PB POWER

EMERGING SUPPLY-SIDE ENERGY TECHNOLOGIES

Prepared for

MINISTRY OF ECONOMIC DEVELOPMENT

Ministry of Economic Development
Manatū Ōhanga

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Prepared by	:	Noel Hall, Chris Taylor
Reviewed by	:	Madeline Cowley, Grant Morris
Approved by	:	Grant Morris
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SECTIONS

ACRONYMS AND ABBREVIATIONS

1G, 2G	First/Second generation development of superconductor wire (see Section 7.2)
A/cm	Ampere per centimetre (measure of current capacity/density)
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
DME	Dimethyl-ether
EECA	Energy Efficiency and Conservation Authority (NZ)
EPC	Engineer, Procure and Construct – related to the scope of contract for supply of power plant
EPRI	Electric Power Research Institute (USA)
GW	Gigawatt (1,000,000 kW)
HDR	Hot Dry Rock (geothermal resource technology)
HHV efficiency	Efficiency calculation based on Higher Heating Value of fuel (HHV assumes water formed during fuel combustion is condensed and latent heat recovered)
HTS	High Temperature Superconductor
HVDC	High Voltage Direct Current
IGCC	Integrated Gasification Combined Cycle
knot	Speed in nautical miles per hour (1 knot = 0.51 m/s)
LHV efficiency	Efficiency calculation based on Lower Heating Value of fuel. For natural gas, LHV efficiency ~ 1.1 x HHV efficiency; for coal LHV efficiency ~ 1.04 x HHV eff.
MWe	Megawatt (1,000 kW electrical output)
MWth	Megawatt (1,000 kW thermal (heat) output)
NIWA	National Institute of Water and Atmospheric Research (NZ)
NREL	National Renewable Energy Laboratory, the US DOE's primary laboratory for renewable energy and energy efficiency research and development
O&M	Operations and Maintenance
sm^3	Standard cubic metre (volume of gas referenced to 15°C and atmospheric pressure of 101.325 kPa)
UPS	Uninterruptible Power Supply
VAR	Volt-Ampere Reactive (unit of reactive power)
VSC	Voltage Source Converter (for HVDC systems)

GLOSSARY

Availability Factor (%)	Hours the unit is available to generate divided by the period hours (usually 8760 hours in a year). Available to generate means that the unit is ready for service whether it is actually generating or not. Available hours equals period hours less planned and unplanned outage hours.
Net Capacity Factor (%)	Net electrical MWh generated divided by period hours x net maximum capacity
Net Maximum Capacity (MW)	Maximum electrical output a unit is able to sustain, net of parasitic loads
Heat Rate (kJ/kWh)	An inverse measure of plant efficiency, defined as the amount of heat input required for a unit of electrical output
Power Island	Collection of plant which together makes up the electrical generating block as part of an industrial complex

EXECUTIVE SUMMARY

PB Power was engaged by the Ministry of Economic Development (MED) to provide, as part of a series of contributing documents for the "New Zealand Energy Outlook", a report on the technology status and expected capital and O&M costs for a number of emerging, supply-side energy technologies. Particular attention was paid to those technologies which would be commercially available within the next 15 to 20 years.

Commercial Status

The following table summarises the commercial status and potential sizes of the technologies included in this report.

Technology	Anticipated Commercialisation Date	Unit Size/ Project Scale (Installed Capacity)
Wave	2010 to 2015	500 to 1,000 kW unit size 15 to 50 MW project scale
Tidal	2015	300 to 1100 kW unit size 5 to 30 MW project scale
Fuel Cells	current, at high cost lower cost product 2015	250 kW to 5 MW for grid connected stationary applications
Photovoltaics	current, at high cost low cost new technology 2020 or beyond	up to several MW
CNG Transport	2008 - 2010	0.038 to 1.13 PJ/ship for ships 0.36 PJ – delivered gas 19 PJ /year continuous
Superconductors	current, but undergoing development for 2G	1 to 2000 MW per cable
Microturbines (gas)	current	30 to 350 kW
Pebble Bed Reactors (Nuclear)	2015	110 to 200 MW
IGCC	2010 to 2015	120 to 550 MW
Geothermal	Kalina Cycle - 2010	5 to 25 MW, larger scale in future
Biofuels	Ethanol from putrescible wastes 2010 - 2015	217,000 tonnes - up to 9% of petrol requirements
	Ethanol from woody biomass 2015 – 2020	Larger proportion limited by land use and economics
	Biodiesel from tallow - current	116,000 tonnes per year - up to 5% of diesel requirements
	Synthetic diesel from bio-syngas - 2020	Larger proportion limited by land use and economics

Costs

The following table summarises predicted costs in today's dollars for the reviewed technologies. Further assumptions, details and descriptions can be found in the relevant technology sections.

Technology	**Capital Cost** **($,000 /kW)**	**Estimated Overseas Portion (%)**	**O&M Cost[1]** **(cents/kWh)**	**Capacity Factor (%)**
Wave power – initial - mature	4.4 to 5.5 1.2 to 2.8	75	6.5 4	25 40
Tidal power – initial - mature	6.0 to 9.0 2.5 to 3.5	75	6 3	30 40
Fuel cells – current (for generation) - future	4.5 to 8 1.6 to 2.4	90	4.5 to 7.1 1.1	90 95
Photovoltaics – current - future	7 to 11 3.5 to 6.5	90	12.5 4	10 20
CNG marine transport	n/a	n/a	$5.3 to $7.2 /GJ transport cost for 19 PJ/year	
Superconductors - future (cable)	12 to 37 ($,000/kW per km)	90	n/a	
Microturbines – current - future	3.8 2.2	75	5.5 to 7.5 2.7	90
Pebble Bed – current[2] Nuclear Reactors -target	3.7 to 4.6 1.55 to 1.85	80	3.7[3] 0.75 to 1.3	90 95
IGCC – current - future	1.8 to 2.7 1.5 to 1.65	75	1.5 0.9	85 90
Geothermal (Kalina Cycle)	2.2 to 3	75	0.4 to 0.9	90 to 95

Technology	Capital Cost ($,000 /kW)	Estimated Overseas Portion (%)	O&M Cost[1] (cents/kWh)	Capacity Factor (%)
Biofuels (Product Cost) Ethanol from putrescible wastes Ethanol from woody biomass Biodiesel from tallow Synthetic diesel from bio-syngas – F-T diesel - DME	 0.6 to 1.25 $/litre near term 0.58 to 1.05 $/litre long term 0.38 $/litre 0.5 to 0.8 $/litre 1.13 $/litre 0.78 $/litre	n/a	n/a	

[1] Excludes fuel costs

[2] Conventional nuclear technology, not Pebble Bed

[3] O&M costs include annual provision for future decommissioning and fuel disposal costs. Nuclear fuel costs are approximately 1.17 c/kWh for conventional nuclear power, targeted at 0.67 to 0.83 c/kWh for pebble bed fuel.

Energy Conversion

The following table compares the energy conversion efficiency of the various technologies.

Technology	Unit	Energy Conversion Efficiency/Utilisation
Wave power		7.5 to 25 MW per km of wavefront
Tidal power	kW/m^2	1.5 to 2.5 m/s tidal current - 5 to 35 MW per km width
Fuel cells (natural gas fuel)	%	35 to 55
Photovoltaics	$kWh/m^2/day$	0.32 to 0.8
CNG marine transport		not applicable
Superconductors AC DC Conventional AC 400 kV HVDC	Losses kW/MW-km	0.13 line + 6 kW/MW termination losses 0.013 line + 17 kW/MW termination losses 0.5 line + 6 kW/MW termination losses ? line + 17 kW/MW termination losses
Microturbines (generation)	%	17 to 40
Pebble bed reactors (nuclear)	%	45 (heat to power)
IGCC (HHV)	%	40 to 50
Geothermal (Kalina Cycle)	%	10 to 15 (60% exergy efficiency)
Biofuels Ethanol	 litres/ha litres/tonne	 Woody biomass 2,500 (sugar cane 5,500) Woody biomass 360

Technology	Unit	Energy Conversion Efficiency/Utilisation
Biodiesel from crops	dry feedstock litres/ha litres/tonne vegetable oil	 Rapeseed 980 (Palm Oil 5,400) Rapeseed 1090

Conclusions

New Zealand continues to participate in research associated with many of the subject technologies. As outlined below, some are unlikely to be commercial within the required timeframe, while others are candidates for inclusion in New Zealand's future generation scenarios.

Wave Power

New Zealand has a very good resource for wave power, one of the best in the world. Has potential to provide significant renewable electricity generation. Characterisation of the resource and its potential is needed.

Tidal Power

New Zealand has a low tidal range. There are very limited opportunities for tidal height technologies in New Zealand.

Limited locations exist where tidal velocities are sufficient for tidal current power. Some opportunities for tidal current devices may exist in areas where the tidal current is enhanced – natural harbour entrances, and in shallower parts of Cook Strait.

Fuel Cells

High costs at present, and progress on lowering costs is very slow. Not likely to be competitive as a grid connected energy source in the report timeframe. Some limited potential for distributed generation in the future because of high efficiency at small scale.

Photovoltaics

High costs and very limited capacity factor make photovoltaics not likely to be competitive as a grid connected energy source in the report timeframe. However summer air conditioning loads are increasing in Auckland, and may cause daytime peak loads where PV systems could usefully provide some peak shaving in future.

Marine Distribution of Compressed Natural Gas (CNG)

CNG shipping into New Zealand could support New Zealand's natural gas markets on a smal scale or as an interim measure, avoiding the commitment of high capital costs for LNG importation infrastructure.

Superconductors

High Temperature Superconductors are not likely to be competitive against conventional transmission lines or HVDC for long distance transmission. The technology is more likely to become commercial in reactive power control systems and other grid support systems. Areas where underground or underwater transmission is required will be the first applications where HTS may become competitive.

Microturbines (Gas)

Microturbines are a distributed technology where combined heat and power production could provide the competitive edge. However at the small scale of microturbines, space heating is the predominant heat load and in New Zealand heating loads are often variable. Microturbines do not perform well under variable load conditions.

Microturbines face strong competition from the established technology of gas reciprocating engines in landfill gas and other biogas applications.

Pebble Bed Reactors

At its current stage of development, the costs of Pebble Bed Reactors are too uncertain to determine if the technology will become competitive in the report timeframe. Nuclear power would probably only become acceptable as a response to reducing carbon emissions. In this context in New Zealand it would be competing with coal technologies that incorporate carbon sequestration.

Integrated Gasification Combined Cycle (IGCC)

IGCC technology could become competitive in the near term. Costs could match conventional coal fired plant, but generate power at higher efficiency. IGCC has lower emissions than conventional coal fired plant, but emissions (other than CO_2) from modern conventional coal fired plant with flue gas treatment are also very low. A key prospect for IGCC is the lower cost of separating CO_2 compared to other generation technologies, if carbon sequestration becomes a cost effective way to reduce carbon emissions.

Geothermal

Hot Dry Rock technology is not promising as New Zealand does not appear to have a high crustal thermal gradient and its volcanic nature poses potential difficulties creating the required underground fractured rock heat exchangers.

Kalina cycle technology has the potential to be a competitive technology in the geothermal area. Cost competitiveness with modular ORC technology may be difficult to achieve until a global market develops for Kalina cycle technology. Initial applications may be on low temperature resources where scalability is important, such as at the Geodynamics Hot Dry Rock programme at the Cooper Basin in Australia.

Biofuels

Waste feedstocks in New Zealand could make a small contribution to New Zealand's liquid fuels requirements. These are tallow and waste vegetable oils for biodiesel, and putrescible wastes (including cereal straw) for ethanol production.

Cereal grains and oil crops such as rapeseed do not appear to be beneficial for large scale biofuel production in New Zealand, owing to the very large areas of arable land that would be required to make a significant contribution to our liquid fuels needs.

Biofuels are liquid fuels and as such are relatively easily and cheaply transportable, only a few cents a litre for international shipping. As a result biofuels could become traded globally, and costs of producing crop-based biofuels in New Zealand should be considered relative to the cost of importing biofuels.

The technology of enzymic hydrolysis of lignocellulosic biomass appears to have the most potential for larger scale biofuels production in the medium term in New Zealand. However the technology needs to be developed further to realise cost reductions.

In all cases some incentives will probably be required to stimulate development, such as biofuels being exempt from at least a portion of the excise tax on fossil liquid fuels. Future larger scale biofuels production may be inhibited by exposure to risks of periodic low oil prices. This may require mechanisms such as excise tax policy on fossil liquid fuels that ensures a price floor that won't drive biofuel producers out of business.

1. INTRODUCTION

1.1 REPORTING CONTEXT

The Ministry of Economic Development (MED) publishes the "New Zealand Energy Outlook" at approximately 3-year intervals, with the next issue due in 2006. The document presents results of supply and demand energy modelling looking ahead 25 years. Given the long forecast period, emerging technologies currently under development could have a significant impact on the future energy market. Therefore there is a need to obtain data on the likely commercialisation status, expected costs and environmental consequences of these technologies within the period under review.

1.2 REPORT SCOPE AND REQUIREMENTS

PB Power was engaged by the Ministry of Economic Development (MED) to provide, as part of a series of contributing documents for the "New Zealand Energy Outlook", a report on the technology status and expected capital and O&M costs for supply side energy technologies now under development that could potentially become commercially viable in New Zealand within the next 10-15 years.

In this context, "commercially viable" has been taken to mean those technologies which are or could be economically viable for use in the New Zealand context, without further prototype or pre-production development. The technologies must have the potential to be fully fundable on their own (because of the proven status) without dependence on any research and development funding or subsidies.

A number of technologies were suggested, the criteria for considering these and other technologies were developed as follows:

- Currently under development
- Has the potential to be commercial in 10-15 years. Commercial means:
  - the technology is proven, ie. technical risks are manageable
  - the technology is at the production level, manufacturing processes are developed
  - the energy supply meets commercially acceptable reliability and quality requirements
  - it has a cost structure that could attract private capital
- Has the potential to be commercial at a single generating unit size of no more than 400 MW, being the maximum size applicable to the New Zealand grid
- Must be economic at no greater than 400 to 500 MW in a single development in order to keep investment risk manageable
- Potential scale more than 10 kW, that is, more than a single dwelling domestic scale
- Has the potential to be grid connected (includes distributed generation technologies but not niche, off grid applications)
- Has the potential to be more than a few percent of our energy supply needs, that is, a level of penetration into the energy markets that will have an impact at a national level.
- Can meet environmental constraints

It should be noted that the energy supply technologies are not all directly related to electricity production, and includes technology designed to produce fuel.

This report summarises supply-side (i.e. as distinct from demand management) emerging energy technologies.

Technologies that offer incremental efficiency gains of existing commercial technology are also not included in the scope of this report. Existing commercial technologies are covered by other reports commissioned by MED:

- East Harbour Management Services, "Fossil Fuel Electricity Generating Costs", MED, June 2004
- East Harbour Management Services, "Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat, 2005 edition", MED, June 2005

The report is not intended as a comprehensive description or guide to all available emerging technologies, as it would never be possible to give justice to any or all of such technologies with the constraints of the reporting assignment. Engineering judgement by practicing power industry professionals has been used to select technologies worthy of investigation according to the criteria listed above. The individual sections summarise various key aspects of the subject technologies, but further technical detail should be sought from other sources, especially to update the changing status of the technologies.

1.3 SURVEYED TECHNOLOGIES

In accordance with the stated criteria, the technologies that were selected as most likely to be commercially viable in the report time frame and included for review were as follows:

- Wave power;
- Tidal power;
- Fuel cells (gas);
- Photovoltaics;
- Marine distribution of Compressed Natural Gas (CNG);
- Superconducting transmission and storage (electric);
- Microturbines (gas);
- Pebble bed reactors (nuclear)
- Integrated gasification combined cycle (coal);
- Geothermal (specific technologies);
- Biofuels.

1.4 QUANTITY ESTIMATES

For some technologies, there are resource constraints as to how much could be deployed in New Zealand. For novel resources where characteristics and size are not well defined quantity estimates are limited to quantity of energy production per unit of resource. Overall scale is only projected at the indicative level.

Potential electricity generation or energy supply for a quantum of resource depends on a combination of:

- The expected installed capacity per unit of resource - as derived from the technically feasible and economic extractable energy for a particular resource and technology

- The capacity factor - a determination of how much annual energy will be generated from the resource, as a proportion of the maximum possible if operating at maximum capacity all year.

The capital costs are driven by the installed capacity, whereas the annual generation expected is the product of the installed capacity times the capacity factor.

For example, a 300MW wind farm of 30% capacity factor produces the same amount of annual energy as a 100MW geothermal plant at 90% capacity factor. And even though the annual energy supplied is the same, the high capacity factor energy is still more valuable, as it is always available to meet demand, whereas the wind energy is independant of demand. In this report, no account is taken of the different value of the energy produced.

1.5 COST REPORTING

Care should be taken comparing capital and operating costs of the technologies. The capacity factor of renewables in particular needs to be taken into account when making comparisons. Levelised unit costs relating capital and O&M costs to life time generation are more appropriate for comparison, but are not within the scope of this report.

Emerging technologies provide unique challenges when it comes to predicting the likely capital and operating costs of the technology, as it involves making assumptions about how the technology will develop in the future. Indeed, many development projects have a particular cost level defined as one of the goals of the development process. In this report a range of costs are presented, the lowest being what is expected if all technical goals are achieved, provided it is reasonable, and the higher costs are based on a less optimistic prediction of the technological outcome. On top of the technological uncertainty must be added the normal cost estimating uncertainty, and consequently the cost ranges presented here will be much wider than with more established technologies.

It should be noted that the costs presented in this report are predictions of costs that may never be realised. The costs are estimated on the basis of physical materials and costs to manufacture as if a technology was at the production stage and the manufacturing processes were developed. No initial judgement is made whether the cost will be competitive and therefore whether the technology will go into production.

Similarly, the estimates of time to commercialisation are not predictions of actual time, but are estimations of when a technology could be available, but not necessarily will be implemented, and is dependant on other economic and political factors, status of competing technologies, ability to embed the generation to avoid transmission charges, and the like.

Because most of the emerging technologies are not being developed in New Zealand, reliance has had to be placed on largely overseas references for costs, with appropriate conversion factors applied in order to estimate likely costs applied to the New Zealand situation.

Costs are generally presented in New Zealand dollars, although for comparison, and where the context requires, other currencies are also reported. Where exchange rate conversions have been included, a US$: NZ$ rate of 0.60 has been used.

Use of the dollar symbol ($) on its own implies New Zealand dollars.

In general, where costs have been converted to New Zealand dollars from other currencies, those conversions have been carried out on the basis of the stated exchange rate with no account taken of ruling wage rate, parity or other cost factors which would have a direct impact on the actual cost of the particular technology in New Zealand. Consequently, costs should be considered on a relative basis between technologies, rather than being absolute.

Little or no detailed information has been sighted which provides an assessment of the proportion of capital costs, for the various technologies, which would be subject to overseas exchange. For each technology, PB Power has estimated these proportions on the basis of its understanding of:

- Details of the “emerging” technology;
- Where various components are likely to be manufactured;
- The general degree of fabrication which would be carried out within New Zealand.

Finally, there are undoubtedly going to be differences of opinion as to the validity of conclusions on the costs of technologies applied throughout this report. Hopefully this will not deter proponents of any of the technologies from continuing to push for its development to the benefit of all New Zealanders.

2. WAVE POWER

2.1 SUMMARY

The Technology

- Two main resources – offshore swell or shoreline breaking wave devices. Wave power is expected to be commercial within 10-15 years.
- Wave power in New Zealand has significant potential to provide sustainable renewable electricity generation. New Zealand has a very good resource for wave power, one of the best in the world.

Current State

- A large number of wave power technologies are proposed. Several are at the full scale testing stage.

Limitations of the Technology

- Capacity factor limited by the size, frequency and variability of waves.
- The wave source provides intermittent power and hence cannot follow demand (similar to wind).

Technological Hurdles

- Prediction of environmental impacts
- Proving the ability of generating devices to withstand extreme wave and weather conditions
- Ability to predict generation obtainable from a particular sea resource
- Demonstrating long term reliability and operating and maintenance costs

Efficiency, Scale and Costs

- How much capacity is economic to install for a particular resource is not yet clear, but estimates range from 30% to 50% of incident wave energy. Capacity factors range from 25% to 40%. For a 2 km wavefront in NZ, with a 50 kW/m annual average incident wave energy, we could expect an installed capacity of 30 to 50 MW. The annual generation would be 30 x 8760 x 0.25 = 65,700 MWh to 50 x 8760 x 0.4 = 175,200 MWh.
- Capital costs range from $4,400 per kW to $5,500 per kW installed capacity of intial commercial plants, and varying from $2,800 per kW down to $1,200 per kW for maturing technology as global installed capacity increases from 1 GW to 10 GW.
- The above capital costs do not include consenting costs, or costs associated with obtaining access and use rights from parties that own or control those rights.
- Near term O&M costs are estimated at 6.5 c/kWh. O&M costs contribute the greatest portion of levelised unit costs, but are the most difficult to predict long term. PB Power suggests future O&M costs for modelling should range from an optimistic 2 c/kWh to 4 c/kWh.

Environmental Issues

- Conflicts with other uses of sea space

- Reduction of wave energy
- Visual Appearance
- Visual impact of cable termination structure at the seashore and transmission lines in the coastal environment
- Overall, wave power has the potential to be one of the most environmentally benign electrical generation technologies.

NZ Context

- Very little information on the NZ resource, the sea state (wave heights and periods), predictability of achievable generation, characteristics of the generation (variability, rate of change, etc.)
- Sea resource ownership, Maori customary rights over the seabed and resource. Uncertainty and cost obtaining access, use and exclusivity rights
- Time and cost of obtaining novel resource consents in the coastal environment
- Effect of subsea cables, termination at the seashore, and extent of underground cabling required in the coastal environment before overhead transmission can be used
- NZ coastal policies, both central and regional, are likely to seriously hinder the development of shoreline devices of significant scale.
- Large scale off-shore navigational restrictions (fishing, cargo, recreational vessels)

2.2 CURRENT STATUS OF TECHNOLOGY

Winds are created through the differential heating of the earth, and as the winds blow over large areas of water some of their energy is converted to waves. The power and size of the waves is dependent on the wind speed, the length of time that the wind is blowing and the distance that it is blowing over or the fetch. Coasts with the most exposure to the prevailing wind direction and long fetches have the highest wave energy resource. The resource is greatest in the winter months. The predictability of wave power is in the order of a few days and the power of waves is highly variable.

A range of technologies is currently being developed. There have been close to 300 designs for wave energy devices put forward to date. Devices are generally of two main types:

- Offshore swell devices rely on differential movement between points along the device, or relative motion of the water surface to the sea bed (e.g. as in oscillating water column devices);
- Breaking wave devices, mostly being fixed devices at the shoreline and making use of the movement of water or air driving small turbines.

The most recent offshore swell devices produced and undergoing testing in Europe, are the Pelamis and the Power Buoy. The following photo shows the Pelamis P-750 device in action. By mid 2004 this unit had operated in three sea trial locations. In June 2005, Ocean Power Delivery Ltd (OPD) announced the award of a contract (8 million Euros) for the installation of 3 Pelamis machines (total 2.25 MW) off the coast of Portugal.

Photo courtesy Ocean Power Delivery Ltd

Due to the prototype and development nature of current wave energy devices there is little operational information available on the wave resource, performance and characteristics for economic development. However, the Pelamis wave energy device is projected to generate 100 GWh/y if 29.25 MW is installed in a wave energy resource of 50 kW per metre of wavefront. This equates to a projected capacity factor of 40%. The wave resource for New Zealand is around 40 to 80 kW/m.

2.3 COMMERCIALISATION

Full scale prototypes are currently being tested. The availability of commercial products is expected to be a few years down the line. With adequate international government and other research funding support it is expected that a number of the wave power technologies could be commercialised within the next 10 years.

Industrial Research Limited (IRL), NIWA and Power Projects Limited are participating in a collaborative venture to deploy a pre-commercial wave energy device in New Zealand by 2008[1].

Two existing wave energy devices, the Pelamis and the Power Buoy, are projected to generate at 10-14 cents per kWh, with future similar production devices reducing generation costs to 4-6 cents/kWh. As at January 2005, only the Pelamis device was considered by EPRI to be at the stage of full-scale testing in the ocean, with most development work complete.

Shoreline breaking wave devices are likely to present significant coastal consenting issues in New Zealand. This is likely to seriously hinder commercial deployment in New Zealand.

2.4 EXPECTED UNIT SIZES, SCALE AND PERFORMANCE

Several large demonstration plants of up to 500 kW have been built and others are planned. Farms of 50 MW or more sited offshore are expected to be commercial scale. Shoreline devices are limited by coastline and are not able to be deployed at this size. These shoreline schemes are more likely to be up to around 5 MW total.

The East Harbour Renewables report shows the global distribution of wave power levels indicating good potential wave energy in comparison with other parts of the world. The

[1] Huckerby J, Oceans of Opportunity – Harnessing New Zealand's Marine Energy, presented at Symposium on New Energy Technologies, Wellington, 12 October 2005

highest waves occur in the South West of New Zealand, although there is also good potential in the North.

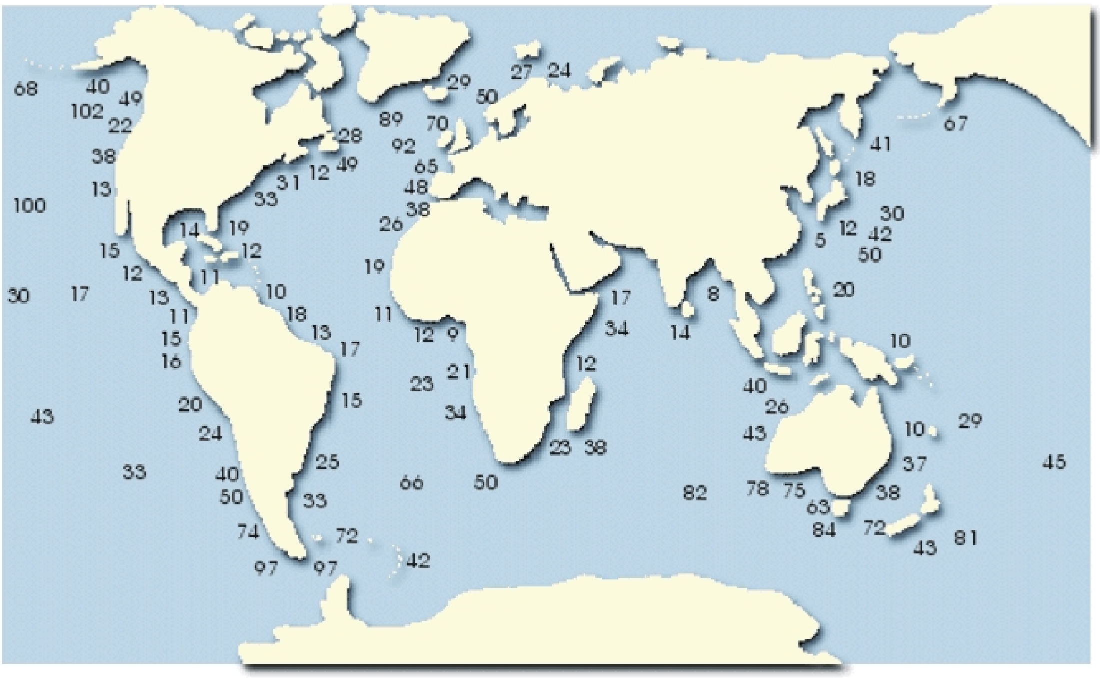
New Zealand has a resource exceeding 20 kW/m of wave front around much of the coastline and reaching up to 100 kW/m in some areas. A resource of 25 kW/m of wave front is considered to be very good for power generation. This means that most of the coast of New Zealand has a very good resource for wave power and one of the best in the world.

A project definition design study[2], sponsored by EPRI, included a commercial-scale arrangement of Pelamis devices for Hawaii of 45 devices in an area 2.225 km x 1.8 km. This gave a potential energy production of 8.8 W/m^2, but is dependent on the wave energy density. The wave energy density for Hawaii is similar to that around many parts of New Zealand, but is highly variable.

Developers for the PowerBuoy (Ocean Power Technologies) claim[3] that 10 MW can be obtained from an area of 4 acres (equivalent to 617 W/m^2).

Transmission losses could be significant, depending on the site location's proximity to the electrical grid. The example sites used in the EPRI report had a distance from the shore to the plant of 2 to 29 km and an onshore grid interconnect distance of 0.5 to 4 km.

The map below shows annual average wave power in kilowatts per metre of crest width for various sites around the world.



2.4.1 Efficiency, Availability and Capacity Factor

The efficiency of the wave generation plant is dependent on the technology used.

The EPRI study gives capacity factors of between 13 to 15% for the Pelamis device and 14% for the Energetech device for a pilot plant. This improves to 32 to 38% for the

[2] EPRI, Final Summary Report, Project Definition Study, Offshore Wave Power Feasibility Demonstration Project. January 2005

[3] See http://www.oceanpowertechnologies.com/technology/

Pelamis and 23% for the Energetech for commercial plants. It should be noted that the capacity factor could be better for New Zealand due to the higher wave energy resource.

Oscillating Water Column (OWC) plants would be expected to operate with a capacity factor of 30-45%. Tapered channel plants are expected to have a capacity factor of 60%.

Availability of the plant might achieve 90% or above.

2.4.2 Life of plant

Given the demonstration nature of the technology the life time of the plant has not been proven. A lifetime of 20 years is considered appropriate and is assumed by the EPRI study.

The EPRI report assumes a year for the design, permitting and financing, and two years for construction of the plant, giving a 3 year lead time in total.

2.5 COSTS

2.5.1 Capital cost

There are various wave energy technologies being developed and no clear market leaders have emerged as yet. The costs provided are based on specific technologies that have been studied. In addition the costs of a wave energy farm will be very site specific. The costs provided are based on specific sites studied and therefore would be expected to vary when transferred to specific New Zealand sites.

The EPRI study[4] took data from manufacturers of wave energy devices and undertook design studies for a selection of US sites. Taking the sites with the higher wave resource of 20-21 kW/m, which are more applicable but still slightly lower than the New Zealand wave resource, the installed capital costs ranged from $5.2 million to 10.2 million for a 750 kW Pelamis device ($6.9 million to $13.6 million per MW) and $ 5.5 million to 10.1 million for a 1,000 kW Energetech device, both installed as pilot demonstration plants[5]. The capital costs for the installation of a commercial plant were calculated to be $4.4 million to 5.5 million/MW for a Pelamis device and $2.7 million/MW for an Energetech device. The commercial scale installation assumes that enough devices are installed to generate 300,000 MWh/y, which equates to the installation of 90-107 MW of Pelamis devices and 152 MW of Energetech devices.

PB Power estimates that approximately 75% of the capital cost of wave power generators will be subject to overseas exchange.

2.5.2 O&M cost

The EPRI report estimates the annual O&M costs for a commercial plant to be about 5.3 c/kWh. To this must be added 10-year refit costs which are expected to be in the range of 1.5 to 2.5 times the annual O&M cost. These figures will need to be updated following further operational experience.

Total levelised electricity costs from wave generation are in the range 4.3 to 15 c/kWh, of which approximately 40% (1.7 to 6 c/kWh) are stated by EPRI to be attributable to O&M. The cost of electricity will be very dependent on the level of resource available in the area under consideration.

[4] EPRI, 2005, Final Summary Report. Project Definition Study. Offshore Wave Power Feasibility Demonstration Project
[5] Using a conversion of 1USD = 1.67 NZD

2.5.3 Future unit costs

The EPRI report assumed that for every doubling of cumulative production volume, there is an 18% drop in production costs. This is consistent with the experience for wind energy, photovoltaics, ship building and the offshore oil and gas industries. On these assumptions, the capital cost for wave plants would reduce to $2.3-2.8 million/MW with a global production volume of 1 GW and $1.2 to 1.5 million/MW with a global production volume of 10 GW.

2.5.4 Cost sensitivities

Plant costs are sensitive to the wave resource, the size of the plant, the length of the grid connection, extreme wave conditions and water depth.

2.5.5 Cost of generation

At a 10% discount rate a commercial plant would generate at a cost of 25 cents/kWh using a Pelamis device and 21 cents/kWh using an Energetech device. It should be noted that these figures are derived from costs and energy generation from the EPRI report using a site of lower energy resource than available in the vicinity of New Zealand.

With the reductions in capital costs but assuming the same energy output and O&M costs, the cost of generation could reduce to 14 to 16 cents/kWh with a global production volume of 1 GW and 9 to 11 cents/kWh with a global production volume of 10 GW. To put the production volume figure in perspective, the cumulative world installed capacity of wind exceeded 50 GW in 2005.

Lower wave energy generation prices were predicted by the World Offshore Renewables Report, although the assumptions used and discount rate are not stated. The report projects generation for two wave energy devices - the Pelamis and the Power Buoy - at 10 - 14 cents per kWh, with future generation costs reducing to 4 - 6 cents/kWh[6] .

The onshore devices, the oscillating water column wave power plant and the tapered channel wave power plant, are projected to produce energy at 10 to 30 c/kWh, in a wave resource of 25 to 35 kW/m of wave front[7]. Again the assumptions behind these projections were not stated. These types of plant will be limited in size to around 3 MW.

The EPRI report assumes a year for the design, permitting and financing, and two years for construction of the plant, giving a 3 year lead time in total.

2.6 ENVIRONMENTAL ISSUES

The environmental impacts of wave energy devices are considered to be low. There are no emissions of greenhouse gases related to the operation of wave devices. Areas of concern may include: visual intrusion and noise for shoreline plants and obstacles to coastal marine traffic for near shore and offshore plants. Very large near shore or offshore plants may affect coastal dynamics. Site specific environmental impact assessments will be required for developments.

Designs must take into account the possibility that installed devices may provide hauling-out space for seals (low freeboard) or colonization space for seabirds.

[6] DTI 2004, World Offshore Renewables Report
[7] DesignPower 1995, New Zealand Wave Power Application

2.7 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

There are significant legal issues regarding consenting and exclusive use rights for coastal activities that will complicate implementation in NZ[8]. Government has recently asserted its rights as exclusive owner of the foreshore and seabed via the Foreshore and Seabed Act, with customary territorial rights reserved for Maori. Government action is vital to ameliorate the legal and consenting uncertainty and prepare the way for implementation in NZ when the technology matures without many years of delay. Such action could include:

- Clarifying or reserving exclusive development rights to priority sites for selling or allocation to developers
- Policy to standardise and expedite resource consenting through tools such as National Policy Statements

There are also significant resource characterisation issues that could delay implementation in NZ. Government action on resource characterisation and prioritising sites for development will help to mitigate this, and will be necessary to support the addressing of consenting and development rights.

The following factors will need to be considered in siting a wave power farm:

- Wave resource;
- Distance from transmission and distribution infrastructure for grid connection;
- Distance from an electrical load centre;
- Access for maintenance;
- Avoidance of major shipping channels;
- Sea depth and practicability of anchoring;
- Existence of oil and gas exploration permits;
- Possibility of conflict with the fishing industry over submarine cables

Further work is required in locating the best sites for wave generation in New Zealand including consideration of the above factors and monitoring of the wave resource.

[8] Simpson Grierson, Letter to EECA dated 11 August 2005, Marine Energy Proposals – Resource Management Act 1991

3. TIDAL POWER

3.1 SUMMARY

The Technology

- Two technology areas: technologies which generate power as a result of the difference in heights between high and low tides, and technologies which generate power from tidal or ocean current flows.
- There are limited opportunities for the tidal height technologies in New Zealand.
- There are limited locations where tidal velocities are sufficient for tidal current power. Some opportunities for tidal current devices may exist in areas where the tidal current is enhanced – natural harbour entrances, and in shallower parts of Cook Strait.
- The technology may be commercial over the next 10 years

Current State

- Full scale prototypes are currently being tested

Limitations of the technology

- Capacity factor limited by the tidal range or tidal current flows.
- The tidal source provides intermittent, but predictable, power and hence cannot follow demand (similar to wind).

Technological Hurdles

- Prediction of environmental impacts
- Proving the ability of generating devices to withstand extreme weather conditions
- Demonstrating long term reliability and quantifying operating and maintenance costs

Efficiency, Scale and Costs

- The capacity factor of plants is estimated at 40%
- Costs are in the order of $ 6,000 to 9,000 /kW for a small plant of 1 MW or less, reducing to $ 3,500 /kW for a 100 MW tidal farm
- Projected annual O&M costs are $ 150 per kW of installed capacity with potential reductions to $ 100 per kW of installed capacity for larger plants

Environmental Issues

- Potential impacts on navigation and fishing, other impacts will be site specific and will require assessment
- Visual appearance for some devices
- Visual impact of cable termination structure at the seashore and transmission lines in the coastal environment

NZ Context

- General tide data is available from NIWA, whose tide model accurately predicts tidal heights. More detailed review of the data available is required to determine how much further data collection and analysis is required to adequately assess the resource
- Tidal current velocities in New Zealand are generally lower than the optimum for economic utilisation. Best prospects are in Cook Strait, Marlborough Sounds and in bay entrances and harbours.
- Economic depths for tidal current devices will be at 20 to 80m in the medium term. This will limit opportunities in Cook Strait to points near the coastline.
- Sea resource ownership, Maori rights over the seabed and resource. Uncertainty and cost obtaining access, use and exclusivity rights
- Time and cost of obtaining novel resource consents in the coastal environment
- Effect of subsea cables, termination at the seashore, and extent of underground cabling required in the coastal environment before overhead transmission can be used
- Large scale off-shore navigational restrictions (fishing, cargo, recreational vessels)

3.2 CURRENT STATUS OF TECHNOLOGY

The current status is addressed in the East Harbour Renewables Report.

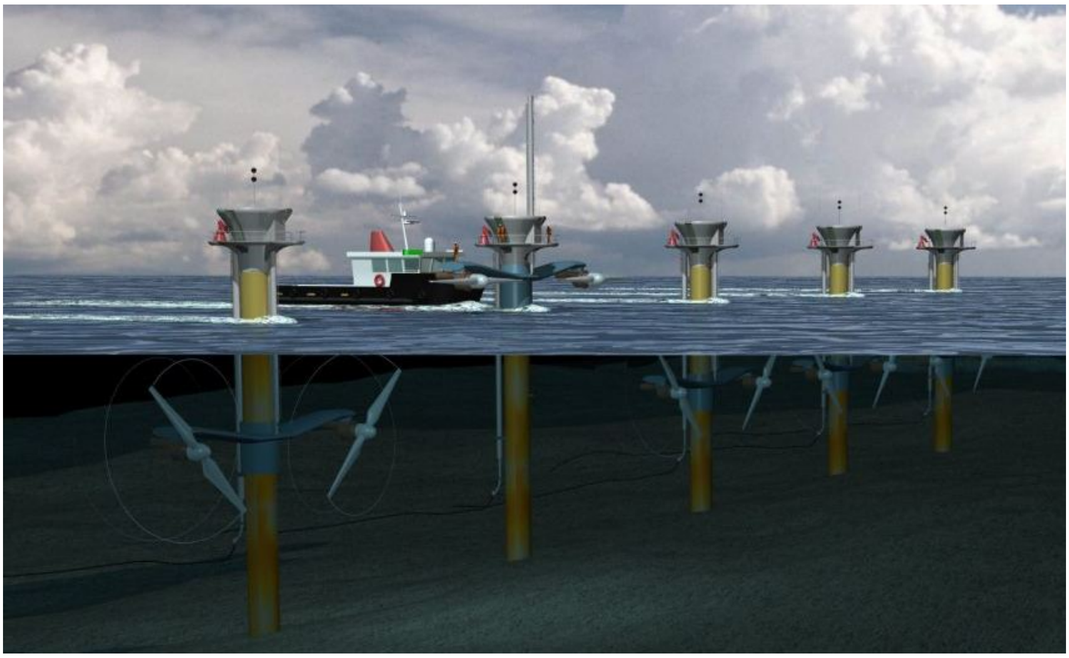
The patterns of tidal movement can be predicted to a high level of accuracy, given their dependence on the interaction of the moon and sun. Current flows are periodic but predictable.

Two technology areas are considered in this section:

- technologies which generate power as a result of the difference in heights between high and low tides;
- technologies which generate power from tidal or ocean current flows.

The following shows an artist's impression of a possible underwater current "farm"[9], with one turbine raised for maintenance. A 300 kW Marine Current Turbines Ltd (MCT) experimental version has been in operation for more than 2 years off the coast of Devon, UK.

[9] See http://www.marineturbines.com/technical.htm



Picture copyright: Marine Current Turbines TM Ltd

MCT is proposing to install a 1.1 MW Seagen unit in the Strangford Narrows, southeast of Belfast, UK[10].

The low tidal range in New Zealand of 2-3 m means that there are limited opportunities for electricity generation through the rise and fall of tides, e.g. tidal barrages. The large natural harbours on the west coast of the North Island such as Kaipara, Aotea, Raglan and Kawhia create constrictions increasing the water level height range presenting greater potential for electricity generation.

Tidal currents with a maximum current velocity in excess of 1.5 m/s are expected to present economic opportunities for exploitation[11]. The best prospects for economic utilisation of the resource is in water depths of greater than 30 m and mean spring peak velocities of greater than 2.5 m/s. Tidal currents are enhanced in the Cook Strait, between the mainland and islands, e.g. between Kapiti Island and the Kapiti coast, and in harbour mouths such as to the Manukau, Kaipara, and Hokianga Harbours. At French Pass in the Marlborough Sounds tidal streams can reach a velocity of 2.5 to 3.5 m/s [12].

Tidal currents are similar to tidal motion in that they are weak in the open sea but very strong in narrow straits and generally accompanied with localised flows.

The adoption of a technology for utilising current energy at depth (e.g. Cook Strait) is likely to require further development and modifications to existing designs for operation in shallower waters. Such installations raise additional implications of impacts from shipping, trawling, etc.

Typical areas that will hold superior ocean current resource are:

- In narrow straits especially where localised flows are present.
- Areas where there are big tidal differences.
- In entrances to bays and possibly harbours.
- Areas where the ocean sea bed is relatively shallow coupled with good tidal changes.

[10] Marine Scientist, No 12, third quarter 2005
[11] Boud, R. 2003, Status and Research and Development Priorities. Wave and Marine Current Energy
[12] Power Projects Ltd., Marine Energy

As New Zealand does not have a high tidal range, tidal current resources should be sought in narrow straits, bay entrances and harbours.

Other impacts that do however have to be considered in the selection of a suitable site for the installation of an ocean current device are:

- Shipping routes.
- Marine life in the area, with special consideration to larger marine life, e.g. dolphins, seals etc. Smaller sea life will tend to build up the turbine blades and reduce the performance, e.g. mussels.
- Present recreational uses for the area e.g. fishing, swimming, diving etc.
- Proximity to existing electrical load requirement.
- Existing supply system to which the generation will be linked. E.g. remote rural community, national distribution network, remote power application.
- Water quality and contaminants which affect the build up of unwanted material on the turbine blades.
- Wave and wind action for surface mounted devices.

First generation tidal turbines have water depths of no more than 40 m [13]. Second generation systems are expected to be able to be deployed in water depths of 40 to 80 m. These technologies are expected to be available post 2010.

In the early 1980s, and subsequently, suggestions were made to use the regular difference in tidal level between the Manukau (western) and Waitemata (eastern – through the Otara Creek) Harbours. Environmental concerns dominated the reasons for such developments not proceeding beyond the “concept” stage.

3.3 COMMERCIALISATION AND FUTURE DEVELOPMENT

Full scale prototypes are currently being tested. The availability of commercial products is expected to be a few years down the line. The commercialisation of the technology will be driven by Government and other research funding for demonstration projects, leading to implementation of commercial power projects. With adequate international government support it is expected that some of the tidal technologies could be commercialised within the next 10 years. Without substantial research and development funding the implementation of the various tidal power technologies is not expected to be significant.

There are currently a number of technologies in the research, development and demonstration phases. As commercial scale technologies are installed, market leaders are expected to emerge. Project models for the UK have a distance from the shore connection to the plant of 1 to 5 km.

3.4 EXPECTED UNIT SIZES, SCALE AND PERFORMANCE

The sizes of current pilot units are up to 750 kW. Commercial scale farms, consisting of multiple units, are expected to be 50 MW or upwards in size.

MCT units operate best with a maximum tidal current of 5 knots (2.6 m/s) and at least 3 knots (1.5 m/s). Based on 1.5 to 2.5 m/s tidal current, intensity of generation is expected to be around 5 to 35 MW per km of tidal current width.

[13] Department of Trade and Industry; Department of Enterprise, Trade and Investment; and Northern Island Electricity 2003, The Potential for the Use of Marine Current Energy in Northern Ireland

3.4.1 Efficiency, Availability and Capacity Factor

The capacity factor of the plants will be dependent on resource, with 40% being cited for two example technologies.

The availability of the plant is expected to achieve 97%. However, for submerged, deep channel current devices, the accessibility of plant for maintenance due to weather (including sea) conditions is likely to have a longer-term adverse effect on availability.

3.4.2 Life of plant

The lifetime of the plant is projected to be 20 to 25 years.

Lead times from project conception to commercial operation are in the order of 3 years.

3.5 COSTS

3.5.1 Capital cost

The capital costs for tidal current plants will be dependent on the location (water depth, distance for electrical connection) and the technology deployed. Costs for Marine Current Turbine's Seaflow and Seagen designs are in the order of $ 6,000 to 9,000 /kW for a small plant of 1 MW or less, reducing to $ 2,500 /kW for larger plants of 30 MW[14],[15],[16]. A study of an alternative technology gave costs of $ 3,500 /kW for a 100 MW tidal farm[17] .

PB Power estimates that approximately 75% of the capital cost of tidal power generators will be subject to overseas exchange. This cost excludes civil works (predominantly a local cost, excluding steel), expected to be a large part of many of fixed tidal schemes (as would be applicable with tidal barrages common in overseas installations, such as Rance River).

3.5.2 O&M cost

The O&M costs can only be estimated given the lack of installed commercial plants. Projected annual O&M costs for two example technologies are $ 150 per kW of installed capacity with potential reductions to $ 100 per kW of installed capacity for larger plants[15].

3.5.3 Future unit costs

It is expected that with increased production and operational experience the costs of electricity generation from tidal plants will reduce. UK projections indicate that tidal current generation could compete with conventional generation following further development.

3.5.4 Cost sensitivities

The cost of the plant will be sensitive to the relationship between the tidal resource and power curve of the units and the length of grid connection. Generally overhead costs will be lower with larger plants.

[14] Binnie Black and Veatch 2001, The Commercial Prospects for Tidal Stream Power
[15] Email communication with Marine Current Turbines Ltd, UK
[16] Using a conversion rate of 1UK pound = 2.5NZ$
[17] PB Power 2004, Audit of a hypothetical turbine for UK DTI

3.5.5 Cost of generation

The cost of generation for an example tidal flow device, Marine Current Turbine's Seaflow device, is 22 cents/kWh for a 1 MW device reducing to 11 cents/kWh for a 30 MW farm[12] with a 10% discount rate. An alternative technology has been estimated to generate electricity at 16 cents/kWh for a 100 MW farm.

Projections from work in the UK[18] estimate that the first large-scale tidal stream farms of approximately 50 MW in size will have generation costs of around 18 cents/kWh (assuming 8% discount rates and sites with a mean spring peak velocity of 2.5 to 3.5 m/s). At around 1,000 MW of installed capacity energy generation is expected to reduce to 13 cents/kWh and with extensive deployment, above 2,000 MW, systems at the highest velocity sites (greater than 5.5 m/s mean spring peak velocity) could generate at 8 cents/kWh. The installed capacity is based on estimated extractable tidal stream resource in the UK. It could be expected that a significant proportion of the generation cost reductions could be transferred overseas with that level of installation in the UK. Further data will need to be collected to confirm, but New Zealand appears to have a tidal resource at the lower range of velocities.

3.6 ENVIRONMENTAL ISSUES

Erection of tidal barrages (similar to the Eling Mill in England and Rance River in France), even if proven to be economic, are likely to result in lengthy and complex discussions and hearings as part of the resource consent process. Their construction in New Zealand is therefore uncertain in the current climate of New Zealand public acceptance.

The environmental impacts of submerged tidal turbines are expected to be low, with the main areas of impact being navigation and fishing. Site specific environmental impact assessments will be required for developments. There are no emissions of greenhouse gases related to the operation of tidal devices.

Tidal turbine rotors generally turn slowly (10 to 20 rpm), meaning lower risk of impact by sea creatures with the rotor blades. By comparison, a ship's propeller, typically runs at 10 times that speed.

3.7 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

The low tidal range in New Zealand of, generally, no more than 2 to 3 metres means that there are limited opportunities for electricity generation through the rise and fall of tides, e.g. tidal barrages.

The large natural harbours on the west coast of the North Island such as Kaipara, Aotea, Raglan and Kawhia create constrictions increasing the water level height and tidal velocity range presenting greater potential for electricity generation. Cook Strait has strong tidal currents, caused by the high and low tides at each end being almost completely out of phase. However as tidal current devices are limited to 40m depth initially and 80m depth for 2nd generation devices, application is limited to the near coastal areas of Cook Strait, limiting the exploitable resource.

General tide data is available from NIWA, whose tide model accurately predicts tidal heights. Tidal currents can also be calculated using data from the NIWA tide model[19]. More detailed review of the data available is required to determine how much additional data collection is required to characterise the resource in key areas mentioned above.

[18] Black and Veatch Ltd. 2005, Tidal Stream Energy. Resource and Technology Summary Report
[19] Stanton, Bell and Goring, Ebb and flow: testing the tides. Water & Atmosphere Vol. 8, No. 4, 2000

As mentioned above, impacts on craft navigation and fishing (trawling and anchoring) is expected to be the main issue from sub-surface tidal and ocean current turbines.

Further research is required to identify and quantify suitable tidal current generation locations around New Zealand, and to develop design concepts and proposals for such generators.

4. FUEL CELLS

4.1 SUMMARY

The Technology

- Fuel cells are electrochemical devices that convert chemical energy into electricity and heat, without combustion as an intermediate step, using hydrogen, natural gas, biogas or coal gas as fuel.

Current State

- Fuel cells are technologically commercial, but high costs mean that they are currently not economic in other than niche applications

Limitations of the Technology

- Current limitations are cost and durability (high maintenance costs for continuous generation).

Technological Hurdles

- Varies with the technology, main hurdle is developing processes for low cost manufacturing.

Efficiency, Scale and Costs

- Electrical efficiency is currently up to 50%, with prospects for up to 70% efficiency with hybrid fuel cell and gas turbine systems.
- Capital costs range from $4,500-8,000 per kW for current stationary applications, to $1,600 to $2,400 per kW in future for high temperature natural gas fuelled fuel cell technologies.
- Based on current and projected costs, fuel cells are not likely to be competitive as a grid-connected energy source with the report timeframe.

Environmental Issues

- CO_2 emissions from natural gas reforming in fuel cells will be similar to other technologies using natural gas as fuel, will be less only to the extent electrical generation efficiency is higher.
- Natural gas reformers either separate or integral with fuel cells will produce some unburnt natural gas and CO emissions, but these are expected to be very low.

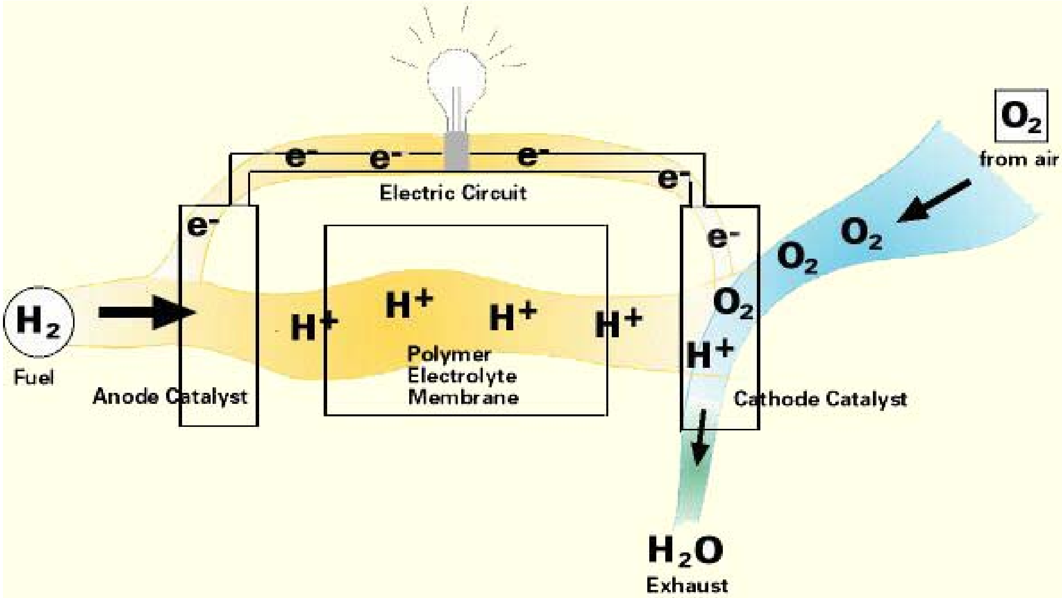
NZ Context

- Initial costs still too high for widespread use
- As costs come down, the competitive advantage for fuel cells is likely to be their potential for very high electrical efficiency (up to 60% stand alone, or up to 70% in hybrid configuration) at distributed generation scale, with very low emissions.

4.2 TECHNOLOGY DESCRIPTION

Fuel cells are electrochemical devices that convert chemical energy into electricity and heat, without combustion as an intermediate step.

The following illustrates the general principles of fuel cell operation[20].



All fuel cells have the same basic operating principle. The input fuel is catalytically reacted, removing electrons from the fuel elements to go through an external circuit to produce an electric current. A basic fuel cell consists of an electrolyte material sandwiched between two thin porous electrodes, comprising an anode and a cathode. Catalysts are incorporated into the electrodes to facilitate the reactions. A single fuel cell produces about 0.7 volts, these are combined together to get the voltage up to a reasonable level, to form a fuel-cell stack

For cells requiring hydrogen, a reformer is used. A carbonaceous fuel is fed to a fuel processor where it is steam-reformed to produce hydrogen (as well as other products, carbon monoxide and carbon dioxide for example), which is then introduced into the fuel cell and electrochemically oxidised

A stationary fuel cell power systems consist of a fuel processor, fuel cell power section, power conditioner, and potentially a cogeneration or bottoming cycle in order to utilise the rejected heat.. The power conditioner converts the direct current fuel cell output into AC power.

A number of different electrolytes are available, giving rise to the development of a number of different types of fuel cell, the type of electrolyte used giving each type its name. The characteristics of each type are very different: operating temperature, available heat, tolerance to thermal cycling, power density, tolerance to fuel impurities, etc. These differences make each technology suitable for particular applications. The most common systems are as follows:

PEMFC – proton exchange membrane fuel cell:

- uses a proton conducting polymer membrane that is insulating to electrons, relies on platinum catalyst.
- low temperature and variable output make them the most suitable for automobile use, but efficiency is low. High sensitivity to fuel impurities. A similar type, the direct-methanol fuel cell, can operate on liquid methanol without reforming. Being considered for small scale stationary use.

AFC – alkaline fuel cell

[20] See http://www.fuelcelleurope.org/

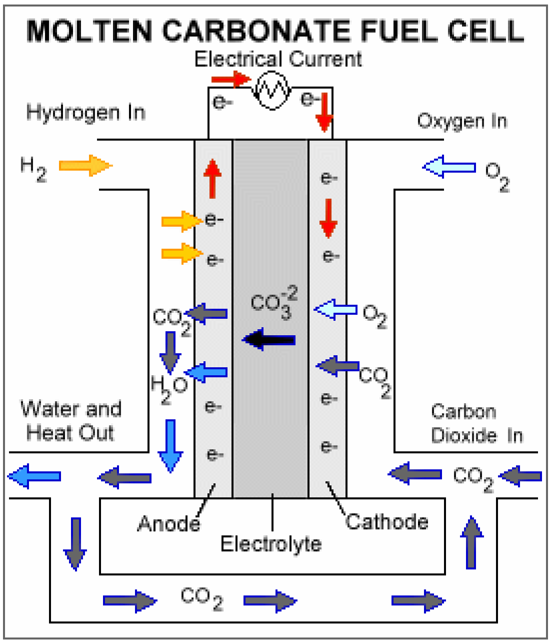
- hydroxide ions travel through potassium hydroxide solution electrolyte, non precious metal catalyst.
- very sensitive to CO_2, must use purified H_2 and O_2 (or air). High efficiency and low cost, but not much development of the technology due to the expensive purification processes required for the fuel

PAFC – phosphoric acid fuel cell

- protons travel through a liquid phosphoric acid electrolyte.
- most commercially developed fuel cell, requires platinum catalyst

MCFC – molten carbonate fuel cell

- carbonate ions travel through a molten carbonate salt mixture. High temperature allows non-precious metals as catalysts and internal reforming of carbonaceous fuels.
- can be fuelled with coal-derived fuel gases or natural gas, main issue is corrosion and use of high temperature liquid, but have very high efficiency



SOFC – solid oxide fuel cell

- oxygen ions travel through a high temperature solid oxide electrolyte to react with hydrogen
- high temperature allows non-precious metals as catalysts and internal reforming of carbonaceous fuels. A solid electrolyte means they can have multiple geometries. The very high temperatures require special materials
- promising technology for high power applications, hot off-gases can be used to fire a secondary gas turbine in hybrid configuration, to achieve very high electrical efficiencies

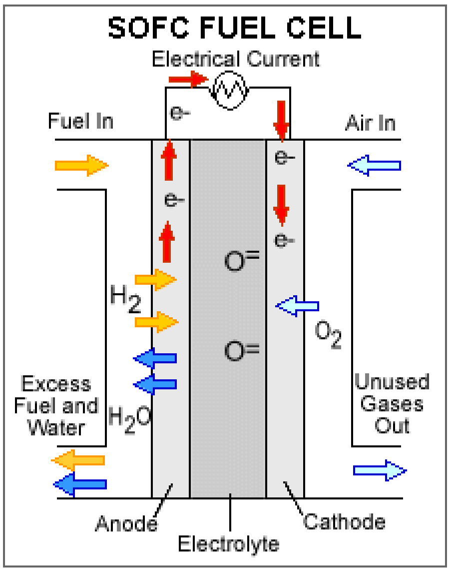


Table 4.1 – Comparison of Fuel Cell Technologies

	PEMFC	AFC	PAFC	MCFC	SOFC
Type of Electrolyte	H^+ ions (with anions bound in polymer membrane)	OH^- ions (typically aqueous KOH solution)	H^+ ions (H_3PO_4 solutions)	$CO_3^=$ ions (typically, molten $LiKaCO_3$ eutectics)	$O^=$ ions (Stabilized ceramic matrix with free oxide ions)
Typical construction	Plastic, metal or carbon	Plastic, metal	Carbon, porous ceramics	High temp metals, porous ceramic	Ceramic, high temp metals
Internal reforming	No	No	No	Yes, Good Temp Match	Yes, Good Temp Match
Oxidant	Air to O_2	Purified Air to O_2	Air to Enriched Air	Air	Air
Operational Temperature	150- 180°F (65-85°C)	190-500°F (90-260°C)	370-410°F (190-210°C)	1200-1300°F (650-700°C)	1350-1850°F (750-1000°C)
DG System Level Efficiency, % HHV	25 to 35%	32 to 40%	35 to 45%	40 to 50%	45 to 55%
Primary Contaminate Sensitivities	CO, Sulfur, and NH3	CO, CO_2, and Sulfur	CO < 1%, Sulfur	Sulfur	Sulfur

Fuels include:

Natural Gas – high efficiency steam gas reforming.

Biogas - anaerobic digester gas

Coal Gas - gasified coal, coal mine methane gas

Other fuels, including liquid fuels, can be used, but for grid connected power generation only the lower cost gas fuels have been considered for this survey.

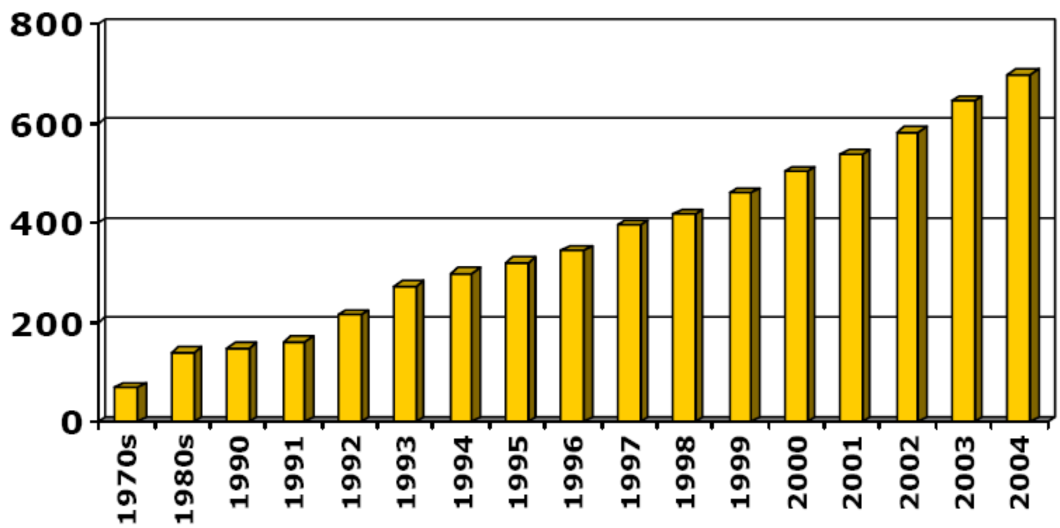
4.3 CURRENT STATUS OF TECHNOLOGY

Fuel cells also have many potential niche applications, but in the context of this report our survey is restricted to medium to large stationary applications for power or combined heat and power generation. As hydrogen is not expected to be available in New Zealand as a raw fuel except as part of a transition to a hydrogen economy, this survey is restricted to fuel cells that use the gaseous fuels that are potentially available in New Zealand.

Fuel cell generators have been sited in hospitals, computer centers and high tech industries where there is a need for standby, high quality, uninterruptible power supplies.

The phosphoric acid fuel cell (PAFC) is the most commercially developed fuel cell. UTC Power claims to have installed more than 265 PAFC fuel cell systems in 19 countries on 5 continents since 1991, with over 1.1 billion kWh and 7 million total hours of fleet operation.

The total global supply of large stationary fuel cells is shown in the following graph[21], it is a small fraction of the total complete fuel cell systems that have been built.



4.4 COMMERCIALISATION AND FUTURE DEVELOPMENT

Fuel cells are technologically "commercial", but high costs mean that they are currently not economic. Commercial availability for different applications are presented below[22]

Table 4.2 – Fuel Cell Applications and Commercial Availability

Application	Commercial From	Fuel Cell Type
<5 MW	1996	Phosphoric Acid (PAFC)
Automotive	2002	Proton Exchange Membrane (PEMFC)
Commercial and Residential Cogeneration <500 kW	2003	Proton Exchange Membrane (PEMFC)
Portable/Backup Power	1999	Proton Exchange Membrane (PEMFC)
Distributed Power/Cogeneration	~ 2005 - 2006	Molten Carbonate and Solid Oxide (MCFC and SOFC)

[21] See http://www.fuelcelltoday.com, December 2004
[22] www.fuelcellworld.org, Status of Technology Development

Application	Commercial From	Fuel Cell Type
Industrial Cogeneration	~ 2005	Molten Carbonate and Solid Oxide (MCFC and SOFC)
Central Generation	unknown	Molten Carbonate and Solid Oxide (MCFC and SOFC)

Accelerated adoption for stationary generation is unlikely to be achieved before 2010, and mass vehicle adoption of fuel cells is unlikely to be achieved until at least 2015[23].

There are only a handful of mature fuel-cell companies, most of which are in North America and Japan. However, none of these companies have ramped up production to any sizable scale, because no sizeable demand exists at current production costs.

The Center for Fuel Cell Research and Applications, Houston Advanced Research Center (HARC), reported[24] that a large-scale application that makes fuel cells a "must have" and dramatically increases market demand has yet to emerge for fuel cells. The revolutionary value proposition for fuel cells is still diluted by unresolved performance and cost issues.

Due to high cost, fuel cells have mainly found applications in niche premium power markets such as uninterruptible power supplies for data centres and sensitive manufacturing processes.

Development work is ongoing to lower the cost of fuel cells and improve their durability. Although fuel cells can be used in combined heat and power applications to increase the overall utilisation efficiency of the fuel, this is also true of other technologies. The competitive advantage for fuel cells is likely to be their potential for very high electrical efficiency (up to 70% in hybrid configuration) at distributed generation scale, with very low emissions.

The U.S Department of Energy is supporting fuel cell/gas turbine hybrids development as part of its FutureGen program. The aim is to ultimately derive gas from coal and compete with IGCC technology. To do this requires a factor of 10 reduction over current costs and development of technology for scale up of fuel cells to much larger sizes. This is a research programme and not a commercial prospect in New Zealand within the report timeframe.

4.5 EXPECTED UNIT SIZES, SCALE AND PERFORMANCE

Fuel cells directly convert chemical energy into electricity and so are not subject to the theoretical limits of fuel efficiency that thermal energy based conversion technologies are. Therefore fuel cells offer the possibility of conversion efficiencies far beyond prospects for thermal energy conversion systems.

Molten Carbonate fuel cells running on pipeline natural gas can achieve efficiencies of approximately 50% (fuel-to-electricity).

Solid Oxide fuel cells running on pipeline natural gas can achieve efficiencies of approximately 50% (fuel-to-electricity). The very hot off gases can be used to fire a secondary gas turbine (hybrid configuration) to improve electrical efficiency to 70%.

[23] Gardiner A, "Status of Fuel Cells for Distributed Generation and Transport", presented at Symposium on New Energy Technologies, Wellington, 12 October 2005
[24] Houston Advanced Research Center, Fuel Cell Industry Assessment 2004, November 2004

Future stand alone fuel cells are expected to achieve up to 60% efficiency for distributed generation and are expected to be in the 250 kW to 5 MW scale.

4.5.1 Fuel Cell Life

For stationary systems, 40,000 hours is desirable. However, no fuel cell technology is yet fully proven at this life time.

4.6 COSTS

4.6.1 Capital Costs

Fuel cells are too expensive to compete in widespread commercial markets, without significant subsidies.

Over the last several years, phosphoric acid, tubular solid oxide, and molten carbonate fuel cell systems have been demonstrated at greater than 200 kW. These stationary and distributed demonstrations have validated current costs of $4,500-8,000 per kW, and reliability of 10,000-20,000 hours.[25]

The high temperature natural gas fuelled fuel cell technologies are expected to reduce to $1,600 to $2,400 per kW in future.

PB Power estimates that at least 90% of the capital cost of fuel cell systems will be subject to overseas exchange.

4.6.2 Operating and Maintenance Costs

O&M costs are difficult to source given little operating experience with fuel cells. Some indicative costs were available in a University of California study[26]. Limited durability of fuel cells requiring replacement of cell stacks after 5 years operation currently has a major impact on O&M costs.

Yearly non-fuel O&M costs are estimated at $90 per kW installed. Plus major costs need to be added in for stack refurbishment of 33% of initial capital costs every 5 years.

In future O&M costs may reduce to around $50 per kW per year, and stack refurbishment 25% of initial capital costs every 10 years.

These costs can be calculated into uniform (levelised) annual O&M costs in today's dollars. The levelised O&M costs vary with initial capital cost and are from 4.5 c/kWh to 7.1 c/kwh currently and in future costs may reduce to 1.1 c/kWh.

4.7 ENVIRONMENTAL ISSUES

Natural gas reforming will be used to power fuel cells in the medium term, and this process will emit CO_2 at levels similar to other energy supply technologies. Any potential reduction in CO_2 emissions will be the result of higher electrical efficiency only.

Natural gas reformers will also produce unburnt gas and CO emissions, but these are expected to be very low.

[25] US DOE, Fuel Cell Report to Congress, 2003
[26] Timothy Lipman, Fuel Cell System Economics, University of California, Berkeley, April 2004

4.8 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

Research is currently being carried out at CRL Energy for proof of concept of coal gasification to fuel cell grade hydrogen. However, the large scale of plant required for economic coal gasification will probably inhibit the gas being used in the smaller distributed scale fuel cells that are likely to be economic within the timeframe of this report.

IRL are conducting research on alkaline fuel cells that operate at low temperatures on pure hydrogen for distributed niche applications. They are not expected to be a commercial grid connected technology within the timeframe of this report.

5. PHOTOVOLTAICS

5.1 SUMMARY

The Technology

- PV is a commercial, but high cost technology
- It is reliable and requires low levels of maintenance
- Development of 3rd generation PV that could become cost effective with conventional electricity generation in the next 20 years requires significant technological breakthroughs

Current State

- World PV production in 2003 was 744MW

Limitations of the technology

- The solar resource is intermittent and cannot follow demand
- Capacity factors are very low, due to the intermittency of the resource

Technological Hurdles

- Efficiency of solar energy conversion to electrical power
- High cost of manufacturing the high purity crystalline silicon and the precise chemical doping required for high conversion efficiency
- Low efficiency of the lower cost thin film PV technologies

Efficiency, Scale and Costs

- Conversion efficiency (electrical kWh / solar kWh) of 8%
- Domestic grid connected systems are around 1kW in size and cost 9-14 $/W
- Due to the modularity of PV grid connected power plants do not have size limits. Current installations are up to 10MW. Current costs for greater than 10kW systems are 7-11 $/W. Future costs depend on global installed capacity and could reduce to 3.5 to 6.5 $/W.
- Indicative annual operating costs of a grid connected PV system are 1% of capital costs

Environmental Issues

- Emission free, noise free operation
- Visual impact

NZ Context

- New Zealand has a medium range solar resource
- The generation profile is not a good fit with the demand profile at present in New Zealand
- The current market uptake of PV in New Zealand is low

5.2 TECHNOLOGY DESCRIPTION

The photovoltaic cell is a semiconductor device that converts photons (light) into electricity.

The most common configuration of this device, the first generation photovoltaic, consists of a large-area, single layer silicon p-n junction diode, which in the presence of sunlight generates usable electrical energy.

The second generation of photovoltaic materials is based on multiple layers of p-n junction diodes. Each layer is designed to absorb a successively longer wavelength of light (lower energy), absorbing more of the solar spectrum and increasing the amount of electrical energy collected.

The third generation of photovoltaics is very different from the other two, and is broadly defined as a semiconductor device which does not rely on a traditional p-n junction to separate photogenerated charge carriers. These new devices include dye sensitized cells, organic polymer cells, and quantum dot solar cells.

5.3 CURRENT STATUS OF TECHNOLOGY

Currently the development of PV applications is proceeding in four primary market areas:

- Off-grid[27] industrial: for communications repeater stations, cathodic protection;
- Off-grid residential: for solar home systems;
- On-grid applications: for domestic systems, commercial systems, PV power plants;
- Consumer products: for calculators, watches, etc.

Photovoltaics (PV) based on crystalline silicon is considered a mature, commercial technology for niche off grid applications. The world PV production in 2003 was 744 MWp[28],[29]. As at 2003, there was a total installed capacity of 1.8 million kW of PV in member countries of the International Energy Agency PV Power System Programme[30], and of this 1.4 million kW was grid- connected, but this is mainly subsidy driven.

Currently PV power units are sold in modules of up to 200 W. As an example the BP3160 polycrystalline silicon PV module is 160 W and is 1.26 m^2 in area (dimensions: 1209 x 537 x 50 mm). The voltage at maximum power is 35.1 V and the current at maximum power is 4.55 A. Numbers of PV modules are connected in series and parallel to generate electricity at the required voltage and current level. PV modules generate DC current. Connection to the electricity network (or if used to power AC appliances) requires the use of an inverter(s) to produce AC current.

5.4 COMMERCIALISATION AND FUTURE DEVELOPMENT

Crystalline silicon solar cell PV is already a commercial technology in niche applications. Next generation polymer, dye-sensitized and quantum dot PV may become commercial in 15 to 20 years.

Costs of the technology are expected to reduce as the world production of PV increases. 2nd generation PV based on thin-film silicon substantially reduces the silicon required and

[27] Off-grid applications are stand alone systems not connected to the electricity network
[28] Paul Maycock, PV News, Annual review of the PV market 2004
[29] Wp is a “Watt peak”, a measure of how much energy a solar panel can produce under optimal conditions
[30] IEA PVPS countries are: Australia, Austria, Canada, Switzerland, Denmark, Germany, Spain, Finland, France, UK, Israel, Italy, Japan, Korea, Mexico, Netherlands, Norway, Portugal, Sweden and USA

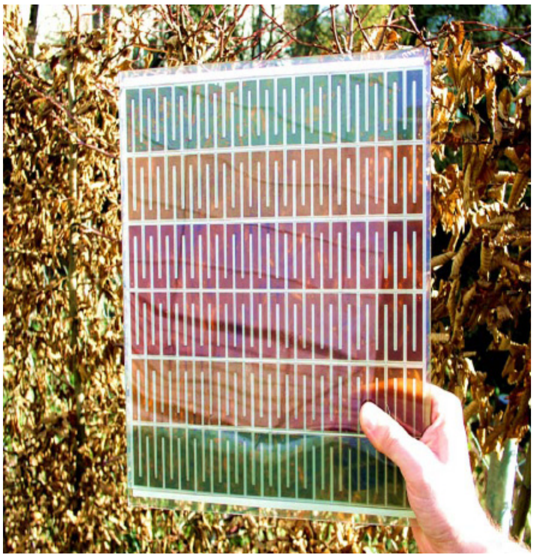
hence costs, but efficiencies are lower. 3rd generation PV technologies such as polymer solar cells, and dye-sensitized solar cells are being researched to improve the efficiency and reduce the costs of PV technology.

Research is being undertaken to increase the efficiency of photovoltaic materials and reduce the production costs. In this regard, a consortium in USA is working to more than double the efficiency of terrestrial solar cells by the end of 2007. Current research in USA is aiming to create solar cells that operate at up to 54 percent efficiency in the laboratory and 50 percent in production. Costs will also be reduced with increases in production volumes.

Development is advancing into liquid-junction titanium dioxide solar cells, which are dye-able, to create a range of products for solar cell applications. This has opened the way for artificial photosynthesis. At the start of development, the plastic cell efficiency was less than 1% but development cells are currently being produced at greater than 6%. Siemens aims to commercialise plastic solar cells at 5% efficiency by 2010. Quantum Solar Energy Linz (QSEL) in Austria has been developing plastic solar cells (dye-sensitized TiO_2) with at least 4% efficiency[31]. Konarka[32] which recently acquired QSEL, has developed this breakthrough in non-rigid, non-bulky and flexible solar panels by developing photovoltaic cells on plastic substrates rather than glass, as indicated in the following pictures.

Use of plastic substrates

(Courtesy Konarka)



Dye-sensitised modules[33]

(Courtesy Dr W Hoffman, Schott Solar)

5.5 EXPECTED UNIT SIZES, SCALE AND PERFORMANCE

Off-grid industrial systems and consumer products systems are sized as required and are not significant in terms of contribution to the national power generation mix. Consumer products have little or no impact on the electricity system, except to dispense for some grid-connected battery charging systems.

Off-grid residential systems range from tens of Watts in size up to a couple of kW, based on a balance between affordability and electricity requirements of the household.

[31] Officer D L, "Nanomaterials for Sustainable Energy Conversion", presented at Symposium on New Energy Technologies, Wellington, 12 October 2005
[32] See http://konartech.com/technology
[33] See http://www.nanoroadmap.it/events/first_conference/presentations/graetzel.pdf

Typical on-grid domestic systems are around 1 kW in size, generating around 750 to 1,000 kWh per annum.

On-grid commercial systems range from kW to MW in size.

PV power plants are sized as required with the largest systems now being installed at up to 10MW in size.

5.5.1 Efficiency

Currently, high-end solar cells operate at a peak efficiency of 24.7%, and solar cells off the production line operate at up to 15-20%[34].

3rd generation multijunction PV technologies such as dye sensitized cells, organic polymer cells, and quantum dot solar cells may increase efficiency up to 38%.

Grid PV systems have a system efficiency of around 8%. At the average solar resource of 4 kWh/m^2/day, PV systems installed at a capacity of 137 Wp/m^2, would be expected to generate around 850 kWh/kWp of installed capacity per year.

Stand alone PV systems have a lower system efficiency as in certain situations the battery will be fully charged when the PV is generating. A typical system efficiency would be around 4%, generating 425 kWh/kWp.

5.5.2 Capacity

At a system efficiency of 10%, an area packing factor of 50% (to allow for tilt), an area of 3.67 x 3.67 km is needed to generate 788 GWh per year. The installed capacity of PV would be around 900 MW, and hence the capacity factor is around 10%. This 900MW system would have the same annual generation as a 100 MW thermal plant.

Capacity factor can be improved by sun tracking arrays, but this adds significantly to system costs. Capacity factors are unlikely to exceed 15-20%. Due to the intermittency of PV, its contribution will be limited to low proportions of the national generation mix for grid stability reasons (up to 15%).

5.5.3 Life of plant

Current commercial PV systems have a lifetime of 25 years.

5.5.4 Lead times from project conception to commercial operation

Photovoltaic systems have short lead times from project conception to commercial operation, of the order of months. This would involve design work, the ordering of the equipment, installation and in some cases application for development approval. Generally PV panels and the balance of system are considered as 'off the shelf' items in terms of manufacture. However, there has been recent evidence of large orders for PV having a long lead time of up to a year for supply from the manufacturer, due to demand for the systems outstripping supply.

5.6 COSTS

5.6.1 Capital cost

The capital costs for PV systems are as shown in the Table below[35].

[34] See http://renewableenergyaccess.com/rea/news/story?id=38812

Connection Arrangement	NZ$/W[36],[37]
Off-grid up to 1 kW	20-27
Off-grid >1 kW	14-20
Grid-connected 1 - 3 kW	9-14
Grid-connected up to 10 kW	8-11
Grid-connected > 10 kW	7-11

The above table assumes that prices in New Zealand are similar to those in Australia, as there is limited available information specific to New Zealand.

Claims by Konarka[38] indicate that the manufacturing cost of the latest generation of plastic-based solar cells is no more than 40% of the cost of standard crystalline and glass cells. Plastic-based cells currently in production have an efficiency of about 5%, and predicted to be 7% by 2007.

PB Power estimates that at least 90% of the capital cost of PV systems will be subject to overseas exchange.

5.6.2 O&M cost

PV systems generally need little maintenance. PV panels for all system types should be cleaned on a regular basis, with the frequency of cleaning depending on the level of dirt collection locally. The cleaning ensures that the panels are receiving the maximum amount of solar radiation. Systems should also be checked for shading such as from the growth of vegetation.

Off-grid systems with a battery will need the battery topped up regularly. The battery may need replacing during the life of the PV but some systems have been known to last for 20 years.

The inverter in a grid-connected system would be expected to need replacing over the lifetime of the PV system.

Indicative annual operating costs for a PV system are up to 1% of capital costs. Although the absolute operating costs appear low, the very high capital cost and low capacity factor mean that operating costs per kWh are high.

5.6.3 Future Unit Costs

The Australian PV industry roadmap[39] published in 2003, projected a cost-competitive PV industry by 2020 with an installed capacity of just below 7,000 MW. The report projects world PV industry annual growth rates of 15 - 30% up to 2010. However it should be noted that the target installed capacity in 2020 is only projected to occur following government commitment to specific support measures for PV, which as yet have not been agreed.

[35] IEA PVPS 2004, National Survey Report of PV Power Applications in Australia
[36] PV module electrical capacity are generally expressed in Watts peak, a measure of how much energy a solar panel can produce under optimal conditions. We have used kW for ease of understanding
[37] Prices have been converted from 2003 Australian dollars to 2005 New Zealand dollars
[38] Konarka Technologies, Inc. From Light to Power - Enabled by Nanotechnology, September 2003
[39] Australian Business Council for Sustainable Energy 2004, The Australian Photovoltaic Industry Roadmap

Given an 8% discount rate a typical grid-connected PV system at current costs ($11.5 /W) would generate at $1.34 /kWh over its 25 year lifetime.

Costs are projected to decrease to $ 0.76 /kWh in 2015 and $0.41 /kWh in 2025. These projections assume a price decrease of 18% for each doubling of installed capacity, prices in New Zealand being driven by global demand with a global annual increase in demand of 25%, and 3% per annum increases in conventional electricity prices.

Over the past decade, global PV prices have reduced by 18% for each doubling of cumulative production, relating to an annual cost reduction of 6% per year. This is projected to continue at least until 2013.

With the development of “nanotechnology” and production of plastic solar cells, costs for photovoltaic cells could lead to a drop in cell cost by between 90% and 99% (costs down 10 to 100-fold).

5.6.4 Cost sensitivities

PV system capital costs are dominated by the price of PV cells. A limiting factor to the expansion of the current PV market is the lack of availability of silicon feedstock. The silicon for PV manufacture is taken from the waste products of the electronics industry. This keeps the costs of PV manufacture down but creates a dependency which has limited production expansion. Some supply problems have been experienced with PV over recent years, with long periods for delivery of orders.

PV systems operating costs are independent of any fuel price fluctuations.

5.7 ENVIRONMENTAL ISSUES

PV has a low environmental impact. During operation, it has no emissions, has no impacts on flora or fauna and does not generate noise.

Photovoltaic systems generate electricity without emitting CO_2. Some CO_2 is emitted in the manufacture of the PV. However the energy payback (time to generate the energy of manufacture) of PV is 3-4 years depending on the type of PV used[40].

5.8 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

All PV application sectors are considered suitable for New Zealand. Off-grid industrial and consumer products will already have niche markets.

Off-grid residential may be economic in areas with high costs for grid connection, but assessments have to be on site-specific and case-by-case bases.

On-grid applications are not currently economic in terms of the price of electricity generation compared to current electricity prices. There is a high capital outlay for photovoltaic systems, and at current electricity prices the value of the electricity generated by the system over the lifetime does not pay back the capital outlay. This will be a limiting factor to the growth of this market sector.

The solar energy resource in New Zealand at an average of 4 kWh/m^2 per day is not as high as Australia or the US, but is higher than that of Germany. Germany has developed a significant market for PV with an installed capacity of 410 MW in 2003. This market has been developed through the setting of preferential tariffs for PV electricity.

Due to New Zealand’s latitude, the solar resource varies between summer and winter by about a factor of 2.5. With current demand in New Zealand reaching its peaks on a

[40] National Renewable Energy Laboratory, http://www.nrel.gov/ncpv/energy_payback.html

winters evening, the generation profile of PV is not a good fit with the demand profile at present in New Zealand. However, in the future daytime peaks may start to appear in Auckland due to air conditioning loads in summer. PV systems may provide a better fit for peak shaving for summer daytime peak loads in future.

The high cost of PV electricity can be alleviated by capturing the price benefits of distributed generation. The lack of standard agreements for connection of DG to local networks is hindering development. However, Contact Energy has recently agreed to pay the retail price for PV electricity exported to the grid. This is higher than the tariffs offered by other companies.

The current market size for PV in New Zealand is small. Incentives would be required to increase the market size in New Zealand.

6. MARINE DISTRIBUTION OF COMPRESSED NATURAL GAS (CNG)

6.1 SUMMARY

The Technology

- Shipping natural gas at high pressure without liquefying or re-gasification

Current State

- No CNG ship has been built yet, but designs are being evaluated. CNG shipping could be commercially available within the next 3 to 5 years.

Limitations of the technology

- CNG shipping is expected to be uneconomic relative to LNG at larger volumes.

Technological Hurdles

- High cost (and weight) of the high pressure containing structures

Efficiency, Scale and Costs

- One technology has an estimated \$5.3 to \$7.2 /GJ transport cost for 19 PJ/year (sufficient for one 350 MW combined cycle power station)

Environmental Issues

- No specific issues with the technology, but by extending the availability of natural gas should domestic sources run out, extends the environmental benefits of natural gas as an energy source.

NZ Context

- Smaller scale of natural gas consumption in New Zealand, and uncertainty over future supplies may make CNG shipping a useful interim technology, without the commitment of high capital costs for LNG importation infrastructure.

6.2 TECHNOLOGY DESCRIPTION

CNG shipping is a natural gas transportation technology that competes with natural gas pipelines and LNG shipping. CNG shipping is thought to have a niche application for transportation of small quantities of natural gas over 'short-medium' distances with small to medium volumes.

CNG offers an advanced, yet simple solution. The gas is compressed to 150–300 atmospheres and is transported onboard ships in pressure vessels, which can be considered as transportable pipeline sections. By comparison, LNG is carried at atmospheric pressure. At the CNG receiving terminal or offloading buoy the vessel can be connected directly to the pipeline network for gas transmission, in one option effectively using the vessel as storage. CNG is carried at ambient temperatures (up to 40°C), or may be cooled somewhat (down to -40°C) to reduce its volume, compared with LNG which is kept at -163°C and requires different materials of construction.

The concept of transporting CNG by sea has been explored since the 1960's[41] . Since that time a number of companies have been developing a variety of CNG shipping technologies in order to establish a commercially viable alternative.

Class rules for construction of such types of ships has been established by American Bureau of Shipping (Notation: ABS-A1 E Gas Carrier). These vessels can be loaded at relatively simple marine facilities, including offshore buoy moorings.

Two proposed technologies for shipping CNG are shown below.

Figure 6.1 - Knutsen vertical steel cylinders

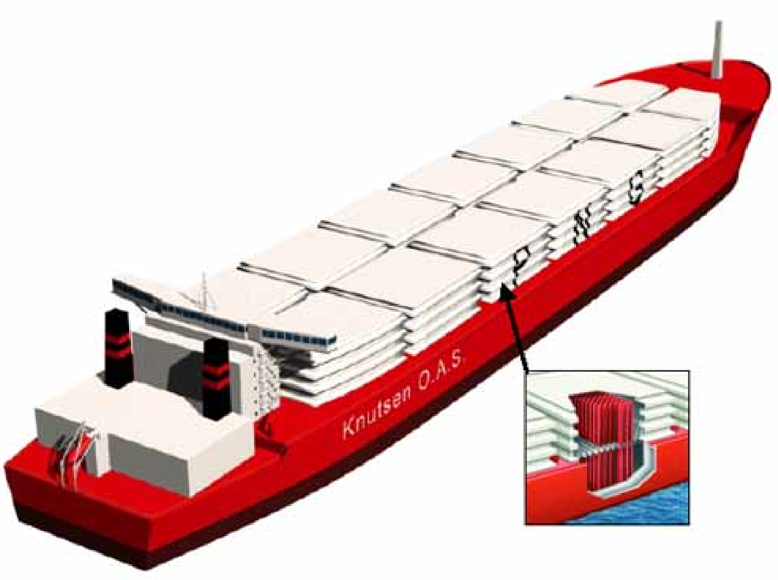
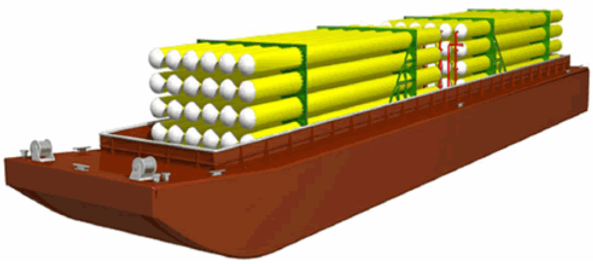


Figure 6.2 - Transcanada barge mounted Gas Transport Modules (GTMs)



In the Transcanada GTM system, a number of barge and tug combinations are shuttled back and forth between loading and unloading ports. The CNG is supplied by a compressor to the barge through high pressure loading connections and the process will be similar to the filling of a CNG tank in a vehicle, though on a much larger scale. In practice, at all times there will be a barge docked at the loading site and one at the unloading site to maintain continuous supply. At the loading site as one barge is nearing its maximum fill pressure of approximately 200 barg, a second barge will be berthed and connected so that when the first barge is full, a seamless switchover is made to the second barge so the essentially continuous flow is maintained. The tug that brought the second barge then picks up the first barge and shuttles it to the unloading site. At the unloading site, a barge is already connected to a pressure letdown station and potentially a compressor station and gas will be either flowing or compressed at a constant rate into the delivery system. When the tug with the full barge arrives, it berths this barge and it is

41 Electronic article "Teekay leading the way in development of CNG technology", at http://www.teekay.com/

connected to the delivery system so that when the barge that is presently there reaches its minimum heel pressure of approximately 10 barg, a seamless switchover can be made to the full barge and constant flow is maintained. The empty barge is then disconnected and picked up by the tug and returned to the loading area for filling.

6.3 CURRENT STATUS OF CNG SHIPPING TECHNOLOGY

Natural gas transmission pipelines and LNG shipping are commonly used to transport large quantities of natural gas. Both forms of transportation are capital intensive, with pipelines generally being cost effective over shorter distances, and with LNG shipping becoming economic over longer distances. However, the capital intensive nature of these two technologies does not lend itself to the transportation of smaller gas quantities.

CNG is a less concentrated form of natural gas compared to LNG, but the production of CNG requires minimal capital expenditure by comparison. Therefore the transportation of CNG is uniquely suited to the transportation of smaller gas quantities over moderate distances. Such an application could be applicable to the supply of natural gas to New Zealand from Australia.

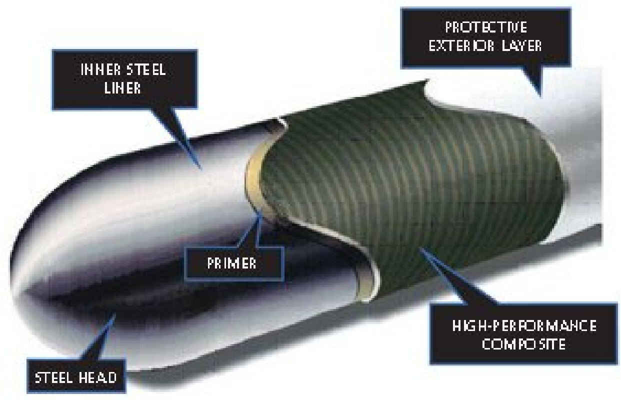
A number of companies around the world are currently looking into a range of different CNG shipping technologies, a sample can be found in the table below:

Table 6.1 - Proposed CNG Shipping Technology[42]

Company	Proposed Vessel
EnerSea	Volume Optimized Transport (VOTRANS) gas carrier. These are essentially large diameter pipes contained within insulated structures integrated onto specially designed and constructed ships. The CNG is cooled to reduce volume, and discharged using the coolant medium (ethylene glycol) to physically displace the gas. VOTRANS technology provides the capability of moving up to 4.4 million cubic metres of CNG per ship over distances up to 6,500 km at significantly lower total cost than liquefied natural gas (LNG) or pipelines.
Knutsen OAS	Pressurized Natural Gas (PNG) carriers. Haugaland Gass, Knutsen OAS Shipping and Norske Shell have signed a letter of intent for a joint project for seaborne transportation of Compressed Natural Gas (CNG)[43]. A small development vessel has been produced to test the technology. This technology consists of vertical pipe-type steel CNG bottles nested in the holds of a ship that stores the gas at extremely high pressure (3,500+psig). This ambient-temperature, high-pressure containment system requires the use of very thick-walled steel pipe containers[44].
Transcanada	Gas Transport Modules (GTM)[45] and Composite Reinforced Pressure Vessels (CRPV). By mounting GTM tubes on barges and ships, gas can be compressed into those tubes and transported to market.
Trans Ocean Gas	Composite pressure vessels for CNG transportation. Trans Ocean Gas Inc. of St. John's, Newfoundland and Labrador, Canada, is the only CNG proponent in the world that will use fibre reinforced plastic (FRP) pressure vessels to transport CNG by

[42] Electronic article “CNG shipping one step closer to commercialisation”, at http://www.poten.com/
[43] See http://www.knutsenoas.no/
[44] Fairplay, 16 September 2004, www.fairplay.co.uk
[45] See http://www.transcanada.com/company/gtms.html

	ship. Trans Ocean Gas owns the patent rights to this non-steel based method of CNG transportation. Steel truss frames are used to house and contain a number of FRP bottles in modules. Bottles are connected with stainless steel manifolds.
Cran & Stenning Technology	In 1990's Cran & Stenning Technology of Canada patented the technology called 'Coselle', short for 'Coil in a Carousel'. The Coselle high pressure gas storage system is a very large coil of small diameter pipe, sitting in a steel girder carousel. A standard Coselle CNG carrier looks like a Panamax bulk carrier with a DWT of 60,000 metric tonnes, consisting of 108 Cosselles with a gas capacity of 0.36 PJ.



Transcanada's GTM gas transport system

The CNG technologies mentioned above are generally conventional land based equipment applied in a marine context. Approvals have already been gained from the American Bureau of Shipping for the EnerSea VOTRANS carrier.

Other infrastructure required to establish a CNG supply chain would include:

- compression facilities (150 to 300 bar);
- CNG ship loading facilities;
- CNG ship receiving facilities;
- CNG storage facilities (if the vessel is not used as storage);
- downstream gas distribution facilities.

6.4 COMMERCIALISATION

The main barrier to commercialisation is the capital cost of the CNG ships. The technology itself is already proven in a land based context, therefore the question of economic viability will be determined on a case by case basis, primarily based upon the transportation distance, and the volume of market demand.

A search of available literature indicates that a number of companies anticipate the commercialisation of CNG shipping within the next 3-5 years (i.e. by 2010).

CNG carriers are presently not part of the International Gas Code. Therefore, this new concept must document that the overall safety of the process is equivalent or better than comparable LNG ships. New Class Rules for CNG were developed and issued by DNV in January 2003, using a formal safety assessment approach. The new DNV rules are mainly confined to containment design using large diameter offshore pipes.

First delivery of Trans Ocean Gas' system is expected in 2007. These systems are expected to enable ship sizes of from 1 to 30 million sm^3, at costs of about US$ 7 per sm^3.

6.5 EXPECTED SCALE AND PERFORMANCE

The scale of marine distribution of compressed natural gas applicable to New Zealand is a function of the specific economics. This is a very complex area and little comment can be made about the potential results, except that it is understood marine importation of CNG would be implemented in 20 PJ/year blocks, and LNG is not expected to be economic at less than 60 PJ/year.

6.6 COSTS

6.6.1 Sea transport cost breakdown

The table below shows an estimate of the sea transport cost for importing CNG by ship to New Zealand from Papua New Guinea using the Cran & Stenning Coselle technology. The estimate is based on a range of assumptions that are largely driven by the information available to develop the estimate. The estimate is based on the arbitrary assumptions that there is always one CNG carrier supplying gas to the New Zealand gas pipeline system and that the unloading time for one carrier is seven days. This assumption requires the use of three carriers to allow for sailing times and filling time.

CNG sea transport cost estimate based on a Coselle CNG carrier

Item	Units	Value
Coselle CNG Panamax carrier		
CNG carrier cost[1]	US$m each	138
No. of ships	each	3
Ship cost (3 ships)	NZ$m[6]	637
Annual running cost per ship[1]	NZ$m[6]	4.9
Annual fuel cost per ship[2]	NZ$m[6]	1.9
CNG carrier energy capacity[1]	PJ	0.36
Unloading time (one per week)	days	7
Loading time	days	4
Ship transit time (one way)	days	5
Annual gas delivered (by 3 ships)	PJ / year	18.8
Port Facilities Capex[1,3]		
Port facilities	NZ$m[6]	9.2
No. of port facilities	each	2

Item	Units	Value
Total Port facilities costs	NZ$m[6]	18.5
Port operating costs (per ship)[4]		
Loading (4 days)	NZ$	57,648
Unloading (7 days)	NZ$	82,848
No. of Loadings	each	17
No. of Unloadings	each	17
Port costs (per year)	NZ$	2,388,432
Summary	**NZ$m**	**NZ$/GJ**
Port capex[5]	18.5	0.10
Ship capex[5]	637	3.39
Ship opex (per annum)	26.3	1.40
Port costs (opex per annum)	7.2	0.38
Total		**5.28**

Notes:

1. Source: "Natural gas developments based on non-pipeline options - Offshore Newfoundland", Worley International Inc & Worley Engineers. February 2000
2. 10MW ship, 10,000 kJ/kWh, US$3.00/GJ fuel cost, 173 days sailing per ship per year
3. Includes only shore based facilities for gas loading/unloading, excludes any wharf development or any dredging costs that may be required to accommodate a Panamax sized vessel.
4. Estimate based on CentrePort rates
5. At 10% of capex per year
6. Exchange rate assumed NZ$1 = US$0.60

6.6.2 Source of an CNG ocean transport cost analysis

The "CNG Ocean Transport 2004: A Progress Update of the Issues and Opportunities for Offshore CNG and Renewed and Expanded Economic Evaluation" report is a multi-client study that provides an objective, third-party assessment of the issues, economics and opportunities for CNG ocean transport. The report also includes economic models in the format of four excel spread sheets which evaluate CNG ocean transport cases and economics. The report is available from Zeus Development Corporation[46].

[46] https://www.zeusdevelopment.com/secure/cngot/report.asp

6.7 ENVIRONMENTAL

The use of natural gas has a number of environmental benefits over other fossil fuels, and the continued use of natural gas in New Zealand is expected to play an important role in minimising greenhouse gas emissions.

6.8 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

The use of CNG shipping would be aimed at supplying natural gas to New Zealand's established natural gas markets.

The smaller scale of natural gas consumption in New Zealand, and uncertainty over future supplies may make CNG shipping a useful interim technology, without the commitment of high capital costs for LNG importation infrastructure.

7. SUPERCONDUCTORS

7.1 SUMMARY

The Technology

Superconductivity is the transfer of electricity with very small losses through certain materials cooled to liquid nitrogen temperatures of approximately 70K (-196 ºC). This class of superconducting materials is called high temperature superconductors (HTS). The core technology of all superconductor devices is superconductor wire.

Current State

HTS wire production is being ramped up around the world, in the order of hundreds of kilometres of first generation wire, with second generation lower cost wire coming onto the market in commercial quantities in the next few years. Some devices using HTS wire are in commercial production (e.g. grid support systems, magnets), some in pre-production testing (e.g. cables, motors), and some in the prototype stage (e.g. transformers). The first commercial HTS reactive power control systems, which supply and control the reactive power in a grid, are being manufactured and planned for shipment late 2006. These are particularly suitable for problems associated with wind farm connections to the grid.

Limitations of the technology

HTS is currently not suitable for overhead transmission lines, and therefore overhead conventional lines are likely to remain the most economic solution in the medium term for transmission over long distances

Technological Hurdles

Technical hurdles include wire costs, refrigeration efficiency, cryostat designs, cable design for long lines, and possible reliability and maintainability issues; however there is no apparent reason why these cannot be all addressed over time with continued improvement. Wire costs are dropping with one prediction by the US government of a 12 fold reduction in cost/capacity in the next 10 years.

Efficiency, Scale and Costs

High costs limit the use of HTS to niche applications. Underground or underwater applications are one area where HTS cables may be able to compete against conventional underground or underwater cable. The HTS cable systems are still significantly more expensive than conventional system, with a ratio of approximately 6:1 for cable only costs. The most promising situation for HTS appears to be where the compactness of HTS cables has advantages for resource consent and easement issues, and where there is restricted space for underground services via roads, which is likely to be cities with very high electricity densities.

Environmental Issues

There are minimal environmental issues with superconductor devices; in fact superconducting devices have numerous environmental advantages over equivalent conventional devices including removal of fire risk, minimal electromagnetic field, and smaller size.

NZ Context

There appears to be few opportunities in New Zealand for HTS transmission at currently expected HTS costs

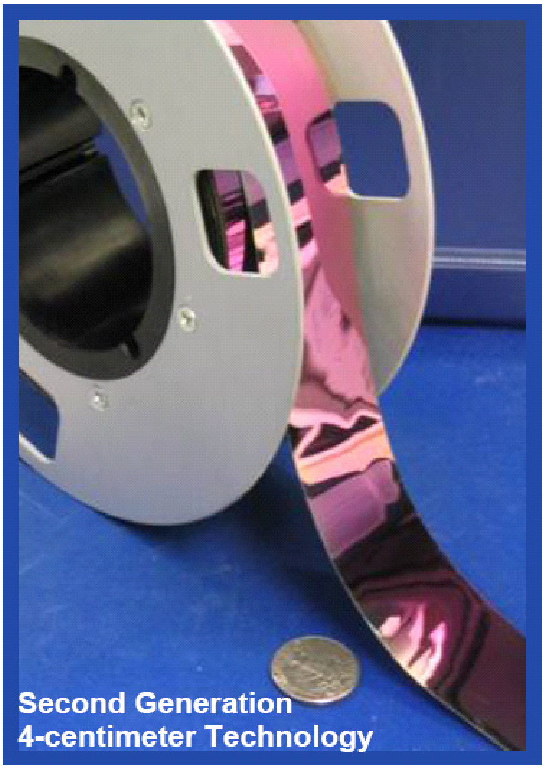
New Zealand may have a potential role in designing and manufacturing HTS devices or components where features outweigh the high cost, in fabrication of pre-production HTS devices, and in testing of HTS devices.

7.2 TECHNOLOGY DESCRIPTION

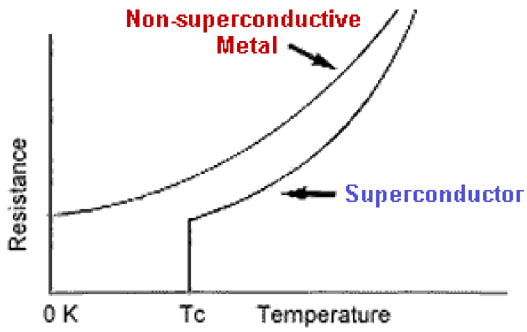
In 1986 a new class of superconducting compound was discovered that could operate at liquid nitrogen temperature of around 77K . This opened up the possibility of a wide range of applications since liquid nitrogen is much less costly to produce and transport compared to liquid helium. This class of superconducting compounds was hence named high temperature superconductors (HTS).

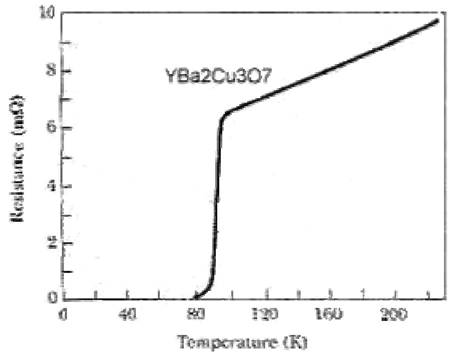
The next step in the development of HTS was to increase the current density of the conductor with increasing temperature. With this development also came the opportunity to apply this technology commercially. Currently, HTS conductors have been produced commercially for a number of years and are known as first generation HTS conductors (1G). The driver has been, and continues to be, to increase the amount of current that can be carried per centimetre of wire width (wires are formed flat and not round) and reduce the manufacturing costs.

Pilot production has started on so called second generation HTS conductor (2G), with experimental versions achieving a current density of 272 A/cm single wire in August 2005 (compared to 120 A/cm width at 77 K for a typical 1G).



The following diagrams show general resistance/temperature curves for superconductors (DC currents only, AC currents have a residual small resistance) and non-superconducting materials, and an actual curve for a superconductor (resistance is to electrical current).





A number of supply side power system applications have been identified to date for superconductors. Each application is at a different development stage, with some in commercial operation. These applications include cables (both AC and DC), transformers, fault-current limiters, generators, and grid support systems.

Cables are intended to be an alternative to existing copper or aluminium based underground or overhead wires. As superconductors need to be cooled and are by themselves relatively weak, they can only be used in a cable assembly. Thus the superconductor cable concept is an alternative to both existing underground insulated cables and to overhead bare conductor cables.

Superconducting transformers involve replacing the copper windings of the transformer with superconducting wiring. Advantages of superconducting transformers include reduction in fire risk, reduction in size, and other features useful to power system control.

Fault-current limiters are devices that limit the fault current (surge) transmitted through the electrical grid when a fault (or short) is created, and may prevent cascade failure of a grid. Superconductors by their nature are ideally suited to this application due to their sudden change from superconductivity to normal state above a certain current or temperature.

Superconducting generators (and motors) involve replacing some or all of their copper windings with superconducting materials. The advantages of superconducting generators and motors differ depending on the application. In some applications such as aircraft and ships, the advantage is the decreased weight, size and electrical noise. In industrial applications the advantage may be related to efficiency. Weight and size reduction may be an advantage for wind turbine generators due to their mounting at the top of the support towers.

Grid support systems are devices that can be connected to the grid at any location and can supply or absorb real and/or reactive power for short periods of time, stabilising the power supply. These devices are useful where (generally large) sensitive equipment is connected to the grid, where wind farms are connected to the grid, and where large loads are at the end of spur lines.

7.3 CURRENT STATUS OF TECHNOLOGY

As stated above, the power system applications identified are at different development stages, with some in commercial operation.

7.3.1 Wire

At the heart of each application is superconducting wire. There are a number of superconductor wire manufactures in the world with American Superconductors, Superpower, and Sumitomo Electrical Industries three of the most significant.

Although producing significant quantities of 1G wire, shipping 389,000 metres in financial year ending March ’05, American Superconductors is advancing its 2G wire production. With a pre-pilot plant now in operation it was recently announced that they had achieved commercial quality wire 4 cm wide, which can be slit into the industry standard 4.4 mm wide strips, shipping 1000 m by February 2006.

Like American Superconductors and Superpower, Sumitomo is shipping 1G wire while working on 2G, however Sumitomo is continuing to improve the performance of the 1G wire.

7.3.2 Cables

Work is being undertaken around the world on developing prototype cables that will lead to cables suitable as replacements for existing copper cables. At present a number of cables are in the construction or demonstration phase. The following are a sample of projects throughout the world.

Table 7.1 – Superconductor Projects

Site	Wire Type	Country	Length (m)	Voltage (kV)	Capacity (MVA)	Cable Type	Year In Op’n
Albany Cable Project	1G	USA	350	34.5	48	3 phase cold dielectric	2006
Bixby Substation, Columbus, Ohio	1G	USA	200	13.2	68	Triaxial cold dielectric	2006
East Garden City Substation, Long Island Power Authority	1G	USA	600	138	570	3-phase cold dielectric	2006
KEPRI	1G	Korea	100	22.9	1250 kA	Cold dielectric	2005
Frisbie Station, Detroit	1G	USA	120	24	100	Warm dielectric	2003
Puji Substation, Kunming	1G	China	33	35	120	Warm dielectric	2004
Changtong Power Company	1G	China	75	6.6	23	N/A	2004
Nexans Cables	2G	Europe	30	10	5.8	N/A	N/A

These cables are at the prototype stage, with layout design, mechanical strength systems, thermal insulation systems, electrical insulation systems, mechanical protection systems, and terminations all integrated into the cable design. Cooling is provided by commercially available refrigeration systems.

Sumitomo also recently announced shipment of the first commercial HTS cable to Korea in July 2005 which can operate at an electrical lines network voltage.

With respect to long distance HTS transmission lines, a number of technical areas require improvements to approach viability.

A significant issue for cables are suitable cryostats to provide the thermal barrier around the HTS wire. These cryostats to date have consisted of twin skin flexible stainless steel tubes with a vacuum drawn between the inner and outer tube. Cryostats up to 100 m long have been routinely made with recent efforts to extend this to 500 – 600 m. Critical issues for cryostats include evacuation (which can take considerable time) and joining cryostat sections.

There is a need to reduce heat load transferred from the environment, which is significant for cables with their large surface area. Coupled with reducing the environmental heat gain is the need to improve cryogenic cooling equipment (cryo-coolers) cost, efficiency, and reliability. Today's cryo-coolers are extensions of laboratory systems and work is underway to develop improved systems.

With longer cables there is also the need to develop intermediate cooling stations, rather than stations located only at the terminations. These intermediate stations need to be robust and reliable as they may be situated in remote locations.

For HTS cables there is also the choice between AC and DC, some differences are:

- HTS DC cables have negligible electrical losses while HTS AC cables have small electrical losses.
- HTS AC cable losses are small compared to conventional transmission systems, however significant refrigeration power is required to remove the resulting heat.
- HTS DC cables require expensive converter stations at either end to convert from and to the AC grid, therefore DC cables are more suited to longer transmission lines.
- HTS DC converter stations introduce greater inefficiencies in the AC/DC conversion process compared to transformers for HTS AC cables.
- HTS DC cable has approximately 5 times the capacity of the equivalent HTS AC cable[47].
- DC transmission can link networks at different voltages and mismatched frequency (inter-country).

Conventional overhead lines will remain for the foreseeable future the most economic solution for transmission over long distances[48], therefore underground or underwater applications appear the most promising for HTS cables, competing against conventional underground or underwater applications.

Future HTS cables are expected to be more expensive (refer to "Costs" below) than conventional cables, however there may be situations where HTS cables are competitive for reasons other than cost, including:

- Space constraints.
- Environmental issues (electromagnetic radiation).
- Public opposition to new/upgraded lines.
- Reduction in total project cost due to reduction in infrastructure costs.
- Other HTS attributes (such as the ability to control current flow in other parts of the grid).

[47] M Hirose – "SEI Technical Review Number 61 Jan 2006".
[48] D Politano et al – "Technical and Economic Assessment of HTS Cables", 2000

7.3.3 Transformers

Prototype superconducting transformers have been constructed and tested since the mid 1990s. A number of transformers have been constructed in the US, Europe, Asia, and New Zealand. At present there appears to be little significant activity in this area other than research and prototype construction. No commercial transformers are being marketed at present.

7.3.4 Fault-current Limiters

Prototype superconducting fault-current limiters have been constructed and tested since the mid 1990s. Currently there is activity in constructing and demonstrating these devices. A 10 MVA, 10 kV limiter was installed in a substation in Germany in mid 2004. A 138 kV demonstration model, presently in the design phase, is planned to be installed in live networks in 2006 as part of the US Department of Energy's $ 12-million Matrix Fault Current Limiter (MFCL) project. No commercial fault-current limiters are being marketed at present.

7.3.5 Generators

Insufficient information was available on HTS generators to provide a status, however a number of superconducting prototype electric motors are in development, and the technology developed for HTS motors should be transferable to HTS generators.

One notable large example is a 5 MW motor being developed for the US Navy, which has recently successfully passed its initial test program. Development of a 36.5 MW motor is in progress with supply of prototype in 2007. The motor is sized for ship propulsion on a future planned US navy destroyer class warship, with potential entry into commercial shipping.

Smaller motors are also being developed.

7.3.6 Grid Support Systems

Grid support systems are one area where superconductor devices appear to be on the brink of commercialization. The two main types are dynamic reactive power (VAR) control and magnetic energy storage.

Superconducting VAR control systems both supply and control the reactive power in a grid. After a period of testing the first commercial superconducting VAR control system is planned to be supplied in late 2006 for installation by a major US utility. These devices are particularly suited to solve voltage regulation and stability problems that can be associated with wind farms.

A Superconducting Magnetic Energy Storage (SMES) system is a device for storing and instantaneously discharging large quantities of power. These systems have been in use for several years to solve voltage stability and power quality problems for large industry customers. More recently these systems are being installed for grid stabilisation and increased grid capacity. SMES provide very short period power inputs (up to a few seconds), they are not designed at present for controlling longer period power variations from generating sources (e.g. a wind farm). A US utility installed a SMES solution in 2000, handling a number of power disturbances since then.

SuperVAR System at TVA Substation

7.4 COMMERCIALISATION

7.4.1 Technological Barriers

From a macro point of view, no information was found on significant technological barriers to large scale commercialization of the devices discussed above. Materials, manufacturing processes, and technical skills all exist today to construct these devices; however there are a significant number of areas where improvements are required in component technology in order to achieve acceptable performance, reliability and maintainability.

One particular area is refrigeration devices to maintain the superconducting material at operating temperature. A range of refrigeration devices exist at present for cryogenic applications, however to date these devices were manufactured in small quantities and used mainly in research or specialised equipment. Refrigeration adds significant parasitic losses to superconductor devices and therefore increases in refrigeration efficiency will assist commercialisation. At present for 1 watt of heat to be removed at 70 K there is a need for approximately 20 to 25 W of refrigeration power. The US Department of Energy's Cryogenic Roadmap lists as an objective to achieve a power ratio of 10 (i.e. for 1 W of heat removal, 10 W of refrigeration is required). This has a particular impact on the economics of cables due to their large surface area for heat transfer

One possible technology barrier is the performance of existing products. For example the efficiency of large existing transformers is in the order of 99.7%, combined with high reliability and long life. Efficiency improvements of superconducting transformers alone may be insufficient to justify superseding of existing transformers.

It is also likely that existing non-superconducting products will continue to improve in performance and cost. One example of this is a new design of overhead power line conductor comprising of a carbon/glass core, which allows more electricity to be carried without the same 'sag' occurring between poles and towers.

7.4.2 Overcoming Technological Barriers

With no significant technological barriers to overcome, commercialisation of power system superconductor devices is likely to require continued development, testing, and cost reduction to the point where these devices offer new services, improvements, and/or cost benefits over existing devices.

A significant boost to power system superconductor devices is the recently signed US Energy Policy Act of 2005. This act, among other requirements:

- Directs the US Department of Energy to develop superconducting cables (DC and AC) including actual grid insertions,
- Requires improvements in the US grid reliability, which may drive further uptake and development of superconductor fault-current limiters and grid support systems.

7.4.3 Factors For And Against Commercialization

Factors working ***for*** commercialization of power system superconducting devices in New Zealand include:

- Public pressure against installation of new power lines, resulting in replacement of existing conductors with superconductor cables or addition of superconductor grid support systems.
- Public pressure on electromagnetic radiation from existing overhead lines, resulting in replacement with superconducting cables, which create virtually no electromagnetic radiation external to the cable.
- Continued growth in high electrical density areas with limited power supply corridors.
- Improvements in superconducting devices pushed by legislation in other countries.

Factors working ***against*** commercialization of power system superconducting devices in New Zealand include:

- Lower population densities compared to some overseas countries, creating fewer opportunities for superconductor applications.
- Continued improvements in existing power system devices.
- Possible lower reliability and increased maintenance of superconductor devices compared to existing devices.
- Investment in existing equipment.

7.5 COSTS

HTS technology is moving rapidly both in development of wire and design of devices. A search was made on cost predictions for HTS devices but little information was available other than for cables, which is presented below.

Two circumstances present themselves for HTS cables in New Zealand: (a) transmission over long distances where overhead lines are unacceptable, and (b) transmission into high energy density locations with restricted access.

The following table provides approximate comparisons between conventional and HTS transmission options. The conventional option details and costs were taken from a recent study undertaken by the New Zealand Electricity Commission for alternative transmission augmentations into Auckland.[49] Assumptions were made on resource consent and easement costs which had been included but were removed for this comparison. The HTS option details were taken from a recent Japanese paper on HTS cables.[50] The HTS wire assumed for the HTS cable analysis had an electrical current capacity of 200 Amps/cm width of tape (Ic), priced at US$100/kA-m. Recent HTS wire laboratory capacity claimed by one supplier is 448 Amps/cm width of tape (2G wire)[51]. US Department of Energy price projections expect a price of US$100/kA-m by 2010[52]. No

[49] PB Power – “Alternative transmission augmentations into Auckland – Preliminary Capital Cost Estimates” Dec 2005.
[50] M Hirose et al - “High Temperature Superconducting (HTS) DC Cables” SEI Technical Review Number 61 January 2006
[51] American Superconductors Fiscal 2006 3rd Quarter and Nine-Month Report.
[52] US Department of Energy “High Temperature Superducting (sic) (HTS) Research and Development Assessment” 2005.

estimates of resource consent and easement costs have been included as these will vary markedly depending on the situation.

Table 7.2 – Conventional and HTS Cable Systems Cost Comparison

Technology	**Conventional AC 400 kV Underground Cable**	**Conventional DC (HVDC) Underground Cable**	**Conventional DC (VSC) Underground Cable**	**HTS AC Underground Cable**	**HTS DC Underground Cable**
Distance, km	200	200	200	200	200
Design MW	950	500	350	1500	1500
Voltage, kV	400	350	150	66	130
Line Cost ($,000)	1,135,600	421000	162,870	10,641,400	3,410,700
Line Cost $/MW-m	6	4	2	37	12
Termination cost ($,000)	275,100	190,000	143,000	434,400[53]	607,000[54]
Termination cost $/MW ($,000)	290	378	409	290	405
Line Energy Losses kW/MW –km[55]	0.5	?	?	0.13	0.013
Termination Energy Losses[56] kW/MW	6	17	32.5	6	17

PB Power estimates that at least 90% of the capital cost of superconductor systems will be subject to overseas exchange.

The above table indicates significant cost difference between conventional underground cables and HTS underground cables. Therefore the most promising situation for HTS appears to be where the compactness of HTS cables has advantages for resource consent and easement issues, which is likely to be cities with very high electricity densities.

[53] The reference did not state if the cost included termination equipment (breakers, transformers, etc). It has been assumed that this has not been included and the costs of two termination equipment sets have been added, scaled to the stated MW. It is assumed that the substation already exists.

[54] The reference did not state if the cost included the converter stations for converting between AC and DC. It has been assumed that this has not been included and the costs of two converter stations have been added based on in-house calculations for a conventional DC cable system

[55] For HTS cables includes electrical losses and refrigeration power input to remove electrical losses/heat invasion.

[56] Total for two terminations. It is assumed for this analysis that all termination equipment is conventional not HTS, therefore termination losses are similar for conventional and HTS systems. There will in fact be some additional losses for the HTS system in the change from conventional to HTS but this is assumed to be minor.

7.6 EMISSIONS AND ENVIRONMENTAL IMPACT

Superconductor devices pose significantly less environmental danger than existing equivalent devices. They contain no insulating oil to burn. The only potential emission is nitrogen which is the main atmospheric gas. In addition HTS devices, including cables, can be designed to minimise electromagnetic fields.

7.7 KEY ISSUES RELATING TO USE IN NEW ZEALAND

With the increasing loading on parts of the transmission system and the increase of wind farms, there are opportunities for superconducting grid support systems where the features of these systems can outweigh their costs. These systems include VAR support and real power injection systems. Grid support systems offered by one supplier are supplied self contained on trailers about the size of standard shipping containers, providing low environmental impact.

HTS transmission systems cannot compete on price when compared to conventional overhead lines or buried cables. There may be possible applications where transmission line costs significantly are outweighed by other factors such as resource consents and easement costs, however with the present and near future HTS costs there appears few opportunities in New Zealand for HTS transmission.

New Zealand is only likely to adopt and/or develop HTS devices that offer significant features over their conventional equivalents or completely new devices. Examples of devices with additional features are transformers with internal fault limiters and powerful magnets. Examples of new devices are real power injection systems and fault current limiters.

New Zealand has significant skills in practical design and fabrication of niche HTS devices and components for HTS devices. New Zealand may have a potential role in designing and manufacturing HTS devices or components where features outweigh the high cost, in fabrication of pre-production HTS devices, and in testing of HTS devices.

8. MICROTURBINES (GAS)

8.1 SUMMARY

The Technology

- Single moving part, low weight and footprint, low emission combustion turbines
- Can be designed to operate on different gaseous and liquid fuels

Current State

- Commercial on landfill gases and in distributed generation applications
- Micro-cogeneration potential where heat is required consistently, such as process industries. Clean exhaust gases at 260°C can be used, or low temperature steam generated at around 130°C or hot water.

Limitations of the technology

- Efficiency not as high as other technologies; conflict between efficiency and emission goals
- Efficiency and emissions significantly affected by part load operation
- High exhaust temperatures in standalone mode
- 45,000 to 80,000 hour lifetime

Technological Hurdles

- Efficiency and cost goals are mutually exclusive
- Operating lifetime

Efficiency, Scale and Costs

- Electrical efficiency of 25 to 30%+
- 30 to 250kW sizes
- $3,300/kW (power-only) and $3,800/kW for CHP for a typical unit up to 60 kW
- In future installed costs could reduce to approximately $2,200/kW.

Environmental Issues

- Noise 65dBA at 10 meters
- Low emissions compared to reciprocating enginers

NZ Context

- Applications for cogeneration may be limited because in small scale distributed generation applications, electrical and heat loads are often variable. Microturbines do not perform well under variable load conditions.
- Strong competition from gas reciprocating engines in areas such as landfill gas.
- At the small scale of microturbines most applications for CHP are in space heating. New Zealand's temperate climate does not provide as high a load factor for space heating as many other countries, limiting the CHP advantage.

8.2 TECHNOLOGY DESCRIPTION

Gas turbines are typically multi-shaft engines, with multi-stage compressors having high compressor pressure ratios, and with outputs ranging from about 500 kW to over 280 MW. In the multi-megawatt sizes, generation is generally limited to central power plants.

Microturbines on the other hand are mechanically simplified to provide small-scale and low cost generation, eminently suitable for generation in distributed generation systems. These very small turbines are generally supplied as completely packaged units for direct connection into a customer's electrical system at low voltage, only requiring connection electrically and for fuel, air inlet and exhaust.

Key design features of the current range of microturbines include:

- There is only one moving part – the single shaft, which has mounted on it the single-stage compressor, radial inflow turbine and permanent-magnet generator rotor;
- Use high shaft rotation speeds (typically in the range 50,000 to 100,000 rpm);
- Generally incorporate a recuperator, extracting energy from the hot exhaust to heat the inlet air, to increase efficiency;
- Have relatively low emissions of NOx, CO, etc (significantly lower than standard gas turbines);
- Have recuperated efficiencies in the range 26 to 28% (LHV);
- They can be designed to operate on different fuels, including natural gas, landfill gas, diesel.

Because the microturbines operate with a permanent-magnet generator, the electrical output has variable frequency in the range 1500 to 4000 Hz, related to the turbine speed. Electrical equipment typically incorporates a rectifier and inverter to produce electrical output of the required grid frequency at distribution level voltages.

Within individual businesses, they can operate either in a constant supply mode, or on demand when power prices are high (to minimise capacity charges).

Units are supplied variously as producing electricity only or, with the addition of a heat recovery unit, as a Combined Heat and Power (CHP) or "cogeneration" package. See the diagram below depicting the various components of a microturbine in CHP mode (with heat recovery unit added).

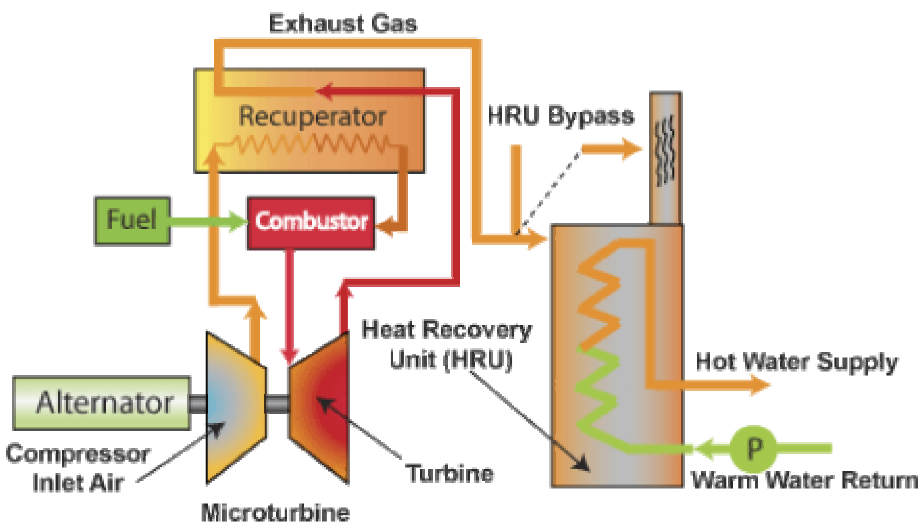


Diagram courtesy Elliott Microturbines

All microturbines operating on gaseous fuel use lean premixed combustion, where the gaseous fuel and compressed air are premixed prior to combustion. Low turbine inlet temperatures and the lean premixed combustion allows combustion at lower temperature (less NOx), while low CO and THC (Total HydroCarbon, ie. unburnt fuel) levels are achieved by retaining the air and fuel mixture in the combustion chamber for a relatively long time.

8.3 CURRENT STATUS OF TECHNOLOGY

Small unit sizes mean that most microturbines are typically installed in individual commercial establishments, although there are a number of locations where multiple units are providing significant electrical output into a local grid system (e.g. multiple units installed at landfill sites, using landfill gas).

Microturbines are supplied globally on a commercial basis by a number of manufacturers, including:

- Capstone Turbine Corporation[57] 30 kW & 60 kW units (landfill gas in 30 kW units only);
- Ingersoll-Rand[58] (70 & 250 kW units)
- Elliott Energy Systems[59] (100 kW CHP units)
- Bowman Power[60] (80 kW units)
- Turbec (100 kW units)

Honeywell (previously AlliedSignal)[61] withdrew from the microturbine market in December 2001, having previously supplied 75 kW units in many locations. DTE Energy Technologies announced in July 2005 that it was closing its subsidiary business, having previously been involved in the design and manufacture of 75 kW, 150 kW and 300 kW units.

Some microturbines are provided for use in battery-charging arrangement (such as electric or hybrid buses). Such buses are in operation in Auckland[62] and Christchurch (buses produced by Designline, Ashburton). Capstone documentation states that a fleet of 4 Capstone-Energized HEV buses in New Zealand have amassed more than 800,000 km worth of revenue service in their 14-hour/day schedules[1].

In excess of 2,100 microturbine units (totalling 156 MW) have been shipped from manufacturers in the past four years[63].

The picture below illustrates the size of a 30 – 60 kW Capstone microturbine package.

[57] See http://www.microturbine.com/
[58] See http://www.irco.com/
[59] See http://www.elliottmicroturbines.com/
[60] See http://www.bowmanpower.co.uk
[61] See http://www.honeywell.com/
[62] See http://www.stagecoach.co.nz/citycircuit/
[63] NREL, Power technologies energy data book, chapter 2, April 2005

Photo courtesy Capstone Turbines Corporation

8.4 COMMERCIALISATION AND FUTURE DEVELOPMENT

This technology has been supplied commercially since before 2000, with the majority of units installed in USA, UK and Europe.

Multiple unit installations (up to 50 units) are common in landfill gas applications.

8.4.1 Advantages

- Low pollutant emissions (NOx, CO) – predicted to be less than 9 ppm for both by 2006;
- Low noise (maximum 65 dBA at 10 m);
- Harmonic distortion (maximums: <5% total, <3% single) are not a problem for generation at low voltages (no NZ requirement for conformance below 66 kV);
- Start-up times (to full load) between 3 and 7 minutes. The major blocks of time are split between holding to stabilise temperatures after introduction of fuel and ramp-up to full load;
- Used in an emergency generation mode, microturbines can result in minimising battery storage for UPS systems to no more than 5 minutes. This is because of their rapid start-up times, with no need for grid connection when providing DC output;
- Can be installed either outside or within existing buildings, with few restrictions because of the small unit footprints.

8.4.2 Disadvantages

- There is a high exhaust temperature (about 260°C). Part of this high energy exhaust can be used in cogeneration (combined heat and power) configuration;
- Higher capital cost (on a $/kW basis) than a large central power station, but very competitive with small-sized gas turbine installations;
- Low gas supply pressures at specific sites may require the addition of a fuel gas compressor to boost gas pressure to that required by the microturbine;
- Applications for cogeneration may be limited because in distributed generation applications, electrical and heat loads are often variable such as in commercial buildings. Microturbines do not perform well under variable load conditions.

8.4.3 Technology Developments

According to US DOE[64] in 2002, for development in USA up to 2006 (programme funded by the DOE), the next generation of microturbines was to focus on "ultra-clean, high efficiency" designs. These designs are based on applying the technology of ceramic radial inflow turbines previously developed for the automotive gas turbines. The design goals include:

High efficiency	at least 40%
Environment	NOx emissions less than 7 ppm on natural gas;
Durability	11,000h of reliable operation between major overhauls (rotor replacement), and a service life of at least 45,000h;
Cost of power	system costs less than US$500/kW (2002 cost basis);
Fuel flexibility	use of multiple fuels including diesel, ethanol, landfill gas and biofuels;
System size	up to 1 MW

Capstone has stated that its 60 kW microturbine will be available for operation on biogas (e.g. landfill gas) by the end of 2005.

8.5 EXPECTED UNIT SIZES, SCALE AND PERFORMANCE

8.5.1 Installation Sizes

Sizes available depend on the manufacturer, but are currently in the range 30 kW to 350 kW. Units may be connected in parallel, and some suppliers also provide centralised control systems equipment. Multiple unit applications are expected to be less than 1MW.

Manufacturers supply units in completely enclosed, fully self-contained cabinets, only requiring connection to air and fuel inlets and hot gas and water outlets as appropriate. Cabinets and enclosures are generally for outdoor use and are thus weather-proof.

Table 8.1 – Installation Capacity and Size

Manufacturer	Unit	Length (m)	Width (m)	Height (m)
Bowman	80 kW	3.1	0.9	2.0
Elliott	100 kW CHP	3.25	0.85	2.25
Capstone	60 kW	1.96	0.77	1.92
Turbec	100 kW CHP	2.9	0.84	1.9
Ingersoll-Rand	250 kW	3.3	2.2	2.3

Note that the above dimensions exclude supplementary equipment such as fuel gas compressors, paralleling switchgear, braking resistors

8.5.2 Performance

Efficiency (LHV)	currently 17 - 20% without a recuperator (as described in Section 8.1), 25 - 30%+ recuperated;

[64] US DOE, "Microturbine and Industrial Gas Turbine Program: 2002 Peer Review Report", June 2002

Start-up	varies between manufacturers – typically 3 to 7 minutes from cold;
Lifetime	5 to 10 years, depending on duty cycle;
Footprint	0.02 – 0.04 m^2/kW.

The recuperated efficiency of microturbine units compares very favourably with quoted efficiencies of small-size commercial gas turbine units (less than 1,500 kW) of 24 - 27%. With the addition of CHP equipment, the energy efficiency can be increased to 80 to 85%.

Efficiency drops to around 85% of maximum efficiency at 50% load, and 65% of maximum efficiency at 20% load.

Power output is reduced at higher ambient temperatures. Inlet cooling (via water spray for evaporative cooling) is proposed but not yet implemented on microturbines.

8.6 COSTS

8.6.1 Capital Costs

Basic cost of a Capstone turbine is $ 1,250 to $ 1,450/kW. To this cost is added site-specific costs such as site preparation, foundations, installation, service connections, commissioning and other Owner's costs. This takes the total cost to about $3,300/kW (power-only) and $3,800/kW for CHP for a typical unit up to 60 kW.

Options are then added as follows:

Operation in grid-connect & stand-alone	$ 7,300 to $ 11,600 per "system"
Integrated cogeneration package	$15,000 per unit
Fuel gas compressor	dependent on gas conditions

Development targets are for lower capital costs and higher microturbine efficiency, but, according to the US DOE, these goals are to some extent mutually exclusive. It is expected capital costs will reduce slowly with increasing market penetration with modest gains in efficiency. A future installed cost in New Zealand of $2,200/kW is suggested.

By comparison, EPC costs for small-scale (less than 1,500 kW) gas turbines installed in Australasia are in the range NZ$ 3,000 to 3,800 /kW, but this is for grid-connected plant. A significant part of these GT costs is for supplementary equipment such as HV transformer (although non-standard LV generators may be available), gearboxes (microturbines instead use permanent generator, rectifier and inverter) and small buildings (microturbines are generally installed directly outside, or within an existing building).

PB Power estimates that approximately 75% of the capital cost of microturbine systems will be subject to overseas exchange.

8.6.2 Operating & Maintenance Costs

Service contracts are generally available, at a cost of 1.5 to 3 c/kWh, which would add an average of about $ 7,000 to $ 14,000 over 8,000 hours of operation for a 60 kW machine.

The currently-expected life of microturbines is 80,000 hours, with major overhaul after 40,000 hours (typical for Capstone units, but noting that these exceed the US DOE 2002 "future development targets" – see above). The overhaul cost is approximately 40 to

50% of new cost, mostly related to replacement of the turbine rotor (the only moving part in a microturbine).

For microturbines installed at landfills, historic O&M costs (including both microturbine and fuel treatment O&M) are about 4.5 c/kWh. Much of this cost is associated with treatment of the gas to remove particulates, etc.

8.7 ENVIRONMENTAL ISSUES

Noise levels are 65 dBA 10 meters, described as a high pitched whine.

Table 8.2 Emissions

Parameter	Current	Future (2010)
CO_2	670 – 1,180 g/kWh (for 17 – 30% efficiency)	
NOx	9 – 25 ppm	<9 ppm
CO	25 – 50 ppm	<9 ppm
Total Hydrocarbon	<9 ppm	<9 ppm
Particulate	negligible	negligible

Emissions levels are stated for microturbines at full load, operating on natural gas. Microturbines need to run at 90% or higher load to maintain low NOx emissions.

The exhaust is relatively clean and oxygen rich (approximately 18%), and hence suitable for a wide range of heat recovery applications.

8.8 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

There do not appear to be any major issues to use of microturbine technology in New Zealand.

Microturbines are a distributed generation technology and face similar issues (benefits and hurdles) as other distributed generation technology. Combined heat and power is a key enabler, but at the small scale of microturbines most applications for CHP are in space heating. New Zealand's temperate climate does not provide as high a load factor for space heating as many other countries, limiting the CHP advantage.

The applications of microturbines that do exist face strong competition from the established technology of gas reciprocating engines.

9. PEBBLE BED REACTORS

9.1 SUMMARY

The Technology

- Modular small scale nuclear power plant (100 to 200 MWe)
- Uses fuel pebbles that encase the fuel in strong pyrolytic graphite and ceramic
- "Passively safe" design that cannot melt down on loss of coolant
- Helium gas used as coolant and as motive fluid in modified gas turbine generator

Current State

- South Africa and China developing demonstration reactors
- Construction due to start in South Africa and China in 2007.

Limitations of the technology

- Unproven design at full scale
- Much greater volume of spent fuel, due to graphite encasement, but easier to handle

Technological Hurdles

- Fuel pebble manufacturing and licensing
- Performance of the packed core and its resistance to the formation of hot spots
- Helium gas turbine generator is a new product not yet proven

Efficiency, Scale and Costs

- Unknowns mean economic analysis is not presently well founded
- Target capital costs are $1,550 to 1,850 per kW. Conventional nuclear capital costs more appropriate for initial analysis - $3,700 to $4,600 per kW.
- O&M costs, including provision for decommissioning and fuel disposal costs, are estimated at 0.75 to 1.3 c/kWh for Pebble Bed Reactors. Conventional nuclear O&M costs are approximately 3.7 c/kWh.

Environmental Issues

- nuclear power could be part of a response to global warming
- potential for graphite fire if air gets into the reactor core
- risks of transport of radioactive fuel into New Zealand and spent fuel back overseas
- long term risks of spent fuel disposal in deep geological repositories (overseas)
- risk of accident and consequent environmental contamination

NZ Context

- a long period of public debate would be required before nuclear energy could be contemplated in New Zealand

- fuel manufacture and disposal would not be feasible in New Zealand, therefore dependant on other countries for these key aspects.
- differences in ethical perspectives mean conflict over nuclear power unlikely ever to be resolved

9.2 TECHNOLOGY DESCRIPTION

This section considers nuclear power in the form of the Pebble Bed Modular Reactor. This technology was looked at because it is the first nuclear technology that is being designed for smaller scale developments that make it potentially technically feasible in New Zealand's smaller electrical system.

9.2.1 Nuclear Power Overview

Today, conventional nuclear power plants use thermal neutron reactors. Here, thermal means the neutrons are slowed down (thermalised) using a moderator, to expedite the nuclear chain reaction of the enriched uranium fuel. Most conventional nuclear power plants are water moderated and also use the water to cool the reactor and to power steam turbines to generate electricity. The UK uses graphite moderated, gas cooled reactors and a secondary water cycle to power steam turbines. These plants are typically large (600 MW to 1,300 MW). Around 440 are in operation around the world today.

Two test nuclear reactors and one Russian nuclear power plant use fast neutron reactors, so-called because the reactors are un-moderated and use high energy neutrons to expedite the nuclear reactions of the plutonium and depleted uranium fuel. These plants are liquid sodium cooled and use a secondary water cycle to power steam turbines.

All of the reactors described above use neutron absorbing control rods to control the rate of the nuclear reaction.

Countries that depend on nuclear power for a high proportion of their electricity generation are France 78%, Sweden 52%, Korea 38%, Germany 32%, Japan 29%, Spain, UK, Taiwan, USA, Russia 16-23%, Canada 15%.

Nuclear power technologies all rely on a nuclear fuel cycle. The basic fuel cycles are as follows:

- Once through fuel cycle – direct disposal – spent fuel of around 27 tonnes per annum for 1000 MWe of nuclear power.
- Reprocessing – recycles the spent fuel, overall around half the volume of waste product compared to a once-through fuel cycle is produced.
- Closed fuel cycle – utilises fast reactor technology that uses a starting fuel of plutonium but then can generate further fuel from spent fuel from thermal reactors or depleted uranium. Fast reactors can process (transmute) all the actinides, and, with on-site fuel reprocessing, produce very small amounts of waste with much shorter half lives than other reactors. 99.5% of the energy in the original natural uranium can be recovered, compared with 1% in thermal reactors.

Not included in the above numbers is the 166 tonnes per annum of depleted uranium produced as by product of the enrichment process. This is currently regarded as low level chemically toxic rather than radioactive waste.

9.2.2 Pebble Bed Modular Reactor

The Pebble Bed Modular Reactor is a high temperature gas-cooled, graphite moderated thermal reactor (HTGR), part of a modular (about 110 MW) nuclear plant.

The key concept is combining the fuel, structure, containment, and moderator into small strong spheres. The natural geometry of close-packed spheres provides the space for gas flow and the correct core spacing for the low power density. The pebbles are suited to a once through fuel cycle only.

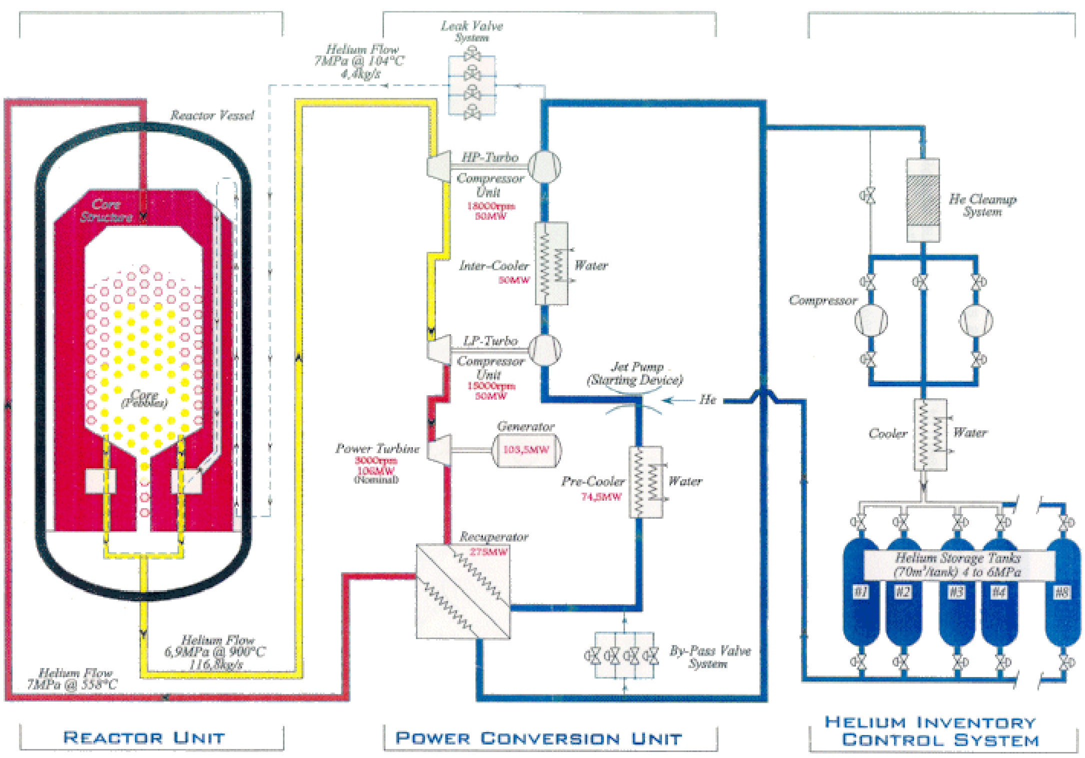
The coolant gas is helium, operating at an upper pressure of about 70 bar. Since helium is not transmuted by neutrons and does not become radioactive, the coolant may be used directly in the (modified Brayton) power cycle, outside the primary containment. The cycle uses gas turbo-expander driven HP and LP compressors in series, and a gas turbo-expander generator. Helium temperature at reactor exit is 900°C and at entry, 500°C. Heat is recovered by recuperating heat exchangers.

Fuel is 8% enriched uranium. (U235/(U235+U238)). The core internals are completely ceramic allowing for very high temperatures with the uranium fuel contained in carbon spheres approximately 60 mm diameter. These provide the containment for storage and disposal and are of a form that makes reprocessing extremely difficult, if not impossible. Not only does the fuel offer a passively-safe feature, but also easily facilitates online fuelling. The fuel pebbles can be cycled through the core as necessary and discharged when fully burned out. Another advantage of having the fuel in pebble form is waste removal and storage. The spent fuel is inherently contained by the carbon material; therefore no spent fuel pool is needed and the storage facilities can be a lot less complex.

Some designs are naturally throttled by temperature rise, and do not use control rods. The reactor can be simpler because it does not need to operate with the varying neutron profiles caused by partially-withdrawn control rods. However, for maintenance, many designs include control rods, called "absorbers" that are inserted through tubes in a neutron reflector around the reactor core.

Use of the Brayton (gas turbine) cycle permits greater use of low-grade thermal energy (bottoming cycles) to increase the overall cycle efficiency. The helium gas is inert, and because it can be operated at high temperatures without oxidation, this eliminates a major cause of corrosion and stress normally found in conventional gas turbine systems with air as the oxidising and transport medium.

PBMR Helium Flow Path Schematic (Brayton Cycle)



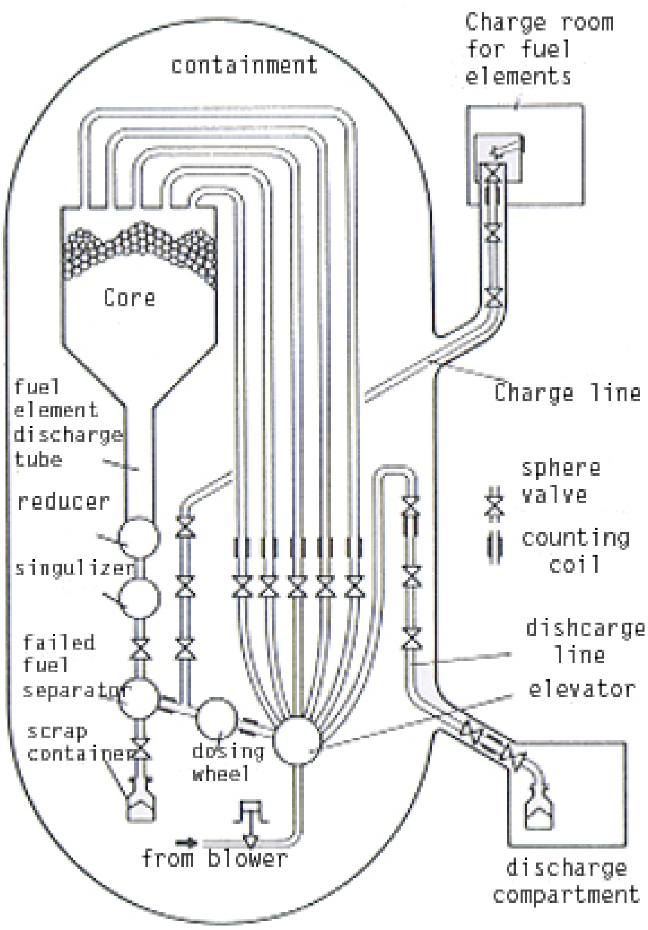
A small (15 MWe) pebble bed research reactor, the Arbeitsgemeinschaft Versuchs-Reaktor (AVR) was operated in Germany for over 20 years. A 300 MWe development plant also operated in Germany for several years. This plant transferred heat to a steam generator for the production of electricity. Thus there is a good experience base with pebble bed nuclear plants. However, Germany is unlikely to proceed further with nuclear in the near future given its current political climate.

Typical pebble details, for a 100 MW reactor, include:

- 360,000 pebbles in core;
- about 3,000 pebbles handled by fuel handling system each day;
- about 350 discarded daily;
- one pebble discharged every 30 seconds;
- average pebble cycles through core 15 times;
- fuel handling most maintenance-intensive part of plant.

Passive safety is claimed for the design. Increased temperature within the core produces “Doppler broadening” of the fuel atom, making fission self-limiting and imposing a maximum attainable temperature for the core. Loss of cooling would therefore produce an initial temperature rise, followed by a fall. The maximum attainable temperature is less than the melting point of the pebble casing and the core containment. This effect is in contrast with conventional designs which may require active measures for moderation.

The following is a diagram of a typical pebble bed reactor and fuel system.



The other design advantages include:

- Capability of modularization and standardization of components

- Self containment of fuel within the pebbles provides a reduction of handling and feed issues.
- Use of inert gas reduces fire risk.
- Spent fuel remains encased within the sphere and may be stored on site until plant decommissioning.

9.3 CURRENT STATUS OF TECHNOLOGY

The high temperature gas reactor (HTGR) technology has been around since the 1960's. However early in the history of nuclear power the industry concentrated on light water reactor technology because it was thought natural uranium was in short supply. The spent fuel from light water reactors was expected to be used in the next generation fast reactors. Now that natural uranium is relatively cheap and plentiful, HTGR technology is being re-considered.

The current status of the technology is demonstration plant only.

The current technology leader is thought to be China, with a 10 MW plant (HTR-10) in operation at Tsinghua University, Beijing. In South Africa, Pebble Bed Modular Reactors Pty. Ltd (PBMR) is pursuing the development of a 110 MW demonstration plant.

PBMR Pte Ltd is comprised of British Nuclear Fuels, Eskom, (the South Africa utility) and the Industrial Development Corporation of South Africa. Eskom purchased the technology rights from the German developer, HTR GmbH (now Siemens-ABB), in 1996.

The PBMR technology used is based upon the German plants built in the mid-1980s and suspended after Chernobyl. These were:

- The 40 MWth, 15 MWe AVR (Arbeitsgemeinschaft Versuchsreaktor) Research Reactor.
- The 750 MWth, 300 MWe Thorium High-temperature Reactor.

The fuel production status is claimed to be "proven", using the above experience.

PBMR is now proposing a prototype 137 MW (previously 110 MW) pebble-bed modular reactor. The Environmental Impact Assessment report was commissioned in 2000 and approval to construct was granted on 25th June 2003. This approval has recently been set aside by the Cape Town High Court in January 2005 on the basis of due process rather than technical issues. In the event that this is resolved and the approval to construct re-established, the project may commence, subject to funding. The South African Government has allocated funds within the 2004 budget, but additional funding and partnerships will be required for the projected $1.3 billion required. It is reported by PBMR that significant contracts have been placed, for example, the R&D for the Turbo-Generator System with Mitsubishi Heavy Industries.

The timetable is still to start construction in 2007 with the demonstration plant (137 MW) to be completed in 2010. A nuclear license will be issued in stages as the development proceeds. A helium cycle test facility commenced construction in November 2004.

The Chinese HTR-10 technology is to be developed by Chinergy, a consortium of Tsighua Institute and the China Nuclear Group. It plans to have a 200 MW version of HTR-10 by the end of the decade. It is reported to be substantially funded by Huaneng Power International and it is claimed that concrete is scheduled to be poured in spring 2007.

9.3.1 Regulatory

The licensing for the PBMR project is proceeding in stages as development proceeds. The progress of development and the response time of the South Africa licensing authorities is uncertain. However it is estimated that the technology could take up to 7 years to obtain a license in the US. Major investments of time and money will be required.

PBMR indicate that the licensing process is organized in four phases, and that the first phase is due to be tabled to the Nuclear Regulator in January 2006. The phases are:

- Construction and Installation;
- Fuel to site/fuel load/ initial criticality and power ascension;
- Operation;
- Decommissioning.

Assuming that a protracted period will be required for licensing, as well as for technology development, construction and commissioning, it is not certain that the target commissioning date of 2010 can be achieved.

9.3.2 Reactor Technical/Design

The record of the AVR reactor was generally good throughout its 21-year operation and it is said to have been closed as a result of public pressure after Chernobyl. The US reactor, Fort St Vrain, ran from 1979 to 1989 and experienced many problems and high operating costs. The 300 MWe Thorium High-temperature Reactor in Germany experienced cost escalation to US$ 13,000 /kW.

The prototype (pebble bed) design has been undergoing a change in capacity (110 to 137 MW), pebble count (440,000 to 452,000), and cycles to removal (ten to six) and enrichment level (8% to 9.6%).

Technical/design hurdles include:

- Nuclear fuel and pellet manufacture to exacting standards for core geometry and symmetry (for uniform flux) and coating layer (for integrity, temperature resistance and containment). Regulatory licensing of the fuel pellets quality and fabrication could take more time than expected and could compromise the proposed schedule of licensing.
- The performance of the packed core and its resistance to the formation of hot spots as a result of non-symmetric flow. Prolonged exposure to hot spots above 1250 deg C may compromise coating integrity. Wear and damage during migration may cause temporal and spatial instability. The vulnerability of the fuel is controlled by limiting core burn-up.
- Fire risk if water, air or steam enter the core. Although there is limited water in the cycle (in the equipment cooling circuits) any compromise to this boundary could permit water to enter the core.
- On site storage with security throughout the life of the plant.
- If the reactors are to be distributed globally (a pre-condition of reduced cost) it is probable that pellet manufacture would have to be centralized and pebble distribution systems would have to be established.
- The multi shaft, gas turbine generator / gas turbo compressor system would be a new product capable of high temperature operation with helium. Proving the technology for continuous operation will take time and resources.
- Mechanical reliability of other components including valves, seals and bearings, core barrel etc in a very hot environment (900 deg C).
- Plant operation world wide: there will be a dependency on outside supply of both technology and fuel. This is analogous to CCGT plant operation, where technology development is outside of owner control, and cost efficient maintenance depends on

long term service agreements with providers. This system works well and provides baseline and load following service in most countries.

The Chinese HTR-10 will proceed on the basis of helium cooling, but with water as the secondary fluid. This requires the development of high temperature helium/water heat exchangers with high integrity, so that the water does not enter the helium cycle and the reactor core.

The pebble bed characteristics mean that some designs claim secondary containment is not required and the proportion of components designated as safety –related is half current designs, reducing the costs of the stringent inspections required. The lower cost of pebble bed reactors also results from a reduced emergency protection zone and a claimed reduction in operating personnel and qualifications.

9.4 COMMERCIALISATION

Despite the conditional support of the South African Government, PBMR is looking for equity partnership and additional funding. There is doubt regarding the PBMR project's ability to continue to attract funding and the reality of future sales, where 10 are assumed for installation in South Africa and 20 in the rest of the world. It is doubtful that the market would support more that one or two units a year and a potential nuclear buyer would have incentive to stick with the existing, proven design rather than opt for the as-yet unproven pebble bed design.

These unknowns mean that economic analysis is not presently well founded. Whereas Eskom or other large traditional utilities may assume a low discount rate and long project life for political reasons, this may not apply to merchant plant regimes where cost recovery is market based. Other factors which are difficult to forecast include capacity factor, the nuclear fuel total cycle cost and basic operation, maintenance and security.

Assuming that completion to commissioning is achieved in 2010 (in China or South Africa), at least a year of sustained operation would be required to attain commercial demonstration status. In that year, the operational learning curve may be completed and multiple units may have been placed on order to permit reduced unit cost. Thus, orders may be contemplated, according to this schedule, in the period 2011 to 2014.

This timetable will depend upon the progress of licensing, financing and technology development. These will not be free of difficulty, as amplified herein, and it is unlikely that purchase of the mature technology could be contemplated until 2014 or later.

9.5 EXPECTED UNIT SIZES, SCALE AND PERFORMANCE

The demonstration units are proposed to be sized from 165 to 200 MW electrical. Unit costs will decline as commercialization and repeat design is adopted. For larger capacity power stations, multiple units are proposed.

The efficiency of the conversion of the heat generated in the reactor to electricity is expected to be 45% based on the helium gas turbine. The utilisation of the potential energy in the uranium fuel is of the order of 1%, in common with all thermal reactors.

9.5.1 Construction Schedule

Based on the modular design concept, parallel construction of all components can take place, so only final assembly is performed on-site. As a result, total time from decision to build until power generation is 36 months for the first unit to be on line, with subsequent units being completed every three months. These times depend on having adequate works manufacture capacity and pre-engineering complete.

By comparison, “conventional” nuclear plants take between 5 and 15 years to build, resulting in large expense due to interest payments on construction capital.

9.6 COSTS

The design target cost of the PBMR commercial production units of 165 MW is US$ 1,000 to 1,200 per kW (NZ$ 1,530 to 1,840 per kW). The projected cost of the demonstration unit is 10 billion Rand or US$ 1.5 billion, or US$ 11,000/kW. The Utility, Eskom, has agreed to purchase 10 units. Equivalent bus bar tariff for the prototype is likely to be 6 to 10 times the present consumer tariff.

Projected O&M costs are indicated to be US$ 2.5 to 3.5 per MWh and fuel costs at US$ 4 to 5 per MWh, and the projected capital cost (US$ 1,000/kW) is arguably 3 to 5 times less than other conventional nuclear plant built to date.

By comparison, typical conventional nuclear plant would be in the order of US $21 (O&M) and US$ 7 (fuel) per MWh, a total of US$ 28/MWh. Current claims in the USA by the DOE for mature plant, at US$ 18/MWh, may not account for start-up cost of new conventional technology.

Future decommissioning and spent fuel management costs of US$ 2.5 million to US$5 million per MW, provided for over the life of the plant, takes the annual O&M costs including provisions to US$ 5.6 to 9.6 per MWh for pebble bed reactors and US$ 27.4 per MWh for conventional nuclear plant.

Until proven otherwise by testing, and by the establishment of firm economic modelling, it is suggested that the costs of conventional state-of-the-art nuclear power generation should be used as a baseline value to assess the present viability of the pebble bed technology.

PB Power estimates that at least 80% of the capital cost of pebble bed reactor systems will be subject to overseas exchange, on the basis that modular reactors are likely to be manufactured outside of New Zealand.

9.7 ENVIRONMENTAL ISSUES

Nuclear power can offer environmental advantages on the basis that it uses a non-fossil, sustainable energy source and does not emit greenhouse or other gases which are produced in other forms of electric power generation. There is some support globally for nuclear power as part of a response to global warming.

Current environmental concern for pebble bed reactors has been focused on the potential for graphite fire, and subsequent release of radioactivity into the atmosphere. Normally the fission products are contained by the coating, and this barrier prevents escape to the atmosphere, even if the pebbles escaped containment.

Pebble bed technology is predicated on a once through fuel cycle. The spent fuel pebbles are unsuitable for reprocessing, or for transmutation in fast reactors. The pebble bed spent fuel would be stored at the nuclear power plant site until decommissioning, for 30 to 50 years or more, to allow sufficient temperature decrease. After that, deep geological repositories are envisaged. Sweden and Finland are probably the most advanced in developing permanent nuclear repositories. Both countries will use storage techniques being tested in the Aspo Hard Rock Laboratory, a full scale trial 500m deep[65]. New Zealand is not suitable geologically for permanent repositories, and the spent fuel would eventually needed to be shipped to an overseas repository.

Pebble bed reactors would produce higher quantities by weight of radioactive waste compared to current designs, but lower quantities by volume in the necessary

65 www.skb.se

configuration for long term storage, as the pebbles are "prepackaged" for long-term disposal.

However, the over-riding concern about nuclear power's environmental effects has been related to risk of accident and consequent environmental contamination, either during fuel transport or a nuclear power plant accident.

9.8 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

As stated earlier, pebble bed nuclear reactors have been included in this survey because it is a nuclear technology that is being developed with the specific goals of small scale cost effective nuclear power, and therefore could be technically applicable to New Zealand.

New Zealand's nuclear free legislation passed in 1987 has the effect of defining an area where prescribed activities cannot take place. It appears parliament's main intention was to keep out visiting warships carrying nuclear weapons, or those warships that were nuclear powered. It does not prohibit nuclear power, but under the Atomic Energy Act 1945 written consent of the Minister is required for activities relating to nuclear power.[66]

Irrespective of the legal situation, the reality is a long period of public debate would be required before nuclear energy could be contemplated in New Zealand. Expected terms of the debate are set out below. These issues have ethical and political dimensions as well as technical.

Nuclear fuel transport – shipments of pebbles from central manufacturing facility overseas to the nuclear power plant in New Zealand.

Safety – during transport and of the nuclear power plant during operation

Decommissioning – power plant components and disposal of spent fuel. Geological disposal would not be feasible in New Zealand, therefore dependant on other countries for these key aspects.

Nuclear Proliferation – fuel pebbles for pebble bed reactors are highly proliferation resistant given the difficulty of reprocessing and extraction of fissile material

Ethics –differences of moral perspective mean that it is unlikely differences will be resolved through education and factual debate, and therefore ways will have to be found to cope with this conflict.

[66] Philippa Jones, Nuclear Energy and Resource Management Law in New Zealand, Lawlink Magazine, Summer 2004

10. INTEGRATED GASIFICATION COMBINED CYCLE (IGCC)

10.1 SUMMARY

The Technology

- IGCC is the integration of three well-established processes: pressurised gasification; gas refining; and combined cycle electricity generation.
- IGCC provides a way for coal to be, in effect, burned in a modern, high efficiency gas turbine combined cycle plant
- IGCC offers the cleanest coal based power generation available today

Current State

- A number of IGCC plants have been constructed as demonstration projects with pricing that is typically "first of a kind".
- Gasification of coal has had lower efficiencies and higher costs than was expected compared to the widely used gasification of petroleum feedstocks in refinery and chemical industry facilities.

Limitations of the technology

- In the absence of CO_2 capture, IGCC plants emit CO_2 at the same level as supercritical power plants of similar efficiency.
- Single gasifier availability – dual redundant gasifiers required at present for availabilities acceptable for power generation.
- Higher cost than pulverised coal power plant currently, may be more difficult to achieve cost effectiveness at the 400 MW scale applicable to New Zealand.

Technological Hurdles

- Gasifier availability
- Technical complexity – plants combine power generation and chemical refinery technology
- High auxiliary load consumption of the air separation unit

Efficiency, Scale and Costs

- Net HHV efficiency 40%
- 120 to 784 MW net
- Auxiliary load 11 to 21%
- Capital costs, current NZ$ 1,800 to 2,700 /kW, future target NZ$ 1,500 to 1,650 /kW
- O&M costs 1.5 c/kWh
- Availability 85%

Environmental Issues

- IGCC plants are the environmentally cleanest coal based power system available today and represent a potentially effective means of capturing CO_2 for sequestration.

- IGCC is currently the only clean coal technology able to economically remove any mercury emission.

NZ Context

- Research and development is required to assess the suitability and costs of using New Zealand coals in IGCC plants.
- IGCC plants may be more costly at the New Zealand scale of below 400 MW.

10.2 TECHNOLOGY DESCRIPTION

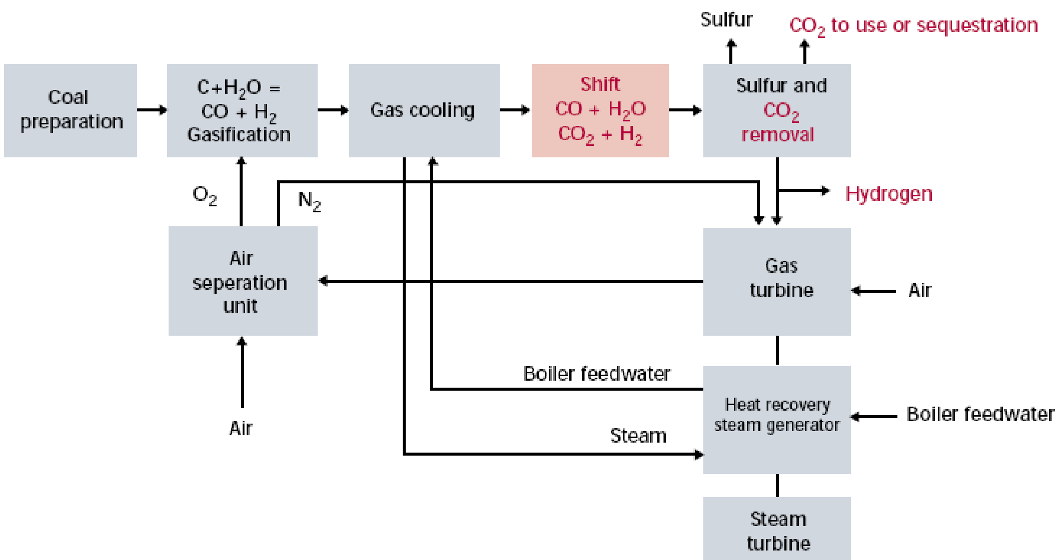
IGCC is the integration of three well-established processes: pressurised gasification; gas refining; and combined cycle electricity generation. The gasification process converts the carbon and hydrocarbons in coal, in the presence of oxygen and steam, into primarily carbon monoxide and hydrogen.

In addition to providing a way for solid fuel (coal) to be, in effect, burned in a modern, high efficiency gas turbine combined cycle plant, standard refinery treatment processes can be used for gas cleanup of particulates, sulphur, and other contaminants. Treating the gas at high pressure before it is combusted is much easier and thus less expensive than treating the flue gas discharges of conventional coal fired generating plant. Pollutant discharge levels approaching that of natural gas fired plant are achievable.

The gasification process is oxygen blown rather than air blown due to the very low calorific value of the air blown syngas and the higher gas volumes that have to be handled.

If concentration of CO_2 is required to facilitate CO_2 capture for subsequent sequestration, the gasification process can include the water-gas shift reaction, where the CO reacts with steam over a shift catalyst. The steam and CO react to form CO_2 and further hydrogen. The CO_2 can then be removed before the hydrogen is passed to the gas turbine for combustion. Removing the CO_2 before combustion keeps overall efficiency about 10% higher than trying to remove the CO_2 after combustion if the shift reaction is not used.

***Figure 10.1 – IGCC with CO_2 removal and H_2 co-production*[67]**



[67] Ian Burdon, Winning Combination. IEE Review, February 2006, pp 32-36

10.3 CURRENT STATUS OF TECHNOLOGY

The East Harbour Management Services report, “Fossil Fuel Electricity Generation Costs” dated (June 2004) briefly comments on IGCC as follows:

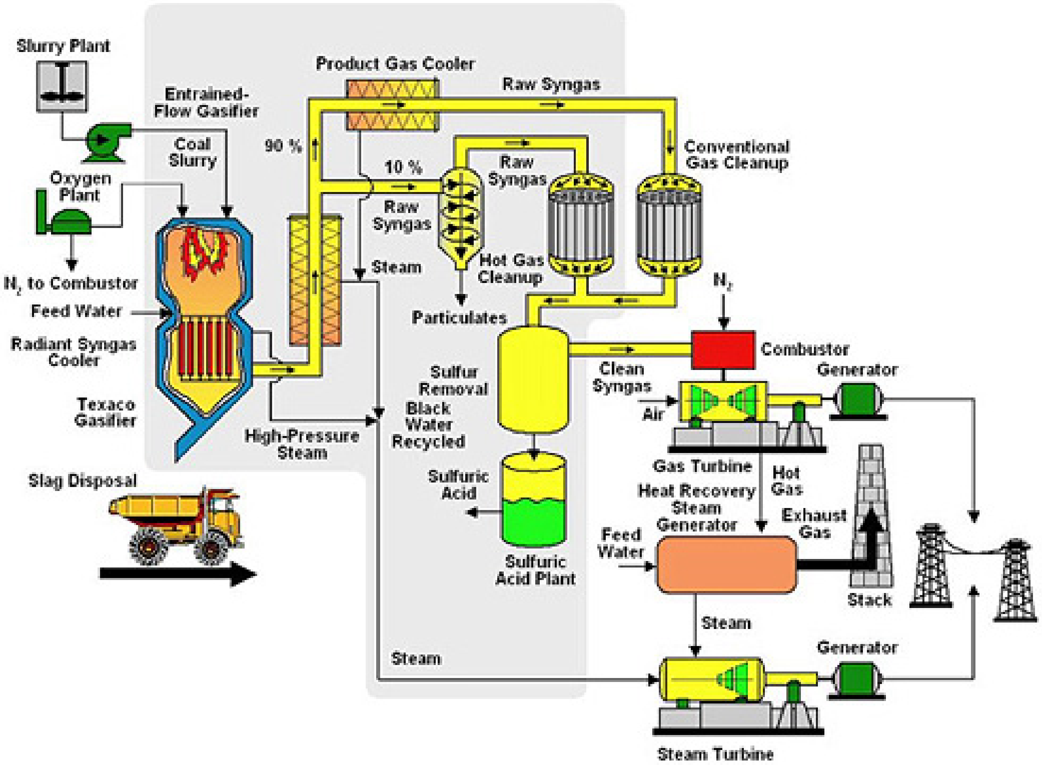
“Integrated gasification combined cycle (IGCC) plant is used in a large number of refinery and chemical industry facilities using primarily petroleum feedstocks. The transfer of IGCC technology using coal as a feedstock for electricity generation has not been as successful. Demonstration plants have had higher costs and lower efficiencies than expected. This technology is considered to be an emerging one.

IGCC has a number of potential benefits: high efficiency, can handle high sulphur coals, emissions similar to gas firing and the potential for carbon dioxide capture. It is receiving considerable interest and funding by US Federal agencies with a target of having similar costs to pf plant.” (note: pf = pulverised fuel, in this context means standard coal fired generating plant).

The attempts to integrate the three processes into a competitive power plant is still at the demonstration stage. While a number of IGCC plants have been constructed with project costs reported in the public domain, they are nevertheless demonstration projects with pricing that is typically “first of a kind”. While there are more IGCC plants under construction, these also have the benefit of significant subsidies or research and development funding. IGCC costs are still highly variable, illustrating that IGCC is not mature with consistent costs.

The next generation of IGCC plants is expected to include a step change in the gas turbine technology to “H” machines with supercritical steam cycles, and the implementation of ion transport membranes for reducing the auxiliary power consumption of the air separation unit (for oxygen production), as the major changes for enhancing performance and reducing capital cost.

Figure 10.2 - Integrated Gasification Combined Cycle Schematic



The promise of IGCC, as exemplified by the U. S. Department of Energy's Futuregen and Vision 21 programs, is as follows:

- Lowest capital cost (when mature) of the coal based technologies.
- Fuel flexibility (with added capital cost)
- Highest efficiency among the coal based technologies (when mature)
- Best emission characteristics among the coal based technologies
- Most cost efficient carbon dioxide capture for sequestration

10.4 COMMERCIALISATION

It is anticipated that the next generation of IGCC plants will be constructed, and capital costs will no longer be "first of a kind" and have matured, within the next 5 – 10 years. This puts commercialisation at 2010 – 2015.

Barriers to IGCC commercialisation include:

- Higher "first of a kind" capital costs – costs not yet mature
- Higher operations and maintenance cost
- Technical complexity – plants combine power generation and chemical refinery technology
- Lower availability and reliability – particularly the gasifiers
- Lack of availability of EPC "wrap" where the contractor takes on the performance guarantee, construction schedule, reliability and availability and service contract risk in a single package.

10.5 EXPECTED UNIT SIZES AND PERFORMANCE

IGCC plant sizes (in MWe terms) are determined primarily by the currently available gas turbine fleet. Gas turbines when fired on oxygen blown syngas have approximately 20 – 25% higher output due to the higher mass flow of fuel. IGCC plant unit sizes are expected to be in the range of 120 – 550 MW.

The ratio of the chemical energy in the gasifier product syngas and the chemical energy in the coal feed is typically around 0.7–0.8. Depending on configuration, some of the produced heat may or may not be recovered.

The 550 MW IGCC with H class gas turbines is expected to have efficiency of better than 45% HHV. Smaller, earlier developed gas turbines such as the 6FA type may receive only minor upgrades and the IGCC efficiency will remain in the range of 38% - 42% HHV.

10.5.1 Availability

Installation of a spare gasifier significantly improves plant availability, although this results in a greatly-elevated capital cost.

The Texaco and E Gas (both USA) refractory-lined gasifiers need planned outages of 25 to 30 days for refractory replacement every 2 – 3 years. To achieve overall IGCC equivalent availabilities above 90%, a spare gasifier would be required. This would reduce the scheduled outage time and some of the forced outage time.

Eastman Chemical report a 99% availability of syngas with the use of a spare gasifier on hot standby.

- 0.9% forced outage rate
- 1.2% planned outage
- 97.9% of time on stream since 1984.

Eastman's single unit gasifier availability was estimated to be 90%. Eastman switched between gasifiers every 62 days on average in 2002[68].

Other USA IGCC plant availabilities were as follows:

- Gasifier availability 83 to 84.2%
- Power block availability 90 to 94.4%

10.5.2 Auxiliary Loads

A major factor in the overall net performance of an IGCC power plant is the high auxiliary load consumption of the gasification plant, due primarily to the air separation unit.

Demonstration IGCC power plant have auxiliary loads in the range of 11% - 21%. This compares with conventional coal-fired power stations ranging from 6% - 13%, but is highly dependent on the fuel quality and level of gas clean-up required.

Most current plants use cryogenic air separation with auxiliary loads up to 17% of the gross plant generation. It is anticipated that the development of ion transport membrane technology could significantly reduce these auxiliary load requirements.

10.6 COSTS

10.6.1 Capital Costs

IGCC costs are still highly variable as the IGCC technologies are still not commercial.. IGCC is not available as a performance guaranteed turnkey plant. Current studies have costs ranging from US$ 1,200 to 1,800 /kW (NZ$ 1,800 to 2,700 /kW). This illustrates that IGCC is not mature with consistent costs. Economies of scale are being applied to large scale IGCC to reduce the capital cost, but in the NZ context scope for larger scale IGCC is limited.

Existing projects with project costs reported in the public domain are demonstration projects that typically have pricing that is "first of a kind".

Current studies show significant pricing differences between the three primary gasification technologies. (Texaco Quench, E Gas, Shell Gasifiers) It is expected that market pressure will ensure that real costs between the technologies will be similar.

The selected IGCC capital costs and plant efficiencies illustrated in the Harvard Report (Financing IGCC – 3 Party Covenant, Harvard University, Feb 2004) tend to use the lower end capital costs of the published data. A significant impact on the IGCC costs will be any requirement for redundancy of the gasification plant to ensure that the IGCC plant availability remains similar to competing clean coal technologies. The plant size of the studies is trending to large plant in the 800+ MW size range.

It is important to note that the cost estimates represent an EPC contract cost for a generic plant configuration. These raw costs do not have any contingency applied and are typically for a base plant with no gasifier redundancy. Locating any such plant in New Zealand will have additional costs for the feed stock delivery and storage infrastructure,

[68] Eastman Chemical Company Statement Future Options for Generation from Coal June 24, 2003, Testimony to Subcommittee on Energy and Air Quality

site specific civil works, additional seismic cost loadings for plant structures, buildings, workshop and administration facilities and owners' project development costs for engineering, legal, resource consenting, financing etc.

GE notes[69] that capital costs are typically apportioned in the following ratios:

- 30% gasification,
- 15% syngas clean up,
- 40% power island
- 15% cryogenic air separation unit.

For IGCC to be a commercially proven technology, the capital costs have to mature with a lower range than current cost estimates (US$ 1,200 /kW - US$ 1,800 /kW), and enough plant experience for financial institutions to consider that risks are understood and managed.

Current IGCC development projects sponsored by the US DOE have targets of 45 – 50% HHV plant efficiency and capital cost of US$ 900 – 1,000 /kW (1999 dollars), equivalent to NZ$ 1,500 to 1,650 /kW by 2010.

PB Power estimates that at least 75% of the capital cost of IGCC systems will be subject to overseas exchange.

10.6.2 O&M Costs

Based on operation of IGCC plant in USA, the following indicates the level of annual expenditure (other than staffing) for the various components of IGCC plant operation and maintenance[70].

ITEM	Proportion of Annual Cost (%)
Catalysts and Chemicals Water treatment, Flocculent, Acid Gas Removal, COS & SAP Catalyst	9
O&M – General Maintenance & Air Separation Unit Building, Structure, and site Maintenance; Safety and general Supplies; Waste Disposal (except Slag)	14
O&M – Gasification Coal and Slurry, High Temperature Gas Cooling, Slag and Fines Handling, Gas Cleaning, Sulphuric Acid Plant.	41
O&M – Power Block, Common & Plant Water Systems	18
Sustaining Capital – Small Projects Replacement of Worn Capital Equipment and Minor Improvements	18

Total O&M costs are around 1.5 c/kWh and relatively predictable with operating information from demonstration plants. Gasifier refractory O&M contributes significantly

69 GE "IGCC- Clean Power Generation Alternative for Solid Fuels", PowerGen Asia 2003
70 Tampa Electric Polk Power Station Integrated Gasification Combined Cycle Project, Final Technical Report, Aug 2002

to the higher O&M costs of IGCC relative to coal and natural gas fired plants. O&M costs are targeted to reduce to around 1.0 c/kWh once the technology is mature.

10.7 ENVIRONMENTAL ISSUES

IGCC plants are the environmentally cleanest coal based power system available today and represent a potentially effective means of capturing CO_2 for sequestration. IGCC is currently the only clean coal technology able to economically remove any mercury emission.

From operating experience of IGCC plant in USA, the following are typical, expected emissions from IGCC plant[71]:

- SO_2 0.07 to 0.6 kg/MWh
- NOx 0.3 to 0.5 kg/MWh
- Particulates 0.005 to 0.06 kg/MWh
- Mercury 2×10^{-5} to 3×10^{-5} kg/MWh

Where CO_2 capture is not used, IGCC emissions of CO_2 will be somewhat lower than conventional coal fired plant, such reduction due only to the higher efficiency of IGCC plant.

10.8 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

The development of an IGCC power plant in New Zealand at the current time is a high cost and high risk strategy. This simply reflects the current lack of maturity of coal-fired IGCC development for power production compared to competing technologies.

Gasification technology selection and costs are dependant on the specific characteristics of the intended coal resource. There are no standard methods for determining relevant coal parameters and hence it is difficult to assess the suitability and costs of using New Zealand coals in IGCC plants. Coal specific research and development is probably required for a commercial design.

Because IGCC plants are high capital intensive plants, economies of scale apply similar to conventional coal fired power plant. IGCC plants can be expected to match commonly available gas turbine sizes, similarly to gas-fired combined cycle plant, and in New Zealand will be limited to approximately 400 MW unit size given the scale of New Zealand's electricity system. IGCC plants are expected to be more costly below 400 MW.

In the early stages, gasification only projects aimed at replacing natural gas supplies may make more economic sense by refuelling stranded gas-fired combined cycle plants if long term gas supplies become scarce.

[71] "Major Environmental Aspects of Gasification Based Power Generation Technologies", Final Report Dec 2002 NETL

11. GEOTHERMAL

11.1 SUMMARY

11.1.1 Hot Dry Rock

Hot Dry Rock technology is not promising as New Zealand does not appear to have a high crustal thermal gradient. New Zealand's volcanic nature means that the stress field in underground rocks may not be ideal for creating the fractured rock underground heat exchangers necessary for extracting the heat.

The relatively abundant hydrothermal resources in New Zealand that are yet to be exploited mean that there are limited incentives to undertake the difficult and costly tasks of assessing and developing hot dry rock or enhanced geothermal systems.

11.1.2 Kalina cycle

The Technology

- Higher efficiency thermal power cycle compared to alternatives
- Ammonia-water mixture working fluid boils at variable temperature
- Suited to heat recovery applications including hot geothermal water

Current State

- Demonstration plant, small scale examples
- Component parts are standard technology

Limitations of the technology

- Use of standard carbon steels with ammonia water mixtures is limited to 300°C

Technological Hurdles

- Demonstrating higher efficiency than competitor Organic Rankine Cycle (ORC) technologies
- Achieving the potential for lower capital costs

Efficiency, Scale and Costs

- Exergy efficiency up to 60% depending on application
- A 10 to 40% improvement in exergy efficiency over existing ORC technology.
- Initial scale of commercial Kalina cycle plant 5 to 25 MW, but potential to scale up once proven.
- Initial capital costs $2,200 to $3,000 per kW
- O&M costs should be similar to ORC plant, in the range 0.4 c/kWh for 25 MW plant to 0.9 c/kWh for 5 MW plant.

Environmental Issues

- The Kalina cycle plant itself does not produce emissions.

- Liquid anhydrous ammonia is stored on site and is a hazardous substance if leaked.

NZ Context

- New Zealand has potential applications for Kalina cycle plant, but cost competitiveness may be dependent on a global market for Kalina cycle plant developing where a single supplier can supply standard designs and has procurement arrangements that lower costs.

11.2 HOT DRY ROCK AND ENHANCED GEOTHERMAL SYSTEMS

11.2.1 Technology Description

The Geothermal energy resource is covered in the East Harbour Renewables Report. However the discussion is restricted to hydrothermal resources in highly permeable rock formations, these are the heat resources that are accessible by extracting naturally occurring deep ground waters that have taken up heat from the rock.

An emerging geothermal energy resource is Hot Dry Rock (HDR). This technology aims to exploit the huge land areas under which the rock temperature exceeds 200°C at depths less than 5 km, but where the permeability of these formations is low.

The principle of HDR technology is to circulate a fluid between an injection well and a production well, along pathways formed by fractures in the hot rocks that act as deep heat exchangers. The fluid transfers heat to the surface where it can be converted to electricity. The deep heat exchanger is fabricated by hydraulic stimulation. This involves pumping high pressure water into the hot rock that opens stressed natural fractures and facilitates micro-slippage along them. Releasing the water pressure allows the fractures to close but the slippage that occurred results in a million-fold permanent increase in permeability along the fracture systems and a heat exchanger is created that can be used to extract energy.

The scope of the HDR technology has broadened as fluids have been frequently found from deep boreholes drilled in crystalline rocks. In fact, between fully hydrothermal reservoirs and totally impermeable hot rocks, there is a complete series of low- to medium-permeability rocks which cannot be exploited for geothermal energy production without specific engineering enhancements. The technology of enhancing the permeability of these systems is called Enhanced Geothermal Systems (EGS).

11.2.2 Current Status of Technology

A number of research programmes have worked towards developing Hot Dry Rock (HDR) technology since the 1970's, first in the USA and the United Kingdom, then also in Germany, France, Japan and Sweden, and more recently in Australia and in Switzerland.

In 1995 the US DOE announced it was terminating its effort to commercialise HDR, instead focussing on integrating the technology with the commercial hydrothermal industry. This includes using hydraulic fracturing to increase production from hydrothermal resources, or from existing wells that have become dry or marginal producers, bringing value to stranded geothermal assets.

Enhanced Geothermal Systems (EGS) have been trialled in the Coso volcanic geothermal field in California, where hydraulic and thermal stimulation to fracture the existing reservoir is being used. On the east flank of the field, due to secondary mineralization processes, tectonically stressed fractures have sealed over time. Through stimulation, the fractures in the reservoir are caused to open, extend and interconnect. A large hydraulic stimulation experiment was planned for 2005.

Australia has increased its HDR efforts, based on the particularly promising resource in the Cooper Basin. Geodynamics Limited was created in 2000 solely to focus on developing renewable geothermal energy generation from hot dry rocks in Australia, attracting both Government and private funding.

Geodynamics has drilled two wells to 4,400 metres and conducted a Hydraulic Stimulation Program. A reservoir testing programme has begun, including a circulation test commenced in the first quarter of 2005. When the results are available, Geodynamics expects to be able to assess the economic value of the known geothermal resource in the Cooper Basin.

At Soultz (France) hydraulic stimulation has been achieved but calcite has formed in fractures. Acid dosing was trialled to dissolve the calcites. Short term circulation is being trialled during 2005 and has been running for 6 weeks. A pilot plant of 1.5 to 6 MW over the next 5 years is planned.

HDR or EGS technology has not yet progressed to pilot plant status, though this is expected within the next 5 or 10 years based on current programmes. Beyond the pilot plant stage, the ability of a HDR or EGS system to sustain long-term commercial production remains unknown.

11.2.3 Commercialisation

HDR and EGS technologies have the potential to be exploited commercially overseas within the next ten years. However, the commercial exploitation is likely to be limited to specific sites where research has been undertaken previously. Extending these technologies to other sites or to New Zealand may not be commercial even if these technologies have been commercially exploited elsewhere. The difficulty of commercialisation arises from the costs to assess potential resources and also whether economically accessible resources exist in New Zealand.

11.2.4 Key Issues Related to its Use in New Zealand

Particularly with respect to HDR, there is little known about potential sites for exploitation. New Zealand's volcanic nature means that the stress field in underground rocks may not be ideal for creating the fractured rock underground heat exchangers. Perhaps most importantly, in NZ there are relatively abundant hydrothermal resources that are not yet exploited, until the barriers to developing them are reduced and they are all utilised there is no incentive to explore higher cost and higher risk alternatives.

11.3 KALINA CYCLE – GEOTHERMAL AND HEAT RECOVERY

11.3.1 Technology Description

An emerging power generation technology for heat recovery systems is the Kalina cycle. The Kalina cycle differs from the already commercial Organic Rankine Cycle (ORC) technology in that an ammonia/water mixture is used as the secondary working fluid instead of a pure organic fluid such as iso-pentane. Both of these technologies are examples of binary cycles, where the heat is transferred to a secondary fluid from which power is extracted.

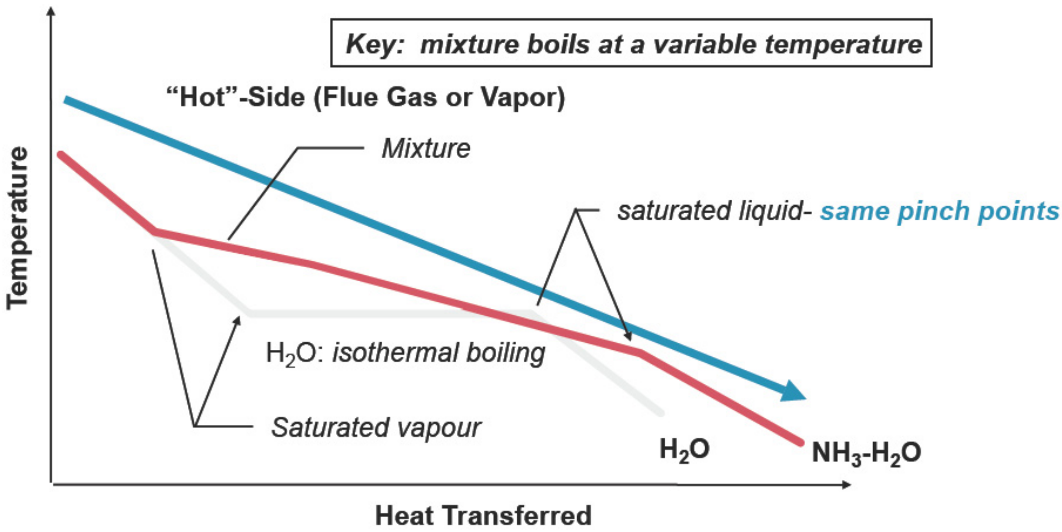
In all thermal power cycles (where heat is converted to mechanical or electrical energy) highest efficiency is obtained by maximising the temperature of the working fluid when heat is absorbed, and minimising the temperature of the working fluid when the heat is rejected to atmosphere or water bodies.

This is especially important when generating power from lower temperature sources such as waste heat or natural sources such as geothermal brine. Another challenge with these sources of heat is that they cool as the heat is extracted, making it even more difficult to transfer the heat to the working fluid at the highest temperature at all times while the heat is being transferred.

With the Kalina cycle, the ammonia water mixture boils at a variable temperature unlike pure substances which boil at constant temperature. Variable temperature boiling permits the working fluid to better match the temperature gradient of the heat source fluid as it cools in a heat exchanger. Also, by using a different mixture composition in the condensing part of the cycle, condensation can be achieved at slightly above atmospheric pressure, avoiding the need for vacuum conditions and costly gas extraction equipment.

The following graph highlights the ability of the ammonia water cycle to more closely match the heat source temperature profile compared to a pure fluid.[72]

Figure 11.1 – Ammonia Water Mixture and Pure Water Temperature Profiles

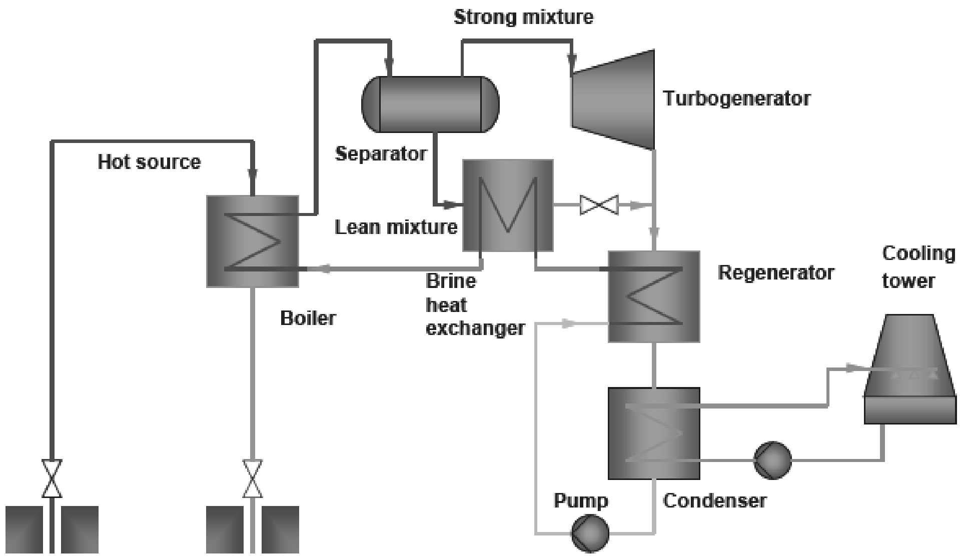


The Kalina cycle consists of a family of proprietary system designs that exploit the properties of the ammonia-water working fluid. Each design is applicable to a specific application, such as high temperature heat recovery (gas turbine based combined cycle) or geothermal brine. The families can consist of distillation/absorption/condensation subsystems, vapour generation/separation subsystems, or a combination of both.

The schematic below shows a Kalina cycle design using a geothermal brine application.

Figure 11.2 – Typical Kalina Cycle Schematic[73]

[72] Recurrent Engineering, "KCT Waste Heat Applications", Company Brochure, March 2005
[73] Valdimarsson P & Eliasson L, "Factors influencing the economics of the Kalina power cycle and situations of superior performance", International Geothermal Conference, Reykjavik, September 2003



11.3.2 Current Status of Technology

Ammonia has been used in mechanical vapour compression freezing plants for decades, and ammonia-water mixtures have also been used in ammonia/water absorption heat pumps and small refrigerators for many years. The Kalina cycle plant consists of a series of separators, heat exchangers and pumps, all of which are constructed with standard power plant components. Operating experience from refrigeration systems can be transferred to Kalina cycle power plant designs.

The Kalina cycle appears complex but this is a thermodynamic design issue and the physical equipment itself consists of standard power plant components. The control systems are no more complex than for a conventional power plant or an ammonia absorption refrigeration plant. The varying ammonia concentrations occur naturally as a result of the temperatures and pressures of the process and do not need special controls. Process controls consist of standard flow and level control valves. Heat exchangers form the bulk of the plant and consist of shell and tube or plate heat exchangers, along with standard cooling system components, all at above atmospheric pressure.

A significant aspect of the design is that the molecular weight of NH_3 is similar to water H_2O (17 and 18 respectively). Therefore standard steam turbines can be used, and the performance is not affected by changes in mixture ratio. However practical experience of operating steam turbines on an ammonia rich working fluid is limited.

At temperatures below 300°C, standard carbon steels are considered acceptable for use with ammonia/water mixtures. The potential for ammonia decomposition and nitride hardening and consequent fatigue cracking limits higher temperature applications[74]..

There have been a number of applications of the Kalina cycle, the first demonstration plant of 3 MW at Canoga Park, Los Angeles, California, in 1992, which had over 7,000 hours of operation and testing over a number of years before being closed down. In 1999 a 3.1 MW heat recovery plant was installed at Sumitomo Metals in Japan, and in 2000 the 2.0 MW Husavik geothermal plant in Iceland was commissioned.

11.3.3 Commercialisation

The Kalina cycle is proposed to be used for heat recovery applications and geothermal applications.

[74] Eliasson L, Valdimarsson P, Eliasson E, “Kalina technology: where and why to utilize”

The technology is ready for commercialisation, however the lack of operating Kalina cycle plants in the 5 MW or larger range, where it is likely to be commercial, make it not sufficiently proven for standard EPC implementation.

Currently the technology is owned by US-based Recurrent Resources, and Geodynamics of Australia has acquired the exclusive licence and intellectual property rights to Kalina Cycle projects in Australia and New Zealand. Kalina cycle plant would carry a performance guarantee by Siemens, which has an agreement with Geodynamics to jointly promote Kalina cycle in New Zealand, based on Siemens power plant equipment.

A large scale plant is planned for construction in the USA by the owner of the rights to the technology. Geodynamics, also intends to establish a demonstration plant in Australia or New Zealand in the near future, which should boost commercialisation.

The Kalina cycle is expected to be initially commercial in applications where it has the highest efficiency advantage, in particular for separated geothermal water as an addition to an existing geothermal steam plant. As the technology matures and proves to be scalable, it may be competitive as the complete solution for hydrothermal geothermal fields.

11.3.4 Expected Unit Sizes, Scale and Performance

Plant Size

Kalina cycle technology is very scalable because the components are standard power plant components and are available in a wide range of sizes. However its competitive advantage in heat recovery and low grade natural heat sources mean that Kalina plants are expected to be commercial in the 5 to 20 MW range initially, with potential larger applications as the superior performance of the technology is proven.

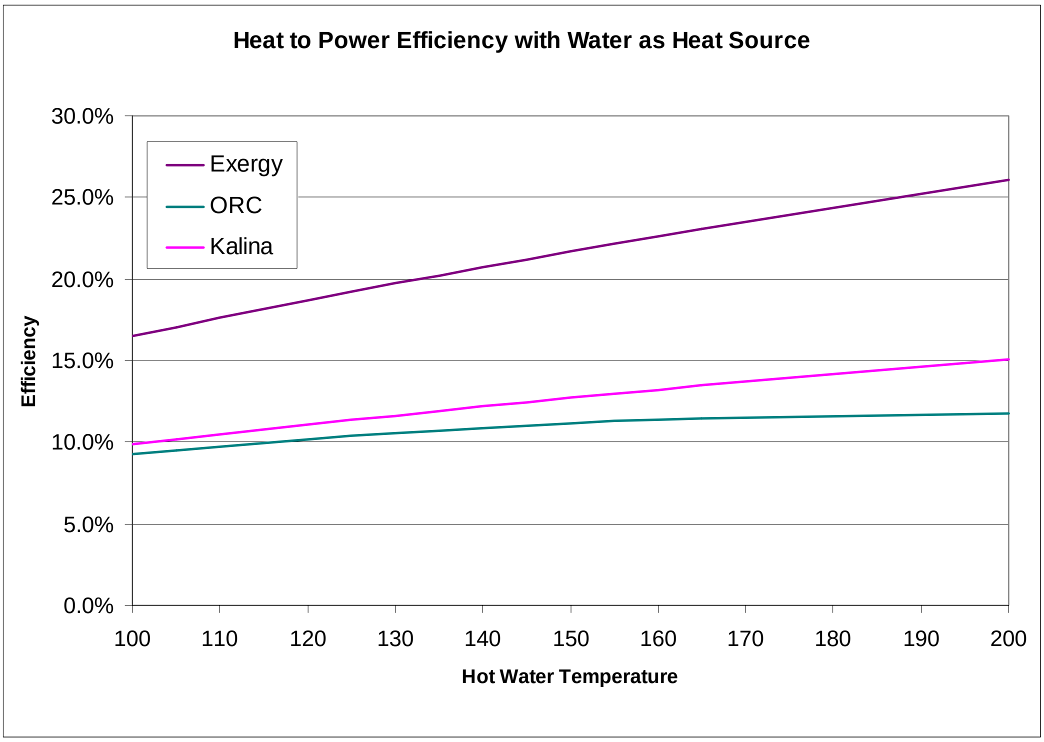
Kalina cycle technology has been proposed for large scale systems, such as in a Heat Recovery Steam Generator on a combined cycle plant, but in these plants high heat recovery efficiency is already achieved by using up to three steam pressure levels. This leads to a complex plant but the large scale of these systems means this is not a major issue and Kalina cycle will be slow to make inroads at this scale.

Performance

With low temperature heat sources, the efficiency of utilisation can vary widely depending on the supply temperature and constraints such as the allowable temperature the source fluid can be cooled to. A typical constraint is the potential for supersaturated silica in geothermal brine to precipitate out and scale heat exchangers if it is cooled too much. Hence to compare the advantages of the Kalina cycle with its closest commercial competitor, the Organic Rankine Cycle, a standard thermodynamic approach is needed.

A representative calculation was done for a typical situation where the energy source is hot geothermal water at various temperatures, which cools as the heat is extracted to a fixed lower temperature of 80°C, and where cooling water is available at 20°C.

Figure 11.3 – Kalina and ORC Efficiency Comparison



The exergy[75] line shown in this graph represents the absolute limit of mechanical work which is able to be extracted from the source heat according to the 2nd law of thermodynamics[76]. The proportion of the exergy actually converted to mechanical work is called the exergy efficiency and is a more meaningful reference for the performance of power conversion cycles at low temperatures than the energy efficiency.

For the graphed example above, the Kalina cycle net power generation exergy efficiency is approximately 60%, compared to approximately 45% to 55% exergy efficiency for the ORC cycle.

The Kalina cycle efficiency is higher, particularly as the temperature range (from geothermal water source temperature to 80°C water out) increases. The margin of the Kalina cycle efficiency over the ORC shown here is not as high as stated in some literature. This arises because the ORC efficiency has been increasing, in line with its status as a maturing technology. Over time, the Kalina cycle efficiency would be expected to increase as well and its margin over ORC increase.

Applications

The advantage of the Kalina cycle over Organic Rankine cycle increases the higher the utilised temperature drop. The most advantage for the Kalina cycle is likely to be when the heat source is in the 120°C to 200°C range. This is the typical range for geothermal brine (and possibly other heat recovery situations).

Where water cooled condensers are possible, the Kalina cycle may be able to take advantage of lower available condensing temperatures better than ORC plant. This is a limitation of the properties of organic fluid used in ORC plant.

[75] Mlcak, H A "An Introduction To The Kalina Cycle," ASME Joint Power Generation Conference, Houston, Texas, 1996
[76] Eliasson L, Valdimarsson P, Eliasson E, "Kalina technology: where and why to utilize"

11.3.5 Costs

Installed capital cost is approximately $2,200 to $3,000 per kW based on limited reference plants, and will depend on use of once through cooling, closed circuit cooling or air-cooled condensers. This cost includes the cost of the Kalina cycle plant, but does not include the cost of the geothermal wells or steamfield costs, which are very similar for any of the geothermal technologies. In initial applications Kalina cycle plant is likely to be an adjunct to geothermal steam plant (so steamfield costs are sunk costs) and the Kalina cycle has wider applications than just geothermal.

O&M costs are expected to be low, similar to other geothermal technologies, but will vary according to plant size. O&M costs excluding geothermal well or steamfield costs are in the range 0.4 c/kWh for 25 MW plant to 0.9 c/kWh for 5 MW plant.

11.3.6 Environmental Issues

The distinguishing feature of the Kalina cycle compared to other technologies is the handling of potentially hazardous ammonia. A large quantity of liquid anhydrous ammonia is stored at the plant. Liquid anhydrous ammonia is a hazardous substance if leaked. It is highly exothermic when it contacts water. It causes chemical burns when contact with exposed parts of the body (sweat or moist parts), or when breathed in.

However ammonia is a very common, widely used chemical, particularly in large scale refrigeration systems such as in freezing works. Procedures for handling ammonia are well known. The distinctive pungent odour of ammonia, even at very low concentrations, ensures operators are aware of any leaks. Ammonia is not a greenhouse gas, unlike methane and chlorofuorocarbons, but is a potential pollutant in terms of soil acidifaction and eutrophication, and releases should be prevented.

In Kalina cycle plant all discharges containing ammonia are directed to a water blow-down tank. Spent fluid is drained and can be used as a fertiliser or returned to the ammonia supplier for reprocessing.

Ammonia is less hazardous than iso-pentane and other organic fluids used in organic rankine cycle plants, which are extremely flammable and whose vapour/air mixtures are explosive.

11.3.7 Key Issues Related to its Use in New Zealand

New Zealand has potential applications for Kalina cycle plant, but cost competitiveness may be dependent on a global market for Kalina cycle plant developing where a single supplier can supply standard designs and has procurement arrangements that lower costs

12. BIOFUELS

12.1 SUMMARY

The Technology

- Hydrolysis of biomass to sugars, then fermentation to ethanol
- Transesterification of animal fats and vegetable oils to biodiesel
- Fast Pyrolysis or Liquefaction of biomass to bio-oil
- Liquid fuel synthesis from bio-syngas produced by biomass gasification to synthetic diesel

Current State

- Acid hydrolysis of biomass is a nearly fully developed process
- Enzymatic hydrolysis of biomass is at demonstration plant status
- Fast Pyrolysis is almost commercial, Liquefaction is less developed
- Transesterification is an established technology

Limitations of the technology

- Transport of waste feedstocks and cost of crop feedstocks limits cost reductions
- The most efficient current technologies favour warm, tropical climates
- Above the 5% displacement level of petrol and diesel, large areas of arable land would be required for biofuel production and would displace current food crops.

Technological Hurdles

- For lower cost biomass (lignocellulosic) feedstocks, the cost of enzymes and capital costs of fermentation plant limit the economics.
- Biomass gasification is at pilot and demonstration plant level only. Synthesis gas cleanup requirements are very high to protect downstream catalysts. Fisher Tropsch synthesis depends on large scale for better economics.
- Bio-oil product of pyrolysis has low heating value and is highly oxygenated. Hydro-deoxygenation is not yet acceptable energetically or economically.

Costs

- Ethanol from putrescible wastes - 0.6 to 1.25 $/litre, depending on feedstock
- Ethanol from woody biomass – near term 0.58 to 1.05 $/litre
  - long term 0.38 $/litre
- Biodiesel from tallow - 0.5 to 0.8 $/litre
- Synthetic diesel from bio-syngas - Fisher Tropsch synthesis 1.13 $/litre
  - DME synthesis 0.78 $/litre

NZ Context

- Tallow and waste vegetable oils could provide biodiesel for 5% of NZ's diesel requirements.

- Putrescible wastes could provide bioethanol for up to 8% of NZ's petrol requirements.
- Larger scale biofuel production in the longer term will require specialty plantation energy crops, of which woody biomass is probably most appropriate for NZ. The technology of enzymic hydrolysis is not expected to be available at competitive costs for 10 to 15 years.
- Important advances for biofuel plantation crops are expected to come from genetic engineering and will require long periods of testing and certification before release.
- Mechanisms to stabilise future prices such as excise tax policy on fossil liquid fuels may be required to attract capital investment.

12.2 TECHNOLOGY DESCRIPTION

From a supply-side energy perspective biofuels comprise any biomass or biomass derivatives, including that derived from animals, which are destined to be utilised as liquid fuels. Liquid fuels only are considered because of their higher value and hence greater potential to be economic. Biofuels may be produced from a wide range of biomass resources, either directly or indirectly, and produced in a variety of ways.

Biofuel technologies considered and the biomass resources used by each technology are summarised in the following table:

Table 12.1 – Biofuel Technologies and Biomass Resources

Biofuel/Process	**Biomass Resource**
Ethanol	
Yeast fermentation of sugars	Sugar cane, sugar beet, lactose
Enzymic hydrolysis of starches to sugars, then fermentation.	Wheat, corn
Acid hydrolysis of lignocelluloses to sugars, then fermentation	Woody crops, crop residues, grasses, municipal solid waste
Enzymic hydrolysis of lignocelluloses to sugars, then fermentation	Woody crops, crop residues, grasses, municipal solid waste
Bio-diesel	
Transesterification	Animal fats, vegetable oils
Fast pyrolysis or Liquefaction to bio-oil, biogas, and char, then hydro-deoxygenation	Woody crops, crop residues, grasses
Methanol / Synthetic Diesel	
Liquid fuel synthesis from bio-syngas produced by biomass gasification	Woody crops, crop residues, grasses

The biofuel processes are briefly described below:

Ethanol

- Yeast fermentation - yeasts or other micro-organisms (biocatalysts) are used to convert sugars into ethanol, with CO_2 as a by-product. The ethanol is in the form of a relatively dilute aqueous solution, which is then distilled.
- Enzymic hyrolysis of starches - the starch polysaccharide is broken into its component sugar molecules using enzymes, then fermented and distilled.
- Acid hydrolysis of lignocelluloses – acid decrystallization of the lignin (a crystalline organic material) to separate the hemicellulose and cellulose (sugar polymers), then acid hydrolysis (break the polymers with water molecules) to produce sugars, which are then fermented and distilled.
- Enzymic hydrolysis of ligncelluloses – acid decrystallization of the lignin then use enzymes to hydrolyze the hemicellulose and cellulose, and microbes to ferment the sugars simultaneously, followed by distillation.

Bio-diesel

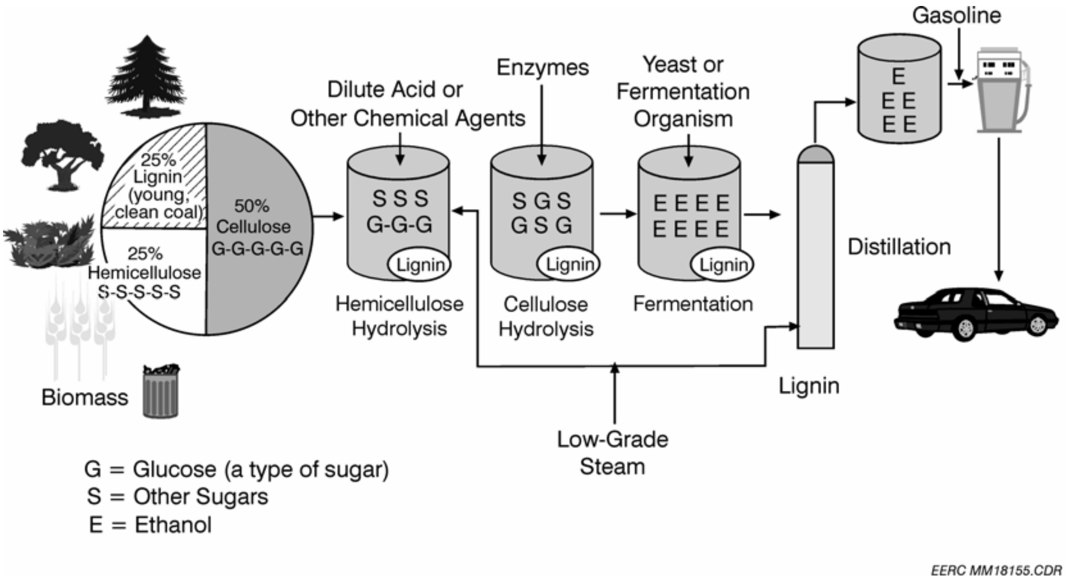
- Transesterification of tallows and vegetable oils – chemical reaction between the oil/fat and methanol in the presence of a catalyst (sodium or potassium hydroxide) to produce fatty acid methyl ester (bio-diesel)
- Fast pyrolysis of biomass – thermal decomposition process at moderate temperatures in the absence of oxygen, to produce a liquid bio-oil.
- Hydrothermal liquefaction of biomass – depolymerisation and deoxygenation of biomass using highly pressurised water at moderate temperatures to produce a liquid bio-crude.
- Bio-oil refining – bio-oil and bio-crude are liquids containing highly oxygenated compounds and approximately 20% water. Developing technologies to upgrade to a transportation fuel include gasification and then synthesis, or by reacting with hydrogen or alcohol (hydrodeoxygenation).

Methanol / Synthetic Diesel

- Gasification – thermal decomposition process in the absence of oxygen with steam reformation to produce bio-syngas.
- Fisher – Tropsch synthesis – bio-syngas is catalytically converted at high pressure and temperature to larger organic compounds and then refined to methanol or synthetic diesel (alkanes).
- Bio-DME – bio-syngas is synthesised directly to dimethyl-ether (DME) using a slurry catalyst. DME is an LPG-like fuel suitable for diesel engines.

The following simplified schematic illustrates the process for production of ethanol from lignocellulose[77].

[77] From http://www.westbioenergy.org/reports/mm-ethanol.htm (but no longer available at this site)



Further information on biofuels is contained in the Renewables Report by East Harbour Management Services. It should also be noted that this is not a comprehensive assessment of all potential candidate biofuel technologies, but rather a review of a limited number of the technologies which were considered to warrant further discussion as having real commercial promise in the review period.

12.3 CURRENT STATUS OF TECHNOLOGY

Ethanol

- Yeast fermentation of sugars –ancient and proven process. Fully developed and not an evolving technology. Costs and conversion efficiency is dependant on feedstock rather than process.
- Enzymic hydrolysis of starches to sugars – a modern industrial enzyme technology that is fully developed and not an evolving technology. Production of ethanol from this source is limited by the available resource base and cost of the raw material which is the largest part of the operating costs.
- Acid hydrolysis of lignocelluloses to sugars, then yeast fermentation – long industrial history, some ongoing development to reduce costs of conversion by improving acid recovery and acid re-concentration. Nearly fully developed processes with little room for further cost savings.
- Enzymic hydrolysis of lignocelluloses to sugars, then yeast fermentation – an emerging technology, with recent successes in improving conversion efficiency. Demonstration scale plant operated by Iogen in Ottawa, Canada; a few companies developing full scale projects. Driver for this process is the low cost of biomass relative to other bio-ethanol raw materials.

Bio-diesel

- Transesterification – already commercial technology that is well understood, widely used, and already yields are near theoretical limits.
- Fast pyrolysis to bio-oil, biogas, and char, then bio-oil refining – fast pyrolysis is a demonstrated technology producing yields of liquid product up to 75%, but the bio-oil upgrading to liquid fuels is at present unacceptable energetically and economically.
- Hydrothermal liquefaction to bio-crude, then bio-crude refining – hydrothermal upgrading (HTU) is a newer technology in early stages of development. Refining can be via hydro-deoxygenation to diesel fuels (HTU diesel). This technology is still

being developed and hydro-deoxygenation is still experimental. The advantage of hydrothermal upgrading is that it can process wet biomass.

- Bio-oil can be burnt as is, in boilers or gas turbines. Heating value of bio-oil is about 40% that of diesel.

Methanol / Synthetic Diesel

- Biomass gasification – large fluidised bed gasification plants have been built to provide a fuel gas for power production. However gasification of biomass for liquid fuel synthesis is different and has not yet developed beyond pilot and demonstration plant stages.
- Fisher-Tropsch synthesis from bio-syngas produced by gasification – the Fisher-Tropsch process is proven, but the necessary bio-syngas purification processes to protect downstream catalysts are not yet commercial. The related process of direct synthesis of dimethyl-ether (DME) from biomass syngas is not yet demonstrated but avoids the methanol synthesis and dehydration process currently used. DME is clean burning in diesel engines but must be compressed to liquefy, similar to LPG.

12.4 COMMERCIALISATION

Ethanol Technology

Ethanol is produced in large volumes globally (41 billion litres in 2004), predominantly from sugar cane, in Brazil (37% of world production), and from corn starch, in USA (33% of world production).

Significant research and development is underway on enzymic hydrolysis of lignocellulosic biomass, and reflects the potential that is seen to be offered by the conversion of biomass to ethanol. In February 2004, Stucley et al reported the following “considerable existing and planned activity to develop biomass to ethanol technologies:

- At least seven pilot scale facilities already built and operated in North America and Europe;
- Probably well in excess of A$200 million spent overseas to date on facilities and research;
- Several demonstration-scale and full-scale facilities at advanced stages of project development;
- More than US$30 million allocated in the USA alone for development of cellulase enzymes over the next few years;
- Other research programs in place to investigate improvement to processes and micro-organisms.”[78]

Enzymic hydrolysis of lignocellulosic biomass is expected to be commercial in 5 to 10 years. The use of cellulosic feedstock could provide a relatively energy efficient production process through the use of left over parts of the plant (mainly lignin) as a fuel source for the fermentation and distillation systems.

Ethanol in New Zealand

New Zealand, namely Fonterra’s Anchor Ethanol Ltd, produces 17 – 21 million litres/year of ethanol from the lactose component of milk whey. It is produced in a wide range of industrial and potable grades for a variety of uses.

[78] Stucley et al, Biomass Enegy Production in Australia: Status, Costs and Opportunities for Major Technologies, February 2004

Commercialisation of ethanol production in New Zealand is dependant on the availability (cost) of feedstock, the conversion technology and the cost of conversion.

Potential feedstocks in New Zealand are considered to be:

- Putrescible organic waste[79], consisting of:
  - Landfilled paper waste
  - Cereal straw
  - Surplus dairy whey
  - Potato waste and cull potatoes
  - Reject kiwi fruit
- The large volume of forest residues distributed throughout the country
- Plantation starch crops grown commercially for ethanol production
- Plantation forests grown commercially for ethanol production

Putrescible Waste

The Waste Solutions report for EECA estimates the technical potential for fuel ethanol production from putrescible waste is in the order of 275 million litres of ethanol (5 PJ/annum). Economics are aided by the fact that some waste products have zero or negative costs, for example via landfill gate fees, or where large volumes of whey are disposed of by spray irrigation onto farmland, at a cost to the dairy companies involved[80]. The high starch food processing waste (and whey) can be converted to ethanol by existing starch/sugar processes, but have very high water contents that increases costs substantially. The dry ligncellulosic wastes (straw plus waste paper) could be gathered together in larger supra-regional biorefineries to produce lignocellulosic ethanol. The Waste Solutions report concludes that fuel ethanol from putrescible waste could become commercially competitive but improvements in fermentation technology and enzyme biotechnology are required for the lignocellulosic wastes.

Forest Residues

The total organic waste stream in New Zealand shown in Table 2.1 below shows that forest residues left in the forest and at skid sites, together with wood processing residues not presently in use, amount to 2.9 million tonnes.

Table 12.2 - Production and Utilisation of Organic Waste per Year, million tonnes (wet)[81]

Organic waste resource M ton per year	Total production	Landfilled today	In use for non-energy purposes	In use for bioenergy	Cleanfilled
Forest residues left in forest	0.8	0.0	0.0	0.0	0.8
Forest residues left at skidsites	1.5	0.0	0.0	0.0	1.5
Wood processing residues	4.0	0.2	1.8	1.6	0.4
Black liquor (Pulp and Paper)	3.0	0.0	0.0	3.0	0.0
Putrescibles	2.0	1.6	0.2	0.2	0.0
Paper and cardboard	0.6	0.3	0.3	0.0	0.0
Demolition waste	0.2	0.2	0.0	0.0	0.0
Biosolids	1.2	0.8	0.2	0.2	0.0
Firewood	0.4	0.0	0.0	0.4	0.0
Total	13.7	3.1	2.5	5.4	2.7

[79] Waste Solutions Ltd, "Estimate of the energy potential for fuel ethanol from putrescible waste in New Zealand", EECA, June 2005
[80] EECA pers com
[81] Nielsen, P S, The Role of Bioenergy to Meet the Renewable Energy Target for New Zealand, 2004

The Nielsen report estimates that 2.5 million tonnes or 29.4 PJ (based on the CV of the biomass at source) of this material could be physically recoverable for bioenergy production. Assuming wet wood moisture content of 50% and an ethanol yield of 340 litres/dry tonne of feedstock[82], this amount of biomass could yield approximately 425 million litres of ethanol.

However, this material is widely dispersed throughout the country and harvesting, handling and transport costs are significant. This is an issue for all biomass to energy prospects targeting forest residues, and has prevented commercial exploitation to date. The lignocellulosic conversion technology has the potential to become commercial, but the cost of retrieving the forest residues will limit this route to ethanol production.

Plantation Starch Crops

If significant volumes of ethanol were to be produced from starchy grains, extensive areas of existing agricultural land would need to be planted with such crops. In the US, corn yields 3,310 litres of ethanol per hectare[83]. However these processes require a large input of fossil energy (natural gas and/or coal) as part of the starch conversion process (partly because the crop residue is left in the fields and not used to contribute to process energy). Grains tend to be grown on prime flat land which is limited in New Zealand. For these reasons, grain to ethanol production does not appear to be preferred in the New Zealand context.

Crop residues will be an important feedstock for cellulosic conversion to ethanol overseas, and it appears that they will be the first resource used for large scale cellulosic biomass to ethanol production. This resource in the New Zealand context is included in the putrescible waste estimate above (as straw).

Plantation Forests

There may be greater potential for forestry specifically for ethanol production as this does not need to be on prime agricultural land. As mentioned above, the production of ethanol from lignocellulose is still developmental, but is expected to be economically competitive with production from starch/sugar within the next 10 years for large bio-refinery complexes.

Biodiesel Technology

Biodiesel production worldwide in 2005 was estimated at approximately 3 billion litres[84], an order of magnitude lower than ethanol production but still a significant volume. Australia produced 52 million litres in 2005 and is forecast to produce an estimated 682 million litres in 2007 if all planned and under construction capacity is realised[85].

The transesterification technology is already commercial, with a number of companies offering designs. Many plants are installed and operating overseas, particularly USA, UK & Europe and biodiesel is used extensively in Europe and the USA without the need for vehicle modification.

Malaysia and Indonesia are prominent in the production of palm oil, which is a huge potential feedstock for biodiesel production. Indonesia is the second largest producer of palm oil in the world, after Malaysia, and home to about 300 palm oil mills. The mills produce more than four billion tonnes of palm oil.

[82] Stucley et al, Biomass Enegy Production in Australia: Status, Costs and Opportunities for Major Technologies, February 2004
[83] Brown, L, How Food and Fuel Compete for Land, February 2006
[84] Brown L, How Food and Fuel Compete for Land, February 2006
[85] Garrad P, State of the Industry, Biodisel Forum 2005

The transesterification of tallow and vegetable oils is already commercial technology and could increase substantially if the cost of fossil fuels continues to increase, particularly from very high yielding plantation crops such as palm oil in tropical countries.

Fast pyrolysis produces a pyrolysis gas, char, and a liquid product, pyrolysis oil (a bio-oil) that can be readily stored and transported. Pyrolysis oil can be used as a liquid fuel directly in stationary applications (boiler or turbines) or refined for production of chemicals. Production of liquid transport fuels is being actively pursued.

Fast pyrolysis units are available on a commercial basis, for example from Dynamotive Energy Systems Corporation, Ontario, Canada. A 100 t/d pyrolysis unit has been constructed and the bio-oil is burnt in a 2.5 MW gas turbine.

The upgrading of pyrolysis oil to liquid fuels is not yet demonstrated to be either energetically or economically viable. The more likely application of this technology is either direct use of the bio-oil in gas turbines, or as a compression technology to transport biomass from source to a central refinery, where it could be a feedstock for gasification and fuel synthesis.

Hydrothermal upgrading technology has been recently demonstrated on a pilot scale. Biofuel B.V. of The Netherlands aims to build a demonstration plant in Amsterdam in 2009[86]. The hydrodeoxygenation technology has some similarities to Fischer Tropsch synthesis but is not yet demonstrated and prospects are uncertain. Commercialisation of the HTU to bio-crude step is 5 to 15 years away.

Biodiesel in New Zealand

Production has not yet commenced in New Zealand as a commercial venture, although there is continuing interest and small amount of production for mostly research purposes. Research continues at a number of establishments, including universities, and there is continuing interest in possibilities for setting up existing commercial ventures in New Zealand locations.

<u>Waste Fats, Tallow and Vegetable Oil</u>

In New Zealand potential feed stocks for the oil/fat component of biodiesel are waste fats and tallow from meat processing and spent cooking oils/greases. In 2005 New Zealand standard NZS 7500:2005 was issued, specifying requirements and test methods for biodiesel to be used either as automotive fuel for diesel engines at 100% concentration, or as a blend component for automotive fuel for compression ignition engines.

Judd[87] reported (2002) that tallow production in New Zealand is about 150,000 t/y of which 30,000 t/y are used domestically for food, soap, and margarine. The balance of 120,000 t/y is exported but could be used for biodiesel production. Quantities of waste cooling oil were estimated in 2002 to be in the range 3,000 to 5,000 tonnes per annum. North Island Recyclers (Napier) and Solvent Services (Auckland) collect waste cooking oil for export, mainly to Asia and Pacific Islands for soap manufacture, but could also be used as a feedstock for biodiesel production.

The main barrier to commercialisation is the pre-existing commercial value of the exported feedstock. If a commercial domestic demand for the wastes develops, the price of the waste will need to increase to divert it from its current use.

<u>Plantation Vegetable Oil Crops</u>

Use of raw vegetable oils (the dominant feedstock overseas) to produce biodiesel would require extensive planting of suitable crops. The highest yielding crop (palm oil) by a

[86] Kampan, den Boer, Croezen, “Biofuels under development”, May 2005
[87] Judd B, Biodiesel from Tallow, prepared for EECA, November 2002

substantial margin is a tropical species. Europe produces mostly rapeseed for oil. Suitable oil yielding biomass crops for the New Zealand soils and climate would need to be determined.

Biomass Thermochemical Conversion

Biodiesel production from fast pyrolysis or hydrothermal upgrading of biomass uses the same potential feedstocks as lignocellulosic conversion to ethanol discussed above. The highly oxygenated bio-oil contains about 20% water and thus has low energy content, and is subject to degradation if stored. It is not suitable as a transport fuel in this state. Its use at present is limited to burning in boilers or modified gas turbines.

Methanol / Synthetic Diesel Technology

Extensive research has been carried out into the production of methanol or synthetic diesel from biomass, but processes (including biomass gasification) have not developed beyond the pilot and demonstration plant stages. It has also been reported that the gasification process is not yet economical, especially for smaller scale systems as would be appropriate for the New Zealand situation[88]. Demonstration plants overseas include:

- At Schwarze Pumpe in the former East Germany there is installed gasification capacity (entrained flow) for producing methanol from waste streams;
- In Freiburg, Germany the company Choren has a demonstration plant producing Fischer-Tropsch (FT) diesel via biomass gasification.

The processes for methanol or synthetic diesel production from biomass are developing, but technological challenges remain and are likely to be more complex than for biomass gasification for power generation, in particular because the synthesis gas cleaning requirements are more onerous in order to protect downstream catalytic processes.

A 100 t/d demonstration plant for direct synthesis of dimethyl-ether (DME) from natural gas has been constructed in Kushiro, Japan by JFE Holdings Inc. The combined operation of biomass gasification and direct synthesis of DME has not yet been undertaken.

Methanol /Synthetic Diesel in New Zealand

The interest in using methanol directly (neat) or blended for transport fuel in internal combustion engines has in recent years waned in favour of ethanol. The New Zealand position according to the EECA website is that methanol is “volatile and corrosive; produces heavier than air vapour; and is poisonous to humans and animals if ingested. Methanol is not considered to be suitable for use as a general transport fuel in New Zealand.”[89]

Methanol is also used for manufacturing biodiesel. Ethanol can also be used, but fossil methanol has been used to date because of its lower cost. If it is desired to avoid the use of fossil methanol then it is likely biodiesel would be manufactured with bio-ethanol rather than methanol.

Of more relevance to New Zealand is biomass based Fisher Tropsch liquids or DME. Commercialisation of these technologies is a prospect for the longer term, and New Zealand application would follow successful operation overseas. it is not expected that these processes will have an impact on New Zealand’s energy supplies in the report timeframe.

[88] Adams J F & Sims R E H, “Methanol production from biomass via gasification at both large and small scale”, Centre for Energy Research, Massey University, November 2001
[89] EECA web site FAQ - http://www.eeca.govt.nz/renewable-energy/biofuels/faqs.html#b21

12.5 EXPECTED QUANTITIES, PRODUCTION SCALE AND PERFORMANCE

Ethanol

The ethanol market largely comprises the automotive petrol market. Total deliveries of petrol to and within New Zealand for the year ended March 2005 were 2,422,000 tonnes (about 3.2 billion litres). However, 100% ethanol can damage engine components, particularly seals and rubber fuel lines. Ethanol is more corrosive and less lubricating than fossil fuels and increased engine wear can result. As a result, blends of ethanol in petrol have become the standard worldwide.

A national vehicle fleet comprises a range of vehicle ages and it is the older vehicles which are less suited to the use of ethanol. The average age of the New Zealand fleet was 12.0 years in 2003[90] and conversion of older vehicles to provide ethanol capability can be problematic. The view of the New Zealand Motor Industry Association (MIA) is that, "99.5% of all new petrol cars available today are suitable to use a 5% ethanol blend and that from January next year [2006] 80% of all new petrol cars could run on a 10% ethanol blend."[91]

A 5% mix of ethanol in petrol blend (an E5 blend) gives rise to a potential market for ethanol of up to 120,000 tonnes per year (160 million litres) at current petrol usage rates. The Waste Solutions report for EECA estimates the technical potential for fuel ethanol production from putrescible waste is in the order of 275 million litres of ethanol, and therefore would more than meet this demand. However 240 million litres of this production is from lignocellulosic waste processing plants, which may be commercial in 5 to 10 years.

EECA believes that over 95% of New Zealand new vehicles can run on E10 (10% ethanol)) blends[92]. On that basis in 10 – 15 years virtually all vehicles should be suitable for E10 blends. On this timing the developing technology for the production of ethanol from lignocellulose may be more developed and commercial with feedstocks other than putrescible waste.

For larger scale contribution of ethanol to New Zealand's liquid fuels market in the future, specialty energy crops will be required to be grown on a large scale. In New Zealand's context this is likely to require cropping on land other than flat plains, probably limiting feedstocks to wood based crops. Running vehicles on higher percentages of ethanol is possible, but will require some vehicle modifications.

Bio-diesel

Total usage of diesel in the year ended March 2005 was 2,291,000 tonnes. However, as for ethanol, using 100% biodiesel in vehicles can cause cold start problems and damage hoses and gaskets and certain metals and plastics (in older vehicles). Biodiesel is therefore generally blended with fossil diesel. To run on blends containing over about 20% biodiesel requires purpose built vehicles, or modifications to existing vehicles. However, a 5% blend can be used in any diesel engine without modification. A 20% blend (B20) is the most common in the USA. A 5% blend (B5) is used in France.

Based on use of B5 (5% biodiesel, 95% diesel), the potential market for biodiesel is approximately 110,000 tonnes per year.

Judd estimated that that some 116,000 t/y of biodiesel could be produced from the available tallow and waste cooking oil, sufficient to give an approximately 6% blend if blended with the total fossil diesel consumption.

[90] Covec, Vehicle Fleet Emission Screening Programme: Social and Economic Impact Assessment: Phase 1, February 2005
[91] MIA News Archive: http://www.mia.org.nz/news.asp?newsitem=56, 30 November 2005
[92] EECA, pers com

Judd also states that glycerol (saleable by-product from biodiesel manufacture) improves the overall biodiesel production economics but prices are volatile.

Any increase in the level of biodiesel mix or non-availability of tallow would require production of indigenous vegetable oil crops, and depend on the economics. By way of example, converting land to rapeseed production could have a rapeseed oil production rate of 800 kg/hectare and a conversion rate of 0.9 t of biodiesel/tonne of vegetable oil[93]).

Ministry of Agriculture and Forestry (MAF) statistics for Land Use by Farm Type indicate that some 425,000 hectares of New Zealand farm land was classified "Arable crop land, fodder crop land and fallow land" in 2002. A further 109,000 heactares was classified as "land in horticulture".[94]. If 50% of this arable land was converted to rapeseed production, 190,000 tonne of rapeseed based biodiesel could be produced.

This quantity of indigenous vegetable oil based biodiesel would substitute another 10% of current diesel consumption. However, the conversion of 50% of existing arable crop land use to vegetable oil production represents a substantial shift in land use and prices for the vegetable oil would have to be high for this to happen.

Synthetic Diesel

The production of Fischer-Tropsch liquids (synthetic diesel) via synthesis from the gasification products of biomass is considered by one European commentator[95] to offer a strong prospect of competitive fuel prices in the longer term, namely around 2020, which is toward the end of the review period for this study.

However Faaij[95] suggests that deployment on a large scale is inherent in the economic production of Fisher Tropsch liquids, of the order of a plant producing 360 million litres of diesel per year which would require 300 t/h of 12 GJ/t biomass (e.g. forest and wood processing residues), or 2.2 million tonnes annually at an 85% capacity factor. This is close to the total amount of the estimated physically recoverable forest residues left in the forest and at skid sites, together with wood processing residues not presently in use. Transport costs would preclude this quantity being brought to a single large scale processing plant.

Therefore this technology will probably require large plantation crop based biomass production and is only likely to be economic towards the end of the report timeframe.

[93] Judd B, Feasibility of Producing Diesel Fuels from Biomass in New Zealand, June 2003
[94] Land Use by Farm Type, MAF, as at June 2002
[95] Faaij A, Modern Biomass Conversion Technologies, July 2005

Summary

Table 12.3 – Indicative Yields and Conversion Efficiencies of Various Bio-fuels

Crop/ Feedstock	**Feedstock Yield** [kg/ha]	**Moisture Content** [%]	**Ethanol/ Bio-diesel Yield** [$kg/kg_{feedstock}$]	**Fossil Energy Ratio**	**Product Yield** [l/ha]	**Product Yield** [MJ/ha]
Wheat	8000	15%	0.276	1.1	2,380	50,326
Corn	8000	15%	0.312	1.4	2,686	56,796
Sugar Beet	45000		0.079	1.5	4,500	95,153
Sugar Cane	65000		0.067	9	5,525	116,827
Woody Biomass	15,260	55%	0.283		2,465	52,128
Switchgrass	8,235	15%	0.237	5.3	2,100	44,403
Rapeseed Oil	900		1.000	2	978	37,080
Palm Oil	5,000		1.000		5,435	206,000

Notes: 1. Fossil Energy Ratio is the ratio of biofuel energy content to the fossil fuel energy used to grow crops, transport them, and convert them into the biofuel.

2. The high fossil energy ratio of sugar cane is due to the combustion of the cane stalk residue (bagasse) to generate process energy requirements.

12.6 COSTS

With such a varied range of potential biofuels of various states of commercialisation, it is not possible to present detailed capital, operating and production costs of these technologies. Instead the costs of the product fuel of near commercial processes are presented where they are applicable to the New Zealand context.

The production costs of biofuels are heavily influenced by the cost of the relevant raw materials. These costs represent the cost of transporting waste to the plant gate, or for other raw materials, the price which those raw materials attract in the national and international markets.

Costs of biofuels are heavily influenced by local factors such as feedstock prices, conversion process, scale of production, local climate, soil conditions, as well as downstream distribution and retailing costs. Therefore costs presented here, largely based on overseas costs or preliminary surveys in New Zealand should be taken as guidelines only. Assessment of real costs, both current and future, would require substantial feasibility and costing studies for a particular chosen technology.

Ethanol

<u>Putrescible Waste</u>

New Zealand studies estimated at-gate ethanol production costs[96] using lignocellulosic conversion processes as follows, from the raw materials noted:

- Whey 0.6 to 0.7 $/litre ($25 – 30/GJ)
- Paper/straw 0.65 to 0.92 $/litre ($27 – 39/GJ)

[96] Waste Solutions Ltd, "Estimate of the Energy Potential for Fuel Ethanol from Putrescible Waste in New Zealand", EECA, June 2005

- Fruit 0.7 to 1.25 \$/litre (\$30 – 53/GJ)

These costs include natural gas consumption of 9.5 MJ/litre and electricity consumption of 0.24 kWh/litre (1 kWh = 3.6 MJ).

Plantation Forests

Stucley et al[78] estimated the production cost of ethanol from woody biomass for an Australian plant at:

- Woody biomass A\$0.59/litre = 0.70 \$/litre (\$30/GJ), assuming a feedstock cost of \$41/green tonne.

Vessia[97] estimated the production cost of ethanol from local forest in Norway at:

- Woody biomass €7 – 23/GJ (\$14 – 46/GJ)

The estimates from Europe are of the same order of magnitude as those from Australia, and all are of the same order of magnitude as those from New Zealand.

The International Energy Agency (IEA) presented estimated[98] ethanol costs from poplar trees in the near term of 0.58 to 0.7 \$/litre and post 2010 as 0.38 \$/litre.

These costs can be compared to the cost for sugar cane based ethanol of 0.25 \$/litre (Brazil) and grain based ethanol of 0.48 \$/litre (USA).

Biodiesel

The Meat Industry Association stated in 2005 that there was acceptance by energy producers and government that tallow has an international price, noting that previously tallow was considered a waste product and had been factored into studies at a minimal cost. This is emphasised by historic prices for tallow which in 2001/02 were \$300/t, and rose to almost \$570/t in late 2002. This price has a direct impact on the economics for its use as a feedstock for biodiesel. Tallow has a current export price of about NZ\$ 400 per tonne.

Fossil-derived methanol prices for production of biodiesel historically have been volatile, the current (October 2005) Methanex price of methanol (Asia Pacific) is US\$ 280/t (NZ\$ 405/t).

An assessment by Duncan for EECA[99], concluded capital recovery and processing costs of NZ 0.10 \$/litre, to which must be added the tallow and fossil methanol costs, and the glycol revenue subtracted. As all these component prices have been volatile historically, it is suggested around up 0.5 to 0.8 \$/litre net biodiesel cost is appropriate.

Synthetic Diesel

The high capital costs of plant for Fisher Tropsch (F-T) liquids or DME from biogas, and the large scale required mean that this technology needs further evaluation in the New Zealand context to determine if it could be economic towards the end of the report timeframe.

The International Energy Agency (IEA) presented estimated synthetic diesel costs[98] from eucalyptus trees assuming large (European) scale and technology improvements, and including distribution costs, of 0.78 \$/litre for DME and 1.13 \$/litre for F-T diesel.

[97] Vessia O, Biofuels from Lignocellulosic Material – In the Norwegian Context 2010 – Technology, Potential and Costs, Norwegian University of Science and Technology, 20 December 2005
[98] Biofuels for Transport, International Energy Agency, 2004
[99] Duncan J, Costs of Biodiesel Production, Prepared for EECA, May 2003

12.7 KEY ISSUES RELATED TO ITS USE IN NEW ZEALAND

The volume of waste feedstocks in New Zealand that are accessible is limited, but could make a small contribution to New Zealand's liquid fuels requirements. These are tallow and waste vegetable oils for biodiesel, and putrescible wastes (including cereal straw) for ethanol production.

Biodiesel production would require the tallow to be diverted from its current markets, and the cost of procuring the tallow would be the major component of biodiesel cost.

Forest residues could have potentially a large contribution to biofuels but detailed evaluation of recovery costs would be required, and it is expected only a small portion of the material would be economic to recover.

For larger scale production of biofuels, specialty plantation energy crops would be required. Globally, the highest yielding crops for biofuel production are sugar cane and palm oil, for ethanol and biodiesel respectively. Unfortunately these are warm climate crops that are not suited to New Zealand conditions.

Cereal grains and other oil crops such as rapeseed are not considered beneficial for large scale biofuel production in New Zealand, owing to the very large areas of arable land that would be required to make a significant contribution to our liquid fuels needs. The acceptability of converting food producing arable land to fuel production may be an issue with these options as well.

Biofuels are liquid fuels and as such are relatively easily and cheaply transportable, around a few cents a litre for international shipping. As a result it is expected a global biofuel market will develop, and costs of producing crop-based biofuels in New Zealand should be considered relative to the cost of importing biofuels. The two key benefits of biofuels - fossil liquid fuel savings and greenhouse gas emissions reduction, are global in nature and it is not necessary or wise for New Zealand to produce these unless economically justified.

The technology of enzymic hydrolysis of lignocellulosic biomass appears to have the most potential for larger scale biofuels production in the medium term in New Zealand. Our climate suits the feedstock production and wood crops can potentially be economically harvested from hilly country not suitable for crop production. However the technology needs to be developed further to realise cost reductions, particularly enzyme costs and fermentation technology capital costs.

The most important advances for biofuels are expected to come from genetically engineering speciality energy crops. According to the IEA[98], these methods are expected to produce in the future major increases in yield, reduction in fertiliser requirements, improvements in pest resistance, and major modifications to product characteristics such as lower lignin content and greater uptake of carbon.

Although these advanced genetically engineered fuel crops will not be consumed by humans, they will be controlled by New Zealand's Hazardous Substances and New Organisms (HSNO) Act and may require long periods of testing and certification before release into New Zealand's environment.

Biomass based power generation, either through gasification, fast pyrolysis or liquefaction (HTU), may also be a more attractive use of biomass than biofuel production in the medium term[100].

Finally, a key issue for biofuel production in New Zealand will be incentives in the short term and price assurance in the longer term. Capital investment in biofuel production is exposed to the risk of large changes in the price of fossil liquid fuels in the future. A necessary precursor to establishing sustainable biofuels production in New Zealand will

[100] Kampman et al, Biofuels Under Development, CE, Delft, May 2005

probably be reducing the risks of periodic low oil prices to biofuel producers. This may require mechanisms such as excise tax policy on fossil liquid fuels that ensures a price floor that won't drive biofuel producers out of business.