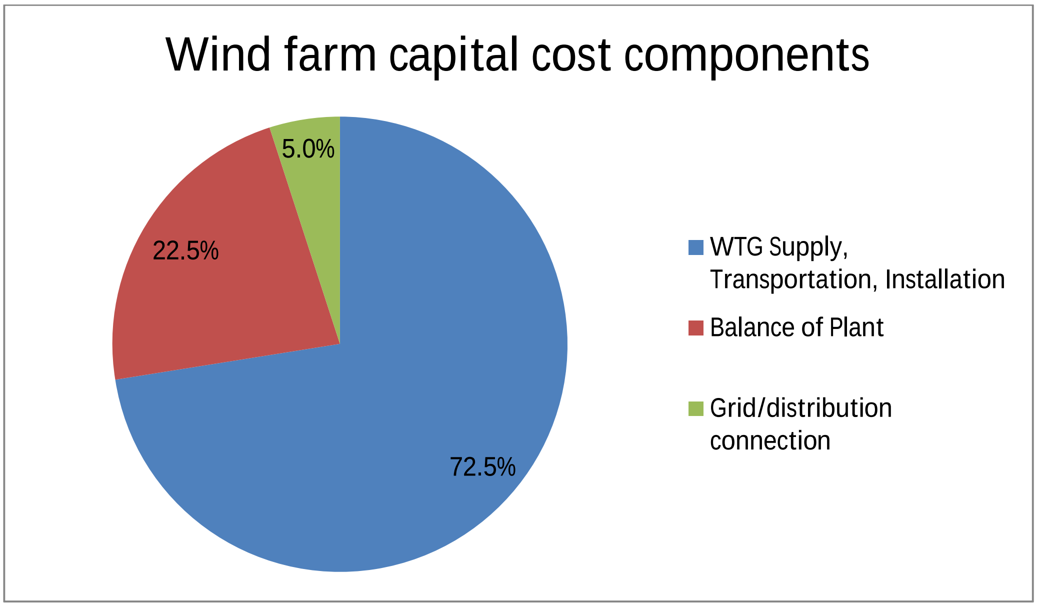


Figure 4.5 Wind farm capital cost components

PB has extracted this component breakdown from a recent report[73] on the projected costs of generating electricity by the IEA estimates an average project operational lifetime at 25 years for modelling wind plant and a report from EWEA[74] from March 2009. Costs were compared with typical PB In-house industry benchmarks.

Typically the WTGs are supplied from Europe which would mean that seventy four percent (74%) of the total Capex would be a foreign component, leaving twenty six percent (26%) a local (New Zealand) component. The NZD component of wind farm costs comprises grid connection, civil costs including foundations, consultancy, financial, control systems, roading, consenting and land costs.

PB is of the opinion, from in-house benchmarking data, that generally the capital costs should be higher for a small wind project than that of a larger project due to economies of scale and hence would expect the $/kW to decrease slightly with increased wind farm size (MW capacity and number of units). Given available reference data PB considers the following $/kW to be appropriate for MED modelling purposes:

Table 4-31 Proposed wind capital cost estimates

Wind farm capital cost estimates			
Category	**NZD component $/kW**	**Foreign currency component €/kW**	**Dominant foreign currency**
Small wind farm (10-100MW)	910	1,370	EUR
Medium wind farm (101 – 300MW)	780	1,180	EUR
Large wind farm (>300MW)	728	1,100	EUR

[73] *Projected Costs of Generating Electricity. 2010 edition. International Energy Agency*
[74] *The Economics of Wind Energy, European Wind Energy Association*

A review of other publicly available cost estimates for proposed NZ wind farms generally supported the above recommendations with the exception of a few data points. The review highlighted the variability in capital cost estimates which arises from project specific factors such as exchange rates, project timing and individual site characteristics.

A recent publication from Bloomberg Clean Energy Finance, reported the average price of wind turbine equipment orders from 28 major purchasers in Europe and America over the first half of 2011 at approximately €1,000/kW. This represented a 7% decrease from values observed in 2009. The index only includes the cost of turbines as well as transport to site which PB estimates represents around approximately 67.5% of the total wind farm cost. Conversion to an installed project cost in NZ dollars using a 1 NZD = 0.47 Euro exchange rate (from MED reference case) provides a value of $3,150/kW value.

PB would expect the WTG cost to decrease with development of the technology. WTGs are getting lighter due to advances in design such as thinner walled towers saving metal costs and lesser capacity transportation and heavy plant requirements. These cost reductions from technology advances are not expected to be material. PB considers any reductions in capital costs due to technology advances will probably be offset by increases in material prices (steel, etc.) and diesel costs (shipping). PB therefore does not recommend any changes in the real capital costs for the wind farms over the modelling period.

4.3.12 Dominant foreign currency

Currently the New Zealand market is dominated by European WTG suppliers due to the maturity and applicability of the technology. Approximately ninety percent of the market has been supplied from Denmark and Germany.

There are more commercial scale WTG suppliers tendering within the market such as; Gamesa - Spain, Suzlon - India, General Electric (GE) – German/American, and Goldwind – China.

PB recommends that the GEM use Euros as the dominant foreign currency.

4.3.13 Lines connection cost

PB has used the following percentages of total wind farm capital costs to derive the estimated lines connection costs for the proposed NZ wind farms:

- Small wind farm (10 – 100 MW) – 5% of total capital cost
- Medium wind farm (101 – 300 MW) – 4% of total capital cost
- Large wind farm (>301 MW) – 3% of total capital cost

4.4 Geothermal

4.4.1 Summary

Table 4-32 summarises the PB recommendations for proposed NZ geothermal plant technical and cost data for use in the GEM.

Table 4-32 PB recommendations: Proposed NZ geothermal plant data

Project name	Plant Technology	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
			Years	*MW (Gross)*	*%*	*%*	*%*	*y/n*	*$/kW/ year*	*NZD/kW (Gross)*	*US$/kW*	*Currency*	*$m*
Rotoma	ORC	KAW	40	35	95	97	100	Y	105	720	4,300	USD	3.25
Ngatamariki	ORC	OKI	40	83	95	97	25	Y	105	510	3,000	USD	12.0
Tauhara II	Conventional	WRK	40	250	95	97	33	Y	105	470	2,800	USD	6.25
Te Mihi	Conventional	WRK	40	170	95	97	50	Y	105	490	2,900	USD	4.75
Tikitere	ORC	ROT	40	45	95	97	100	Y	105	660	3,900	USD	3.25
Te Ahi o Maui	ORC	KAW	40	12.5	95	97	100	Y	105	660	3,900	USD	3.25
Tasman Mill upgrade	ORC	KAW	40	20	95	97	100	Y	105	660	3,900	USD	0

4.4.2 Plant

Proposed NZ geothermal plant included in this section of the Report are:

- Rotoma (East of Rotorua near Lake Rotoma)
- Ngatamariki (near Taupo)
- Tauhara II (at Taupo)
- Te Mihi (at Wairakei)
- Tikitere (near Rotorua, on the edge of Lake Rotoiti)
- Te Ahi o Maui (near Kawerau)
- Norske Skog Tasman Paper mill upgrade (near Kawerau)

4.4.3 Plant technology

Proposed plant technology:

- Rotoma: Organic Rankine Cycle
- Ngatamariki: Organic Rankine Cycle
- Tauhara II: Dual flash conventional condensing steam turbine
- Te Mihi: Dual flash conventional condensing steam turbine
- Tikitere: Organic Rankine Cycle
- Te Ahi O Maui: Organic Rankine Cycle
- Tasman Mill upgrade: Organic Rankine Cycle

The above proposed technologies have been verified by Web searches, News Paper articles and from Generator supplied information as follows:

- Rotoma: Press report - www.rotoruadailypost.co.nz/news/...geothermal...plant/1011685/
- Ngatamariki: Information provided by MRP.
- Tauhara II: Generator web site www.contactenergy.co.nz/web/ourprojects/tauhara-phase-two
- Te Mihi: Contact Supplied information.
- Tikitere: www.energybusinessnews.com.au/tag/tikitere-geothermal/
- Te Ahi O Maui: http://www.eastland.co.nz/eastland-group/group-news/te-ahi-o-maui-new-geothermal-development/

- Tasman Mill Upgrade: http://www.scandinavia.org.nz/Latest/norske-skog-plans-extra-20-mw-of-geothermal-at-tasman.html

4.4.4 Substation

Locations of the transforming substations for the future proposed geothermal plant:

- Rotoma – Connection to Kawerau substation (KAW)
- Ngatamariki – Connection to Ohaaki (OKI)
- Tauhara II – Connection at Wairakei (WRK)
- Te Mihi - Connection at Wairakei (WRK)
- Tikitere - Connection at Rotorua (ROT)
- Te Ahi O Maui – Connection at Kawerau (KAW)
- Tasman Mill upgrade – Connection at Kawerau (KAW).

4.4.5 Project lifetime

The economic life of geothermal power projects for project financing is generally taken as 25 years, although subject to resource limitations, the actual project operational life is often higher than this. For example, the Wairakei plant is now 50 years old and still operational.

For this reason, PB recommends a value of 40 years is appropriate as an average operational lifetime for proposed NZ geothermal projects for the purposes of the MED modelling.

4.4.6 Operational capacity

The gross plant capacities shown below have been derived from public information sources including newspaper articles and generator web pages.

The net plant capacities can be calculated from the following:

- Conventional steam geothermal plant: net capacity=gross installed capacity x 0.94
- Organic Rankine Cycle/Binary plant: net capacity=gross installed capacity x 0.92

So, for the future proposed plant:

- Rotoma: 35 MW
- Ngatamariki: 83 MW
- Tauhara II: 250 MW (3 x 83 MW)
- Te Mihi: 170 MW (2 x 85 MW)
- Tikitere: 45 MW

- Te Ahi O Maui: 12.5 MW (developer estimated range of 10 MW to 15 MW)
- Tasman Mill upgrade: 20 MW

4.4.7 Availability Factor

The AF for new geothermal plants over their operational life is generally taken as 95% for modelling purposes.

4.4.8 Net Output Factor

Assuming an AF of 95% and a capacity factor for new plant over their economic life of 92%, the NOF is calculated as 97% (92% divided by 95%). However, after initial operational issues common with new plant are resolved (usually within the first year or two), the capacity factor can be as high as 95% for a number of years and therefore, the Net Output Factor could be at or close to 100%, for the first 10 years of operation.

PB recommends an average Net Output Factor of 97% for all proposed geothermal plant over their life for modelling purposes.

4.4.9 Unit largest proportion

These proportions have been calculated based upon the disclosed plant size and configuration, such as is known for Tauhara and Te Mihi, generator information given by MRP for Ngatamariki but has been assumed for Rotoma, and Tikitere as little information is publically available for these two proposed projects.

- Rotoma largest size unit: Estimated 35 MW. Proportion: 100%
- Ngatamariki largest size unit: Estimated 20 MW. Proportion: 25%
- Tauhara II largest size unit: Estimated 82 MW. Proportion: 33%
- Te Mihi largest size unit: Estimated 85 MW. Proportion: 50%
- Tikitere largest size unit: Estimated 20 MW. Proportion: 44%
- Te Ahi O Maui largest size unit: Estimated 12.5 MW. Proportion: 100%
- Tasman Mill upgrade largest size unit: Estimated 20 MW. Proportion: 100%

4.4.10 Baseload

PB would expect all proposed geothermal plant to operate as baseload plant.

4.4.11 Fixed O&M costs

PB recommends using $105/kW/year, to estimate total O&M costs for proposed geothermal plant, as per Section 3.4.11.

4.4.12 Capital cost (NZD and foreign currency components)

The recommended capital costs of proposed NZ geothermal plant have been derived from the following sources;

- Generator web pages
- Newspaper announcements
- Extracts from the Bloomberg Clean Energy Finance dataset.
- PB in-house geothermal cost data base.

The capital costs below have largely been produced from a PB in-house cost data base for international geothermal projects, but have also been compared with any public records and from available generator web pages.

Table 4-33 Proposed geothermal plant capital cost estimates

Proposed geothermal plant capital cost estimates			
Category	**NZD component $/kW**	**Foreign currency component US$/kW**	**Dominant foreign currency**
Rotoma	720	4,300	USD
Ngatamariki	510	3,000	USD
Tauhara II	470	2,800	USD
Te Mihi	490	2,900	USD
Tikitere	660	3,900	USD
Te Ahi o Maui	660	3,900	USD
Tasman Mill upgrade	660	3,900	USD

Generally with new geothermal plant, the only portion which is denominated in NZD would be the construction, erection and installation of plant and associated commissioning. PB estimates this local component at between 7-10% of the total plant cost. The remaining 90-93% of the cost would be denominated in generally a mixture of USD and YEN.

Note that the above cost estimates include the wells and steam field in addition to the power plant, exploration costs and owner’s costs or financing costs including interest during construction (IDC). Estimates of these additional cost items have been calculated as follows:

- Exploration costs, allowing for scientific field surveys followed by a three well exploration drilling programme:
  - Exploration costs: NZ$19 million (applicable to Rotoma and Tikitere)
- Indirect costs: including management and administration, legal, and engineering
  - 10% of direct project capital costs (applicable to all the above projects)
- IDC costs: based upon 70% debt finance at an interest rate of 8%.
- No allowance has been made for permitting costs, insurance or land acquisition costs.

Please note that the cost estimates are considered to be at the ‘concept’ level and would involve an accuracy level of approximately +/- 30%.

4.4.13 Dominant foreign currency

The dominant foreign currencies applicable to the proposed NZ geothermal plant would be as follows:

- Rotoma = USD
- Ngatamariki = USD
- Tauhara II = JY, USD
- Te Mihi = JY, USD
- Tikitere = USD
- Te Ahi O Maui = USD
- Tasman Mill upgrade = USD

For the purposes of the MED modelling it is reasonable to assume all foreign costs are denominated in USD for the proposed geothermal plant.

4.4.14 Lines connection cost

The methodology outlined in Section 4.2.16 has been used to generate the following estimates:

- Rotoma = $3.25m
  - A 5 km equivalent transmission line connection to Kawerau substation is assumed at a cost of NZ$250,000/km plus fixed costs of $2 million, giving a total of NZ$3.25 million.
- Ngatamariki = $12m
  - Generator provided estimate.
- Tauhara II = $6.25m
  - A 5 km equivalent transmission line connection to Wairakei substation is assumed at a cost of NZ$250,000/km plus fixed costs of $5 million, giving a total of NZ$6.25 Million.
- Te Mihi = $4.75m
  - A 5 km equivalent transmission line connection to Wairakei is assumed at a cost of NZ$250,000/km plus fixed costs of $3.5 million, giving a total of NZ$4.75 Million.
- Tikitere = $3.25m

  - A 5 km equivalent transmission line connection to Rotorua substation is assumed at a cost of NZ$250,000/km plus fixed costs of $2 million, giving a total of NZ$3.25 million.

- Te Ahi O Maui = $3.25m

  - A 5 km equivalent transmission line connection to Kawerau substation is assumed at a cost of NZ$250,000/km plus fixed costs of $2 million, giving a total of NZ$3.25 million.

- Tasman Mill upgrade = $0m

  - Given the plant is already embedded in the paper mill, PB has assumed no transmission connection related capital expenditure is required.

4.5 Other proposed plant

4.5.1 Kaipara Harbour tidal project

The project proposes using up to 200 submerged tidal turbines in the Kaipara Harbour, Northland to generate an estimated capacity of around 200MW.

The project website estimates costs over the first ten years of the project at around $600,000,000, but it is not clear of the scope or breakdown of project capital and operating costs.

It is PB's opinion that the project is more likely to be staged in line with consent and commercial requirements. The initial stage would be around 20MW, with subsequent stages every two years increasing to 40MW, 80MW and 200MW. Unit sizes are estimated to be around 1MW, which is consistent with the scale of devices currently commercially available.

PB expects the availability of marine current turbines to be slightly lower than that of onshore wind turbines. This is primarily related to the relatively harsher ocean environment. An availability factor of 90% would be representative of the frequency and duration of scheduled and unscheduled outages associated with tidal turbines.

Average capacity factors for tidal schemes are between 25-35%, which when combined with the availability factor assumptions provides a net output factor range of between 27.5% and 37.4%. PB recommends a NOF value of 32.5% for the GEM input data.

5. Future generic plant data

This section provides technical specifications and cost estimates for a range of generic projects that may provide future generation post-2020 and out to 2050.

The data provided for each of the generic project types provides a means to forecast the concept level technical and cost parameters of plant to assist in the development of future new generation build scenarios for New Zealand.

The expanded lists of generic projects are based on the defined generic plant categories and are intended to be representative of future generation alternatives. The list is not a view or opinion of what will be built over the modelling period or what type of plant has a greater probability of being built.

The decision to build new generating plant depends on a wide range of complex technical and commercial factors, only some of which are considered in this report. It is also important to note that actual generation plant technical and cost parameters will vary widely and hence the estimates provided in this report are intended only as a concept level guide.

5.1 Thermal

5.1.1 Summary

Table 5-1 summarises the PB recommendations for future generic thermal plant technical and cost data.

Table 5-1 Future generic NZ thermal plant data

Project name	Plant technology	Energy type	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Heat rate	Variable O&M costs	Fixed O&M costs	Fuel delivery cost	Capital cost NZD component	Capital cost (foreign)	Dominant foreign currency	Lines conn. cost
Generic thermal project types				*Years*	*MW net*	*%*	*%*	*%*	*y/n*	*GJ/GWh*	*$/MWh*	*$/kW/y*	*$/GJ*	*NZD/kW*	*Currency /kW*	*Currency*	*NZD million*
CCGT	CCGT	Gas		35	475	93	85	100	Y	7,100	4.3	35.0	1	600	477	EUR	15
OCGT peaker	OCGT	Gas		30	200	87	10	50	N	10,500	8.0	16.0	1	385	472	USD	10
ASC without CCS (coal)	ASC	Coal		45	560	90	85	100	Y	8,560	5.4	38.9	0.1 to 0.67	2,042	120,269	YEN	15
ASC without CCS (lignite)	ASC	Lignite		45	540	90	85	100	Y	9,420	6.0	48.6	0	2,736	161,160	YEN	15
ASC with CCS	ASC + CCS	Coal		40	440	89	85	100	Y	11,830	18.5	65.1	0.1 to 0.67	3,448	203,116	YEN	15
IGCC without CCS	IGCC	Coal		35	720	88	85	100	Y	8,380	15.1	85.5	0.1 to 0.67	2,760	1,337	USD	15
IGCC with CCS	IGCC + CCS	Coal		30	570	87	85	100	Y	11,560	23.5	122.0	0.1 to 0.67	3,377	2,228	USD	15
Recip Bio	Recip	Biogas		20	10	90	75	50	Y	11,400	12.1	16.0	0	630	779	EUR	0.5
Recip Diesel	Recip	Diesel		20	10	90	10	50	N	8,700	12.1	16.0	3	612	942	USD	0.5
Cogen Coal	Steam Cogen	Coal		35	45	85	75	100	Y	3,600	5.0	38.0	0.1	2,475	1,337	USD	5
Cogen Lignite	Steam Cogen	Lignite		35	45	85	75	100	Y	3,600	5.0	38.0	0.1	2,600	1,400	USD	5
Cogen Bio	Steam Cogen	Bio-mass		35	45	85	75	100	Y	3,600	5.0	38.0	0	2,475	1,337	USD	5
CCGT Cogen	CCGT Cogen	Gas		35	40	90	75	100	Y	3,600	4.3	35.0	1	780	772	USD	5
Generic thermal project list																	
ASC w/o CCS 1	ASC	Coal	HLY	45	560	90	85	100	Y	8,560	5.4	38.9	0.67	2,042	120,269	YEN	15
ASC w/o CCS 2	ASC	Coal	MDN	45	560	90	85	100	Y	8,560	5.4	38.9	0.1	2,042	120,269	YEN	15
ASC w/o CCS 3	ASC	Coal	NPL	45	560	90	85	100	Y	8,560	5.4	38.9	0.1	2,042	120,269	YEN	15
ASC w/o CCS 4	ASC	Coal	ISL	45	560	90	85	100	Y	8,560	5.4	38.9	0.1	2,042	120,269	YEN	15

Project name	Plant technology	Energy type	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Heat rate	Variable O&M costs	Fixed O&M costs	Fuel delivery cost	Capital cost NZD component	Capital cost (foreign)	Dominant foreign currency	Lines conn. cost
ASC w/o CCS 5	ASC	Coal	TGA	45	560	90	85	100	Y	8,560	5.4	38.9	0.1	2,042	120,269	YEN	15
ASC w/o CCS 6	ASC	Coal	GOR	45	560	90	85	100	Y	8,560	5.4	38.9	0.1	2,042	120,269	YEN	15
ASC w/o CCS 7	ASC	Lignite	GOR	45	540	90	85	100	Y	9,420	6.0	48.6	0.0	2,736	161,160	YEN	15
ASC with CCS 1	ASC + CCS	Coal	HLY	40	440	89	85	100	Y	11,830	18.5	65.1	0.1	3,448	203,116	YEN	15
ASC with CCS 2	ASC + CCS	Coal	MNI	40	440	89	85	100	Y	11,830	18.5	65.1	0.1	3,448	203,116	YEN	15
CCGT Cogen 1	CCGT Cogen	Gas	HAM	35	40	90	50	100	Y	3,600	4.3	35	1	780	772	USD	5
CCGT Cogen 2	CCGT Cogen	Gas	MNI	35	40	90	50	100	Y	3,600	4.3	35	1	780	772	USD	5
CCGT Cogen 3	CCGT Cogen	Gas	SFD	35	40	90	50	100	Y	3,600	4.3	35	1	780	772	USD	5
CCGT Cogen 4	CCGT Cogen	Gas	MDN	35	40	90	50	100	Y	3,600	4.3	35	1	780	772	USD	5
CCGT Cogen 5	CCGT Cogen	Gas	MPE	35	40	90	50	100	Y	3,600	4.3	35	2	780	772	USD	5
CCGT 1	CCGT	Gas	NPL	35	475	93	85	100	Y	7,100	4.3	35	1	600	477	EUR	10
CCGT 2	CCGT	Gas	SFD	35	475	93	85	100	Y	7,100	4.3	35	1	600	477	EUR	10
CCGT 3	CCGT	Gas	MDN	35	475	93	85	100	Y	7,100	4.3	35	1	600	477	EUR	10
CCGT 4	CCGT	Gas	HLY	35	475	93	85	100	Y	7,100	4.3	35	1	600	477	EUR	10
Cogen sub-bit 1	Steam Cogen	Coal	HAM	35	45	85	75	100	Y	3,600	5	38	0.1	2,475	1,337	USD	5
Cogen sub-bit 2	Steam Cogen	Coal	GOR	35	45	85	75	100	Y	3,600	5	38	0.1	2,475	1,337	USD	5
Cogen lignite 1	Steam Cogen	Lignite	GOR	35	45	85	75	100	Y	3,600	5	38	0.1	2,600	1,400	USD	5
Cogen Bio 1	Steam Cogen	Biomass	ROT	35	45	85	75	100	Y	3,600	5	38	0	2,475	1,337	USD	5

Project name	Plant technology	Energy type	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Heat rate	Variable O&M costs	Fixed O&M costs	Fuel delivery cost	Capital cost NZD component	Capital cost (foreign)	Dominant foreign currency	Lines conn. cost
IGCC w/o CCS 1	IGCC	Coal	HLY	35	720	88	85	100	Y	8,380	15.1	85.5	0.67	2,760	1,337	USD	15
IGCC w/o CCS 2	IGCC	Coal	MDN	35	720	88	85	100	Y	8,380	15.1	85.5	0.1	2,760	1,337	USD	15
IGCC w/o CCS 3	IGCC	Coal	NPL	35	720	88	85	100	Y	8,380	15.1	85.5	0.1	2,760	1,337	USD	15
IGCC w/o CCS 4	IGCC	Coal	ISL	35	720	88	85	100	Y	8,380	15.1	85.5	0.1	2,760	1,337	USD	15
IGCC w/o CCS 5	IGCC	Coal	TGA	35	720	88	85	100	Y	8,380	15.1	85.5	0.1	2,760	1,337	USD	15
IGCC w/o CCS 6	IGCC	Coal	GOR	35	720	88	85	100	Y	8,380	15.1	85.5	0.1	2,760	1,337	USD	15
IGCC with CCS 1	IGCC + CCS	Coal	HLY	30	570	87	85	100	Y	11,560	23.5	122	0.1	3,377	2,228	USD	15
IGCC with CCS 2	IGCC + CCS	Coal	MNI	30	570	87	85	100	Y	11,560	23.5	122	0.1	3,377	2,228	USD	15
OCGT peaker 1	OCGT	Gas	NPL	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 2	OCGT	Gas	SFD	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 3	OCGT	Gas	OTA	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 4	OCGT	Gas	SWN	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 5	OCGT	Gas	MDN	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 6	OCGT	Gas	HLY	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 7	OCGT	Gas	PAK	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT peaker 8	OCGT	Gas	HAM	30	200	87	10	50	N	10,500	8	16	1	385	472	USD	10
OCGT (dsl) peaker 1	OCGT	Diesel	MDN	30	200	87	10	50	N	10,700	8	16	3	385	472	USD	10
OCGT (dsl) peaker 2	OCGT	Diesel	WHI	30	200	87	10	50	N	10,700	8	16	3	385	472	USD	10
OCGT (dsl) peaker 3	OCGT	Diesel	NPL	30	200	87	10	50	N	10,700	8	16	3	385	472	USD	10
OCGT (dsl) peaker 4	OCGT	Diesel	ISL	30	200	87	10	50	N	10,700	8	16	3	385	472	USD	10
Recip Bio 1	Recip	Biogas	SDN	20	10	90	75	50	Y	11,400	12.1	16	0	630	779	EUR	0.5
Recip Bio 2	Recip	Biogas	ISL	20	10	90	75	50	Y	11,400	12.1	16	0	630	779	EUR	0.5

Project name	Plant technology	Energy type	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Heat rate	Variable O&M costs	Fixed O&M costs	Fuel delivery cost	Capital cost NZD component	Capital cost (foreign)	Dominant foreign currency	Lines conn. cost
Recip Diesel 1	Recip	Diesel	SDN	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5
Recip Diesel 2	Recip	Diesel	HAM	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5
Recip Diesel 3	Recip	Diesel	WIL	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5
Recip Diesel 4	Recip	Diesel	NPL	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5
Recip Diesel 5	Recip	Diesel	TGA	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5
Recip Diesel 6	Recip	Diesel	HWB	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5
Recip Diesel 7	Recip	Diesel	ISL	20	10	90	10	50	N	8,700	12.1	16	3	612	942	USD	0.5

5.1.2 Generic plant technologies

This section identifies the generic thermal plant technologies that may provide future generation post 2020 and out to 2050, based on the following rationale.

'Thermal power generation plant' is the term that describes the technology used for converting the potential chemical energy in combustible materials (fuels) into electricity (primarily). In a cogeneration plant the fuel energy is converted into heat and electricity.

Therefore the consideration of future generic plant must be based firstly on consideration of available fuels. The potentially available fuels for power generation or cogeneration in the future, post 2020 are considered to be:

- Indigenous natural gas, assuming that there are new discoveries
- Indigenous coal seam gas, assuming that it can be recovered in economic quantities
- Underground coal gasification (UCG) synthetic gas (syngas), assuming that the process is proved for New Zealand coal resources
- Imported liquefied natural gas (LNG)
- Coal, including North Island sub-bituminous and South Island lignite resources
- Biomass, comprising both forestry industry waste and plantation grown fuel species
- Biogas, as landfill gas and biogas from sewage treatment, assuming population growth gives rise to growth in resources
- Petroleum liquid fuels, ranging from crude oil to automotive diesel and including heavy fuel oil (HFO).

Given those fuels, the following are considered the future generic plant technology options for New Zealand:

- Combined cycle gas turbine (CCGT), using indigenous natural gas, coal seam gas (CSG), UCG syngas, or LNG
- Open cycle gas turbine (OCGT) peaker, using indigenous natural gas, coal seam gas (CSG), UCG syngas, LNG, or petroleum liquid fuel
- Advanced supercritical coal-fired (ASC), with and/or without carbon capture and storage (CCS), using North or South island coal resources
- Integrated Gasification Combined Cycle (IGCC), with and/or without carbon capture and storage (CCS), using North or South island coal resources
- Reciprocating engines, using biofuels such as landfill gas and biogas from sewage treatment, in a base load or 'fuel following' (analogous to 'run-of-river' hydro generation) role
- Reciprocating engine peaker, using petroleum liquid fuels
- Sub-bituminous or lignite coal cogeneration

- Biomass cogeneration using forestry industry waste and/or plantation grown fuel species
- CCGT cogeneration using indigenous natural gas, coal seam gas (CSG), UCG syngas, or LNG

5.1.3 Location

5.1.3.1 Introduction

This section considers and identifies a potential location for one or more of each of the above technology options, based on fuel availability or proximity to fuel source, proximity to load or transmission connection point, and grid constraints. The output or deliverable of this section is a unique name for each generic plant option. In subsequent sections the generic plant options are identified by this name.

Hydro, geothermal and wind generators must be located where their "fuel" resource occurs. However, thermal generators can be located either where the fuel resource occurs or where the electricity is required. Unless the two (fuel resource and electricity requirement) coincide, a choice must be made between:

Locating the thermal generator at the fuel resource and transporting the electricity to where it is required. Of the proposed thermal generators covered in section 4.1, only the 100 MW Todd Peaker is likely to be in this category, although its exact location is unknown.

Locating the thermal generator where the electricity is required and transporting the fuel to the generator. All of the proposed thermal generators covered in section 4.1, with the possible exception of the 100 MW Todd Peaker, are likely to fall into this category.

Estimation of the likely location of future generic thermal generation therefore requires consideration of fuel resource location and electricity requirement (demand) location.

5.1.3.2 Electricity demand

New Zealand's major electricity demand centres are predominantly in the northern half of the North Island, with Auckland being the largest electricity load centre. New Zealand Aluminium Smelter's (NZAS) aluminium smelter at Tiwai Point and Christchurch are the major exceptions.

Figure 5.1 below shows the location of the major supply (generation sources) and demand (load) centres, together with the core national transmission system (national grid). This was taken from a presentation by Dr Patrick Strange, Chief Executive, Transpower New Zealand Ltd, titled Transmission Challenges, to the Australasian Universities Power Engineering Conference (AUPEC) 2010, on 6 December 2010. Dr Strange included with this illustration, the comment that, "*Auckland will continue to use more electricity than can be supplied locally*."

In an another presentation, to the New Zealand Council for Infrastructure Development (NZCID) on 12 August 2010, Dr Strange included the diagram and data shown in Figure 5.2 below. It is understood that this shows the forecast energy transfers between eight country zones. Energy transfers are consistently northwards, toward Auckland, and from sometime after 2020 even northern-most energy generation flows back towards Auckland.

Thus unless future generic generators are associated with specific loads at particular locations (as are all cogeneration generators), they will all be contributing to the load centres in northern part of the North Island and predominantly to Auckland (that is, the Auckland region).

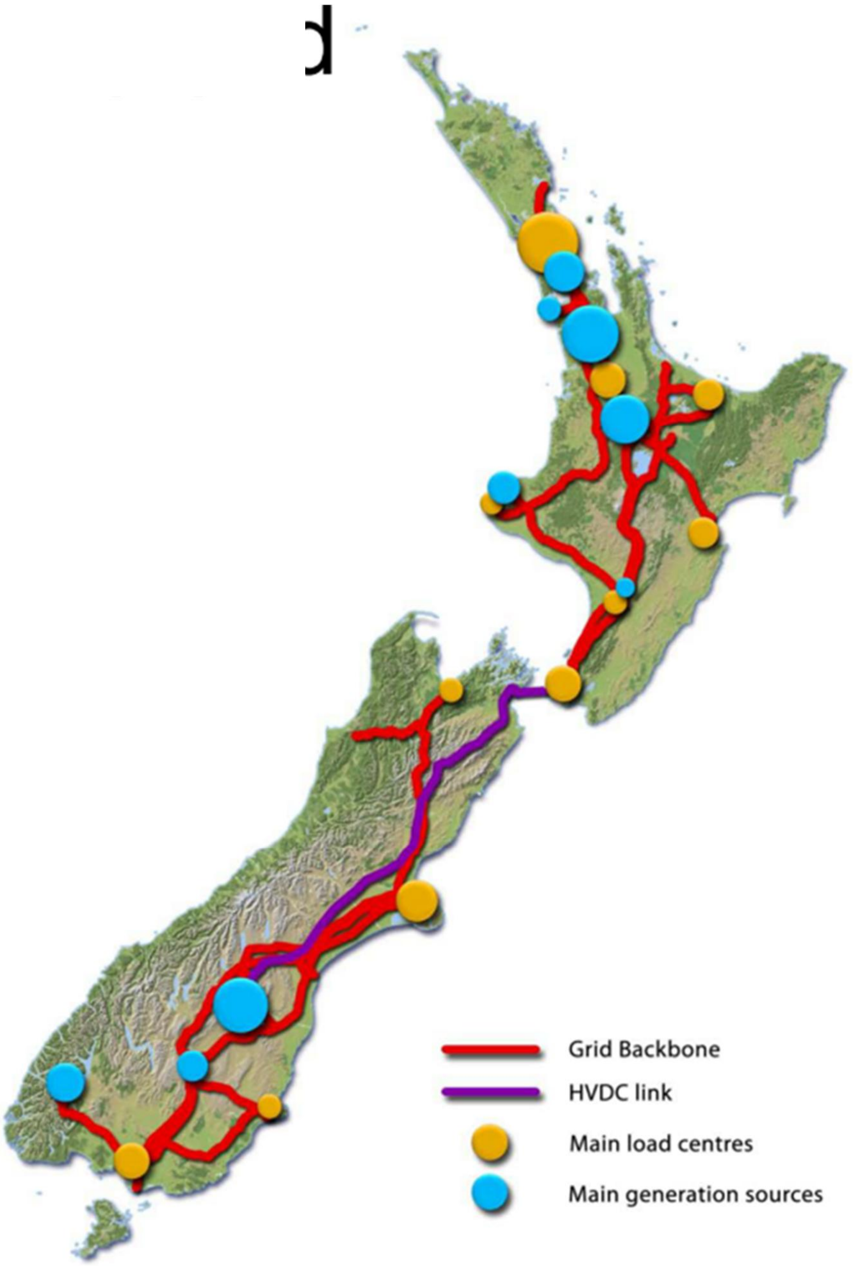
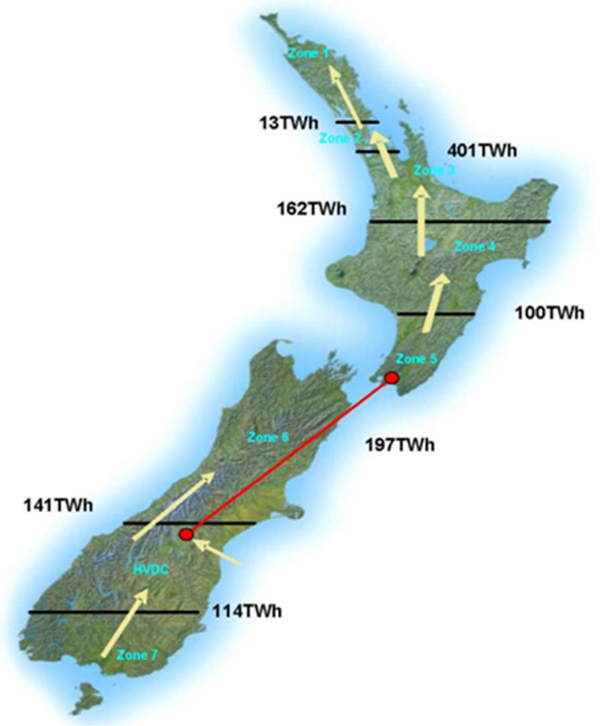


Figure 5.1 Major supply and demand and core national grid[75]

Therefore if proximity to the electricity demand (load) centre was the only location criteria, all future generic thermal generators would likely be located within the vicinity of Auckland. This is estimated to be a major part of the rationale for the location of the planned generator Rodney at Helensville.

[75] *Dr Patrick Strange, Chief Executive, Transpower New Zealand Ltd, Transmission Challenges, presented to Australasian Universities Power Engineering Conference (AUPEC) 2010, 6 December 2010, downloaded from* *http://www.transpower.co.nz/presentations*



Zone x to y (TWh)	2011	2020	2030	2040
2 to 1	1.4	0.4	-0.3	-0.3
3 to 2	9.0	12.0	14.0	17.0
4 to 3	3.0	5.0	6.0	8.0
5 to 4	1.0	2.4	4.0	6.0
HVDC to 6	5.0	5.4	4.3	4.0
HVDC to NI	4.0	5.6	7.4	9.0
7 to HVDC	1.2	3.5	4.4	5.5

Figure 5.2 Forecast total energy transfers[76]

The existence of the national grid however, enables generators to be located distant from the centres of demand. The New Zealand electricity system is in fact characterised by having major demand centres predominantly in the northern part of the North Island, while there is major hydro generation centred in the southern part of the South Island.

The high-voltage, long distance transmission system (grid) therefore forms a vital "backbone" to the electricity system, enabling generators to be located according to other criteria (proximity to fuel). If proximity to demand or load centre is a first order location criteria, then proximity to a transmission line or substation would be a close second order location criteria.

5.1.3.3 Natural gas resource location

New Zealand's natural gas resource remains confined to the North Island and to the Taranaki region, and presently producing reserves are running down. However, New Zealand is also considered to be under explored and to have considerable prospectivity, such that it is also considered simply a matter of time before commercial discoveries are made outside of Taranaki.[77]

[76] *Dr Patrick Strange, Chief Executive, Transpower New Zealand Ltd, Investing in the grid – beyond the catch up, presented to New Zealand Council for Infrastructure Development (NZCID), 12 August 2010, downloaded from http://www.transpower.co.nz/presentations*

[77] *Venture Taranaki, The Wealth Beneath Our Feet, The Value of the Oil and Gas Industry to New Zealand and the Taranaki Region, a fresh perspective on the industry and its economic impact, December 2010, downloaded from http://www.pepanz.org/publications.cfm#PT8*

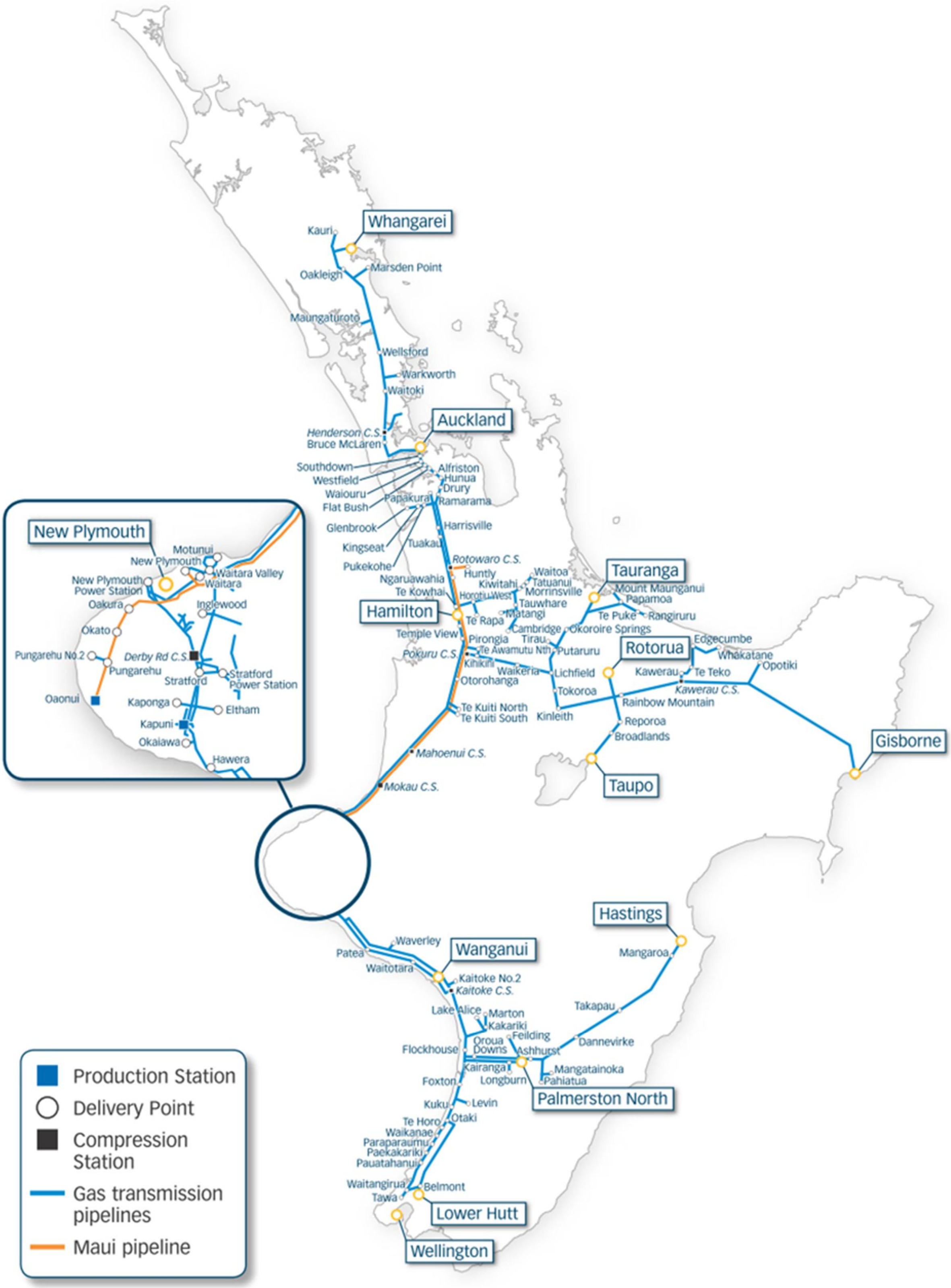


Figure 5.3 Natural gas transmission pipeline map[78]

[78] Downloaded from http://www.gasnet.co.nz/assets/About-Us/transmission-pipeline-map.pdf

New Plymouth (decommissioned) and existing thermal generators, Taranaki CC, Stratford, and Mangahewa, and cogenerators Kapuni and Hawera are all located in Taranaki, close to their fuel gas resources.

Natural gas is also reticulated widely in North Island, from Wellington in the south to Kauri and Whangarei in the north, and to Napier and Gisborne in the east, as shown in Figure 5.3. This has effectively dispersed the natural gas fuel resource to all the main centres in the North Island.

As a result, existing thermal generators Huntly units 1 – 6, Otahuhu B and Southdown, and cogenerators Southdown, Te Rapa and Edgecumbe, are also located close to their fuel resources. Proposed thermal generators Otahuhu C and Rodney are similarly located close to their natural gas fuel resource, and to a substation or transmission line, and also to the major load centre, Auckland.

However, gas supply north of Rotowaro, from what is called Vector's North Pipeline is apparently capacity constrained (at or near its capacity limit). The Gas Industry Company Limited has reported that, "*in an industry presentation in September 2009 (01 Capacity Presentation (Hugh Driver–Sept 2009)), Vector concluded: '[a]t peak demand times Rotowaro North is operating at the margins of system capability, and reinforcement is required to provide additional physical capacity*'."[79]

There has been discussion over whether the constraint is physical or commercial but it appears Vector's North Pipeline does not presently have the capacity to supply Otahuhu C and Rodney at the same time as existing customers. An industry presentation by Vector in 2009 apparently set out three main options: pipeline looping ($80 - 200 million), additional compression ($20 - 30 million), or a combination of the two.

For the purposes of this report, it will be assumed that both natural gas reserves and natural gas transmission are unconstrained.

5.1.3.4 Coal seam gas resource location

A number of parties have explored New Zealand coal fields for coal seam gas (CSG) potential. In 2003 it was reported that, "*Assessment of New Zealand's CSG resource started in the 1980's. However, to date it has not progressed beyond the assessment phase. The recent changes in the New Zealand energy scene have prompted renewed interest and activity in the area of CSG exploration. At the current time, New Zealand does not have a commercially producing CSG project although significant progress has been made over the last few years by a number of individuals and groups in assessing the nature and size of the potential resource*."

"*Over the past couple of years Kenham Holdings Ltd and CRL Energy Ltd have approached the assessment of the coal seam gas potential in a staged programme. Preliminary assessment of the data on the permit areas indicates that the potential resource may be up to 500PJ. To date, preliminary appraisals have been completed or are underway on a significant number of fields. Exploratory drilling has been completed or initiated on several of those fields,*

[79] *Gas Industry Company Limited, Retail Competition and Transmission Capacity Statement of Proposal Submissions Analysis and Next Steps, April 2011, downloaded from* *http://gasindustry.co.nz/sites/default/files/u180/retail_competition_and_transmission_capacity_sop_submissions_analysis_final_155240.9_1.pdf*

with results from this work being fed into the preliminary modelling as it has become available."[80]

Solid Energy appears to be at the forefront of CSG activity today and its web site records that, "*Solid Energy is successfully continuing CSG exploration and resource proving in our Huntly field in the Waikato, and the Tahora-Tangarakau area in Taranaki. Exploration is most advanced in the Waikato, where test wells have yielded high quality gas containing 98% methane and just 1% CO2. Exploration is continuing across all these sites*." [81]

Solid Energy's Quarterly Report to 30 June 2011 noted that, "*Construction of the Huntly pre-commercial wells and infrastructure is complete. Initial gas production from these appraisal wells will commence over the next few months to confirm gas profiles, but will also power an onsite 1MW generator injecting electricity into the local network. Our Taranaki exploration drilling programme is nearing completion*."[82]

Comet Ridge Limited announced in March 2011 that it had commenced "New Zealand's first extensive airborne survey for CSG." The company has exploration permits in the Waikato and West Coast of the South Island and when the survey data is interpreted it would then "*prioritise drilling targets based on the best combination of gas resource potential and proximity to infrastructure and markets. Drilling is currently planned to commence before the end of the 2011 calendar year*."[83]

5.1.3.5 UCG syngas resource location

Solid Energy is understood to be the only party in New Zealand pursuing underground coal gasification (UCG). Solid Energy's web site advises that, "*Solid Energy is developing a small pilot project in Huntly, just north of Hamilton, to trial UCG technology in local conditions*."

"*The pilot project will trial UCG technology in local conditions and is expected to gasify about 35 to 50 tonnes of coal per day to produce syngas over a period of about 18 months before shutdown. We will monitor how UCG affects the environment throughout the project, while measuring gas quality and quantity, in adherence with all resource consent conditions. Information gathered from the pilot project will help Solid Energy make a decision on whether to proceed to the next stage of a small commercial operation*."[84]

5.1.3.6 LNG resource location

In October 2003, Contact Energy Ltd and Genesis Power Limited, New Zealand's two largest gas users, formed an alliance to explore the logistical and market implications of importing Liquefied Natural Gas (LNG) to New Zealand. By 2006 Port Taranaki had been identified as the preferred site for an LNG import terminal. In 2009 Contact and Genesis decided to put on hold the development of the land based LNG terminal and an offshore terminal was proposed. It is understood that the project remains on hold.

[80] *D.A. Manhire and S. Hayton, Coal Seam Gas in New Zealand: Perspective from New Zealand's most active CSG explorers, 2003, downloaded from L&M Mining web site*
[81] *http://www.coalnz.com/index.cfm/1,255,0,0,html/Coal-Seam-Gas*
[82] *Solid Energy, Quarterly Report to 30 June 2011*
[83] *Comet Ridge Limited, ASX Announcement, Pioneering NZ aerial survey for Coal Seam Gas starts new phase, 17 March 2011*
[84] *http://huntlyucg.co.nz/the-huntly-ucg-pilot-project.html*

5.1.3.7 Coal resource location

At the time Huntly Power Station was being constructed (1977 – 1985) a second coal-fired power plant was planned for the Waikato coal resources. MED Coal Report CR141, Waikato Coal-fired Power Station, Preliminary Evaluation of Coal Supply, June 1981 noted the following:

- "*In June 1980 Mines Division* (now Solid Energy) *was asked by NZE* (New Zealand Electricity Division of the Ministry of Energy) *to investigate the supply of coal for a second 1000 MW Coal-fired Power Station to be sited in the Waikato Region*."
- "*The new station was to be built in two 500 MW stages one of which would be commissioned in 1992/93. This date has since been put back to 1993/94. The second 500 MW is due in 2000/01*."
- "*The proposed source of supply for the power station is Huntly West sector and Ohinewai*."
- "*Detailed investigation should commence on Ohinewai opencast as soon as possible because this mine will supply both Huntly and Waikato Thermal Power Station*."
- "*If the power station siting decision is delayed the potential exists for it to be supplied from Mokau coalfield*.'
- "*Some coal will be transported within the region because no single coalfield can meet the supply requirements*."

It is understood that the Huntly West sector supply option became impractical following experience with the Huntly West Mine. The option for such a coal-fired power station remained at least until the electricity industry was restructured in 1997. At that time land was still held for the station south of Meremere at Hampton Downs. It is understood that this land is now occupied, at least in part by the Hampton Downs landfill.

A further coal source considered for the station at that time was the Maramarua/Kopako coalfield, and a transport corridor was being preserved from Maramarua/Kopako to Hampton Downs.

Other coal resources that have been considered in the past for potential coal-fired thermal power generation are the South Island West Coast and Southland (lignite) resources.

With respect to the South Island lignite resources, PB is not aware of any interest in these for power generation at this time. There is interest in exploiting South Island lignite resources for other purposes, but so far not for power generation, e.g. Solid Energy's proposals for lignite conversion to briquettes, fertilizer, and transport fuels. There are a number of barriers to the development of New Zealand lignite resources for power generation:

- Lignite comprises 40 – 45% moisture and it is not economic to transport large quantities of moisture over long distances. For this reason, lignite-fired power plants are always mine-mouth power plants, located adjacent to or within reasonable belt conveyor transport distance from the lignite resource.
- Lignite conversion to electricity has a low conversion efficiency (high heat rate) because of the high natural moisture level of lignite.

- As a result of the above it also has the highest specific CO_2 emission rate.
- NZ lignite resources are located in the south of the South Island while the demand for electricity is predominantly in the north of the North Island, resulting in particularly long transmission distances.
- As a result of the above, significant generation in the South Island will likely require increased capacity of the DC link.

If there is public resistance to the development of coal-fired power plant, as demonstrated with Mighty River Power's Marsden B proposal, then there is likely to be more so in the case of lignite fired power generation proposals.

PB has therefore not proposed large lignite-fired power generation options in the South Island, but has allowed for the future development of a 45 MW lignite-fired boiler and steam turbine cogeneration plant in the vicinity of Gore, designated "Cogen lignite 1" in Table 5-1.

5.1.3.8 Biomass fuel resource

Biomass fuel resources are presently located within the large areas of plantation forestry in New Zealand, and at the ports and processing plants handling plantation forestry resources.

5.1.3.9 Biogas fuel resource

Biogas fuel resources based on landfills and sewage treatment plants will be located near large population centres.

5.1.3.10 Petroleum liquid fuel resources

Petroleum liquid fuels are generally transportable, or otherwise located in oil company depots at the main New Zealand ports, including Marsden Point (refinery and port).

5.1.3.11 CCGT

PB considers the pre-eminent site for the next (after the proposed Otahuhu C, Rodney and CCGT 1) large scale (i.e. similar to Taranaki CC, Otahuhu B and Huntly Unit 5 (e3p)) CCGT to be the site of the now decommissioned New Plymouth Power Station. This is because the site is already connected to both natural gas supplies and the electricity transmission system.

Such a plant could be fuelled by either natural gas in the event of new discoveries, or by imported LNG as previously proposed by Contact and Genesis.

The Transpower standard site abbreviation for New Plymouth power station and substation is NPL[19].

Mighty River Power's site at Marsden, previously occupied by the Marsden A & B power stations, is also a similarly prospective site but gas supply north of Auckland is understood to be presently inadequate for large scale power generation. However, if that constraint was removed it would offer the same advantages as the New Plymouth site.

The Transpower standard site abbreviation for Marsden substation is MDN[19].

Given the potential future availability of the alternative fuel gases CSG and UCG syngas in the Waikato, PB proposes that a Waikato site also be considered. This could possibly be accommodated on the site of the existing Huntly Power Station as a 'brown field' development, or at some other location with ready access to both fuel and the electricity transmission system.

PB proposes the following location based names for three future generic CCGT generators:

- New Plymouth CC, connected at NPL
- Marsden CC, connected at MDN
- Waikato CC, connected at HLY (Huntly).

5.1.3.12 OCGT peaker

The present and planned OCGT peaker generators in New Zealand are fuelled with either natural gas or diesel (Huntly Unit 6 (P40) is dual fuelled and Whirinaki is diesel fuelled).

Diesel fuel is readily transported by road tanker and stored on site in tanks, although it cannot be stored indefinitely and must be ‘turned over’ on an annual basis or treated to prevent deterioration. This means that a diesel fuelled OCGT peaker could be located anywhere, ‘where most needed’ in the electricity transmission system.

Given the potential for gas supply constraints, having the option to use diesel seems prudent and Genesis has taken this approach with its Huntly Unit 6 (P40) OCGT peaker.

The sites nominated in section 5.1.3.11 above appear to be suitable sites for OCGT peakers, along with sites adjacent to major substations serving the main North Island load centres at Auckland, Hamilton, and Wellington.

PB proposes the following location based names for six future generic OCGT generators:

- New Plymouth OC, connected at NPL
- Marsden OC, connected at MDN
- Waikato OC, connected at HLY (Huntly)
- Auckland OC, connected at Pakuranga (PAK)
- Hamilton OC, connected at Hamilton (HAM)
- Wellington OC, connected at Wilton (WIL).

5.1.3.13 Carbon capture and storage (CCS)

Some comment on CCS is warranted because it is mentioned in the section(s) following and gives rise to further potential future thermal generation options, namely ‘with” and ‘without’ CCS. CCS is expected to have a significant impact on coal-fired power plant costs in the future. The following comments are taken from various references referred to elsewhere in this report, and the reader is referred to those references for more detailed information.

IEA/NEA recently noted that, “*There are three main technology options for CO_2 capture: post-combustion capture through capturing CO_2 from the flue gas, pre-combustion capture by separating the carbon from the fuel before burning it, and oxy-combustion under an oxygen atmosphere resulting in a flue gas stream mainly consisting of CO_2 for final storage*”

"*The basic technology for separating the CO_2 from the flue gas uses a chemical absorption process (with amine-based solvents such as MonoEthanolAmine* (MEA)*) and has been applied in industry on a commercial scale for decades. The challenge, however, is to recover the CO_2 from the solvent with a minimum energy penalty and at an acceptable cost*."

The IEA/NEA report concludes that, "*Successful demonstration and rapid deployment of CCS in the next 10 to 15 years is essential in order to contribute substantially to CO_2 emission reduction in the long-term. So far, no power plant with CO_2 capture operates on a commercial scale. Although many of the technology components involved in capturing and storing CO_2 have been applied for many years in large scale plants (e.g. coal gasification to produce chemicals, chemical absorption in the food industry), the integration of the different components needed to capture CO_2 in the power plant design has not been demonstrated on a commercial scale. Also, the integrity of the various methods to store CO_2 has to be verified; in addition legal and regulatory issues related to the transport and storage of CO_2 have to be addressed in many countries*."[85]

Worley Parsons has recently noted that, "*In addition to improved Rankine cycle efficiency by increasing steam temperature and pressure, it is also assumed that post-combustion CO_2 capture technology will improve significantly by 2030. The current MEA based amine system is expected to improve significantly over the next several years and there is likely to be a few step changes in lower cost and higher efficiency processes such as Chilled Ammonia CCS system. Advancement in CO_2 compressor technology, with inter-cooling systems, will also work towards reducing the overall \$/kW cost and reduce the auxiliary loads need to run the CCS plant*."[86]

EPRI (Electric Power Research Institute) and Worley Parsons have recently noted regarding the maturity of CO_2 removal technology that, "*The post-combustion CO_2 removal technology for the PC (pulverised coal), Oxy combustion and CCGT capture cases is based on mature component technology but has not been incorporated in the power industry. This technology is currently in the initial stages of commercial scale demonstration but remains unproven in power generation applications.*

The pre-combustion CO_2 removal technology for the IGCC capture cases has a stronger commercial experience base. Pre-combustion CO_2 removal from syngas streams has been proven in chemical processes with similar conditions to that in IGCC plants, but has not been demonstrated in IGCC applications. While no commercial IGCC plant yet uses CO_2 removal technology in commercial service, there are currently IGCC plants with CO_2 capture well along in the planning stages."[87]

Mott MacDonald has also recently noted that, "*We have assumed that all new plant orders from 2010 will be required to be designed to be capture-ready in accordance with the EU directive implemented in April 2009. Making plant capture ready means changing the plant layout, for instance include setting aside space for capture plant, and identification of outline routes for evacuating CO_2 as well as design changes in some items. It is unlikely that these modifications, except possibly securing extra land, would significantly increase capital costs, if factored in at the initial design stage*."

[85] *International Energy Agency (IEA), Nuclear Energy Agency (NEA) & Organisation for Economic Co-operatrion and Development (OECD), Projected Costs of Generating Electricity, 2010 Edition, March 2010*
[86] *Worley Parsons, AEMO Cost Data Forecast For the NEM, Review of Cost and Efficiency Curves, 31 January 2011*
[87] *EPRI and Worley Parsons, Australian Electricity Generation Technology Costs – Reference Case 2010, February 2010*

"*There are no existing utility-scale carbon capture installations on working power plants, so all the estimates have been made from scaling up from prototypes, detailed bottom-up engineering estimates or vendors preliminary estimates*."

"*The impact of CCS on levelised costs of electricity generation comes through the following components:*

- *CCS plant and equipment capex (for the basic scrubbing plant or pre-combustion gas treatment works, often including a small stand alone steam generator);*
- *Increased auxiliary electricity load (for driving all the equipment, including the absorbers, oxygen production and CO_2 compression);*
- *A loss of overall system conversion efficiency, which arises from stealing steam from the host ST/condenser or more likely via adding a standalone GT and steam generator alongside the host plant for meeting the CC steam and power needs;*
- *Increased plant fixed costs (staffing, materials and spares, insurance, etc) from the additional on-site and off-site process works;*
- *Increased variable operating and maintenance costs (repair and maintenance staff/services, absorber chemicals; transit and storage fees for CO_2 transport and storage);*
- *Reduced availability for the host plant (the additional CCS plant may increase unplanned outages for the host plant).*

All the above items, excepting the last one have significant impacts on levelised costs, with the CCS capex being the single largest element, and broadly comparable in size with the combined indirect plant impacts."

"*CCS is clearly an immature technology and as such there should be considerable scope for learning over the next decade. There are a number of areas where the industry has set targets, such as reducing energy penalties and reducing the cost of transport and storage*."

"*It is clear that any developers of CCS facilities will face a considerable FOAK* (first of a kind) *premium in the near to medium term. Our assessment is that this FOAK premium is likely to be of the order of 35%. In practice the premium is likely to be higher as initially developers will build smaller scale plants. This allows for a certain amount of strategic entry pricing by at least some of the competing OEMs and EPC contractors seeking to win business and prove-up their technologies*."

"*By 2020, there should be a number of CCS installations of each of the main technologies that will have operated for a number of years, with some UK experience also. Some countries may have also signalled that CCS should become mandatory on certain installations and/or have put in place arrangements for funding investment in CCS. Most likely, public support will come in the form of provision of the CO_2 transport and storage infrastructure and a minimum guarantee on the value for avoided carbon emissions. The learning on the early demonstration projects and construction of the second generation projects will allow the OEMs and EPC contractors to improve designs and construction techniques. At the same time the prospect of significant forward orders will allow OEMs to expand capacity and invest in their supply chains, so offering production scale savings. This should see prices settling down towards the NOAK* (next of a kind) *level sometime by 2025*.[88]

[88] *Mott MacDonald, UK Electricity Generation Costs Update, June 2010*

5.1.3.14 CCS siting issues

For all thermal generator options with CCS a further siting consideration is added, that of access to a carbon storage reservoir. With respect to storage opportunities, GNS Science has recently completed a review of potential storage opportunities for onshore and immediate offshore locations in the Waikato region and the onshore Taranaki region. Reporting through its Globe Magazine, Issue No. 2, August 2011, GNS Science noted the following:

- "The largest four stationary sources of industrial carbon dioxide in New Zealand emit nearly 10 million tonnes of carbon dioxide annually into the atmosphere. Our view is that ideally these types of emissions should be captured at source, turned into a liquid, and stored safely underground in depleted oil and gas reservoirs."

- "Globally there are limited economic incentives to encourage industry to adopt CCS and the scale of the issue in New Zealand is smaller than many countries due to our small population and relatively high use of renewable energy."

- "Our research indicates that New Zealand has enough underground storage capacity to store captured emissions from large industrial sources over the next 30 years. In the short term, we consider it unlikely that the development of CCS in New Zealand would be associated with coal-fired electricity generation. However, we anticipate that CCS could become an important component of the future energy sector."

5.1.3.15 CCS effectiveness

Several of the references in section 5.1.3.13 provide estimates of the carbon (as CO_2) capture rate. These range from 80% to 95% depending on the source (of the estimate) and the technology. PB estimates the following capture rates for the future generic coal-fired generators:

- Advanced supercritical (ASC) coal fired generators: 85%

- Integrated gasification combined cycle (IGCC) coal-fired generators: 90%

5.1.3.16 ASC with and without CCS

New Zealand's only coal-fired power station, Huntly Power Station units 1 – 4 was located adjacent to the Waikato River to give access to cooling water, and as close as possible to its proposed coal fuel source, the Huntly West Mine. It was in effect a mine-mouth power plant, albeit connected to the mine by 2.5 km of overland conveyor.

In recent years, Huntly Power Station has used both local Waikato coal and imported coal. The imported coal was offloaded at the Port of Tauranga and initially trucked, and then railed to Huntly.

With respect to consentability, it is reasonable to assume that all coal-fired generator options without carbon capture and storage (CCS) will face strenuous opposition. Consentability will therefore be a major siting consideration, along with access to fuel and electricity transmission.

Given the above considerations, PB proposes the following possible connection locations for future generic advanced supercritical (ASC) coal-fired generators:

- ASC without CCS, using coal at HLY, MDN, NPL, ISL, TGA and GOR;

- ASC without CCS using lignite at GOR; and
- ASC with CCS, using coal at HLY and MNI.

5.1.3.17 IGCC with and without CCS

Integrated gasification combined cycle (IGCC) is little more than a complicated means of burning coal in a gas turbine based combined cycle plant. Except for the word “simply”, which is an oxymoron in this context, IGCC is simply a coal-fired CCGT plant with a slightly higher conversion efficiency (lower heat rate) than ASC.

The comments and siting rationale presented in section 5.1.3.13 above regarding ASC technology therefore apply equally to IGCC.

On that basis, PB proposes the following connection locations for future generic integrated gasification combined cycle (IGCC) coal-fired generators:

- IGCC without CCS, using coal at HLY, MDN, NPL, ISL, TGA and GOR; and
- IGCC with CCS, using coal at HLY and MNI.

5.1.3.18 Reciprocating engine using biogas

These will be located at the fuel source previously identified as biogas fuel resources based on landfills and sewage treatment plants will located near large population centres.

These are most likely to be embedded generators and included in the MED GEM as a result of successive additions of small capacity additions eventually totalling 10 MW or more. This would not apply to existing, closed landfills.

The Auckland region, being the largest population centre in New Zealand, is the most likely host for such a generator(s) and PB nominates only one future generic reciprocating biogas fuelled generator: a South-Auckland Recip, using biogas and embedded in local network.

5.1.3.19 Reciprocating engine peaker

Future reciprocating engine peakers are considered likely to follow the Orion Belfast and Bromley models, using diesel fuel and located (embedded) in local distribution network zone substations.

The main population centres appear to be the candidates for diesel fuelled, reciprocating engine peaking plant. It seems likely, if this type of plant is to be used at all, that it will appear in the main cities, Auckland, Wellington, Dunedin, Christchurch, Hamilton, New Plymouth and Tauranga.

5.1.3.20 Coal cogeneration

Cogeneration plants are located at or near their process heating (steam) ‘hosts’ and, in this case, the process heating host will also be located where there is access to either sub-bituminous or lignite coal.

It is therefore likely that coal cogeneration plant will be located at large industrial sites in the Waikato and Southland regions. This could comprise additional generation capacity at existing sites such as Edendale, or new generators at new industrial sites. PB proposes Hamilton (HAM) and Gore (GOR) as representative transmission nodes for this type of plant.

5.1.3.21 Biomass cogeneration

The Bioenergy Association of New Zealand (BANZ) web site notes that, "*The annual production of woody biomass residues from plantation forestry alone is estimated to be between 4 and 6 million tonnes. At an energy value of 9MJ/kg this biomass quantity equates to around 45TJ, roughly equivalent to 10% of New Zealand's total consumer energy demand. Furthermore, the disposal of this biomass poses a problem if not used and its eventual decay can add to greenhouse gas (GHG) emissions through the generation of methane gas*."

"*Currently throughout New Zealand there are large amounts of organic material that is wasted. In particular is the 20% of forest residues that are currently thrown away. Nearly all this organic material being wasted could be used as a feedstock and turned into energy*."

"*Small localised power stations are a promising future for the electricity supply industry. These will cut down on transmission losses and contribute to minimising the costs of reinforcing or upgrading electricity distribution systems. They may also increase reliability of supply and replace the need for future large centralised power stations*."[89]

However, this resource is widely dispersed and the latter comment above recognises that, because of the high moisture content, transport of biomass as a fuel for electricity generation quickly becomes uneconomic as distances increase.

Cogeneration plants are located at or near their process heating (steam) 'hosts' and biomass cogeneration host plants are presently the most attractive, if not the only, opportunity for biomass electricity generation because they have already 'gathered' the fuel resource to a central location. The existing Kinleith cogeneration generator is an example.

Biomass cogeneration therefore appears to depend on the development of further "Kinleiths". These are expected to be located at existing and/or new plantation forestry processing plants or ports. The larger processing plants are at Kinleith, Kawarau, Rotorua, Taupo, and Napier. The ports could be Marsden Point (near Whangarei), Tauranga, Napier and Nelson.

PB proposes Rotorua as a potential location for a biomass cogeneration plant and estimates that this will be an embedded generator.

5.1.3.22 CCGT cogeneration

As noted in section 5.1.3.21 above, cogeneration plants are located at or near their process heating (steam) 'hosts' and, in this case, the process heating host will also be located where there is access to either indigenous natural gas, coal seam gas (CSG), UCG syngas, or LNG.

It is therefore likely that CCGT cogeneration plant will be located at large industrial sites in the Waikato and Taranaki regions. This could comprise additional generation capacity at existing sites such as Hawera, Te Rapa and Edgecumbe, or new generators at new industrial sites.

PB proposes Motunui in Taranaki and Te Rapa in Waikato as potential locations for CCGT cogeneration plants.

[89] http://www.bioenergy.org.nz/bioenergyinfo.asp#potential

5.1.4 Project lifetime

5.1.4.1 Introduction

This section considers the project lifetime for the future generic thermal plant options. Unless there are particular mitigating circumstances, the project lifetimes for the generic plant options will be the same as the lifetimes for the existing and proposed generators.

Advanced supercritical (ASC) with and without carbon capture and storage (CCS) and integrated gasification combined cycle (IGCC) with and without CCS have no counterpart among the existing and proposed generators. These technologies are therefore considered for the first time in this section.

5.1.4.2 Data sources

Two references used elsewhere in this report also used plant life assumptions:

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[90]. This report assumed the following plant lifetime for ASC and IGCC technologies:
  - ASC without CCS: 45 years
  - ASC with CCS: 40 years
  - IGCC with or without CCS: 35 years.
- International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA), "**Projected Costs of Generating Electricity, 2010 Edition**" March 2010[91]. This report assumed the following plant lifetimes for similar plant:
  - Gas-fired power plants: 30 years
  - Coal-fired power plants: 40 years.

Based on the above references there is a 10-year difference between ASC and IGCC, and a 5-year difference between 'with' and 'without' CCS. PB therefore proposes the following lifetimes for ASC and IGCC technologies:

- ASC without CCS: 45 years
- ASC with CCS: 40 years
- IGCC without CCS: 35 years
- IGCC without CCS: 30 years.

5.1.4.3 Data

The data for this section is reported in the summary, Table 5-1 only.

[90] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[91] http://www.mit.edu/~jparsons/current%20downloads/Projected%20Costs%20of%20Electricity.pdf

5.1.5 Operational capacity

5.1.5.1 Introduction

This section considers the operational capacity for the future generic thermal plant options.

The operational capacity of thermal plants is typically the sum of the rated or 'nameplate' capacity of the generating units, less the power consumed in-house. The latter is otherwise known as the auxiliary power demand or load, or the house-load.

Power plants comprise either single or multiple units. The choice between single or multiple units depends upon a number of factors. It is therefore necessary to firstly determine the likely 'block' of power a prospective new generation owner would be contemplating. This in turn depends on a number of factors and the process is best illustrated by looking at historical precedent.

The only three CCGT, central generation plants built in New Zealand to date all comprise the modern, large scale, single shaft technology. These are at Stratford (Contact's Taranaki CCGT), at Otahuhu (Contact's Otahuhu B CCGT) and at Huntly (Genesis' Huntly Power Station Unit 5 CCGT). All these are single unit plants of around 380 - 400 MW nominal capacity.

Two further CCGT are currently proposed and consented, Contact's Otahuhu C and Genesis' Rodney project. Otahuhu C is proposed to be modern, large scale, single shaft technology, and single unit plant of around 400 MW nominal capacity. Genesis' Rodney project is proposed to be developed in two stages, comprising an initial 240 MW unit followed later by another 240 MW unit.

Four of the above examples illustrate conventional wisdom regarding economies of scale, which suggests that the larger the unit the lower the specific capital cost, and the lower the operating cost. The reason for Genesis' Rodney 2 x 240 MW configuration could be related to load growth and future electricity pricing, system stability issues or gas supply constraint.

It is understood that both the Otahuhu C and Rodney projects cannot proceed until further gas supplies are found.

Assuming that future generic thermal plant options are not fuel supply constrained, and unless there are particular mitigating circumstances, the operational capacities of the future generic plant options will generally be single or multiples of the largest unit sizes offered by vendors.

The size of the largest unit is limited by New Zealand generation and transmission system (national grid) stability issues, to the maximum capacity that can backed up by rapid responding 'spinning reserve'. This means that if the largest unit trips, there must be sufficient unused generating capacity available to immediately take up the load. This is like having sufficient unused capacity to provide for someone switching on an equivalent load.

At present the maximum unit size appears to be around 400 MW. However, as the system capacity grows, and the number and size of the largest units increase, the system capacity for even larger units may increase.

5.1.5.2 CCGT

The largest single unit CCGT generators are the single-shaft CCGT power plants produced by Alstom, GE Energy, Mitsubishi, and Siemens (and under licence by others). These are:

- Alstom KA26-1 SS (single-shaft arrangement), consisting of 1 GT26 gas turbine with 1 Alstom triple-pressure reheat drum-type HRSG, 1 Alstom STF15C steam turbine, both driving 1 Alstom hydrogen-cooled TOPGAS turbogenerator, on a common shaft-line with a SSS-clutch (Self-Shifting Synchronous).[92] Nominal performance: **431 MW** net output, 6130 kJ/kWh (LHV) net heat rate.[93]

- GE Power Systems STAG 109H/S109H/MS9001H, consisting of 1 MS9001H gas turbine with a triple-pressure, reheat steam cycle, and steam turbine in a single shaft arrangement. Nominal performance: **480 MW** net output, 6000 kJ/kWh (LHV) net heat rate.[94] [95]

- Mitsubishi MPCP1 (M701G), consisting of 1 M701G gas turbine with a triple pressure steam cycle, and steam turbine in a single shaft arrangement. Nominal performance: **498 MW** net output, 6071 kJ/kWh (LHV) net heat rate.[96]

- Siemens SCC5-8000H 1S reference power plant (RPP), consisting of 1 SGT5-800G gas turbine with one triple-pressure, reheat HRSG with BENSON HP evaporator, 1 SST5-5000 steam turbine, both driving an SGen5-3000W water/hydrogen-cooled generator, on a single shaft and a synchronous self-shifting (SSS) clutch installed between the generator and the steam turbine. Nominal performance: **530 MW** net output, 6000 kJ/kWh (LHV) net heat rate.[97]

Single unit (single shaft) CCGT capacities presently range from 431 – 530 MW (net). A gross capacity of around 490 MW is recommended for the future generic CCGT plant, resulting in a net operational capacity of 475 MW (assuming 3% auxiliary power consumption).

5.1.5.3 OCGT

Existing and proposed OCGT plant capacities range from around 44 MW (Southdown E105 & Huntly Unit 6 (P40)) to around 200 MW (Stratford). PB is uncertain of the drivers giving rise to these sizes without further study outside the scope of this report.

PB has assumed that future OCGT peaker plant will exhibit a similar range of capacities, of 50 – 200 MW.

5.1.5.4 ASC

Advanced supercritical (ASC) pulverised coal plant has a lower size limitation which is close to the present maximum unit size (400 MW) in New Zealand. The lower size limitation for supercritical technology is owing to the following:

- The challenge of providing adequate cooling of the water walls with a limited flow of fluid in designing once-though boilers for supercritical conditions.

- The higher pressure decreases the specific volume of the steam resulting in:

[92] *Alstom, Gas Power Plants, brochure PWER/BPROB/GSPWPS10/eng/THS/10.10/CH/7282, 2010*
[93] *Alstom, Gas Power Plants Technical Performance, brochure PWER/LEAF/GPPTP-10/eng/TS/04.10/FR/6944, 2010*
[94] *GE Power Systems, Gas Turbine and Combined Cycle brochure GEA 12985C (5M, 03/03)*
[95] *GE Power Systems, Advanced Technology Combined Cycles, brochure GER-3936A, 05/01*
[96] *Gas Turbine World, 2009 GTW Handbook*
[97] *http://www.energy.siemens.com/hq/en/power-generation/power-plants/gas-fired-power-plants/combined-cycle-power-plant-concept/scc5-8000h-1s.htm*

- A relatively higher mass flow of steam through the steam leakage paths in the turbine, the glands and seals at the blade tips, resulting in a lower internal cylinder efficiency.

- A smaller blade height in the first two rows of blades in the HP cylinder and the smaller the blade height, the lower the efficiency of the blade.

While probably owing as much to the pursuit of economies of scale as the above considerations, it was reported by SKM in 2002 that the average size of supercritical units built in USA was approximately 650 MW[98]. The SKM report noted that, "*the smallest supercritical pressure unit built with the USA type of furnace wall circuitry (vertical wall tubes) was one of 350 MW*." In Europe there have apparently been a number of modern supercritical plants installed in the smaller size range. The SKM report noted that, "*at least eight plants in the size range 260 to 400 MW have been installed, some with double reheat*."

However, PB has no data on the performance of these smaller units and expects that the use of supercritical steam conditions has given only marginal efficiency gains for those sizes.

The 2002 SKM report concluded that, "*it is considered that there would be no significant cost or technical disadvantage in adopting a supercritical pressure cycle for unit in the range of 330 MW to 420 MW*." PB would argue that there is also no significant cost or technical advantage in adopting a supercritical pressure cycle for unit in that size range for the reasons given above.

In 2005 industry standard supercritical boiler designs typically had a unit size of 400 - 500 MW, with the largest supercritical coal-fired boiler in operation at 1300 MW. A unit of this scale allows the high supercritical efficiencies and economies of scale to be fully realised.

In 2007 the Wyoming Department of Environmental Quality wrote, "*In the August 30,2007 Final Statement of Basis for the Deseret Power Electric Cooperative Bonanza Power Plant, EPA Region VIII stated that, "The use of supercritical pressure in a power plant affects the design of all components within the plant cycle, boiler, turbine, pumps, etc. The steam cycle is based on available turbine designs. The boiler and other equipment are designed to meet the steam cycle defined by the turbine." . . . EPA Region VIII also recognized that the smallest supercritical pressure steam turbines available are for power plants in the range of 500 MW*."[99]

The US Environmental Protection Agency's (EPA) Final Statement of Basis discussing the background and analysis for a Prevention of Significant Deterioration (PSD) permit for the construction of a new 110 MW Waste Coal Fired Unit (WCFU) at Deseret Power's Bonanza power plant noted that:

"*. . . according to Babcock & Wilcox and Foster-Wheeler, two major boiler suppliers, supercritical pressure steam turbines are not available in the size needed for the WCFU project. The smallest supercritical pressure turbine currently known to be available is three to four times larger (i.e. 330 – 440 MW) than is needed for the WCFU project . . .*

In addition, the following information was provided by Siemens Power Systems to Deseret Power . . . :

[98] *Sinclair Knight Merz (SKM), SWIS POWER PROCUREMENT, Comparative Supercritical Study, 19 December 2002*
[99] *Wyoming Department of Environmental Quality and Wyoming Air Quality Division decision IN THE MATTER OF A PERMIT APPLICATION (AP-3546) FROM BASIN ELECTRIC POWER COOPERATIVE TO CONSTRUCT A 385 MW PULVERIZED COAL FIRED ELECTRIC GENERATING FACILITY TO BE KNOWN AS DRY FORK STATION, 15 October 2007*

To our knowledge, no manufacturer offers supercritical steam turbines in 110-120 MW range. The reason is that you would be unlikely to see any significant performance improvements for units that small. Key reasons are as follows:

1. When you go to supercritical steam conditions the specific volume of the steam is reduced because of the higher pressure. This means the blades in the HP section have to be shorter. A major source of inefficiency in steam turbines is due to "flow disruptions" at the top and bottom of the blade where the moving flow meets the stationary rotor or casing. As the blades get shorter the impact of this "end wall" condition increases which in turn increases the flow losses.

2. The supercritical conditions require a once-through boiler which requires a more powerful feed pump drive (higher pressures). That decreases plant efficiency and it you can't make that difference up with improved cycle performance, supercritical makes no sense.

We generally don't see units less than 500 MW being built as supercritical because the performance improvement isn't significant and the unit is more expensive than subcritical."[100]

PB would therefore not recommend an advanced supercritical unit smaller than 500 MW and proposes for the GEM a unit size of 600 MW (gross). Currently the largest unit size in Australia is CS Energy's Kogan Creek plant in Queensland at 750 MW (gross). This is solely to take full advantage of the supercritical conditions and economies of scale.

This assumes that the addition of further CCGT generators of around 400 – 500 MW will occur before the coal-fired ASC plants and that the New Zealand electricity system will accept this unit size at the time they are proposed.

This also means that if smaller sized coal-fired plants were to be built in New Zealand, PB is suggesting that such will not be "ASC" technology but conventional, subcritical thermal technology like Huntly Power Station.

PB notes that the last subcritical coal-fired plant built in New Zealand was Huntly Power Station, commissioned 1981/85. The last one proposed for New Zealand was Mighty River Power's proposal to convert the 250 MW Marsden B Power Station to coal firing. According to Wikipedia Mighty River Power lodged an application with Northland Regional Council for resource consents to convert and commission Marsden B power station on coal in October 2004. The proposal apparently drew record numbers of submissions, mostly in opposition and Greenpeace New Zealand staged an occupation of the site in 2005. In March 2007 Mighty River Power abandoned its coal-firing plans for Marsden B and in 2009 the Marsden B plant was sold. In October 2011 it was being dismantled.

5.1.5.5 IGCC

References used elsewhere in this report also address the matter of unit size:

- Worley Parsons, "**AEMO Cost Data Forecast For the NEM, Review of Cost and Efficiency Curves**", 31 January 2011[101]. This report estimated the current status of IGCC on the development continuum as shown in the following Figure 5.4, a "*Grubb curve assumed for fossil fuel technologies*".

[100] http://www.epa.gov/region8/air/pdf/FinalStatementOfBasis.pdf
[101] http://www.aemo.com.au/planning/0419-0017.pdf

The report notes that, "*IGCC technology is expected to improve in output and performance at a faster rate over the next decade and slowing down as the technology matures and gains become smaller*."

The report records the assumptions made for modelling four IGCC plants:

- Brown coal IGCC without carbon capture and storage: "*The unit as modelled was for a **504MW**, two unit plant, with GE Frame 9E gas turbines, operating in a combined cycle configuration, fed by syngas produced in two oxygen-blown Shell gasifiers, using brown coal of a mid-range moisture content of 37%*."

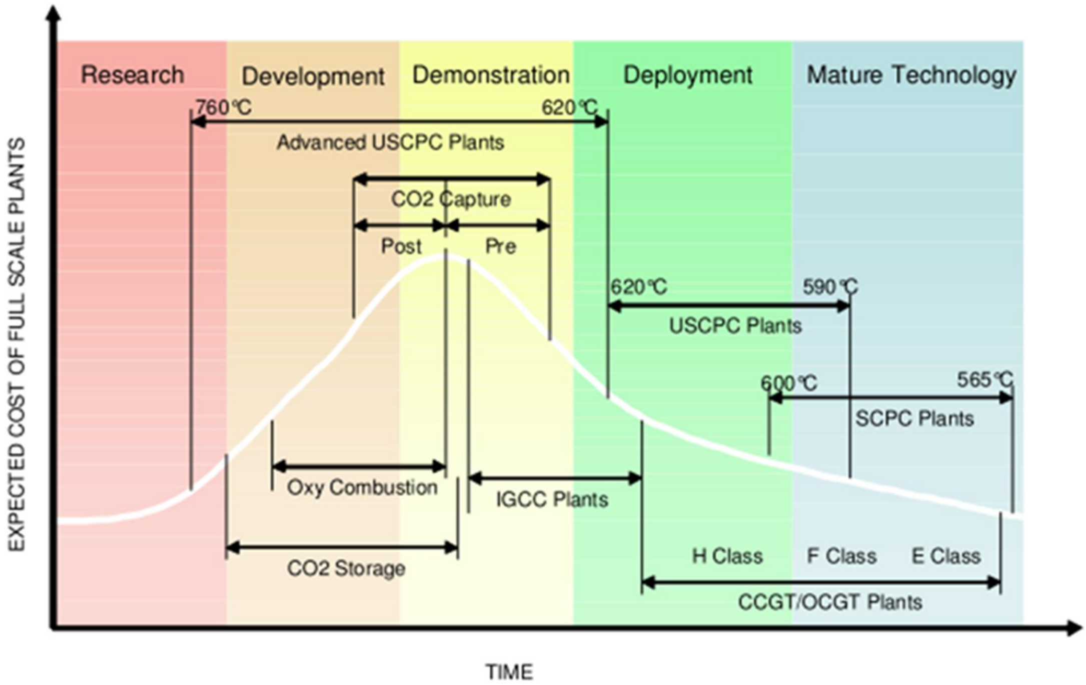


Figure 5.4 IGCC development status

- Black coal IGCC without carbon capture and storage: "*IGCC for black coal was modelled using a similar model to that which was used for the Brown coal . . . A net plant output of **509MW** and a HHV basis efficiency of 41.1% was calculated for the plant as modelled, using Shell gasifier technology, GE Frame 9E gas turbines, and acid gas syngas cleanup without carbon dioxide capture from the syngas stream*."

- Brown coal IGCC with carbon capture and storage: "*Brown Coal fuelled IGCC with carbon capture was modelled around two oxygen-blown, dry-feed, Shell gasifiers with convective cooling of the raw syngas, fuelling GE 9FA gas turbines . . . The GE9FA was selected due to its higher thermal efficiency . . . The results of the plant performance and cost modelling for this baseline configuration were a net plant output of **764MW***".

- Black coal IGCC with carbon capture and storage: "*Black Coal fuelled IGCC with carbon capture was modelled as for Brown coal ICGG-CCS, with two oxygen-blown, dry-feed, Shell gasifiers, convective cooling of the raw syngas, fuelling two GE 9FA gas turbines. The results of the plant performance and cost modelling for the baseline black coal IGCC-CCS configuration were a net plant output of **750MW***".

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[102]. This report notes that IGCC, "*is shown to have a significant cost premium versus advanced super critical coal plant, which reflects the still largely demonstration status of this technology*." The representative, close-to-market, advanced coal generation IGCC technology plant was, "*assumed to be a single gasifier driving a 2+1 (**830 MW gross**) CCGT, with and without pre-combustion CCS*". "*IGCC has been around for several decades however, it has yet to move into genuine commercial deployment*".

- International Energy Agency (IEA) and the OECD Nuclear Energy Agency (NEA), "**Projected Costs of Generating Electricity, 2010 Edition**" March 2010[103]. This report notes that, "*complexity and cost mean that IGCC has not yet achieved commercialisation, although a small number of demonstration plants are operating successfully at the 250 MWe to 300 MWe scale*."

- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[104]. This report notes that, "*Since the Integrated Gasification Combined Cycle (IGCC) plants are limited in size selection based on the sizes of combustion turbines available, all IGCC cases were evaluated with GE 9FA combustion turbines*." "*The sent-out capacity of the Integrated Gasification Combined Cycle (IGCC) plants vary between the cases due to constraints of the gas turbine equipment selected. All of the IGCC alternatives were configured with GE 9FA gas turbines as the primary power generation components and these were arranged as 2+1 combined cycle units*." "*Integrated gasification combined cycle (IGCC) units with and without CCS are between 500 MW and 750 MW. The sent-out capacity of the IGCC plants varies for each case since their output capacity is dictated by the size and type of gas turbine used as a primary power generator for this technology*." Unit sizes chosen were:

  - Black coal without CCS: 884 MW (gross), **728 MW** (net)

  - Black coal with CCS: 850 MW (gross), **576 MW** (net).

While smaller unit sizes could be built, to take full advantage of the efficiencies offered by the large, heavy industrial gas turbines, and of economies of scale, PB recommends that the largest unit sizes are assumed for the GEM, as follows:

- Waikato IGCC without CCS, using Waikato coal: 870 MW (gross), 720 MW (net)

- Waikato IGCC with CCS, using Waikato coal: 840 MW (gross), 570 MW (net)

- Marsden IGCC, without CCS, using imported coal: 880 MW (gross), 728 MW (net)

- Taranaki IGCC with CCS, using imported coal: 850 MW (gross), 576 MW (net)

This assumes that the addition of further CCGT generators of around 400 – 500 MW, and the addition of coal-fired ASC generators of around 600 MW will occur before the coal-fired IGCC plants and that the New Zealand electricity system will accept this unit size at the time they are proposed.

[102] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[103] http://www.mit.edu/~jparsons/current%20downloads/Projected%20Costs%20of%20Electricity.pdf
[104] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf

5.1.5.6 Reciprocating engine using biogas

PB estimates that future additions of this type of generic generator will be around 10 MW.

5.1.5.7 Reciprocating engine peaker

PB estimates that future additions of this type of generic generator will be around 10 MW.

5.1.5.8 Cogeneration

PB estimates that future additions of this type of generic generator will be in the range of 30 – 60 MW.

5.1.5.9 CCGT cogeneration

PB estimates that future additions of this type of generic generator will be in the range of 25 – 50 MW.

5.1.6 Availability Factor

5.1.6.1 Introduction

This section considers the availability factor for each of the future generic thermal plant options. This will generally be the same as for like existing and proposed plants. Technological advance over the next 40 years (out to 2050) is expected to maintain the focus on increasing turbine inlet temperatures, for both gas and steam turbines, in the pursuit of higher efficiencies. This amounts to pushing the boundaries of material capabilities to withstand high stress at high temperature, requiring increasingly exotic materials and manufacturing techniques.

It could be argued that this may come with a risk of decreasing reliability and availability. However, this would not be acceptable to the industry and it is therefore considered that reliability and availability expectations for the future will be that things will remain much as they are now.

Advanced supercritical (ASC) with and without carbon capture and storage (CCS) and integrated gasification combined cycle (IGCC) with and without CCS have no counterpart among the existing and proposed generators. These technologies are therefore considered for the first time in this section.

5.1.6.2 Data sources

Only one reference used elsewhere in this report also offered availability assumptions:

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[105]. This report assumed the following availabilities for ASC and IGCC technologies:
    - ASC without CCS: 90.2%
    - ASC with CCS: 89.0%

[105] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

- IGCC without CCS: 87.5%
- IGCC with CCS: 87.4%.

5.1.6.3 Data

The data for this section is reported in the summary, Table 5-1 only.

5.1.7 Net Output Factor

5.1.7.1 Introduction

In section 2.1.4 the Net Output Factor (NOF) is defined as the net actual generation (in MWh) divided by the product of the time period (in hours) when the plant is available and the operational capacity in (MW), and is a measure of the average loading in MW terms on the units over the period when the plant is available.

This definition is contrary to industry practice, which defines the Net Output Factor (NOF) as the Net Actual Generation (in MWh) divided by the product of the Service Hours (NOT the 'available' hours) and the Net Maximum Capacity in (MW), and is a measure of the average loading in MW terms on the units over the period when the plant is in service (NOT when it is available).

This is a significant difference because generators can be shut down even though they are available. Operators may choose to shut generators down when prices are low, due to their higher marginal costs. Transmission constraints owing to maintenance or contingency events can also result in generators being shut down when they are available.

Baseload gas and coal fired future generic thermal generators would be expected to have load factors in the range of 85 – 90%. This is because such generators are most efficient at their maximum continuous rated output, and exhibit falling efficiency with reduced output.

5.1.7.2 Data

The data for this section is reported in the summary, Table 5-1 only.

5.1.8 Unit largest proportion

5.1.8.1 Introduction

This section considers the largest proportion of station output carried by a single unit for each of the future generic thermal plant options.

As noted in section 5.1.5 above, it is generally expected that the largest proportion of the future generic plant options will generally be single or multiples of the largest unit sizes offered by vendors.

5.1.8.2 Data

The data for this section is reported in the summary, Table 5-1 only.

5.1.9 Baseload

5.1.9.1 Introduction

This section considers the generating role for each of the future generic thermal plant options. 'Baseload', according to the North American definition, is anything over a 50% capacity factor, meaning generation at 50% load for 100% of the time, or 100% load for 50% of the time, and every combination in between with a product of 50%.

In New Zealand the term 'baseload' has tended to be used firstly for those generators that run continuously, except for maintenance, up to the maximum capacity allowed by their water, steam or fuel supply. This includes all 'use it or lose it', 'run-of-river' hydro and geothermal plants.

The term 'baseload' is also used for those generators that run generally at constant load and do not follow the daily load curve. In New Zealand this includes significant hydro generation capacity which has limited storage capacity. In Australia and North America this would include a large proportion of coal-fired, conventional thermal generation.

Generators that participate in load following, but are not peakers, have been termed 'intermediate' generators in New Zealand. In North America they would be considered to be baseload.

Peak load generators, or peakers, are those generators that generate only for minutes or hours each day, during the sharpest demand peaks.

The nature of the New Zealand generation system, being predominantly (around 55%) hydro based means that New Zealand is subject to varying climatic conditions and to what has come to be termed, 'wet years' and 'dry years'. During 'dry years', intermediate and peaker generating plants will normally generate more, making up for 'dry year' water shortage in the hydro systems.

The MED definition poses the question, "is the plant designed to be operated near/at full capacity most of the time?"

Most power generation equipment is designed to be operated at its maximum continuous rating (MCR), which is why there is such a term. The gas turbines (GT) in OCGT plant and CCGT plant are not dissimilar to the jet engines on aircraft, which are capable of operating at MCR for indefinite periods (or until the fuel runs out!).

Conventional thermal generation equipment, particularly boilers and steam turbines are usually capable of operating for extended periods at MCR, from 4 – 6 years between major overhauls. They can also operate for more than 365 days without shutting down, however they normally have annual maintenance. Running continuously at MCR is also usually the most economic operating mode. Life can be consumed quicker by cycling than by continuous steady load with this type of plant.

However, most power generation equipment has a finite life between maintenance or overhaul, generally based on operating hours. This is most pronounced for the gas turbines (GT) which have mandated inspections and overhauls at clearly defined, thousands of hours, intervals.

Diesel engines for power generation are somewhat uniquely subject to relatively strict life consumption and maintenance regime based on both operating hours and load. This has given rise to a set of engine ratings expressed as follows:

- ***Emergency standby rating*** *is the power that the generator set drive engine will deliver continuously under normal varying load factors for the duration of the power outage.*
- ***Prime power rating*** *is the power that the generator set drive engine will deliver when the unit is used as a utility type power plant under normal varying load factors, operating continuously as required. This incorporates a minimum overload capability of 10%.*
- ***Industrial rating*** *is the power that the generator set drive engine will deliver 24 hours per day when the unit is used as a utility-type power plant where there are non-varying load factors and/or constant dedicated loads.*
- ***Limited running time rating*** *is the power that the generator set will deliver when used as a utility type power source, typically in load curtailment service (peaker), for a limited number of hours, where there are non-varying loads and/or constant dedicated loads.*[106]

The above ratings are designed to ensure a proper understanding of the intended operating regime, and to assure satisfactory life from the engine.

It is therefore considered that only the diesel peaker future generic options are likely to be designed to be operated near/at full capacity for limited periods only.

5.1.9.2 Data

The data for this section is reported in the summary, Table 5-1 only.

5.1.10 Plant heat rate

5.1.10.1 Introduction

This section considers the plant heat rate or efficiency for each of the future generic thermal plant options. That is, for each GJ of fuel input, how many useful (station export) GWh of electricity are generated.

Note that heat rates are normally expressed in 'kJ/kWh' terms, but that:

1 kJ/kWh = 1 MJ/MWh = 1 GJ/GWh, and

Efficiency, % = 3600/(kJ/kWh), and

Heat rate, kJ/kWh = 3600/efficiency, %.

Plant heat rates are estimated based on the heat rates of like existing and proposed plants. Advanced supercritical (ASC) with and without carbon capture and storage (CCS) and integrated gasification combined cycle (IGCC) with and without CCS have no counterpart among the existing and proposed generators. These technologies are therefore considered for the first time in this section.

[106] *Electrical Generating Systems Association (EGSA), On-Site Power Generation, A Reference Book, 3rd Edition, 1998*

5.1.10.2 Data sources

Two references used elsewhere in this report also used plant heat rate assumptions:

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[107]. This report assumed the following net heat rates (HHV) for ASC and IGCC technologies:
  - ASC without CCS: 8,560 kJ/kWh
  - ASC with CCS: 11,830 kJ/kWh
  - IGCC without CCS: 8,380 kJ/kWh
  - IGCC with CCS: 11,560 kJ/kWh.
- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[108]. This report assumed the following net heat rates (HHV) for ASC and IGCC technologies:
  - ASC without CCS: 9,480 kJ/kWh
  - ASC with CCS: 12,673 kJ/kWh
  - IGCC without CCS: 9,144 kJ/kWh
  - IGCC with CCS: 12,467 kJ/kWh.

The Mott MacDonald, June 2010 heat rates are lower (more efficient) than the Electric Power Research Institute (EPRI) & Worley Parsons, February 2010 heat rates. This is understood to be owing to the higher ambient temperature (25°C) and relative humidity (60%), and the use of dry cooling systems for the Australian plants.

UK conditions are considered more like New Zealand conditions and PB therefore proposes that the UK heat rate data is used in the GEM.

5.1.10.3 Data

The data for this section is reported in the summary, Table 5-1 only.

The HHV heat rates expressed for baseload plant can be assumed to be the long term average heat rates applying at or around full load or maximum continuous rating (MCR). The heat rates expressed for the peaking plants can be assumed to be long term averages and to include the depreciating (heat rate increase) effects of multiple startups. Note that diesel and gas engine plant heat rates are not significantly affected by multiple startups and part load operation.

[107] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[108] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf

5.1.11 Variable O&M costs

5.1.11.1 Introduction

Sections 3.1.12 and 4.1.13 set out PB's rationale for estimating the variable O&M costs for the existing and proposed thermal generation plants, and provides, in Table 3-8 and Table 4-7, PB's estimates for those plants.

Variable O&M costs for the future generic thermal generation are estimated by PB to be approximately the same as those for the existing and proposed plants, in present dollar value terms, and on the basis of 'like for like' technology. There is not expected to be significant changes to variable O&M costs in the future.

Advanced supercritical (ASC) with and without carbon capture and storage (CCS) and integrated gasification combined cycle (IGCC) with and without CCS have no counterpart among the existing and proposed generators. These technologies are therefore considered for the first time in this section.

5.1.11.2 Data sources

Two references used elsewhere in this report also provided variable O&M cost data:

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[109]. This report assumed the following variable O&M costs for ASC and IGCC technologies:
  - ASC without CCS: £2.0/MWh (NZ$5.00/MWh)
  - ASC with CCS: £3.1/MWh (NZ$7.75/MWh)
  - IGCC without CCS: £2.5/MWh (NZ$6.25/MWh)
  - IGCC with CCS: £3.1/MWh (NZ$7.75/MWh)

The above British Pound (GBP) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.40 GBP.

- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[110]. This report assumed the following variable O&M costs for ASC and IGCC technologies:
  - ASC without CCS: AUD 4.6/MWh (NZ$5.41/MWh)
  - ASC with CCS: AUD 15.7/MWh (NZ$18.47/MWh)
  - IGCC without CCS: AUD 12.8/MWh (NZ$15.06/MWh)
  - IGCC with CCS: AUD 20.0/MWh (NZ$23.53/MWh).

The above Australian Dollar (AUD) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.85 AUD.

[109] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf
[110] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf

The Mott MacDonald, June 2010 variable O&M costs for ASC without CCS are consistent with the Electric Power Research Institute (EPRI) & Worley Parsons, February 2010 values. For all other generator technology types the Australian O&M cost estimates are around twice that of the UK estimates. PB has reviewed the scope of the estimates of both sources and confirmed that CO_2 transport and storage costs are NOT included in either of the estimates.

The difference between the UK and Australian variable O&M cost estimates cannot be resolved without further study outside the scope of this report. Variable O&M costs do not include labour or productivity differences as these are part of the fixed O&M costs.

PB recommends using the Electric Power Research Institute (EPRI) & Worley Parsons, February 2010 (Australian) values for the GEM.

5.1.11.3 Data

The data for this section is reported in the summary, Table 5-1 only.

5.1.12 Fixed O&M costs

5.1.12.1 Introduction

Sections 3.1.13 and 4.1.13 set out PB's rationale for estimating the fixed O&M costs for the existing and proposed thermal generation plants, and provides, in Table 3-11 and Table 4-8, PB's estimates for those plants.

Fixed O&M costs for the future generic thermal generation are estimated by PB to be approximately the same as those for the existing and proposed plants, in present dollar value terms, and on the basis of 'like for like' technology. There is not expected to be significant changes to fixed O&M costs in the future.

Advanced supercritical (ASC) with and without carbon capture and storage (CCS) and integrated gasification combined cycle (IGCC) with and without CCS have no counterpart among the existing and proposed generators. These technologies are therefore considered for the first time in this section.

5.1.12.2 Data sources

Two references used elsewhere in this report also provided fixed O&M cost data:

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[111]. This report assumed the following fixed O&M costs for ASC and IGCC technologies:
    - ASC without CCS: £56,000/MW/y (NZ$140,000/MW/y)
    - ASC with CCS: £79,000/MW/y (NZ$197,500/MW/y)
    - IGCC without CCS: £51,500/MW/y (NZ$128,750/MW/y)
    - IGCC with CCS: £71,000/MW/y (NZ$177,500/MW/y)

[111] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

The above British Pound (GBP) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.40 GBP.

- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[112]. This report assumed the following fixed O&M costs for ASC and IGCC technologies:
  - ASC without CCS: AUD 33,100/MW/y (NZ$38,940/MW/y)
  - ASC with CCS: AUD 55,300/MW/y (NZ$65,060/MW/y)
  - IGCC without CCS: AUD 72,700/MW/y (NZ$85,530/MW/y)
  - IGCC with CCS: AUD 103,700/MW/y (NZ$122,000/MW/y).

The above Australian Dollar (AUD) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.85 AUD.

Except for IGCC with CCS, the Mott MacDonald, June 2010 (UK) fixed O&M costs are around three times the Electric Power Research Institute (EPRI) & Worley Parsons, February 2010 (Australian) values. PB has reviewed the scope of the estimates of both sources and confirmed that CO_2 transport and storage costs are NOT included in either of the estimates.

The difference between the UK and Australian fixed O&M cost estimates cannot be resolved without further study outside the scope of this report. Fixed O&M costs are dominated by labour costs, which suggests that labour rates and productivity differences may be at least part of the explanation for the wide disparity between UK and Australian fixed O&M costs.

PB recommends using the Electric Power Research Institute (EPRI) & Worley Parsons, February 2010 (Australian) values for the GEM.

5.1.12.3 Data

The data for this section is reported in the summary, Table 5-1 only.

5.1.13 Capital cost components

5.1.13.1 Introduction

As noted in section 4.1.16 for proposed generation, the GEM requires estimates of the capital cost of future generic generation in two components:

- The portion of the capital cost not exposed to foreign currency movements (in *NZD/kW*), and
- The capital cost exposed to foreign currency movements (in *Dominant foreign currency/kW*).

Capital costs for the future generic thermal generation are estimated by PB to be approximately the same as those for the proposed plants, in present dollar value terms, and

[112] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf

on the basis of 'like for like' technology. Changes to capital costs in the future are outside the scope of this report.

Advanced supercritical (ASC) with and without carbon capture and storage (CCS) and integrated gasification combined cycle (IGCC) with and without CCS have no counterpart among the existing and proposed generators. These technologies are therefore considered for the first time in this section.

5.1.13.2 Validation data sources

Four references used elsewhere in this report also provided capital cost data:

- Worley Parsons, "**AEMO Cost Data Forecast For the NEM, Review of Cost and Efficiency Curves**", 31 January 2011[113]. This report assumed the following capital costs for ASC and IGCC technologies:
  - ASC without CCS: AUD 2,695/kW (NZ$3,171/kW)
  - ASC with CCS: AUD 4,959/kW (NZ$5,834/kW)
  - IGCC without CCS: AUD 4,802/kW (NZ$5,649/kW)
  - IGCC with CCS: AUD 6,288/kW (NZ$7,398/kW)

The above Australian Dollar (AUD) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.85 AUD.

- ACIL Tasman, for the Australian Department of Climate Change and Energy Efficiency (DCCEE), "**Modelling Greenhouse Gas Emissions from Stationary Energy Sources**, Electricity sector and direct combustion emissions over the period to 2029-30", 18 January 2011. This report assumed the following capital costs for ASC and IGCC technologies (without CCS):
  - ASC without CCS: AUD 2,451/kW (NZ$2,884/kW)
  - IGCC without CCS: AUD 3,207/kW (NZ$3,773/kW)

The above Australian Dollar (AUD) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.85 AUD.

- Mott MacDonald, "**UK Electricity Generation Costs Update**", June 2010[114]. This report assumed the following capital costs for ASC and IGCC technologies:
  - ASC without CCS: £1,789.4/kW (NZ$4,474/kW)
  - ASC with CCS: £2,434.4/kW (NZ$6,086/kW)
  - IGCC without CCS: £1,964.0/kW (NZ$4,910/kW)
  - IGCC with CCS: £2,442.7/kW (NZ$6,107/kW)

[113] http://www.aemo.com.au/planning/0419-0017.pdf
[114] http://www.decc.gov.uk/assets/decc/statistics/projections/71-uk-electricity-generation-costs-update-.pdf

The above British Pound (GBP) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.40 GBP.

- Electric Power Research Institute (EPRI) & Worley Parsons, "**Australian Electricity Generation Technology Costs – Reference Case 2010**" February 2010[115]. This report assumed the following capital costs for ASC and IGCC technologies:

    - ASC without CCS: AUD 2,967/kW (NZ$3,491/kW)
    - ASC with CCS: AUD 5,855/kW (NZ$6,888/kW)
    - IGCC without CCS: AUD 5,099/kW (NZ$5,999/kW)
    - IGCC with CCS: AUD 7,715/kW (NZ$9,076/kW)

The above Australian Dollar (AUD) values were converted to New Zealand Dollars (NZD) using the rate of 1 NZD = 0.85 AUD.

5.1.13.3 Summary

The following Table 5-2 summarises the validation data extracted by PB from the above sources. In some cases the data in a source report is dated earlier than the date of its report, therefore both the report date and the dollar value date is given. Where a range was given in the source data, the higher of the mean, median or midrange value is recorded below.

Table 5-2 Validation specific capital cost data summary, NZD/kW

Report source/author	GEM	Worley Parsons	ACIL Tasman/DC CEE	Mott MacDon.	EPRI/ Worley Parsons
Report date	**2010**	**January 2011**	**January 2011**	**June 2010**	**February 2010**
Dollar date/time value	**Not known**	**"Real 2009-10"**	**"Real 2009-10"**	**2009**	**June 2009**
Generator	**NZ$/kW**	**NZ$/kW**	**NZ$/kW**	**NZ$/kW**	**NZ$/kW**
ASC without CCS	No data	3,171	2,884	4,474	3,491
ASC with CCS	No data	5,834	No data	6,086	6,888
IGCC without CCS	No data	5,649	3,773	4,910	5,999
IGCC with CCS	No data	7,398	No data	6,107	9,076

Reviewing the data in Table 5-2 suggests that the ACIL Tasman, 18 January 2011 capital costs are unusually low, and the Electric Power Research Institute (EPRI) & Worley Parsons, February 2010 data for IGCC with CCS is unusually high. If these data are excluded, the means of the data remaining are as follows:

- ASC without CCS: NZ$3,712/kW
- ASC with CCS: NZ$6,269/kW

[115] http://www.ret.gov.au/energy/Documents/AEGTC%202010.pdf

- IGCC without CCS: NZ$5,519/kW
- IGCC with CCS: NZ$6,753/kW

PB recommends these values are adopted for the GEM.

PB considers no escalation from 2009/10 to 2011 dollars is required for these estimates.

5.1.14 Dominant foreign currency

The dominant foreign currency will depend on which country or countries the major equipment is sourced from. This is not readily determined because there are competing OEMs (original equipment manufacturers) located in different countries for all the future generic thermal generator technologies. However, for the purposes of providing a value for use in the GEM, the dominant values are the same proposed in Section 4.1.17.

5.1.15 Lines connection cost

The same estimating methodology used for the proposed thermal plant in section 4.1.18, has been adopted for future generic project types.

5.2 Hydro

5.2.1 Summary

Table 5-3 summarises the future generic plant data. PB has provided recommendations based on arbitrary estimates and approximation techniques, as detailed through this report.

Table 5-3 Future generic NZ hydro plant data

Region	Project name	Plant technology	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Variable O&M costs	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
Generic hydro project types				*Years*	*MW*	*%*	*%*	*%*	*y/n*	*$/MWh*	*$/kW/y*	*$/kW*	*€/kW*		*$M*
	Medium run of river	HydRR	New	50	50	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.2
	Medium dam and reservoir	HydRR	New	80	150	92.3%	59%	33%	N	0.86	6.38	4,455	304	EUR	$14.1
	Large dam and reservoir	HydRR	New	80	450	92.3%	59%	25%	N	0.86	6.38	3,689	234	EUR	$21.5
Generic hydro project list															
Central Canterbury	Bush Stream	HydRR	HOR	50	30	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Marlborough	Clarence 54	HydRR	CUL	80	270	92.3%	59%	33%	N	0.86	6.38	4,455	304	EUR	$14.10
Marlborough	Clarence to Waiau Diversions	HydRR	CUL	50	70	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Marlborough	Clarence/Conway	HydRR	CUL	80	300	92.3%	59%	33%	N	0.86	6.38	4,455	304	EUR	$14.10
Otago	Clutha River Beaumont	HydRR	ROX	80	185	92.3%	59%	33%	N	0.86	6.38	4,455	304	EUR	$14.10
Otago	Clutha River Luggate	HydRR	ROX	50	86	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Otago	Clutha River Queensberry	HydRR	ROX	80	160	92.3%	59%	33%	N	0.86	6.38	4,455	304	EUR	$14.10
Otago	Clutha River Tuapeka	HydRR	ROX	80	350	92.3%	59%	25%	N	0.86	6.38	3,689	234	EUR	$21.50
North Canterbury	Hope River	HydRR	ISL	50	55	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
North Canterbury	Hurunui River at Lowry Peaks	HydRR	ISL	50	35	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
North Canterbury	Hurunui River North Branch 1	HydRR	ISL	50	18	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Marlborough	Lower Clarence River	HydRR	CUL	50	35	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Wanganui	Mangawhero Wanganui Diversion	HydRR	BPE	50	60	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20

Region	Project name	Plant technology	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Variable O&M costs	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
West Cost	Matakitaki River	HydRR	IGH	50	40	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Hawkes Bay	Mohaka at Raupunga	HydRR	TUI	50	44	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
Central Canterbury	Potts River	HydRR	HOR	50	35	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
West Cost	Taramakau	HydRR	IGH	50	50	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20
North Canterbury	Waiau 21	HydRR	ISL	80	140	92.3%	59%	33%	N	0.86	6.38	4,455	304	EUR	$14.10
West Cost	Whitcombe River	HydRR	IGH	50	30	92.3%	59%	50%	N	0.86	6.38	3,827	394	EUR	$7.20

Note: The information provided in this table should only be used in conjunction with the information provided in the relevant sections contain within the body of this report.

5.2.2 Plant

The following Table 5-3 lists the categories of generic hydro power plants that have been considered for this report. These categories have been based on similar categories used in the report *'Renewable Energy Essentials: Hydropower, International Energy Agency 2010'*.

Table 5-4 Generic Hydro Power Plant Categories

Generic Hydro Categories		
Category	**Unit Output**	**Plant Storage**
Medium	10MW – 100MW	Run-of-River
Medium	100MW – 300MW	Dam and Reservoir
Large	>300MW	Dam and Reservoir

5.2.3 Plant technology

Typically, the most significant cost in a new hydro power station construction is the civil construction costs. The two categories of plant storage have been considered for the generic plant, as they typically have significantly different construction costs associated with them.

The run-of-river type hydro schemes typically only have a small dam or weir structure and hence typically have a lower construction cost, when compared to the dam and reservoir type schemes.

The three main types of turbines (Kaplan, Francis and Pelton) have not been considered independently, as the number of generic plants would become extensive. However the accuracy of the cost estimation takes this into consideration (refer to Section 5.2.13).

5.2.4 Substation

The sub-station costs for the generic hydro plants have been estimated using the report *'Optimised Deprival Valuation of Transpower's Fixed Assets, 30 June 2006'.* Refer to Section 4.2.16.2 for further details on estimating the sub-station costs.

5.2.5 Project lifetime

The generic hydro power plants are expected to have an operation life of around 50 years for plants ≤ 50 MW and 80 years for plants > 50 MW. Refer to Section 3.2.5 for further details on the lifetime of hydro power plants.

5.2.6 Operational capacity

The range of operational capacities for each generic hydro category is listed in Table 5-3 above.

5.2.7 Availability Factor

The estimated availability factor for each of the generic plants is assumed to be 92.3%. Refer to Section 3.2.7 for details on this estimated availability factor.

5.2.8 Net Output Factor

The estimated net output factor for each of the generic plants is assumed to be 59%. Refer to Section 4.2.8 for details on this estimated Net Output Factor.

5.2.9 Unit largest proportion

For large hydro power plants, multiple generating units are typically used to provide flexibility in the power station operational flow range and the ability to provide partial generation output during generator repairs/maintenance.

Based on PB's experience, the following unit largest proportions have been arbitrarily assumed for the generic plants. For 10 MW – 100 MW, the generic plants are assumed to have two generating units, for plants 100 MW - 300 MW the plants are assumed to have three generating units and for plants > 300 MW the plants are assumed to have 4 generating units. The number of generating units per plant can vary depending on project specific requirements and should be considered in a case-by-case basis for actual hydro schemes.

5.2.10 Baseload

The generic hydro power plants are not considered to generate base-load. Refer to Section 3.2.9 for details.

5.2.11 Variable O&M costs

The variable operation and maintenance costs have been based on $340/MW per month for a new plant. Refer to Section 3.2.10 for details on determining operating and maintenance costs.

5.2.12 Fixed O&M costs

The fixed operation and maintenance costs have been based on $532/MW per month for a new plant. Refer to Section 0 for details on determining operating and maintenance costs.

5.2.13 Capital cost (NZD)

Determining accurate capital costs of hydro power schemes should be done on a case by case basis as the costs are very project specific, due to factors such as geological conditions, location, storage type, transmission distance and excavation requirements. This is highlighted by the International Energy Agency's report *'Renewable Energy Essentials: Hydropower, 2010'* which states that *"The initial investment needs for particular projects must be studied individually due to the unique nature of each hydropower project."*. However this report uses the following technique to provide an approximate capital cost estimate for the generic hydro plants.

The report *'Determining 'Ballpark' Costs For a Proposed Project, James L. Gordon, Hydro Review Worldwide, March 2003'* provides the following Gordon's formula for determining *"all costs directly associated with construction of the project, including interest and owners costs and overheads".* The formula was developed to *"provide a check on pre-feasibility cost estimates"* and is not intended to include pre-development costs.

Cost = k . P . S. $(MW / (H)^{0.3})^{0.82}$: where the cost is in $USD millions in 2003.

MW = Installed capacity in MW

H = Developed head in meters of water

k = Cost coefficient (k factor): this is country specific and is determined from known projects with similar characteristics. Refer to Section 5.2.13.2 for more details on determining the k factor.

P = Project scale factor: The following categories are used for the P factor.

Table 5-5 Project Scale Factor

P Factor Categories	
P Factor	**Category**
1	Complete hydro project with seasonal storage
0.75	Complete run-of-river project with daily pondage
0.44	Addition of intake, penstock and power plant to an existing dam
0.33	Addition of a penstock an power plant to an existing dam

S = Project standard factor: The following categories are used for the S factor.

Table 5-6 Project Standard Factor

S Factor Categories	
S Factor	**Category**
1	Power plant with an installed capacity greater than 20MW
0.64	Power plant with an installed capacity greater than 1MW and less than 20MW

The estimated cost determined by the formula does not include *"expenses associated with building access roads, nor does it include the sub-station, transmission, navigation locks, land, or environmental mitigation costs."*

5.2.13.1 Important Notes on Capital Cost Estimates

As mentioned above, the capital costs of hydro power plants can vary widely depending on many project specific attributes. The Gordon's formula was developed to confirm project cost estimates (which have already been established through other techniques), rather than being used to establish cost estimates. However, it has been used in this report to provide a 'ball park' project cost, but the results should be treated with caution as actual costs can vary significantly when project specifics are considered.

Arbitrary estimates have been provided throughout this report to enable generic plant cost estimates to be established and the Gordon's' k factors to be calculated where insufficient publically available information exists on proposed plants. These arbitrary estimates should also be treated with caution as they are project specific and vary significantly (and cause a significant variation in capital costs). Where more detailed project specific information is available it should be used to provide a more accurate project cost estimate.

5.2.13.2 Gordon's K Factor

The k factor in the Gordon's formula has been determined using the following technique.

The k factor is determined by using capital costs of similar local projects. As no new large scale hydro projects have been undertaken recently in New Zealand, the estimated capital costs for the proposed hydro plants in Section 4.2 have been used. The capital costs of these projects have been escalated to 2011 values. The proposed project costs (publically available) have been assumed not to include the pre-development costs, when calculating the k factors.

The proposed project costs had the 'additional costs' of the access roads, substation, transmission line, land and environmental mitigation removed from the overall project costs (where the costs originally had these costs included). Where the details of these costs have not been provided by the generators, or they are not publically available, they have been estimated using the techniques described in Section 5.2.13.3.

The adjusted escalated proposed project costs (with the above additional costs removed) were used to calculate the k factor for each project. These k factors were then averaged to determine the k factor for the generic plant costs.

As the calculated k factor is based on 2011 New Zealand Dollar project costs, the generic hydro estimated costs calculated using the Gordon's formula (using these k factors) can be considered to be current New Zealand dollar costs.

The average k factor for the proposed hydro schemes, where the capital cost is publically available, was calculated to be **35**. The minimum k factor was 18 and the maximum was 47.

Three of the schemes (Wairau, North Bank Tunnel and Stockton Plateau) had a k factor of between 44 and 47. These three schemes have significant construction challenges and corresponding costs associated with the project, such as multiple power stations with long canals, significant amounts of tunnelling and an off-shore outlet. Therefore where a project cost estimate is to be made where significant and costly construction challenges are anticipated, a k factor of **45** should be used.

For the generic plants, a k factor of **35** has been used.

5.2.13.3 Estimation of Additional Costs

The following techniques have been used to estimate the 'additional costs' that are not included in the Gordon's formula.

Pre-Development

The pre-development cost, for assessing the scheme feasibility and obtaining land and environmental consents, has been assumed to have a typical cost of **3%** of the total project costs. The pre-development costs can vary significantly, depending on many factors such as the level of research studies that are required, the environmental considerations that need to be taken into account, opposition to the scheme and the time taken to obtain final approval.

This typical cost for the pre-development is based on the article in the Otago Daily Times *'Almost $12m spent on tunnel scheme, 07/10/2009'*, which mentions that $45 million was spent on investigations, research, studies, engineering and resource consents for Project Aqua. The report from the Commerce Committee *'2002/03 Financial review of Meridian Energy Limited'* mentions that the project was estimated to cost $1.2 billion dollars. Using this 2003/2004 information, the pre-development expenses represent approximately 3.8% of the total project costs.

This Otago Daily Times article also mentions that almost $12 million has been spent on the North Bank proposal, and that these costs were likely reduced because of the research and studies during Project Aqua. This 2009 value is approximately 1% of the 2009 project costs and considering that 'the costs would have been far greater' if the work from Project Aqua was not utilised, this percentage of total project could be considered to be underestimating the total pre-development costs.

Access Road

The cost of access roads is very project specific and can vary widely, depending on many factors including the remoteness of the plant, the number of bridges and tunnels required, the local terrain, the distance to the nearest suitable existing road and the amount of upgrading that the existing roads may have to undergo to service the plant during construction and operation.

For the generic plant, an access road cost of $250,000 per km has been assumed, with a typical access road length of 10km. Both the cost and length can vary significantly for each project, so accurate project specific information should be used, where available, to more accurately determine overall estimated project costs.

Substation

Refer to Section 4.2.16.2.

Transmission Line

Refer to Section 4.2.16.1.

Land

The land purchase costs have been assumed to be $109,000 per hectare, based on land costs estimates used in the report *'Transmission to enable renewables potential NZ hydro schemes, Parsons Brinckerhoff Associates, June 2008',* escalated to 2011 costs using the Consumer Price Index. Where this cost is used for generic plants or where insufficient project information is available, it can also be considered to be arbitrary as the location and land ownership can significantly impact on this cost.

The following Table 5-7 lists the typical area of land that would need to be purchased for each generic hydro plant category.

Table 5-7 Generic Hydro Power Plant Estimated Land Area

Estimated Land Area			
Category	**Unit Output**	**Plant Storage**	**Land Area (Ha)**
Medium	10MW – 100MW	Run-of-River	50
Medium	101MW – 300MW	Dam and Reservoir	300
Large	>301MW	Dam and Reservoir	900

Environmental Mitigation

As mentioned in the report '*Transmission to enable renewables potential NZ hydro schemes, Parsons Brinckerhoff Associates, June 2008*', historical information indicates that "effects mitigation" costs are approximately 0.5% of the project total costs. However, there continues to be more emphasis on minimising social and environmental impacts for hydro projects, so the costs of mitigation effects has been assumed to be 1% of total project costs. As with other project costs, this cost can vary significantly depending on many project specifics, such as environmental requirements for particular sites and local community recreational area improvements.

5.2.13.4 Total capital costs of generic hydro plants

The total capital costs of the generic plants, in each category, can be determined by calculating the capital costs using the Gordon's formula (using the appropriate k, P and S factors) and adding the 'additional costs' as estimated in Section 5.2.13.3.

This technique was used to estimate the project costs of projects with a more accurately determined capital cost, so that a comparison can be made to determine the accuracy of the generic capital cost estimation. Based on this review, the ±25% error indicated in the Gordon's formula report and the error of between ±50% and ±75% in the report '*Hydro-Electric Potential in New Zealand, A Hydro-Electric Resource Database, Parsons Brinckerhoff Associates, February 2005*', the overall capital cost estimates of generic hydro plants can be considered to be +100%, -50%.

Using this information and the arbitrary typical attributes for the generic plants, the following graph was produced for the overall hydro power plant project costs versus plant power output (refer to Figure 5.5 below). For each of the lines shown on the graph, the plant developed head is constant and the three lines show the effect of an increase in head or a higher k factor on the overall project costs. Also shown are two indicative maximum and minimum generic plant costs, where the arbitrary values have been varied as follows to provide an indication as to how the project costs can vary.

For the indicative minimum case in the graph below, the following values were used to calculate the project costs; k factor = 20, the land costs and areas were halved, the road costs and distances were halved, the pre-development and mitigation costs were halved and the lower transmission line costs were used over half the distance.

Similarly for the indicative maximum case, the following values were used to calculate the project costs; k factor = 45, the land costs and areas were doubled, the road costs and distances were doubled, the pre-development and mitigation costs were doubled, the substation costs were increased by 50% and the higher transmission line costs were used over double the distance.

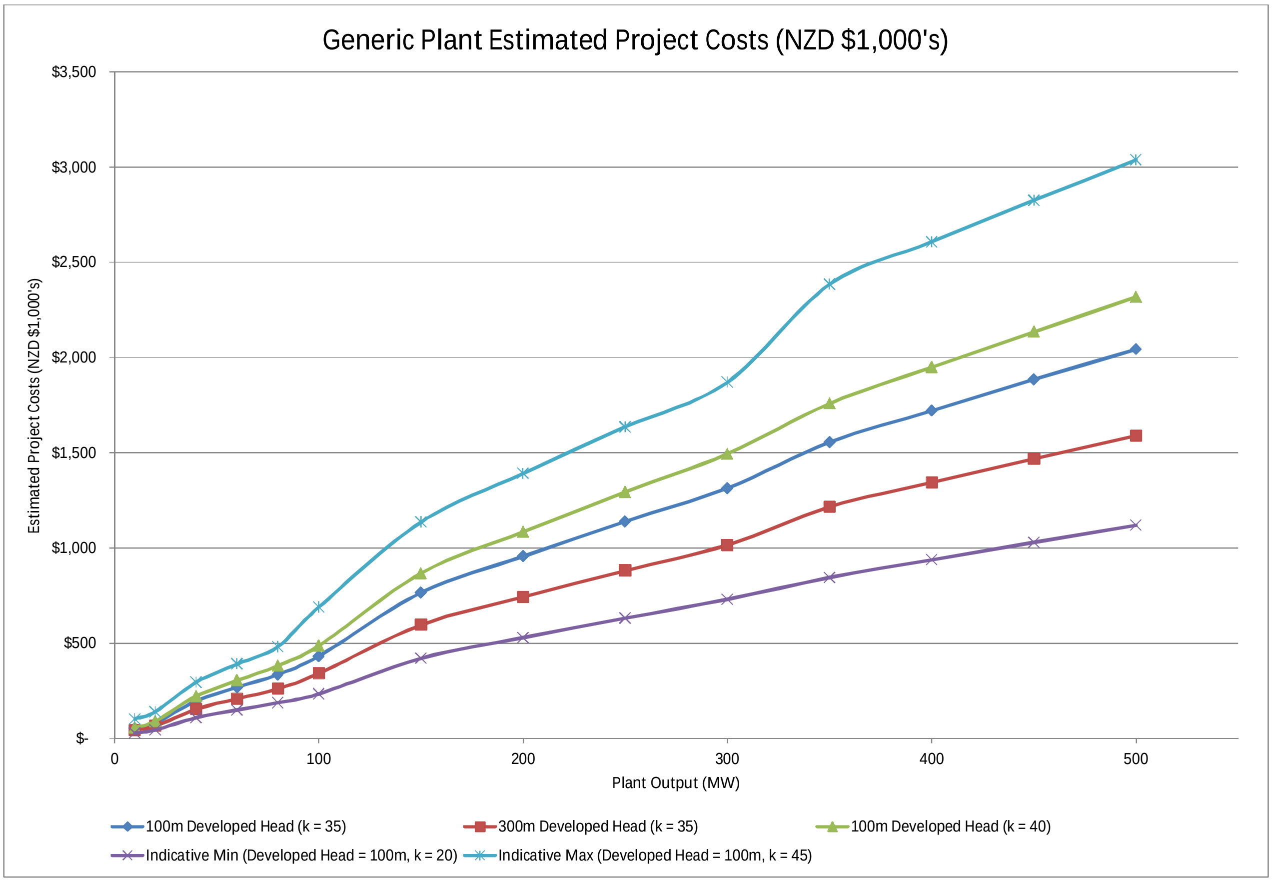


Figure 5.5 Generic Plant Estimated Project Costs

The capital costs shown in Table 5-3 represent the portion of total project capital costs which is typically denominated in NZD currency. The portion of total project capitals costs (in $/kW) which is denominated in a foreign currency has been deducted (refer to Section 5.2.14 below).

5.2.14 Capital cost foreign

Typically the main foreign currency cost of large hydro plants are the electrical and mechanical (E&M) powerhouse equipment. For details on determining the foreign currency costs, refer to Section 4.2.14.

5.2.15 Dominant foreign currency

The electrical and mechanical (E&M) powerhouse equipment are most likely to come from Europe and hence the dominant foreign currency is assumed to be the Euro (€). For details on the foreign currency cost, refer to Section 4.2.15.

5.2.16 Lines connection cost

Refer to Section 4.2.16 for details on the estimated transmission line costs per kilometre.

For the generic plant, a typical transmission line length of 10km has been assumed. The estimated transmission line cost is calculated from this average transmission length, the estimated voltage in Table 4-25 and the median transmission line cost per km.

The transmission line costs and sub-station costs were combined to calculate an estimated line connection costs for the generic plants (refer to Section 4.2.16.2 for details on the technique used to estimate the sub-station costs).

5.2.17 Location

The number and location of new generic plants that can be considered to be viable is very limited due to resource consent issues, suitable available water resources and the location/remoteness of the proposed generic plant. Therefore each case would need to be considered on its own merits. This report provides the following indication of the possible locations and capacities of future generic hydro plants, using the following technique. This has been based on reports from 1990 and 2005 (as detailed below). Recent, up-to-date information has not been obtained, so this information has not been updated or cross-referenced with generator data or an alternative source of information, for example the report *'Waters of National Importance – Identification of Potential Hydroelectric Resources, East Harbour Management Services, January 2004'*.

The report *'Hydro-Electric Potential in New Zealand, A Hydro-Electric Resource Database, Parsons Brinckerhoff Associates, February 2005'* reviews a report by Works Consultancy Services (1990), which considered country-wide potential large hydro-electric schemes greater than 10 MW. The 2005 Parsons Brinckerhoff report considers all schemes > 50 MW identified by the Works report, and some of the schemes between 10 MW and 50 MW, due to a cross-over from another paper looking at small hydro schemes. The report identifies which of the potential schemes were considered to; have no significant environmental impacts, are located in areas that are not extremely remote, and are outside areas of national importance, such as national parks. The following

Table 5-8 provides a summary of the schemes (in Appendix B of the 2005 report) that were considered to be in this category for each assessed region around New Zealand.

This information in the 2005 report was also used to provide indicative samples of possible future generic plants that may be considered around each region in New Zealand (refer to Table 5-3 above). Refer to the 2005 report for a more comprehensive list of potential future schemes. The relevant information from the 2005 report was compared to the existing GEM database, and the scheme descriptions and plant capacities were updated where this information was available. All other data, aside from the plant description and capacities, is based on the example generic plant types provided (50 MW, 150 MW and 450 MW as listed in Table 5-3 above). For more accurate information, each potential generic scheme should be considered on its own merits. Up-to-date information has not been obtained so the information in Table 5-3 has not been updated or cross-referenced with generator data or alternative sources of information.

Table 5-8 Summary of potential regional hydro schemes

Regional capacities of potential large hydro schemes around New Zealand			
Region	**Total Capacity of Potential Schemes**	**Largest Potential Scheme Capacity**	**Smallest Potential Scheme Capacity**
Waikato	None considered viable as located in tourist and scenic area		
Bay of Plenty	None considered viable as located in water conservation area		
Wanganui	60 MW*	60 MW*	60 MW*
Hawke's Bay	44 MW*	44 MW*	44 MW*
Marlborough	850 MW	300 MW	35 MW*
West Coast	375 MW	100 MW	30 MW
North Canterbury	587 MW	140 MW	36 MW*
Central Canterbury	81 MW	35 MW	16 MW
Waitaki	295 MW	260 MW	35 MW
Otago	981 MW	350 MW	17 MW
Southland	None considered viable as located in Fiordland National Park		

The information for the Waitaki, Central Canterbury, West Coast and Otago regions has been updated to consider the cancellation of Project Aqua and the inclusion of the proposed schemes for Lake Pukaki, North Bank Tunnel, Mokihinui, Stockton Mine, Stockton Plateau, Hawea Control Gates and the 16 MW Rakaia River Scheme.

The future generic plant capacities considered for Luggate, Queensberry, Beaumont and Tuapeka schemes in the Otago region were also updated as this information was available on the Contact Energy website.

5.3 Wind

5.3.1 Summary

In order to provide a methodology from which the technical and cost data for future generic wind farms can be estimated, PB recommends the use of three generic types of plant:

- A small wind farm for plant between 10MW and 100MW capacity;
- A medium wind farm for plant between 101MW and 300MW capacity; and
- A large wind farm which would be greater than 301MW capacity.

Table 5-9 summarises the PB recommendations for future generic wind plant technical and cost data.

Table 5-9 Future generic NZ wind plant data

Project name	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Variable O&M costs	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
Generic project type		*Years*	*MW*	*%*	*%*	*%*	*y/n*	*$/MWh*	*$/kW/y*	*NZD/kW*	*EUR/kW*	*Currency*	*$m*
Small Wind	New	25	10-100	92	39/43/48	5	N	3	70	910	1,370	EUR	8.75
Medium Wind	New	25	101-300	92	39/43/48	1.5	N	3	60	780	1,180	EUR	18
Large Wind	New	25	>301	92	39/43/48	1	N	3	50	728	1,100	EUR	25.2
Generic project list													
Generic small wind 1 (Wellington)	WIL	25	50	92	48	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 2 (Manawatu)	WDV	25	50	92	48	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 3 (Waikato)	HLY	25	50	92	43	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 4 (Hawkes Bay)	FHL	25	50	92	43	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 5 (Wairarapa)	WDV	25	50	92	43	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 6 (Wanganui)	BPE	25	50	92	43	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 7 (Northland)	MPE	25	50	92	43	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 8 (Canterbury)	WPR	25	50	92	39	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 9 (Otago)	ROX	25	50	92	39	5	N	3	70	910	1,370	EUR	8.75
Generic small wind 10 (Southland)	NMA	25	50	92	39	5	N	3	70	910	1,370	EUR	8.75
Generic medium wind 1 (Manawatu)	WDV	25	200	92	43	1.5	N	3	60	780	1,180	EUR	18

Project name	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Variable O&M costs	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
Generic medium wind 2 (Waikato)	HLY	25	200	92	43	1.5	N	3	60	780	1,180	EUR	18
Generic medium wind 3 (Wanganui-Taupo)	BPE	25	200	92	43	1.5	N	3	60	780	1,180	EUR	18
Generic medium wind 4 (Hawkes Bay)	FHL	25	200	92	43	1.5	N	3	60	780	1,180	EUR	18
Generic medium wind 5 (Otago)	ROX	25	200	92	39	1.5	N	3	60	780	1,180	EUR	18
Generic large wind 1 (Manawatu)	WDV	25	500	92	43	1	N	3	50	728	1,100	EUR	25.2
Generic large wind 2 (Southland)	NMA	25	500	92	39	1	N	3	50	728	1,100	EUR	25.2

5.3.2 Location/Substation

The likely locations for future wind farms are close to existing transmission lines in areas with good wind resource. PB would recommend that the modelled wind farms are located in the following regions and connected to the following transmission nodes:

- Waikato – HLY;
- Manawatu/Wanganui – WDV;
- Hawkes Bay – FHL;
- Wairarapa – MST;
- Wellington – WIL;
- Canterbury – WPR;
- Central Otago - ROX; and
- Southland – NMA.

5.3.3 Project lifetime

PB recommends using 25 years for the operational life of a future generic NZ wind farm.

5.3.4 Operational capacity

An estimate of the overall potential for additional wind generation in New Zealand has been quoted in the NZ wind industry as high as 2,500MW however this figure would likely include the proposed wind farms covered in Section 4 of this report. The number of new future onshore wind farm opportunities is limited by a number of technical factors including available land with suitable wind resource and transmission capacity constraints.

When considering the contribution that wind generation could make to the future mix of energy supply, PB has estimated the breakdown of the number of wind farms that could be developed for each generic category proposed (small, medium and large). The estimates have been based on the characteristics of existing wind farms and the breakdown of proposed wind farms covered in Section 4.3. PB considers the estimated breakdown to be indicative of the future pattern of development (out to 2050) and in addition to the proposed wind farms covered in Section 4.3.

Table 5-10 Future NZ wind farm potential

Wind farm potential in NZ			
Category	**Unit Output**	**Total number of wind farms**	**Estimated potential capacity**
Small	10 MW – 100 MW	10	500 MW
Medium	101 MW to 300 MW	5	1,000 MW
Large	>301 MW	2	1,000 MW

PB considers that re-powering of existing wind farms is also a modelling alternative to building new wind farms which should be considered. When existing wind farms reach the end of their original design lives, the WTGs may be replaced by higher capacity rated or more efficient WTGs, which provides the option of reducing the number of WTGs. Given the assumption that the existing wind farms would already occupy the 'best' sites for wind generation, this may prove to be the most economically beneficial option for developers/generators.

PB is of the opinion that offshore wind farms won't be as viable as onshore due to New Zealand's small population, relatively limited energy consumption growth and large unpopulated areas of land suitable for constructing a wind farm. Countries currently pursuing offshore wind options, such as the UK, are limited in both greenfield and brownfield onshore development sites and hence offshore wind provides a viable option to meet renewable energy targets.

In the future PB would expect there to be a larger number of small distributed generation type wind projects. This would typically be from land owners and small communities wanting to develop a small (<10MW) wind energy project for their own supply which would be connected to the local distribution network for the export of any surplus energy.

5.3.5 Availability Factor

There may well be some advances in WTG design and materials development which would have a positive effect of the availability of WTGs over their operational life. It is still likely that scheduled servicing and maintenance will still be required, and the unscheduled outages become less frequent in the future however any effects are likely to be within the margin of error for the GEM analysis. PB recommends using the AF of 92%, estimated in section 3.3.7.

5.3.6 Net Output Factor

The majority of the best wind farm sites with respect to wind resource have already been identified and either developed, consented or are in development. Given the assumption that remaining sites which are not already constructed or under investigation will not be the 'best' sites in terms of wind resource, there could be an argument to suggest that the likely NOF to be used should be lower.

In PB's opinion technology and wind farm development advances are likely to offset any decrease in the NOF resulting from slightly lower wind regimes. PB therefore recommends using the same average NOFs estimated in section 3.3.8, for the future generic wind farms.

Table 5-11 PB estimated average lifetime NOF for future generic wind farms

Region	Estimated average NOF (%)
North Island	43
South Island	39
High wind areas (Tararua or direct equivalent)	48

5.3.7 Unit largest Proportion

WTGs are generally becoming larger in capacity, with currently available WTG that have nameplate capacities of over 5 MW. Although, New Zealand will be restricted over their technology selection by their IEC classification (refer to sections 3.3.6 and 3.3.7).

PB has estimated the ULP based on the following assumptions:

- Small wind farm – Capacity = 40 MW, WTG size = 2 MW, ULP = 5%
- Medium wind farm – Capacity = 200 MW, WTG size = 3 MW, ULP = 1.5%
- Large wind farm. Capacity = 300 MW, WTG size = 3 MW, ULP = 1%

Typically sites with extreme wind speeds, high capacity factors and turbulences require specific technology to withstand the conditions and last the designed life (as per the international standard IEC 61400-1 design requirement). New Zealand has high capacity factors compared to that of the rest of the world which limits their technology selection and can curtail the introduction of WTGs with a greater nameplate capacity of 3 MW.

5.3.8 O&M costs

Advances in WTG technology may produce better reliability and reduced servicing requirements in the future, which may have a negative pressure on O&M costs over the life of the wind farm. Given the level of materiality for the modelling input data, any impacts are likely to be small and within the margin of error. PB recommends using the same variable and fixed O&M costs as estimated in section 4.3.10.

5.3.9 Capital cost components (NZD and foreign)

PB recommends using the same estimated capital costs for the future generic wind farms as included in Section 4.4.12 for the proposed NZ wind farms.

5.3.10 Dominant foreign currency

Although it is possible to source the major WTG component from Asia, PB would recommend that the MED use the Euro as the dominant foreign currency for estimating foreign denominated capital costs for future generic wind farms.

5.3.11 Lines connection cost

PB has used the estimates provided in Section 4.3.13 to calculate the lines connection cost (LCC) values for the 3 generic types of future NZ wind farms.

- Small wind farm – Capacity = 50 MW, LCC = $8.75 million
- Medium wind farm – Capacity = 150 MW, LCC = $18 million
- Large wind farm. Capacity = 300 MW, LCC = $25.2 million

5.4 Geothermal

5.4.1 Summary

Table 5-12 summarises the PB recommendations for future generic geothermal plant technical and cost data.

Table 5-12 PB recommendations: Future generic NZ geothermal plant data

Project category/ name	Plant technology	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload?	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
Generic project types			*Years*	*MW*	*%*	*%*	*%*	*y/n*	*$/kW/y*	*NZD/kW*	*USD/kW*	*Currency*	*$M*
Small geothermal	Conv, ORC	Grid/ Embedded	40	<50	95	97	50	Y	105	720	4,280	USD	2.5
Medium geothermal	Conv, ORC	Grid	40	51-100	95	97	50	Y	105	505	3,000	USD	5
Large geothermal	Conv, ORC	Grid	40	>101	95	97	50	Y	105	394	2,340	USD	7.5
Future generic project list													
Kawerau generic 1	Conv, ORC	KAW	40	70	95	97	50	Y	105	505	3,000	USD	5
Kawerau generic 2	Conv, ORC	KAW	40	30	95	97	100	Y	105	720	4,280	USD	2.5
Mangakino generic 1	Conv, ORC	WKM	40	40	95	97	100	Y	105	720	4,280	USD	2.5
Ngatamariki generic 1	Conv, ORC	OKI	40	100	95	97	50	Y	105	394	2,340	USD	7.5
Ngawha generic 1	Conv, ORC	KOE	40	25	95	97	100	Y	105	720	4,280	USD	2.5
Ohaaki generic 1	Conv, ORC	OKI	40	40	95	97	100	Y	105	720	4,280	USD	2.5
Rotokawa generic 1	Conv, ORC	WRK	40	130	95	97	50	Y	105	394	2,340	USD	7.5
Rotokawa generic 2	Conv, ORC	WRK	40	130	95	97	50	Y	105	394	2,340	USD	7.5
Rotoma generic 1	Conv, ORC	KAW	40	35	95	97	100	Y	105	720	4,280	USD	2.5
Tauhara generic 1	Conv, ORC	WRK	40	80	95	97	50	Y	105	505	3,000	USD	5
Tauhara generic 2	Conv, ORC	WRK	40	80	95	97	50	Y	105	505	3,000	USD	5
Tikitere-Taheke generic 1	Conv, ORC	ROT	40	160	95	97	50	Y	105	394	2,340	USD	7.5
Tikitere-Taheke generic 2	Conv, ORC	ROT	40	80	95	97	50	Y	105	505	3,000	USD	5

5.4.2 Plant and location

As geothermal projects must be located close to or within geothermal energy resources, then such plants are naturally restricted to where geothermal resources are located in New Zealand. The regions are in the Central Volcanic Plateau from Tongariro national park, across Taupo and north East through Rotorua to Whakatane and White Island. The only other region in New Zealand to contain significant geothermal resources is in the far north near Kaikohe at Ngawha.

There are no geothermal resources suitable for significant power generation in the South Island.

5.4.3 Plant technology

The currently known geothermal plant technology which future plant could feasibly employ would be:

- Conventional single, dual or triple flash condensing steam turbine plants;
- Organic Rankine Cycle plants;
- A mixture of the two technologies above either Binary Combined Cycle or single flash condensing plant with an Organic Rankine Cycle plant on the brine stream; and
- Kalina Cycle plant, although PB understands this is not yet commercially proven.

There is potential to utilise ‘deep geothermal energy’ technology to extract stored heat (at >300 degrees centigrade) which exists beneath the Taupo volcanic zone. Investigations into the viability of using this type of technology are underway around the world and not yet commercially available.

5.4.4 Substation

The most likely transmission grid nodes for connection of future geothermal plant to the grid would be Wairakei (WRK), Ohaaki (OKI), Whakamaru (WKM), Kawerau (KAW), Rotorua (ROT) and Kaikohe (KOE).

5.4.5 Project lifetime

PB recommends the MED use an average operational life expected from future geothermal projects as 40 years.

5.4.6 Operational capacity

The future generic plant we have assumed to fall into one of the following size categories.

- Small = <50 MW;
- Medium = 51-100 MW; and

- Large = >101 MW.

Excluding the proposed geothermal plant included in Section 4.4, PB's high level estimate of the amount of potential 'developable' new geothermal generation in NZ using currently available technology is around 1,200 MW. We would expect new geothermal plants in the foreseeable future (out to 2050) to be an even spread over the three sizes, but the emphasis may shift more to smaller size plants as additional stages are added to existing developments, and smaller, lower quality resources are utilised.

PB has used a recent estimate[116] (by Lawless, 2002) of potential capacity by steamfield to verify the size and spread of possible future generic plant for use in the GEM analysis. This list of generic plant represents PB's estimate of the maximum potential generation available given existing information. Additional geothermal generation capacity may exist over the above estimated limit but would require investment in resource investigation.

5.4.7 Availability Factor

PB recommends the average Availability Factor of 95% for future generic plant in the GEM. PB does not expect that this is likely to significantly increase in the foreseeable future, and we believe that it would equally be applicable to both Organic Rankine Cycle as well as conventional condensing steam turbine technology and would also be independent of plant size.

5.4.8 Net Output Factor

PB recommends using an average Net Output Factor of 97% for future generic geothermal plant. The Net Output Factor is often lower during the first years of a plant's commercial operation as technical issues are resolved, then can rise during the next 10 years of operation to close to 100%. As the plant becomes older and technical issues start to arise, the NOF will decrease.

However, over the plants economic life we consider an average of 97% as being appropriate for the purposes of modelling plant in the GEM.

PB does not expect that this is likely to significantly increase in the foreseeable future, and we believe that it would equally be applicable to both Organic Rankine Cycle as well as conventional condensing steam turbine technology and would also be independent of plant size.

5.4.9 Unit largest proportion

This would very much depend on the technology, size of the plant and the size and number of each unit. The largest current conventional geothermal unit technically feasible at this time is about 140 MW (Nga Awa Purua station). Most Organic Rankine Cycle units can be up to 20 MW in size.

In the future, it is possible that the size of the largest unit will increase as steam turbine technology and materials science continues to advance. However, there would likely be significant technical issues to overcome for geothermal steam turbines in excess of 150MW.

[116] *Assessment of New Zeland's high temperature geothermal resources. Lawless, 2002.*

For modelling purposes, PB recommends using a ULP of 50% for generic future geothermal plant.

5.4.10 Baseload

Because of their relatively high capital costs but low running costs, including zero fuel costs, geothermal plant are likely to be operated as baseload stations.

5.4.11 Variable O&M costs

For geothermal plant, variable O&M costs are a very small proportion of the total O&M costs, and mainly made up of consumable materials and chemicals. Therefore, PB recommends these are modelled as zero.

5.4.12 Fixed O&M costs

As per Section 3.4.11, for the modelling of future generic geothermal plants, PB recommends a value of $105/kW/year.

5.4.13 Capital cost (NZD and foreign currency components)

The capital cost per kW for geothermal plant is primarily dependant on the total size (MW capacity) of the plant, and in particular the size of the individual units.

PB has based estimates on recent experience with worldwide geothermal projects. The indicative costs below are based upon PB in-house geothermal cost database and experience gained by our geothermal specialists.

The capital cost estimates (NZD and foreign currency components) provided in Table 5-13 are based on the following set of assumptions:

- The costs shown below assume condensing rather than back pressure units.
- The costs below assume an EPC type project implementation.
- The costs include all geothermal project development costs including:
  - Exploration costs (including the cost of three exploration wells)
  - Cost of all development wells.
- Direct (EPC) costs for the project including steam field pipelines and facilities as well as the power plant.
- Owner's costs (indirect costs) including management, administration, Owners Engineer, financing (including IDC), and legal costs. These indirect costs have been estimated at 10% of the direct costs.
- These costs are expected to have an accuracy of not better than +/- 30%.

Table 5-13 Capital cost – future generic geothermal plant

Generic geothermal plant capital cost estimates			
Plant size	**NZD component $/kW**	**Foreign currency component $/kW**	**Dominant foreign currency**
10-20MW	965	5,730	USD
21-50MW	720	4,280	USD
51-100MW	505	3,000	USD
>101MW	394	2,340	USD

These generic high level costs are applicable to both conventional as well as Organic Rankine Cycle plant. These costs are provided as a guideline only, as actual costs may vary considerably due to market conditions at time of bid and costs of raw materials.

5.4.14 Dominant foreign currency

The two dominant currencies for geothermal plant are expected to be USD and YEN. For MED modelling purposes it is reasonable to assume that all foreign currency denominated plant costs are in USD.

5.4.15 Lines connection cost

The potential locations for future geothermal plant are generally located in close proximity to existing transmission lines and grid substations. For estimating average lines connection costs PB has assumed the same distance (5km) for each size category of plant. The substation size and associated equipment ratings have been assumed for a 25MW, 75MW and 150MW plant as the mid-point in each of the generic categories, and costs estimated as per the methodology in Section 4.2.16.

5.5 Other

5.5.1 Summary

Table 5-14 summarises the PB recommendations for future generic marine, solar and pumped storage plant technical and cost data.

Table 5-14 PB recommendations: Future generic NZ tidal, wave, solar and pumped storage plant data

Project category/ name	Plant technology	Energy Type	Substation	Project lifetime	Capacity	Availability Factor	Net Output Factor	Unit largest proportion	Baseload	Fixed O&M costs	Capital cost NZD component	Capital cost foreign	Dominant foreign currency	Lines connection cost
Future generic project list				*Years*	*MW*	*%*	*%*	*%*	*y/n*	*$/kW/y*	*NZD/kW*	*USD/kW*		*$M*
Tidal small	Tidal	Marine	MPE	20	10	90	32.5	10	N	100	2,100	1,700	EUR	9
Tidal medium	Tidal	Marine	WIL	20	50	90	32.5	2	N	90	1,800	1,450	EUR	9
Tidal large	Tidal	Marine	WIL	20	200	90	32.5	0.5	N	80	1,700	1,350	EUR	18
Wave small	Wave	Marine	MPE	20	10	90	32.5	10	N	100	2,100	1,700	EUR	9
Wave medium	Wave	Marine	NPL	20	50	90	32.5	2	N	90	1,800	1,450	EUR	9
Wave large	Wave	Marine	INV	20	200	90	32.5	0.5	N	80	1,700	1,350	EUR	18
Solar small 1	Solar PV	Solar	HPI	20	10	95	20	100	N	70	2,250	2,800	EUR	9
Solar small 2	Solar PV	Solar	STK	20	10	95	20	100	N	70	2,250	2,800	EUR	9
Solar medium 1	Solar thermal	Solar	HPI	20	50	95	30	100	N	70	1,650	2,050	EUR	9
Solar medium 2	Solar thermal	Solar	STK	20	50	95	30	100	N	70	1,650	2,050	EUR	9
Solar large 1	Solar thermal	Solar	HPI	20	200	95	30	100	N	70	1,500	1,850	EUR	18
Solar large 2	Solar thermal	Solar	STK	20	200	95	30	100	N	70	1,500	1,850	EUR	18
Pumped Storage medium	Pumped storage	Hydro	TKN	80	100	95	35	50	N	20	6,400	850	EUR	15
Pumped Storage large	Pumped storage	Hydro	BEN	80	300	95	35	33	N	20	6,000	800	EUR	20
Pumped Storage medium	Pumped storage	Hydro	TKN	80	100	95	35	50	N	20	6,400	850	EUR	15
Pumped Storage large	Pumped storage	Hydro	BEN	80	300	95	35	33	N	20	6,000	800	EUR	20

5.5.2 Marine

Marine energy resources suitable for commercial scale generation using currently available technology are primarily located around the West coast of New Zealand (including Kaipara Harbour), the Cook Strait and around Chatham Island.

Given that the GEM input variables are predominantly influenced by the size of a scheme, a representative category list of future generic marine energy projects for use in the MED modelling consists of the following:

- An array of marine energy devices of 10 MW in net capacity
- An array of around 50 MW in net capacity; and
- An array of around 200 MW in net capacity.

There is a considerable amount of difficulty around estimating generic capital costs for marine energy projects due the lack of reference plant information and the current stage of technology development for the generating equipment. Current reference information indicates total project capital costs including equipment and installation at around a multiple of 1.5 times the capital costs for wind plant. PB recommends using this multiple of the generic wind project capital costs estimated in Section 4.3.11 for modelling marine energy plants in GEM.

PB expects the availability of marine generating equipment to be slightly lower than that of onshore wind turbines. This is primarily related to the relatively harsher ocean environment and more complex maintenance access issues. An availability factor of 90% would be representative of the duration of scheduled and unscheduled outages for marine generating equipment.

PB has assumed average O&M costs are approximately 25% more than those for onshore wind due to the expected increased maintenance (unscheduled and scheduled) requirements and harsher marine environment.

Average capacity factors for marine energy schemes are estimated at between 25-35%, which when combined with the availability factor assumptions provides a net output factor range of between 27.5% and 37.4%. PB recommends a NOF value of 32.5% for the GEM input data.

Currently marine energy generating equipment is predominantly being manufactured and developed in Europe but can also be sourced from the United States. PB recommends that the GEM uses the Euro (EUR) as the dominant foreign currency.

Based on the analysis of capital cost components, there is a 60%/40% split for the foreign/domestic capital component breakdown which is similar to that estimated for wind plant. This is consistent with our opinion that the NZD denominated installation and contractor costs will represent a larger portion of the overall project capital cost (compared to wind).

Representative transmission network nodes for connection of possible future marine energy projects (>10MW) are Maungatapere (MPE), Wilton (WIL), New Plymouth (NPL) and Invercargill (INV). PB has assumed that the lines connection cost relates to the connection from the transmission (or distribution network) to the marine project substation/connection point onshore. Given the possible locations of the marine energy projects will involve similar transmission connection distances to wind farms, the costs estimated in Section 4.3.13 have been used.

PB recommends the GEM adopts a project lifetime of 20 years for marine energy projects, which is regarded as a minimum for a commercial scale generation scheme.

5.5.3 Solar

The two dominant solar technologies are solar photovoltaic (solar PV) and solar thermal. For the purposes of providing future generic solar plant options, and given that the choice of solar technology and scheme size are the primary drivers of the overall solar plant capital cost, PB has split the plant category options into the following:

- Solar PV technology for a scheme size of 10 MW operational capacity; and
- Solar thermal technology for two scheme size options of 50 MW and 200 MW capacity.

The most likely locations of future commercial scale solar projects are in areas of higher solar radiation. Suitable representative transmission network nodes for connection of possible future solar energy projects (>10 MW) are Huapai (HPI) in the North Island, and Stoke (STK) in the upper South Island.

Using the reference case exchange rates, available reference data indicates total project capital costs in NZD in the following ranges:

- Solar PV – $5,500/kW to $8,500/kW
- Solar Thermal – $4,500/kW to $6,500/kW

PB recommends using the following values for modelling future generic solar plants in GEM which take into account the economies of scale associated with larger capacity solar thermal plant.

Table 5-15 Generic solar plant capital cost estimates

Generic solar plant capital cost estimates			
Technology	**NZD component $/kW**	**Foreign currency component €/kW**	**Dominant foreign currency**
Small PV	2,250	2,800	EUR
Medium solar thermal	1,650	2,050	EUR
Large solar thermal	1,500	1,850	EUR

Based on our analysis of the capital cost components there is a 70%/30% split of the foreign/domestic capital cost breakdown which is similar to that estimated for a CCGT plant in section 4.1.16 and that the level of total O&M costs would be comparable to the level of running an OCGT plant.

Given the relatively early developmental stage of commercial scale solar generating technologies, it is appropriate to consider the future price path for the capital costs. Reference information suggests a progress ratio[117] of around 80% - 85% which suggests that plant capital costs (in real terms) could fall by up to 50% over the next 10 to 20 years. These

[117] *The progress ratio r is defined as the complementary to the learning factor l, that is: r=100 percent-l.*

forecasts are based on a number of assumptions including forecast efficiency improvements, learning effects from increased volume production and economies of scale from larger plant and unit sizes.

PB expects the availability of solar plant to be equivalent to other renewable technologies such as geothermal and wind. An availability factor of 92.5% would be representative of the duration of scheduled and unscheduled outages for solar generating equipment.

Average capacity factors for PV solar projects schemes are estimated at between 10-25% and at around 25-35% for solar thermal projects. When combined with the availability factor, PB recommends the GEM adopts a NOF value of 20% for solar PV and 30% for solar thermal projects.

PB recommends that the GEM uses the Euro (EUR) as the dominant foreign currency.

Given the possible locations of the solar energy projects will involve similar transmission connection distances to wind farms, the costs estimated in Section 4.3.13 have been used.

PB recommends the GEM adopts a project lifetime of 20 years for solar energy projects, which is regarded as a minimum for a commercial scale generation scheme.

5.5.4 Pumped storage hydro

In order to provide estimates for generic future pumped storage hydro plant in New Zealand, PB has assumed the same methodology as that provided in section 4.2 for conventional hydro projects, with the following exceptions:

- Reference information suggests a range of NZ$7,000 to $9,000/kW for pumped storage plant in the range of 100 MW to 300 MW. This is consistent with PB's data which suggests that the additional civil, electrical and mechanical components associated with the pumping function of the plant will add between 10% and 20% to the total project cost compared to conventional hydro schemes. Given the potential for economies of scale, PB recommends the GEM should adopt the following generic pumped storage plant categories and associated capital costs:

Table 5-16 Generic pumped storage hydro plant capital cost estimates

Generic pumped storage hydro plant capital cost estimates			
Type	**NZD component $/kW**	**Foreign currency component €/kW**	**Dominant foreign currency**
Medium PS hydro (100MW)	6,400	850	EUR
Large PS hydro (>300MW)	6,000	800	EUR

- Approximately 20% of the total capital cost is denominated in a foreign currency which is slightly higher than conventional hydro given the additional E&M equipment relating to the pumping function.

- For possible transmission connection points for a generic pumped hydro scheme, PB has assumed one North Island (Tokaanu) and one South Island location (Benmore) close to existing large scale hydro schemes for each of the size categories suggested above.

6. Plant component cost breakdowns

6.1 Thermal

The majority of the capital costs of thermal power plants are the generating equipment costs. The estimated breakdown of project capital costs contained in sections 4 and 5 has been expanded to include the major cost components included in Table 6-1. The typical cost breakdown has been based on the generic 400MW CCGT project.

Table 6-1 Thermal project cost breakdown

Component	% of total project capital cost	Likely cost range (% of total cost)
Project		
Pre-Development	5	3-7
Equipment	60	50-70
Civil Works	15	10-20
Engineering	5	3-7
Owners Costs	10	8-12
Contingencies	5	3-7
Total	**100**	

6.2 Hydro

The majority of the capital costs of hydro power plants are highly project specific, as the majority of the project costs are the civil costs, which depend heavily on the location, geological conditions and the type of scheme. However, as discussed in Sections 4 and 5, estimations can be determined using typical arbitrary values. These estimations were compared to projects Parsons Brinckerhoff has previously worked on, to provide the following typical estimates of the cost breakdown for future hydro projects (refer to Table 6-1 below).

The typical percentage of total project costs for **power plant E&M** is considered to include direct E&M costs (as detailed in Section 4.2.14), substation costs, transmission costs, design engineering costs and the E&M contractor’s contingencies.

The typical percentage of total project costs for **civil works** is considered to include direct civil construction costs, access roads, buildings and powerhouse structures, design engineering costs and the civil contractor’s contingencies.

The typical percentage of total project costs for **contractor indirects** is considered to include costs such as project management, risk allowance, site mobilisation, contractor’s margins and other overheads.

The typical percentage of total project costs for **owner’s costs** is considered to include the owners overall supervision of the projects and other owner costs associated with the project, such as legal fees, insurances and community engagement.

Table 6-2 Hydro project cost breakdown

Component	Percentage of total project capital cost	References / Information
Project		
Pre-Development	3%	Refer to Section 5.2.13.3
Power Plant (E&M)	19% (+50%, -30%)	Refer to Section 4.2.14 for direct E&M costs, percentage includes substation and transmission costs, refer to information below
Civil Works	49% (+60%, -30%)	Including access roads and buildings/structures, refer to information below
Contractor Indirects	19%	Including contractor overheads and profits, refer to information below
Owners Costs	2.5%	Including project supervision, refer to information below
Contingencies	7.5%	Refer to information below
Total	**100**	

The typical percentage of total project costs for **contingencies** is considered to allow for potential project cost escalation from delays or project uncertainties.

6.3 Wind

Table 6-3 summarises PB's cost breakdown estimates and likely cost ranges for the main categories of capital costs for a NZ wind farm:

Table 6-3 Generic wind farm project cost breakdown

Component	Average percentage of total cost (%)	Dominant Currency	Likely cost range (% of total cost)
Capital costs			
Nacelle and power conversion	45	EUR	40-50
Blades	11	EUR	9-13
Towers	6.5	EUR	5-8
Transport	5	USD	4-6
Installation (WTG)	5	EUR	4-6
Grid connection	5	NZD	2-8
Civil including foundation	6	NZD	4-8
Electrical installation	1.5	EUR	1-2
Other (including consultancy, consent, financial, legal, roading and land costs)	15	NZD	10-20
Total	**100**		**-**

6.4 Geothermal

The approximate capital cost breakdowns have been generated using our (PB) in-house geothermal cost data base for geothermal projects. The values are based on an EPC type project implementation method.

We have assumed that the indirect costs (taken as 10% of direct costs) are spread through the components based upon the proportion of each component. The indirect costs covering all owner's costs include management, administration, Owners Engineer, financing, and legal costs. These indirect costs have been taken as 10% of the direct costs.

However, land acquisition costs, insurance and permitting have **not** been included in the 10% indirect costs. The IDC costs also are apportioned according to the % of the capital cost of each component.

Table 6-4 Geothermal project capital cost breakdown

Component	Average percentage of total project capital cost (%)	Likely cost range (% of total cost)
Project		
Exploration	8	5-10
Wells	36	30-45
Steam field	10	5-15
Power plant	46	30-60
Total	**100**	**-**
Power plant		
Engineering/design	9	7-11
STG supply	22	20-24
Electrical/Controls	11	9-13
Condensing System	20	15-25
Pipe/valves/vessel	15	12-18
Other Misc	5	5
Civils	11	7-15
Erection	7	5-9
Total	**100**	**-**

7. Thermal plant heat rate vs. utilisation

Heat rate is a measure of fuel conversion efficiency given as fuel energy input per power output. The primary factors affecting average plant heat rate over the life of a thermal plant are:

- Type of plant
- Equipment selection;
- Fuel supply type and quality;
- Operational role (frequency of starts, trips, load factor); and
- Plant location/environmental factors (e.g. elevation, ambient temperature).

There are some generic principles that apply to understanding how heat rates apply to different thermal plant types.

- Thermal plant heat rates improve (decrease) as unit size increases;
- As new production models are introduced and existing GT designs are advanced over time, heat rates will improve.
- Typically new gas turbine designs are conservatively rated when introduced. They are periodically upgraded over the service life to increase power and efficiency (heat rate). Net heat rate gains associated with these upgrades can range up to 7%.
- High efficiency GT models and thermal plant designs command a higher price premium than less efficient machines.
- Heat rates degrade over the service life of thermal plant, with performance losses usually classed as recoverable or non-recoverable. Recoverable losses are typically reduced or eliminated through maintenance and replacement of components. Typical average heat rate degradation for GTs may be between 2% and 6% for the first 24,000 hours of operation.
- When thermal generating plants start up they use fuel to get the equipment up to operating speed and temperature. Similarly, fuel is used as the plant reduces speed to its coast-down condition. Thus the more often a plant is started the lower the overall efficiency (higher heat rate) will be.
- When thermal generating plants run at less than full load or maximum continuous rating (MCR), the heat rate tends to increase as the load is reduced. This is particularly so for gas turbines and most pronounced at loads lower than 50% for gas turbines. It is less pronounced for steam turbine plant and generally insignificant for diesel and gas engines (reciprocating engines).

PB has used GT Pro software to estimate the effects of part loading on the heat rates for selected gas turbines, with the results recorded in Table 7-1 following.

Table 7-1 Gas turbine heat rate change with load factor

Gas turbine plant gross heat rates (kJ/kWh)			
Load condition	**OCGT 120MW GE PG9171E**	**OCGT 162MW Alstom 13E2**	**OCGT 155MW Siemens V94.2**
30%	17,625	16,381	14,253
50%	14,015	12,817	12,412
75%	11,917	11,013	11,262
100% (full load)	10,706	10,018	10,476

PB recommends the following heat rate performance reductions should be applied to thermal plant for the following load conditions:

Table 7-2 Thermal plant heat rate change with load factor

Thermal plant gross heat rate increases				
Load condition	**OCGT 50MW**	**OCGT 150MW**	**CCGT 400MW**	**Coal plant**
30%	40%	40%	-	-
50%	15%	15%	15%	5%
75%	5%	5%	5%	2%
100%	-	-	-	-

The HHV heat rates expressed in this report for baseload plant can be assumed to be the long term average heat rates applying at or around full load or maximum continuous rating (MCR). The heat rates expressed for the peaking plants can be assumed to be long term averages and to include the depreciating (heat rate increase) effects of multiple startups. Note that diesel and gas engine plant heat rates are not significantly affected by multiple startups and part load operation.

Note that the parameter, “net capacity factor” (NCF) is a very coarse means of adjusting heat rate to make allowance of part load operation. This is because a 50% NCF can represent both 50% load for 100% of the time AND 100% load for 50% of the time, and all combinations between.

8. Uncertainty in estimating future plant costs

8.1 Thermal

8.1.1 Introduction

The references used earlier in this report, in particular for the estimation of O&M and specific capital costs, also contain comment on the uncertainty involved in estimating future plant costs. Given that PB has relied on those references for its estimation of O&M and specific capital costs, it is relevant to declare the submissions of those same references on the matter of uncertainty.

8.1.2 EPRI/Worley Parsons, February 2010

EPRI/Worley Parsons, February 2010 notes that:

"*Many factors contribute to the overall uncertainty of an estimate. They can generally be divided into four generic types.*

1. *Technical—Uncertainty in physical phenomena, small sample statistics, or scaling uncertainty.*
2. *Estimation—Uncertainty resulting from estimates based on less-than-complete designs.*
3. *Economic—Uncertainty resulting from unanticipated changes in cost of available materials, labour, or capital.*
4. *Other—Uncertainties in permitting, licensing, and other regulatory actions; labour disruption; or weather conditions.*

As a technology moves along the continuum of development from R&D through commercial installation, the type of risk—and the corresponding uncertainty—tends to change. At the R&D level, technologies face a high degree of both technical and estimation uncertainty. The extent of the uncertainty depends on the number of new parts in a technology and the degree of scale-up required to reach commercial size."

This latter comment applies in particular to new or developing technologies such as IGCC, and does not apply in its fullest sense to mature technology. PB has assumed that all the proposed generators (Belfast, Bromley, Otahuhu C, Rodney, Diesel 1, Todd Peaker, Cogen 1, & CCGT 1) are mature technologies.

Successful R&D efforts resolve many technical uncertainties, but others persist until initial demonstration."

"*Demonstration and commercialisation reduce technical and estimation uncertainties, but economic and other uncertainties always remain. The level of these uncertainties depends largely on the magnitude of capital investment, length of time for field construction, and number of regulatory agencies involved in the project. Recently, this economic uncertainty has been even more extensive with highly volatile pricing that has been seen in the past two years for power plant equipment due to market and macro-economic forces*."

8.1.3 Mott MacDonald, June 2010

Mott MacDonald, June 2010 notes that:

"*The first challenge in estimating the cost of electricity generation is finding appropriate data and interpreting it. There are a number of key questions to address in examining data:*

- *How reliable is it?*
- *What is included in the scope?*
- *How current is it?*
- *Is it representative?*"

Mott MacDonald goes on to make the following comments against each of the above "key questions":

"***Reliability**: The most reliable data is likely to be the detailed prices and terms from commercially confidential contracts between vendors and purchasers*." If it did in fact exist, the owners of the planned generators have not provided such data to PB. Any data PB is privy to could not be divulged for reasons of confidentiality. The "most reliable" data has therefore not been used for this report.

"*Vendors' tender price offers may provide another reasonably reliable estimate of EPC prices, especially if they are the final prices (often called the best and final offer (BAFO) and the project goes ahead*." For the same reasons as noted above, such other "reasonably reliable" data has also not been used for this report.

"*Press releases from original equipment manufacturers (OEMs) and/or developers can provide a high level price, however often in this case it is difficult to ascertain the scope and terms. The same applies to most press reports*." PB has not sought or used press releases or reports for this report.

"*Studies and surveys by international agencies, academic and industry institutes can provide useful insight in terms of comparative levels across jurisdictions and technologies, although they are rarely based on real projects*." PB has relied extensively on such data for this report.

"***Scope and terms**: the scope of works and the price terms for which the headline price relates can vary hugely. Typically EPC contract prices will provide a base price to which adjustments need to be made for material and sub-component price movements or variations for design changes called for by the developer. These EPC bases prices also tend to exclude grid connection (except in the case of wind), off-site fuel supply facilities (ports, gas connections, etc) and decommissioning. They also exclude owners development costs (design and feasibility studies, planning and licensing, etc) and financing costs (interest during construction and other financing charges).*

Another aspect of scope is the technical definition of the plant in terms of its technology, associated facilities and any particular issues or constraints arising from its location. Non-UK experience needs to be adjusted for different project management and working practices, local materials and labour cost differences. Also, there is an issue of the appropriateness of *technology to UK situation (- for instance, experience in Chinese supercritical coal and Korean nuclear technology is of limited relevance to the UK in the near to medium term). One also needs to take into account unit scale issues, impacts of multiple unit installations and series ordering in making price comparisons.*

Terms of pricing also needs to be defined in terms of currency and the date to which the price refers and any agreed indexation, beyond the subcomponent indexation arrangements."

"***Timeliness****: This is the most straight forward question as all that is required is to define the date to which the data refers. The more time that has passed since the date, the greater is the prospect that changes will have made the prices unrepresentative of current levels. This is especially so for the EPC market conditions, though much less so for technology improvements, which tend to advance at a slower rate*."

"***Fair representation****: How representative the cost data is will depend largely on whether the scope and the timing can be easily adjusted to our chosen representative plant technology and size."*

"Another aspect of how representative the data is the number of deals that are done at the price."

"Cost data also needs to be viewed in the context of its relationship with cost data/estimates for related technologies. There are many shared components between technologies and so technology costs should broadly move together."

"*Excluding CCS, the hierarchy of capital costs runs as follows: nuclear is more expensive than coal (due to the much greater cost of a "reactor island" versus a "coal boiler island" and the more substantial and complex civil works [foundations and buildings]); coal is more expensive than oil fired plant given higher fuel handling costs. Fired boiler-steam plant is more expensive that CCGTs as the GT and associated heat recovery steam generator is much lower cost than a fired boiler, even without adding the mandatory "bolt-on" clean-up equipment of flue gas desulphurisation (FGD) and selective catalytic reduction (SCR). In turn, CCGT costs some 50% more than an equivalent open cycle GT given the lower cost of GT than HRSG and steam turbines*."

8.2 Hydro

There are many factors that have an impact on the capital costs of future proposed/generic hydro plants. The following is a summary of the factors that are currently considered to have an impact on future plant costs:

- Resource consent approvals

  The resource consent approval process is long and costly, with significant cost and timeframe variability, and a highly level of uncertainty on the outcome. Public perception and concern on hydro power schemes can have an impact on the approval process and opposition to proposed schemes. Public perception and government political influence may change in the future to reflect both a greater importance of the environment balanced with an increased demand for renewable generation. In the future this may have an impact on the approval requirements, timeframe, costs and likelihood of project approval.

As river hydrology modelling techniques and assessment of ecological impacts of flow modification to rivers continues to develop and improve, the understanding of allowable flow ranges in rivers improves. This may either lead to more flexible or more restrictive operating conditions for future hydro schemes, which will impact on the available energy to generate.

- Environmental/climate change issues

  As the demand for renewable generation increases, the public perception and political influence for acceptance of hydro power schemes may change in the future, as discussed above. The pressure for increased renewable energy is driven from predictions/concerns over climate change. The extent of climate change that may occur could have an impact on future hydro plant generation, as it may impact (positively or negatively) on precipitation rates and corresponding available energy for generation.

  Demand for investment in hydro plants from other industries may also impact on future return on investments of schemes, for example irrigation schemes in the farming industry.

- Market forces and competitiveness of major contractors

  The EPC tender costs can vary significantly depending on the market conditions and corresponding workloads of the EPC contractors and the time of tendering.

- The competition for electricity generation from sources other than hydro, such as wind or photovoltaic generation, may increase or decrease. This may have an impact on the rate of return on investments for future hydro plants.

- Inflation and commodity prices

  The commodity prices of materials can have a significant impact on the project costs, particularly with the prices of oil and metal, such as steel and copper.

  The rate of inflation can change, along with labour costs, both of which can have a significant impact on the overall project costs.

- Location of electrical and mechanic equipment manufacturers

  In sections 4.2.14 and 4.2.15 above, the dominant foreign currency is suggested to be the Euro (€). This is because some of the major hydro plant equipment manufacturers are currently based in Europe. However, the current global trend is for lower cost items to be sourced out Asia. The country of origin for plant equipment and the overall impact this may have on project costs will depend on many factors, such as equipment direct costs, transport costs, lead-times, O&M costs, the preference of the owner, lender and/or contractor and the level of tender documentation, procurement management and inspection and testing required.

- Technology improvements

  Hydro power generation is a mature technology and significant step changes in output or cost are unlikely to occur. However, there have been recent technological advances and small incremental improvements in cost and output may be expected in the future.

  Computer fluid dynamics have enabled incremental improvements in turbine efficiencies and other benefits such as ‘fish friendly’ turbines that have been developed to reduce fish mortality. These benefits can improve the financial viability of proposed systems, through increased plant outputs and reduced environmental impacts. However this currently is not expected to have a significant impact on the capital expenditure of the plant equipment.

Other advances in technology, such as improved monitoring equipment and maintenance software/systems may assist to reduce the operating and maintenance expenses through preventative maintenance and early fault detection.

Future material developments may also assist in reducing maintenance expenses and increase hydro plant life expectancy.

8.3 Wind

PB considers the following to be significant cost drivers of future wind farm capital costs:

- Consenting
- Environmental
- Resource utilisation
- Market competition
- Inflation and commodity prices
- Manufacturer location
- Technology

There are other factors that may influence the overall level of wind farm costs such as development of in-house capabilities and the increased availability of third party contractors, but these are not considered to be as material. The more significant cost drivers are discussed below.

- Consenting

  The resource consent process in New Zealand is typically long and costly by international standards. The level of opposition to proposed future wind farms and the complaints received from parties on recently developed projects (relating to noise, shadow flicker and visual impact) increases the risks (and hence costs) around future wind farms being consented and constructed.

  Any project delays caused by a lengthy and complex consenting process increases the risks of wind farm project development primarily through additional consultation requirements and the potential impacts that final consenting decisions may have on the number and location of consented units due to visual impacts, noise, and other environmental factors.

  With all other factors equal, wind farm developers would choose to develop the easiest to consent sites first. It can therefore be assumed that future wind farm developments would not face an easier consenting process and hence lower consenting relating costs. It is more likely that population growth and urban sprawl over the modelling time frame will increase the risks of future wind farm sites being located close to population centres and provide an upward pressure on consenting costs.

- Environmental and resource utilisation

  As more wind farm sites are being developed, preferable resource zones are being utilised leaving lower generation sites which tilts the project profitability, often making projects unviable at the current technology and contractor costs. New Zealand has little in the way of renewable energy financial incentives with projects typically being financed off the Owner/Developer's balance sheets.

  There are concerns that climate change appears to be affecting the “wind seasons” and resources globally, shifting wind regimes and temperatures can cause positive or negative effects on generation. During the feasibility stage, modelling is undertaken to assess the potential generation from a site. Typically environmental modelling inputs include:

  - Air density

  - Standard deviation

  - Extreme events

  - Average wind speed

  - Temperature

  - Relative humidity

  The modelling period needs to be at least 12 months of onsite data and 10-15 years of historical data sourced from local bureaus of meteorology (dependent upon quality of data). From the time of submission for consent to the time of approval and build, the environmental conditions may have changed effecting the technology to be used and relative CAPEX figures, thus viability.

- Market competition

  The EPC tender costs can vary significantly depending on the market conditions and corresponding workloads of the EPC contractors and the time of tendering.

  The competition for electricity generation from sources other than wind, such as hydro, geothermal or solar generation may increase or decrease

- Inflation and commodity prices

  The commodity prices of materials can have a significant impact on the project costs, particularly with the prices of oil and metal, such as steel and copper.

  The rate of inflation can change, along with labour costs, both of which can have a significant impact on the overall project costs.

- Manufacturer location

  PB suggests the dominant foreign currency to be the Euro (€). This is due to the major WTG equipment manufacturers to be currently based in Europe, irrespective of where their components are manufactured. The current global trend is for lower cost items to be sourced out Asia. Although this may be the case, contracts are signed and projects are paid for in Europe.

  Currently WTG manufacturers in Asia and the United States of America (USA) are attempting to service the NZ market which may significantly affect the total CAPEX as the majority (74%) of total CAPEX is from offshore.

  As with Hydro, countries of equipment origin will have influence on total project costs (CAPEX and OPEX) such as; equipment direct costs, transport costs, lead-times, O&M, the preference of the owner, lender and/or contractor and the level of tender documentation, procurement management and inspection and testing required.

- Technology improvements

  Wind energy, although relatively mature as a form of generation, is still young in design. PB understands there is yet to be a technology released that has not suffered serial defect in some shape or form.

  The current trends in design are to increase the capacity (greater nameplate capacity with similar size rotors), simplify the design (reduce issue components such as gearboxes and unnecessary drive train components) and make the WTGs lighter which reduces installation costs and power to weight ratios.

  Variable speed direct drive technology appears to be the future, eliminating the use of a gearbox which is perceived as a WTG weak point, and thus simplifying the generation.

  Other advances in technology, such as improved monitoring equipment and maintenance software/systems may assist to reduce the operating and maintenance expenses through preventative maintenance and early fault detection.

  Future material developments may also assist in reducing maintenance expenses and increase WTG life expectancy.

8.4 Geothermal

The future capital costs of geothermal power projects will be very much dependent on the following factors:

- Financing:
  - World Economic climate and in particular the ease of financing for power projects
- Market forces and competitiveness of major contractors
  - The EPC market activity. Are EPC contractors very busy, or is the market tight.
- The size and quality of the geothermal fields.

   - Large projects will cost less in terms of $/kW but with all the low hanging fruit now taken, future projects in NZ may be smaller and on resources which are not as attractive (lower temperature, or in remote areas) Therefore, costs per MW are likely to rise.

- The world commodity prices for raw materials and in particular metals

- Environmental/global warming issues

   - The political will of the governments to drive generators into low carbon footprint projects worldwide, (such as the carbon credit market) which would put a strain on the capability of the geothermal industry worldwide to deliver all projects, and also the shortfall of skilled technologists in this field will undoubtedly all lead to higher project costs.

- Technology

   - The ongoing advance in geothermal power technology is expected to increase the efficiency of machines, and drive down costs. However, any efficiency gains in conventional geothermal power plant are likely to be small increments.

8.5 Level of uncertainty by plant type

Table 8-1 indicates the level of uncertainty around estimating future plant costs derived from the main factors discussed above. To simplify the analysis, the main sources of uncertainty affecting accurate estimation of future plant costs have been aggregated into three categories:

- Technological.

   - Technological sources of uncertainty in estimating future plant costs are derived mainly from the level of maturity of each generating plant type. For example, hydro generating technologies are considered mature and hence the possible effects on capital cost from technology advances for hydro plants will be minimal. Technology advances predominantly provide a negative pressure on plant capital costs.

- Materials.

   - Fluctuations in commodity and component prices such as steel, concrete, energy, labour and transport costs has an impact on the cost of key raw materials which form a large part of overall plant capital cost. As commodity and materials prices can and do move up and down, the impact on overall plant cost can either be positive or negative at any given time, however the overall trend is a positive one.

- Environmental, regulatory and financial.

   - This category includes such sources of uncertainty as a future price of carbon emissions, consenting costs, financing costs and political or regulatory support for the generating technology type. The sources of uncertainty in this category can either provide a positive or negative pressure on plant capital costs in New Zealand.

For each category of uncertainty and generic plant type, PB has provided its view on the level to which future plant costs could be affected. These have been defined as:

- Low – The source of uncertainty has the potential to affect the estimation of future plant costs less than 10%;
- Medium – The source of uncertainty has the potential to affect the estimation of future plant costs within a range of 10-20%; and
- High – The source of uncertainty has the potential to affect the estimation of future plant costs by more than 20%.

For example, utility scale solar generating technologies are relatively new (compared to other forms of generation) and hence a significant amount of technological advancement is possible which may have a similar sized effect on reducing the overall plant cost (per MW) of a future project.

Table 8-1 Uncertainty in future New Zealand plant costs

Sources of uncertainty and potential effects on future plant costs			
Plant type	**Technological**	**Materials**	**Environmental, Regulatory and Financial**
	Includes design innovation, efficiency improvements, learning effects and economies of scale.	*Factors include commodity prices, supplier competition and engineering costs.*	*Includes consenting costs, carbon price, interest rates and land costs.*
Thermal			
- CCGT	Low (-)	Medium (+/-)	Medium (+/-)
- Conv. ST	Low (-)	Medium (+/-)	Medium (+/-)
- OCGT	Low (-)	Medium (+/-)	Medium (+/-)
- Recip	Low (-)	Medium (+/-)	Medium (+/-)
- IGCC	High (-)	Medium (+/-)	Medium (+/-)
- ASC	Medium (-)	Medium (+/-)	Medium (+/-)
Hydro	Low (-)	Medium (+/-)	Medium (+/-)
Wind	Medium (-)	Medium (+/-)	Medium (+/-)
Geothermal	Low (-)	Medium (+/-)	Medium (+/-)
Solar	High (-)	High (+/-)	High (+/-)
Marine	High (-)	High (+/-)	High (+/-)
Pumped storage hydro	Low (-)	Medium (+/-)	Medium (+/-)

Note: The '+/–' symbols indicate the direction future plant costs may typically move, i.e. 'up', 'down' or 'up and down' in response to the source of uncertainty.