NEW ZEALAND ENERGY OUTLOOK TO 2020

February 2000

A report prepared by the

Ministry of Commerce

Energy Modelling and Statistics Unit, Resources and Networks Branch,

Ministry of Commerce, PO Box 1473, Wellington, New Zealand

ISBN 0-478-23432-5

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EXECUTIVE SUMMARY

New Zealand's energy sector has experienced a period of significant change and reform over the past decade and is projected to continue to alter significantly over the period to 2020. The composition of energy demand and supply is projected to change as, amongst other factors, the demand for energy grows, the Maui gas field declines, and new technologies for the production, delivery and use of energy become economic.

The scenarios presented in this Outlook are the results of modelling the complex interactions of the New Zealand energy market using the Ministry of Commerce's SADEM energy model. This formal, structured, approach allows a detailed understanding to be gained of how the New Zealand energy sector operates, its dynamics, and how it may change over time. The SADEM model is a partial equilibrium model (confined to the energy sector) which identifies a market clearing price consistent with supply and demand being in balance. The scenarios are not attempts to project what will actually happen in the energy sector; rather, they provide an indication of the range of possible outcomes under a number of different assumptions.

The key assumptions of the baseline scenario[1], which covers the period 1998 to 2020 (March years), are:

- 3% per annum (pa) GDP growth from 2003 (short-term forecasts are used prior to 2003);
- current policy settings;
- oil prices fall from around US$21 per barrel in 2000 to around US$19 per barrel (bbl) in 2002 before rising to US$22/bbl by 2015 and remaining constant thereafter[2];
- coal prices rise from around $2.66/GJ in 1998 to $3/GJ in 2010 and are constant thereafter;
- new gas discoveries averaging around 80 PJ pa;
- given this gas discovery rate, wholesale gas prices rising to around $3.5/GJ by 2010 and to $3.9/GJ by 2020;
- gas use by the petrochemicals plants does not continue after existing take-or-pay Maui gas contracts expire: ie, 2003 for the Motunui tranche, and 2005 for the Waitara Valley and ammonia/urea tranches. However, Methanex's recent gas contract with Contact could extend their operations out to 2006/7;
- a US$/NZ$ exchange rate of US$0.54 to NZ$1.

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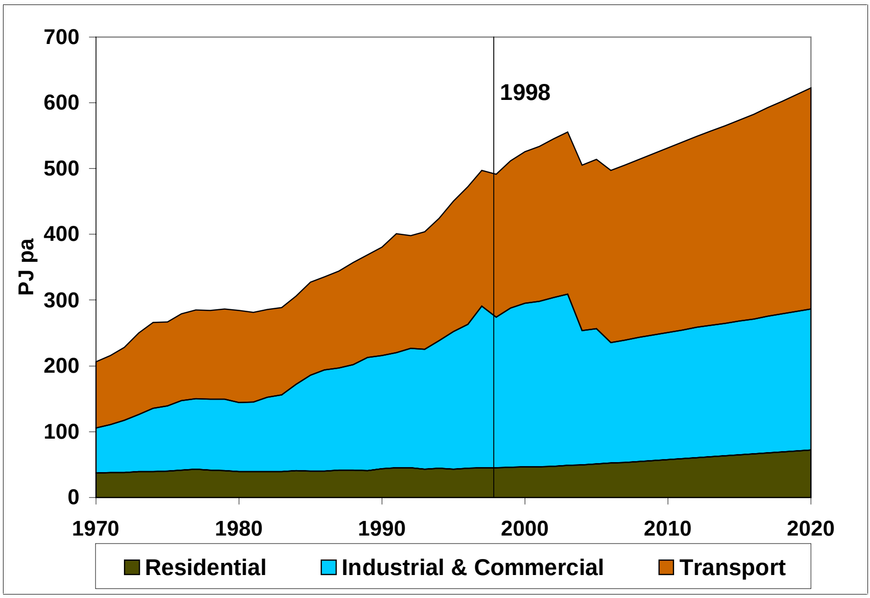
[1] *The baseline scenario assumptions are presented in detail on page 9.*

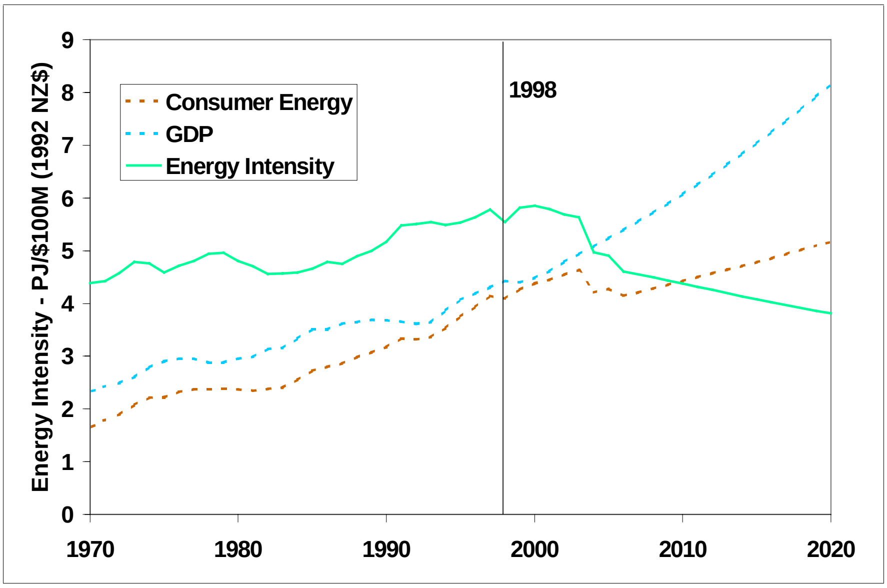
[2] *The oil price assumptions and their sources are discussed in more detail on page 32. Two alternative oil price assumptions are described briefly and examined on pages 10 and 45.*

Consumer Energy by Sector 1970-2020



The baseline scenario projects that consumer energy demand will grow by 1.1% pa between 1998 and 2020 for 3% pa GDP growth. Residential sector consumer energy is projected to grow, on average, at around 2.1% pa between 1998 and 2020, the industrial and commercial sector to decline by 0.3% pa, and the transport sector to grow by around 2.0% pa. Over the same period electricity consumption is projected to grow by around 1.8% pa, the consumer energy of coal by 0.7% pa, oil by 1.9% pa, and gas to decline by an average of around 2.6% pa. The decline in gas consumption is the result of the draw-down of the Maui field over the next decade, and the consequent closure of the petrochemicals plants.

Energy Intensity 1970-2020 *(Scaled)*



New Zealand's energy intensity increased from 4.4 PJ/$100M in 1970 to 5.5 PJ/$100M in 1998. It is projected to decline to 3.8 PJ/$100M in 2020. This is associated with the projected decline in the ratio of energy growth to GDP growth from its average of the past 25 years, 1.3:1, to around an average of 0.37:1 for the outlook period. In part, this decline is the result of the closure of the petrochemicals plants. Excluding the petrochemicals sector, consumer energy demand grows by an average of 1.8% pa between 1998 and 2020, still significantly less than GDP growth.

In the baseline scenario, around 2200 MW of new electricity generating capacity[3] is projected to become economic between 2000 and 2020, as demand for electricity exceeds the economic capacity

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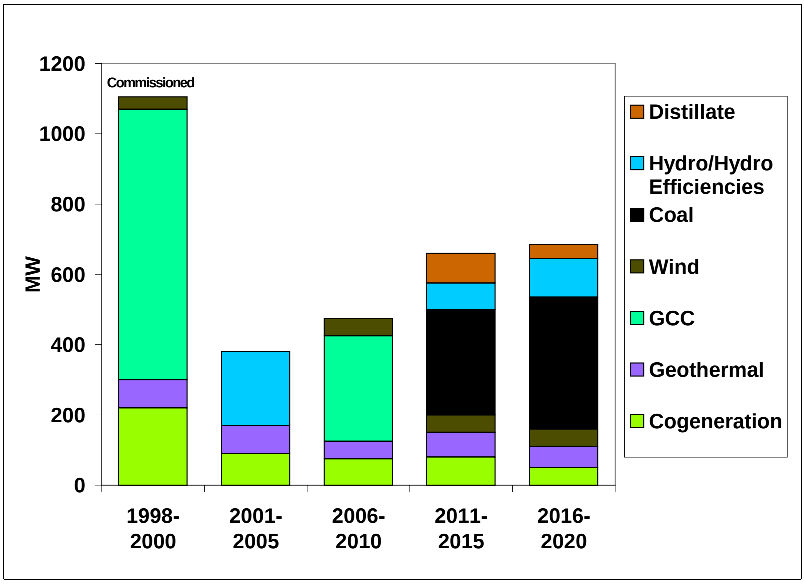
[3] *The system capacity as at 31 March 1999 was 8530 MW.*

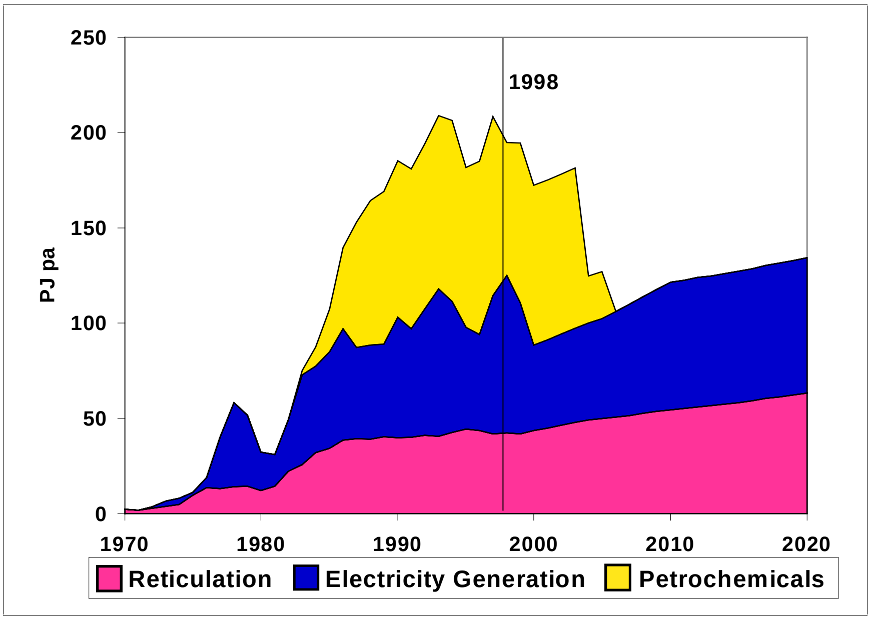
of the current system. This compares with approximately 1100 MW that will have been commissioned in the three years to 2000. The 2200 MW therefore excludes capacity which has been built, but is in the process of being fully commissioned, such as Otahuhu B. The 2200 MW is comprised of 300 MW of gas combined cycle (GCC), 675 MW of new coal, 260 MW of geothermal, 395 MW of hydro and hydro efficiencies, 295 MW of cogeneration, 150 MW of wind, and 125 MW of distillate peaking plant. This economic new capacity is driven not only by electricity demand growth, but also by the assumed mothballing of New Plymouth after 2005.

Projected Economic New Power Station Sequence 1998-2020



The composition of electricity generation is projected to change significantly as a result of this new capacity. When it is economic for Huntly to generate, it is generally coal-fired, as the projected price of coal is below that of gas. Hydro's share of electricity generation is expected to decline from around 65% now (depending on inflows) to around 52% in 2020, gas's share from around 20% to around 15%. Coal's share grows, from around 5% in 1998 to around 14% in 2020. The uncertainty surrounding these particular projections is discussed with reference to issues such as technological change and prices in the main body of the Outlook, while the possible increased potential contribution of traditional and non-traditional renewables is examined in a separate scenario.

Primary Energy Supply of Gas by Use 1995-2020

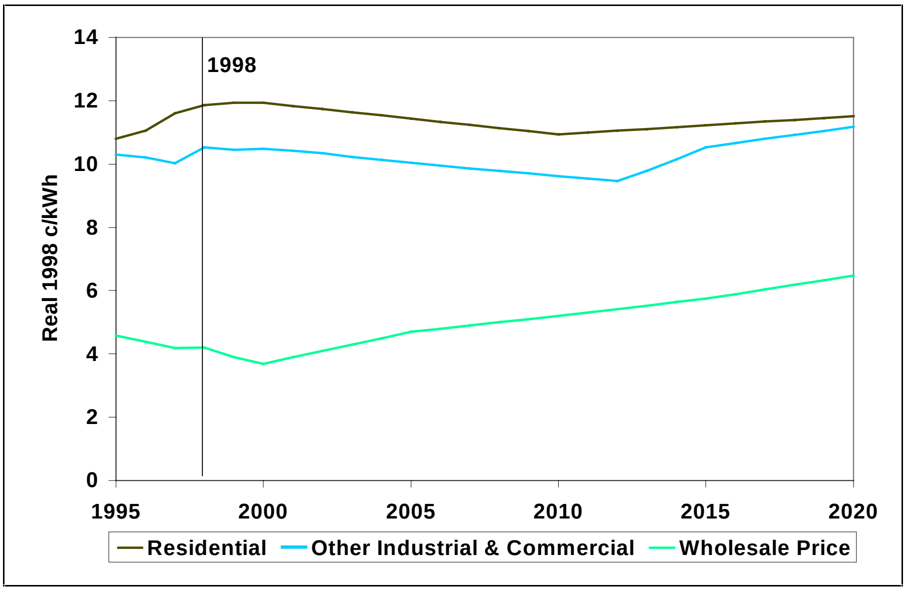


New Zealand's primary energy supply is projected to grow at 1.3% pa between 1998 and 2020, from around 652 PJ pa to 872 PJ pa. The primary energy supply of geothermal energy is projected to more than double, and that of coal to double. Oil grows strongly at around 1.9% pa, while the primary energy supply of hydro experiences more modest growth. Gas alone experiences a decline in its primary energy supply as Maui draws down and the petrochemicals plants close between 2003 and 2005. Gas consumption for electricity generation declines to 2000 as Huntly switches to coal. However, it then experiences growth to around 2015 as electricity demand grows, the existing GCC plant are run harder, and a new GCC plant is built in 2010. Reticulated gas demand grows steadily throughout the period.

Carbon dioxide emissions are projected to grow, as newly built thermal electricity capacity is used, and as consumer energy demand grows, in particular petroleum products for transport. There is a temporary reduction in emissions with the closure of the petrochemicals plants in 2003 and 2005. However, overall carbon dioxide emissions are projected to grow by around 1.6% pa between 2000 and 2020 (calendar years).

The increases in the wholesale prices of oil, coal, and gas do not transfer into significant changes in delivered energy prices to consumers, with the exception of petroleum products, due to constant, or declining unit costs of transmission, distribution, and retailing.

Projected Electricity Generation Costs and Delivered Prices 1995-2020



Wholesale electricity prices are projected to dip from their 1998[4] levels in both 1999 and 2000, before beginning to rise as more expensive generation options are required to satisfy demand growth. The wholesale price of electricity reaches around 6.5 c/kWh in 2020. Declines in unit transmission and distribution costs after 2000 ensure that, despite the rise in the wholesale price, delivered electricity prices decline until around 2010. After 2010 delivered electricity prices start to rise, however, the other industrial and commercial sectors price only rises slightly above current levels in 2020. The residential electricity price remains slightly below current levels by 2020.

The baseline scenario provides a reference point from which analysis of the uncertainties and sensitivities surrounding the key assumptions can be made. By analysing some of these factors in alternative scenarios a picture of the range of possible outcomes for the energy sector can be built up.

The main body of the Outlook includes scenarios on alternative economic growth rates, renewable energy, oil prices, new gas discoveries, forestry processing, energy efficiency and carbon dioxide pricing (see page 10 for a fuller description of these scenarios).

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[4] Wholesale electricity prices in this Outlook refer to a mix of contract and spot prices to 2005. After around 2005 the wholesale electricity prices presented in this Outlook are very close to the projected long run marginal cost of generation. The projected dip in the wholesale price of electricity between 1998 and 2000 is consistent with the recent low electricity spot prices. More details on wholesale electricity prices are given on pages 33 and 34.

The elasticities of the demand models are presented in a separate section. This section also includes a comparison of the projections in this Outlook with those of the February 1997 Outlook.

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GLOSSARY AND ABBREVIATIONS

bbl	Barrel of oil. 159 litres.
biogas	Energy produced from the anaerobic digestion of sewage and industrial waste.
calorific values	The *energy content* of a fuel can be measured as the heat released on complete combustion. The SI derived unit of energy and heat is the joule, here generally expressed in petajoules (PJ), being 10^{15} joules. The energy content can be expressed as an upper (or *gross*) value and a lower (or *net*) value. The difference between the two values is due to the release of energy from the condensation of water in the products of combustion. In general, the difference between gross and net calorific values is of the order of 6% to 8% for liquid fuels, and 10% for gaseous fuels. In coals, the greater chemical variability (in contrast with petroleum products) gives rise to a much wider range of gross/net differences, from 2% to 15% or more.
c/kWh	Cents per kilowatt hour.
CNG	Compressed natural gas. Natural gas which has been compressed, or contained under pressure, in a small volume. Mainly used as a transport fuel.
CO_2	Carbon dioxide. One unit of CO_2 is equal to 12/44 units of carbon.
cogeneration	The simultaneous or sequential production of two or more forms of useful energy from a single primary energy source.
condensate	A light crude oil which is present in natural gas deposits.
consumer energy	Amount of energy consumed by final users.
crude oil	A mineral oil consisting of a mixture of hydrocarbons of natural origins, yellow to black in colour, of variable density and viscosity.
effective energy	The amount of useful energy derived from using a fuel. It is the consumption of energy multiplied by the efficiency of use.
elasticity	The responsiveness of energy demand to other variables, primarily energy prices and national income.
energy efficiency	Efficiency with which energy is used.
energy intensity	Energy use (primary or consumer) per unit of GDP.
fossil fuels	Coal, natural gas, LPG and fuels derived from crude oil (including petrol and diesel). They are called fossil fuels because they have been formed over long periods of time from ancient organic matter.
GCC	Gas combined cycle.
GDP	Gross domestic product.
gigawatt hour (GWh)	Unit of electrical energy, equal to 1,000,000 kWh.

GJ	Gigajoules. 10^9 joules. A unit of energy.
greenhouse gases (GHG)	Gases that increase the temperature of the earth's surface. They include water vapour, tropospheric ozone, chlorofluorocarbons, carbon dioxide, carbon monoxide, methane and nitrous oxide.
gross	Refer to *calorific values*.
ha	Hectare.
IPCC	Intergovernmental Panel on Climate Change.
kilowatt (kW)	A unit of electrical power, equal to 1000 watts. One kilowatt is equivalent to the power required to use a one bar radiator, or ten 100-watt light bulbs.
kilowatt hour (kWh)	Unit of electrical energy, equal to 0.0036 GJ.
LNG	Liquefied natural gas.
LPG	Liquefied petroleum gas. It consists of propane (60%) and butane (about 40%).
LRMC	Long-run marginal cost.
megawatt (MW)	One million watts. One megawatt is enough power to supply the peak electricity needs of about 500 houses.
merit order	Term used for the ranking of power stations in terms of increasing order of fuel costs.
Mt	Million tonnes.
MtC	Million tonnes of carbon.
natural gas	Consists mainly of methane occurring naturally in underground deposits. It may be associated or free gas.
net	Refer to *calorific values*.
pa	Per annum.
Petralgas	Petralgas Chemicals New Zealand Ltd.
Petrochem	Petrochemical Corporation of New Zealand Ltd.
PJ	Petajoules. 10^{15} joules. A unit of energy. Approximately, 1 PJ = 278 GWh of electricity = 44,000 tonnes of sub-bituminous coal = 21,000 tonnes petrol = 26 Mm^3 Maui gas.
primary energy	Energy as it is first obtained from natural sources.
SRMC	Short-run marginal cost.

thermal generation	The generation of electricity by heat, usually from burning fossil fuels but also including geothermal generation.
transformation energy	Energy used or lost during the transformation, treatment or refining of one energy form into another.
transmission energy	Energy used or lost in the transmission or transportation of energy.

INTRODUCTION

In the 1980s and 1990s successive governments deregulated the economy and the energy sector, providing challenges and opportunities for existing and new energy sector participants. The last two years, in particular, saw quite dramatic changes in the structure of the electricity industry with the separation of lines and energy companies, and the split of ECNZ into three generators.

The composition of New Zealand's energy supply and demand balance is projected to alter significantly over the next 20 years, as demand growth is met, and as:

- the relative growth rates for fuels change;
- the Maui gas field depletes;
- the diversity of new electricity generation projects increases; and
- climate change issues impact on energy use.

The interdependence of these and many other factors is a complex issue which is best addressed in a formal, structured manner in order to identify and understand better the interrelationships and dynamics, both within the energy sector and between it and the rest of the economy. This is done by the Energy Modelling and Statistics Unit of the Ministry of Commerce, using its SADEM energy supply and demand model.

This Outlook provides a comprehensive set of new projections to replace the Ministry's recent Energy Outlooks, published in February 1997 and updated in March 1998[5]. This report firstly reviews the New Zealand energy scene in the 1998 March year, before going on to provide a brief explanation of the analytical approach and the main assumptions used in the analysis. The projected supply and demand for energy is then presented, by consumer energy by sector. The implications this has for fuel shares, primary energy supply and power system requirements, carbon dioxide (CO_2) emissions and energy prices are then discussed.

To augment the baseline analysis a number of alternative scenarios are presented and are briefly introduced in the section on the baseline scenario (see page 10). The elasticities of the demand models are also presented, and a comparison made of the results from this Outlook with the February 1997 Outlook.

The SADEM Model

The SADEM model is a descriptive market equilibrium model focusing on the entire energy sector. The model is a partial equilibrium model and does not link in any interactive way to the macro-economy. As such, some key factors, such as GDP growth rates, oil prices etc are exogenous and fixed within a model scenario.

The model determines an equilibrium in the energy market by projecting demands for a given set of prices and comparing this with the modelled cost of supplying this level of demand. If the prices implied by modelling the level of supply are not consistent with the prices used to determine the initial demand, then demand is re-estimated. This process is iterated until equilibrium is achieved with demand and supply in balance at market clearing prices. The model is deterministic in that, for

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[5] *Eng G. and Taylor M.,* New Zealand Energy Outlook*, Ministry of Commerce, February 1997, and Lear M.,* Energy Supply and Demand Forecasts for New Zealand – An Update*, Ministry of Commerce, March 1998, paper presented at the 1998 New Zealand Petroleum Conference, Queenstown.*

a given set of assumptions, it produces a single projection. It thus provides projections of the mean energy outcomes for a given set of assumptions and does not attempt to quantify the distribution of uncertainty around each outcome.

The demand models provide annual projections of energy demand and are generally dynamic models providing a short-run and long-run response to changes in prices, incomes, and other drivers. The supply side electricity simulation is run annually every five years beginning in the year 2000, and prices are interpolated between these dates. Electricity capacity is therefore increased once every five years to meet the level of demand in that year.

There are a number of uncertainties inherent in conducting scenarios such as the ones presented in this Outlook. The alternative scenarios presented in this Outlook are designed to examine the sensitivity of the model to some of these factors and to other input assumptions. However, a number of uncertainties relate to the structural nature of the model itself.

These uncertainties are that:

- the historical relationship between energy demand and its drivers derived from past data may not be applicable for use in the future. The underlying drivers of demand are unlikely to change significantly in the short term, however it is possible that the magnitude of the relationship might change materially.

- the SADEM model is a partial equilibrium model, and does not interactively link to the macro-economy, or the global economy (including the international markets for oil and coal). Therefore, the model does not capture any change in GDP, or oil and coal prices, from their assumed paths induced by the variation in the assumptions of a scenario[6].

- the SADEM model only projects energy demand. However, changes in the projections of energy demand are driven by underlying changes in the structure of the economy and its output mix. It is possible that by projecting energy demand using only an aggregate GDP figure the *implied changes* in the structure of the economy may not accurately reflect the *actual changes* in the economy, its output mix, and hence energy consumption and emissions.

When examining the results of the scenarios presented in this Outlook these points should be kept in mind.

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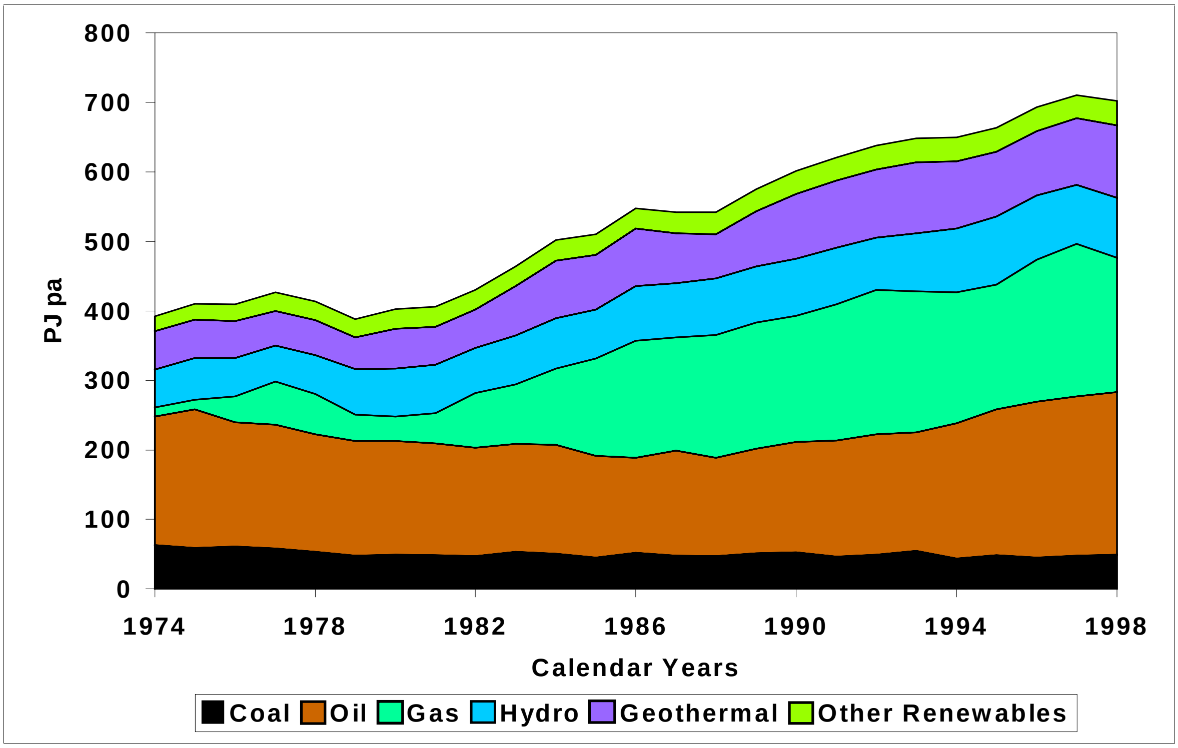
[6] *This could stem from the domestic, and/or international, impacts of the assumptions on the traded and non-traded portions of the economy.*

THE NEW ZEALAND ENERGY SECTOR IN 1998

Energy is sought for the work it does, rather than for any intrinsic value. As such, it plays a critical role in the economy as an essential input into virtually all industrial, commercial, transport and household activities. The production and distribution of energy constitutes around 2.7% of New Zealand's gross domestic product (GDP) and directly employs about 8000 people, or around 0.5% of the work force.

New Zealand's total primary energy supply for the period 1974 to 1998 is presented in Figure 1 and was around 689 PJ[7] pa in the year ending March 1998[8]. Oil provides around 224 PJ (33%), gas around 202 PJ (29%), coal 47 PJ (7%), hydro 84 PJ (12%), geothermal 98 PJ (14%), wood 30 PJ (4%), and other renewables slightly less than 4 PJ (1%). These fuel shares are presented in Figure 2.

Figure 1: **New Zealand's Annual Primary Energy Supply 1974-1998**



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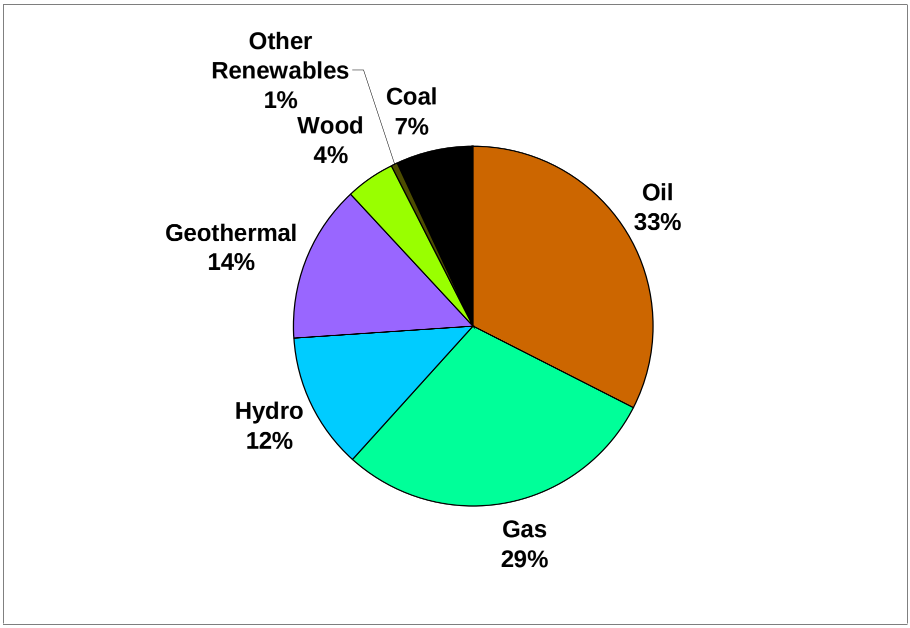
[7] *This section on the current New Zealand energy sector reports all petajoules (PJ) in gross terms. Throughout the rest of this report all PJ are in net terms. See the glossary for a description of these terms. All data presented in this publication are for the year ending in March, unless otherwise noted, and some totals may not add due to rounding. The data presented in this section are from the January 1999* Energy Data File *and include certain renewable data that are not included in the modelling database due to inadequate time series information.*

[8] *The modelling work was initiated prior to results being available for the year ending March 1999.*

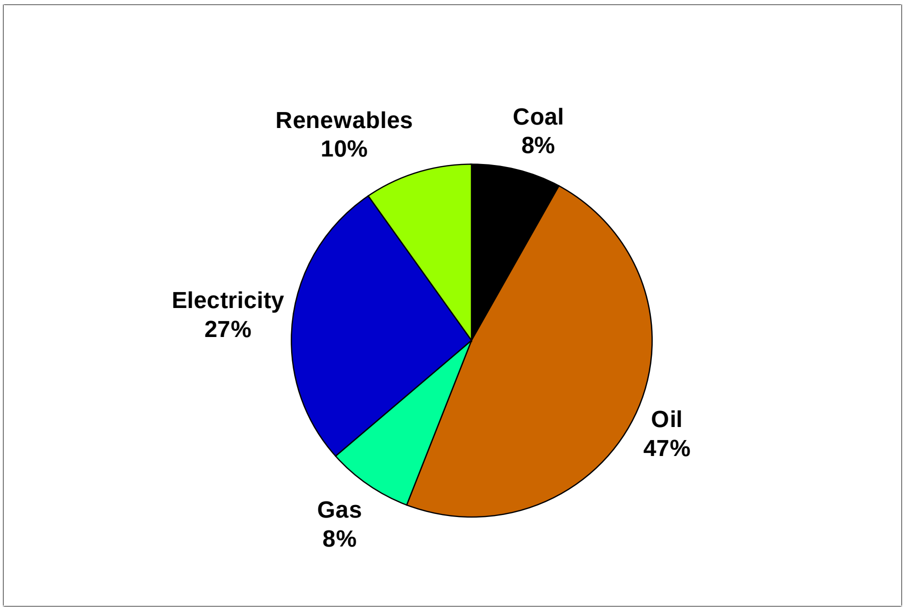
New Zealand is self-sufficient in all energy forms, apart from liquid fuels. In 1998 New Zealand was around 90% self-sufficient in its primary energy needs and 53% self-sufficient in liquid fuels.

Figure 2: **New Zealand's Primary Energy Supply by Fuel 1998**



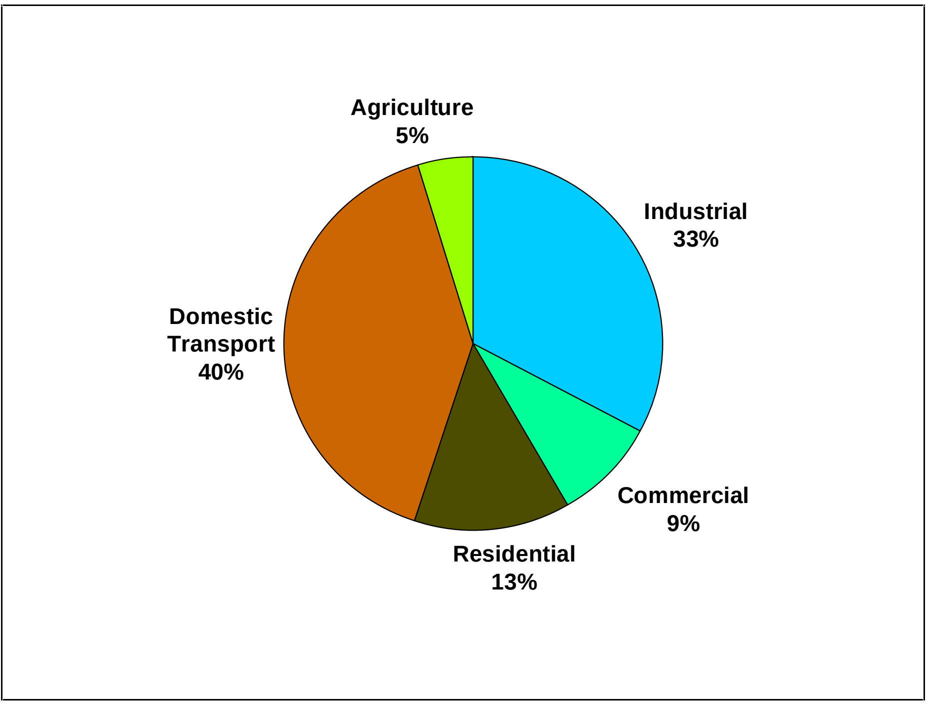
New Zealand's (observed) consumer energy is dominated by oil, comprising almost half (203 PJ pa) of total consumer energy consumption of around 424 PJ in 1998 (Figure 3). Electricity accounts for around 113 PJ (27%) of consumer energy, coal around 34 PJ (8%), gas around 33 PJ (8%), with renewables such as geothermal, wastes and wood making up the remainder.

Figure 3: **New Zealand's Consumer Energy by Fuel 1998**



[9] is the largest consumer at around 171 PJ pa (40% of the total) in 1998. Industrial consumption accounted for around 139 PJ pa (33%) of consumer energy demand in 1998, residential around 57 PJ pa (13%), commercial around 38 PJ pa (9%), and agriculture around 20 PJ pa (5%).

Figure 4: **New Zealand's Consumer Energy by Sector 1998**



Gas

New Zealand's gas reserves are dominated by the Maui field, which accounted for around 65% of New Zealand's estimated total estimated net gas reserves of around 2560 PJ as at 1 January 1998. The Kapuni field is estimated to contain 16% and the Kupe field around 11% of remaining reserves.

The Maui field also dominates gas production, producing 79% of New Zealand's net gas production[10] for the calendar year 1997. Kapuni produces around 11% of net production, with the remainder coming from the McKee, Waihapa/Ngaere, Tariki/Ahuroa, Kaimiro, Mangahewa, Ngatoro and Piakau fields. The Kupe field is yet to be developed.

Around 37% of New Zealand's gas in 1998 was used in electricity generation (Figure 5), and around 9% in cogeneration applications. The petrochemicals sector used around 34% (in Methanex's Motunui and Waitara plants, and the Petrochem ammonia/urea plant), and around 17% was reticulated by the Natural Gas Corporation Ltd through its high pressure pipeline system direct to major users, and to gas utilities. The remainder was made up of losses and own use by the gas sector.

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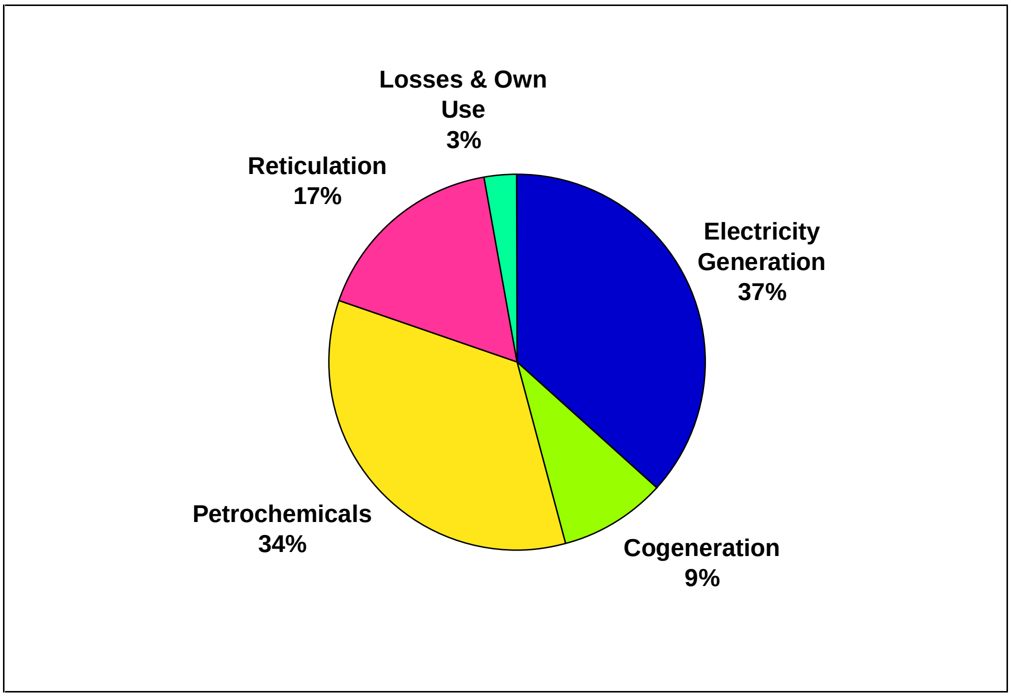
[9] *Transport in this section excludes fuel used for international transport, while the model results include fuel used for international transport unless otherwise stated.*

[10] *Gross production, less flaring, reinjected, own use, losses and LPG extracted.*

Figure 5: **New Zealand's Primary Energy Gas Supply 1998**



Of the 33 PJ of consumer energy reticulated throughout the North Island in 1998 around 22 PJ was used in industry, 5 PJ in the commercial sector, 5 PJ in the residential sector and 1 PJ in domestic transport.

Oil

New Zealand's estimated remaining crude oil and condensate reserves are dominated by the Maui field, which (as at 1 January 1998) contained around 62% of New Zealand's reserves, with Kupe, McKee and all the other fields together sharing about one-third each of the remaining reserves.

New Zealand's production of crude oil and condensate was around 121 PJ in the calendar year 1997. The Maui field also dominates oil production, comprising around 77% of total production in the calendar year 1997.

Domestic transport is the dominant consumer energy use of petroleum products, with 170 PJ (84%) of the total of 203 PJ in 1998 being consumed in the transport sector. Around 15 PJ (6%) was consumed in the agriculture and fishing sectors, 12 PJ (6%) in the industrial sector, 4 PJ (2%) in the commercial sector and around 2 PJ (1%) in the residential sector.

Coal

New Zealand extracted around 80 PJ of coal in 1998, exporting around 33 PJ (41%) of that. Production is dominated by bituminous and sub-bituminous coal. Virtually all exports are of bituminous coal from the West Coast of the South Island.

Around 14 PJ of coal was used in electricity generation in 1998, while around 5 PJ of coal was used in cogeneration applications.

Of the 34 PJ of consumer energy of coal in 1998, around 1 PJ was used in the agricultural sector, 14 PJ in the basic metals sector, another 14 PJ in other industry, 4 PJ in commerce, and around 1 PJ in the residential sector.

Renewables

Renewables make a major contribution to New Zealand's primary energy supply, contributing around 215 PJ (30%) to the total primary energy supply of 689 PJ in the March year 1998. This is dominated by hydro and geothermal, which contributed around 84 PJ pa and 98 PJ pa[11] respectively in the year ending March 1998. Wood was estimated to provide the next largest contribution of around 30 PJ, with around 4 PJ from wastes and biogas.

The total consumer energy provided by renewables in the March year 1998 was around 41 PJ. Most of the primary energy supply of geothermal and all of the hydro is used in electricity generation, so the renewable consumer energy is dominated by wood, with 27 PJ consumed in the March year 1998. Wastes and biogas provided around 0.5 PJ pa of consumer energy, and direct geothermal use around 13 PJ pa.

Electricity

New Zealand's electricity generation system[12] is predominantly hydro (see Figure 6), and of the around 36,300 GWh of electricity generated in 1998, around 65% was hydro (although this varies year to year depending predominantly on inflows and to a lesser extent demand). Gas's share has been increasing as new combined cycle capacity and gas-fired cogeneration has come on stream. Gas comprised around 23% of total generation in 1998. Coal use at Huntly also rose in 1998, with coal accounting for 5% of generation, while geothermal contributed around 6%, and other forms of generation around 1%. The variability of hydro inflows and the small storage capacity of the hydro system mean that significant thermal capacity is required to manage the system through peak winter demands, which also coincide with the lowest inflows over the annual cycle.

Of the approximately 8100 MW of installed capacity in New Zealand in 1998 around 64% was hydro, 27% was thermal, 4% was geothermal, and 6% was cogeneration plant.

New Zealand's thermal system was primarily dependent on gas (or coal in Huntly's case) in 1998 to fuel the Huntly (1000 MW) and New Plymouth (580 MW) stations. Other gas-fired and oil-fired capacity are uneconomic as baseload stations and are only used in hydro firming, peaking, and backup roles. The Huntly power station is dual fuel capable on coal and gas.

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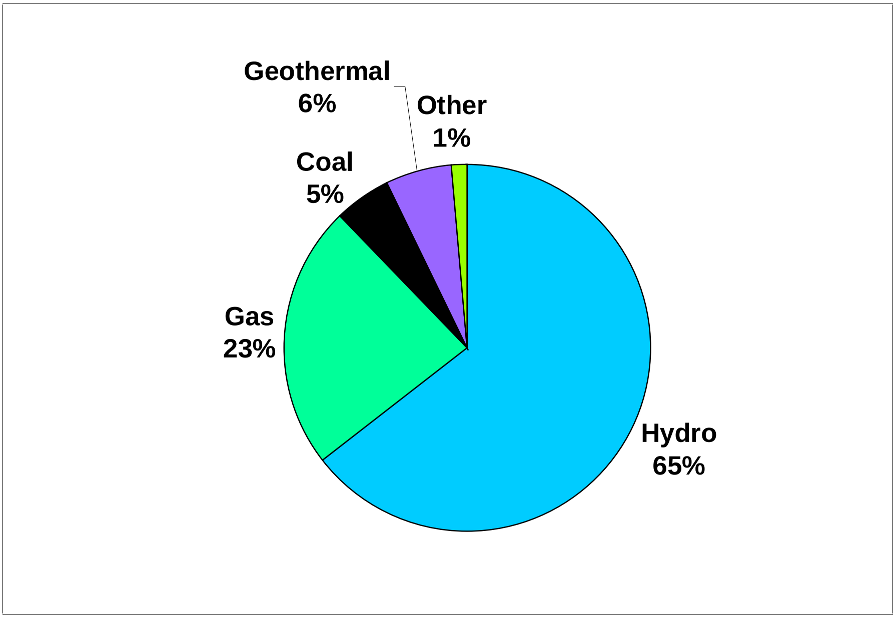
[11] *Geothermal's share is as high as hydro due to its assumed efficiency of only 10% in electricity generation, whereas hydro is assumed to be 100% efficient.*

[12] *As at 31 March 1998. The figures here include electricity generated from cogeneration plants.*

Figure 6: **New Zealand's Electricity Generation by Fuel 1998**



THE ASSUMPTIONS OF THE BASELINE AND ALTERNATIVE SCENARIOS

The SADEM model uses a series of quantitative and qualitative methods to project New Zealand's energy demand and supply by fuel and sector. The major influences on energy supply and demand, such as GDP growth rates, technological advance, population growth, and consumer preferences, cannot be predicted into the future with any real certainty. In order to examine possible future outcomes some assumptions about these and other factors are made. These assumptions for the baseline scenario (presented below in Box One) have been arrived at through analysis of past experience and the likelihood of, and ability for, future change. The alternative scenarios, described briefly over the page, are designed to examine the sensitivity of the model to variations in the underlying assumptions.

Box One: **Key Baseline Assumptions**

The baseline scenario to 2020 uses the following key assumptions for parameters determined largely or solely by factors external to the New Zealand energy market:

- GDP growth of 3% per year from 2003 on, short-term forecasts for 1999-2002;
- current policy settings (in particular, no allowance has been made for a possible GHG emissions trading scheme, or other economic instrument);
- oil prices decline from around US$21 per barrel (bbl) in 2000 to US$19/bbl in 2002 before increasing to US$ 22/bbl by 2015 and remaining stable thereafter[13];
- coal prices increase from around $2.7/GJ in 1998 to $3/GJ in 2010, remaining flat thereafter;
- new gas discoveries (of 80 PJ pa) are sufficient to provide production of between 100 and 130 PJ pa from 2005;
- a constant exchange rate of US$0.54 = NZ$1;
- costs of additional electricity generation capacity as shown in Box Two. These are based on current commercial technologies;
- no additional autonomous energy efficiency uptake, ie, rates of energy efficiency uptake remain at historical levels; and
- the marginal increase in the available wood supply in any year will be split 50/50 between processing in New Zealand and log exports.

In addition, the following assumptions are derived from the new gas discoveries assumption above:

- wholesale gas prices rise to around $3.5/GJ by 2010 and to $3.9/GJ by 2020; and
- the petrochemicals plants close when their existing take-or-pay Maui gas contracts expire: the synthetic petrol plant in 2003, and the methanol and ammonia/urea plants in 2005[14].

The sectors and fuels projected with econometric techniques (the residential, other industrial and commercial, and diesel and petrol demands) have energy efficiency improving at the historical rate implicit in the econometric equations. In the basic metals, forestry and petrochemicals sectors,

[13] A more detailed description of these assumptions and their sources can be found on page 32.

[14] Methanex's recent gas contract with Contact for 130 PJ could extend Methanex New Zealand's operations out to around 2006/07. However, it is uncertain at this stage what contractual limitations on the consumption of the gas exist, and exactly how and when Methanex intends to consume the additional gas.

industry views as to the future patterns of energy demand and supply in their sector have been evaluated and used where appropriate.

Given the difficulty and resources required in projecting the rate of change in technology it has been assumed that there is no change in the efficiency of electricity generating technologies[15]. This assumption has been made both in respect of emerging technologies and the more mature technologies. The uncertainty this creates is discussed in the electricity generation section. Box Two below presents the assumptions used for the cost and quantity of new electricity generation available in the baseline scenario.

These judgements about certain key factors provide only one possible view of the future. The reality is that significant uncertainty surrounds each of the assumptions above, and each variable will have an unknown probability distribution associated with it. To explore further the possible future patterns of energy supply and demand, scenarios can be analysed by changing a wide range of key input assumptions. In this way it is possible to identify a range of energy consumption patterns based on variations in the underlying assumptions of the SADEM model.

Variations to some of these assumptions are explored in later sections of this Outlook via scenario analysis. Specifically, variations in the following underlying assumptions are presented:

- *GDP growth:* a high-growth scenario of 4% pa GDP growth from 2003 on, and a low-growth scenario of 2% pa GDP growth from 2003 on;
- *Oil prices:* a high oil price scenario assumes oil prices reach $US28/bbl by 2015 before stabilising, while a low oil price scenario assumes oil prices fall to $US15/bbl by 2015 before stabilising;
- *Gas availability:* a high gas availability scenario assumes new discoveries of around 120 PJ pa, while a low gas availability scenario assumes new discoveries of 40 PJ pa. These assumptions have a corresponding impact on prices;
- *Forestry processing:* a high forestry processing scenario where all the marginal increase in wood supply in any one year is processed in New Zealand, ie, there is no increase in log exports from their 1998 levels;
- *Energy efficiency:* an increased energy efficiency uptake scenario, where energy efficiency is assumed to increase faster than the historical rate;
- *Renewables:* in this scenario it is assumed that coal does not become the backstop technology for electricity generation, and that renewables make an even larger contribution to satisfying demand growth;
- *CO_2 pricing:* in these two scenarios a high and a low carbon dioxide price is modelled. The carbon dioxide price profiles are based on indicative carbon dioxide prices in 2010 discounted back to 2005.

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[15] *The reasons for this are as follows. The model's focus, and its strength, is on trends in the energy sector, rather than absolute levels which are subject to significant uncertainty. The expectation is that all technologies will continue to improve, and the model's ordering of new technologies will therefore only be out when one technology improves significantly faster than the others.*

This is by no means a complete examination of all the possible assumptions that could be varied, but it does cover most of the significant drivers of energy demand, and a few of the more interesting supply side possibilities.

Although the focus of the chapter on renewables is on traditional renewables, the potential of emerging renewable technologies in the long term is also discussed.

In the short term, significant impetus has been given to cogeneration by the development of the wholesale electricity market. However, the activity seen in recent times is unlikely to be sustainable given New Zealand's relatively modest industrial base. The economics of cogeneration plants are very site-specific and no generic estimate of their cost has been provided. It is assumed that the capacity for cogeneration growth is primarily driven by developments in the industrial and commercial sector.

Box Two:

Cost of Additional Electricity Generation Capacity

The estimated electricity generation supply curve based on currently commercial technologies used in the analysis is summarised below[16]. It indicates not only how much capacity and generation might be available, but also how much relative costs need to change for some technologies to become more economic than others.

Generation type	**Total cost** *c/kWh*	**Potential capacity** *MW*	**Potential supply** *GWh pa*
Hydro efficiencies in current system	4.0-5.0	100	700
Gas combined cycle	4.3-4.5	700	5300
Low-cost geothermal	5.5	200	1650
Coal	6.3	no limit	no limit
Mid-cost geothermal	6.5	200	1650
Low-cost wind	6.7	200	850
Mid-cost wind	8.2	200	850
High-cost geothermal	8.5	400	3300
High-cost hydro	8.6	500	4200
High-cost wind	9.5	400	1700
Distillate (fuel oil)	11.3	no limit	no limit

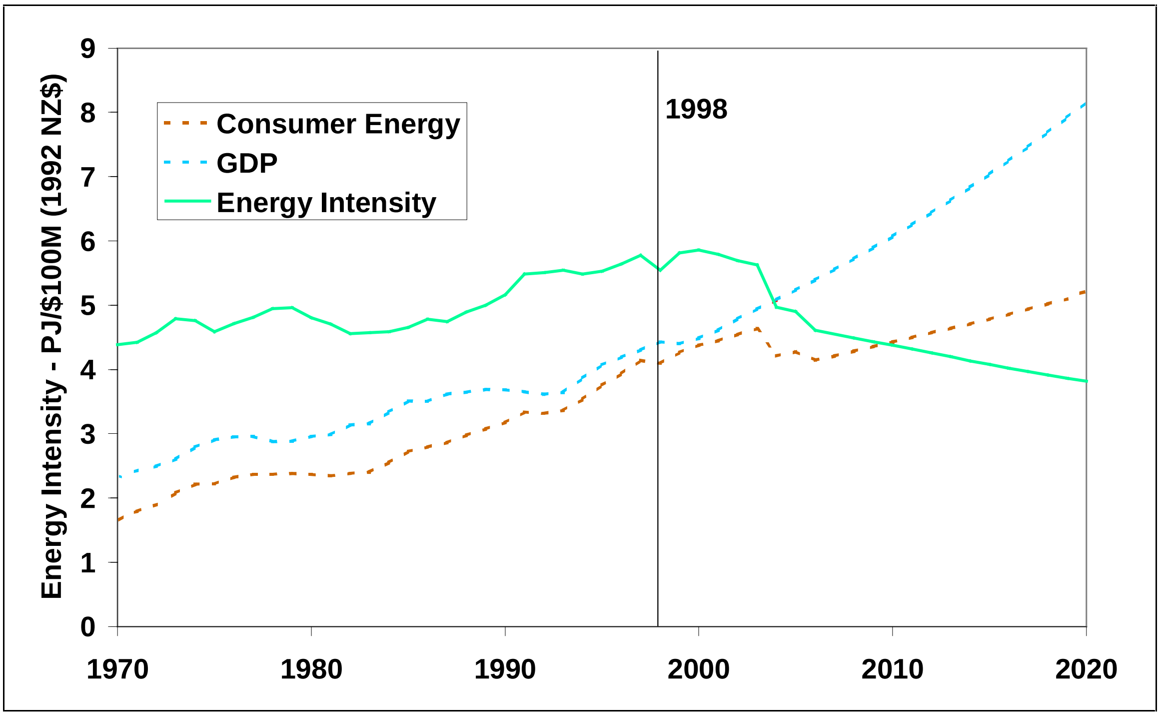
[16] *These estimates are subject to significant uncertainty, and must be viewed in this light. There are a multitude of factors which affect the cost and quantity estimates used. These include, assessment of the resource potential, exchange rates, fuel prices, capital costs, operating costs, and technology development.*

PROJECTED GROWTH IN CONSUMER ENERGY

Figure 7 shows that New Zealand's energy intensity increased from around 4.4 PJ/$100M to 5.5 PJ/$100M between 1970 and 1998. This is associated with the fact that over the past 25 years consumer energy consumption grew by 2.7% pa, while real GDP growth averaged around 2.1% pa. This implies an average ratio between consumer energy growth and GDP growth over that period of about 1.3:1.

The detailed sectoral projections of energy demand presented in this section for the baseline scenario see consumer energy projected to grow by around 1.1% pa between 1998 and 2020, for GDP growth of around 3% pa in the baseline scenario. A substantial change in the relationship between consumer energy demand and GDP is thus projected over the period, with the ratio of consumer energy growth to GDP growth falling to around 0.37:1 over the outlook period to 2020. As a result energy intensity declines to around 3.8 PJ/$100M by 2020 as shown in Figure 7.

Figure 7: **Consumer Energy, GDP Growth, and Energy Intensity** *(Scaled)*



Note: The Y axis units apply only to energy intensity. The GDP and consumer energy data have been scaled to fit this graph.

The projected divergence between GDP growth and consumer energy can be attributed to a number of factors. These include projected higher and increasing real energy prices, a removal of the drivers that favoured energy-intensive projects in New Zealand in the past, an increased uptake of energy efficiency, closure of some energy-intensive projects, increased environmental awareness, and higher capital turnover with faster economic growth.

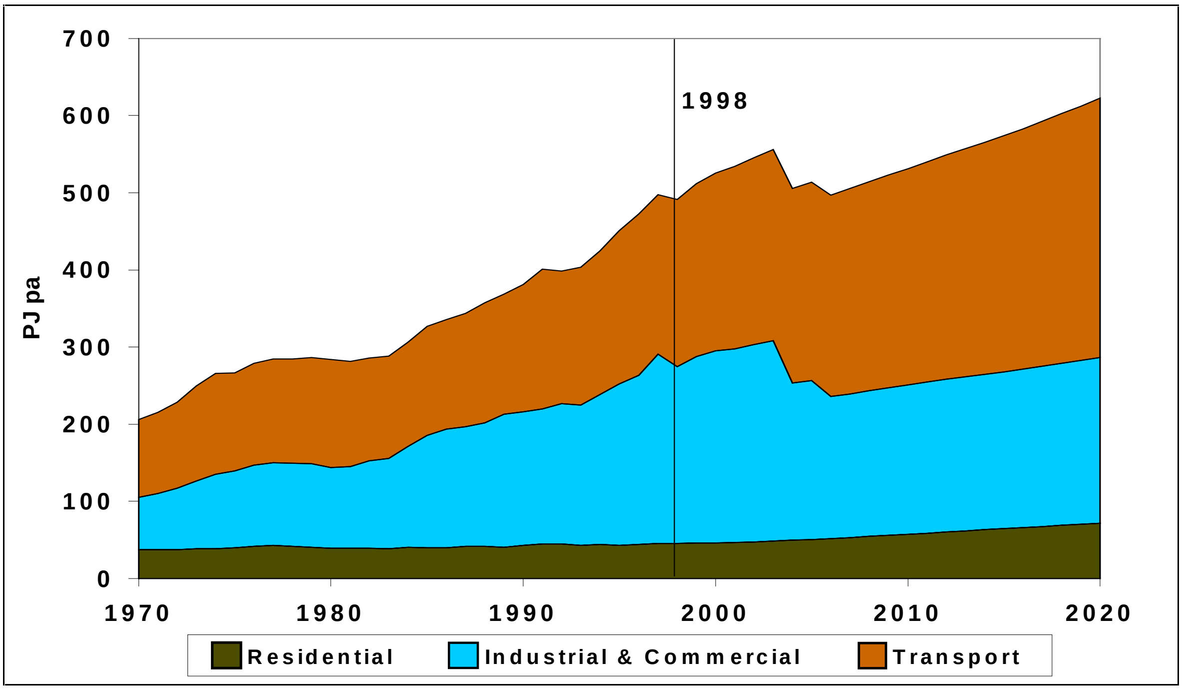
[17] pa to 623 PJ pa. However, if we exclude the petrochemicals plants, which are assumed to close by 2005, then the picture is quite different. Consumer energy growth, excluding the petrochemicals plants, is projected to grow at around 1.8% pa. The projected consumer energy profiles by sector are presented in Table One and Figure 8.

Table One: **Consumer Energy Demand by Sector 1995-2020** *(PJ pa)*

March Years	**Residential**	**Industrial and Commercial**	**Transport***	**Total**
1995	43.0	208.9	198.6	450.5
1998	45.4	228.9	217.0	491.4
2000	46.3	249.0	229.6	524.9
2005	50.7	206.0	255.2	512.0
2010	57.4	193.5	279.4	530.2
2020	71.8	214.8	335.9	622.5

**Includes domestic and international transport consumption.*

Figure 8: **Consumer Energy by Sector 1970-2020**



[17] *Unless otherwise noted, all data from this section on are for years ending in March, all petajoules (PJ) are in net terms, and 1998 is the last year of historical data. See footnote 7 on page 3. Some totals may not add due to rounding.*

Figure 9: **Transport Consumer Energy by Sub-Sector 1970-2020**

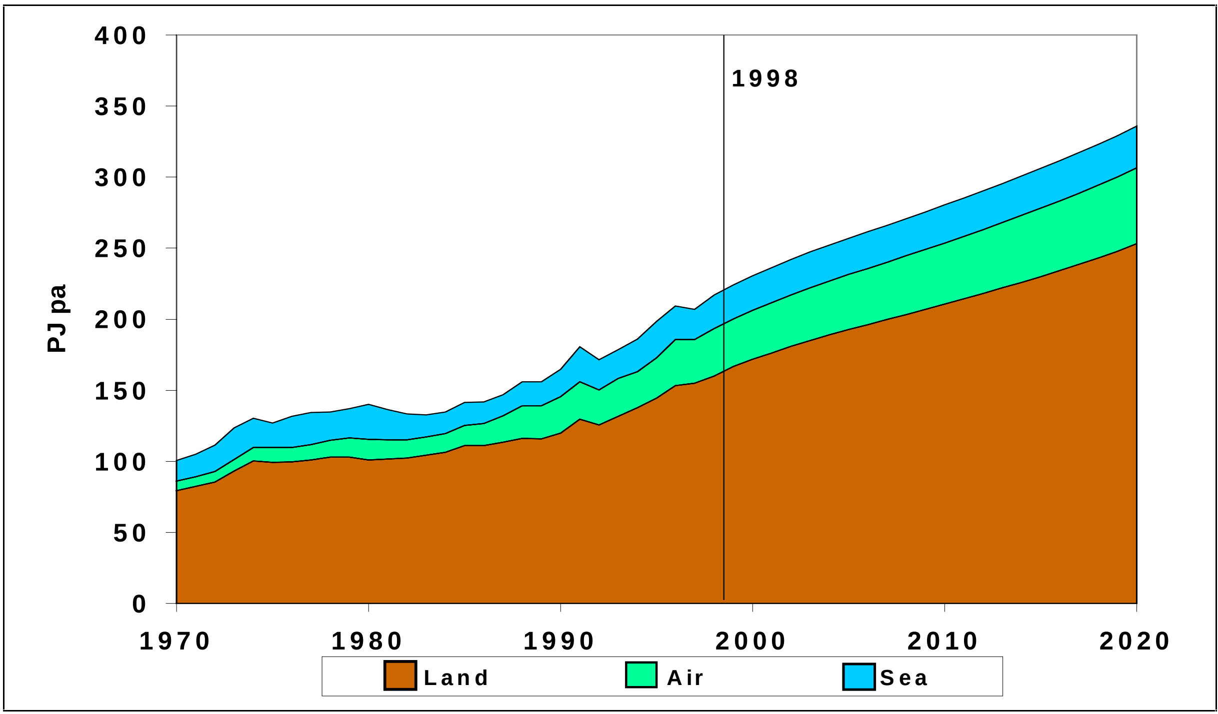


Table Two: **Land Transport Consumer Energy 1995-2020** *(PJ pa)*

March Years	**Rail Diesel**	**On/Off Road Diesel**	**Petrol**	**CNG**	**LPG**	**Total**
1995	2.2	45.5	91.1	1.6	4.3	144.6
1998	2.3	59.0	93.8	0.6	4.3	160.0
2000	2.3	63.4	100.2	0.5	4.3	170.8
2005	2.3	72.3	111.9	0.4	4.1	191.0
2010	2.3	81.0	122.7	0.3	3.2	209.5
2020	2.3	101.7	147.0	0.2	1.9	253.1

Air transport (domestic and international) is projected to grow strongly, at an average of around 2.2% pa, between 1998 and 2020, from around 33 PJ pa in 1998 to 54 PJ pa in 2020 (see Table Three). International air transport is projected to grow as strongly as land transport diesel at around 2.4% pa between 1998 and 2020. Domestic air transport energy consumption grows at a more modest 1.6% pa over the period. Sea transport is projected to experience slower growth, growing at 1.0% pa, from around 24 PJ pa in 1998 to around 29 PJ pa in 2020.

Table Three: **Air and Sea Transport Consumer Energy 1995-2020** *(PJ pa)*

	Air Transport			**Sea Transport**		
March Years	**Domestic**	**International**	**Total**	**Domestic**	**International**	**Total**
1995	11.4	16.8	28.2	8.9	16.9	25.8
1998	11.7	21.7	33.4	9.1	14.5	23.6
2000	12.2	22.3	34.5	9.5	14.8	24.3
2005	13.3	25.4	38.7	9.9	15.5	24.5
2010	14.3	28.8	43.1	10.4	16.3	26.7
2020	16.6	36.9	53.5	11.4	18.0	29.4

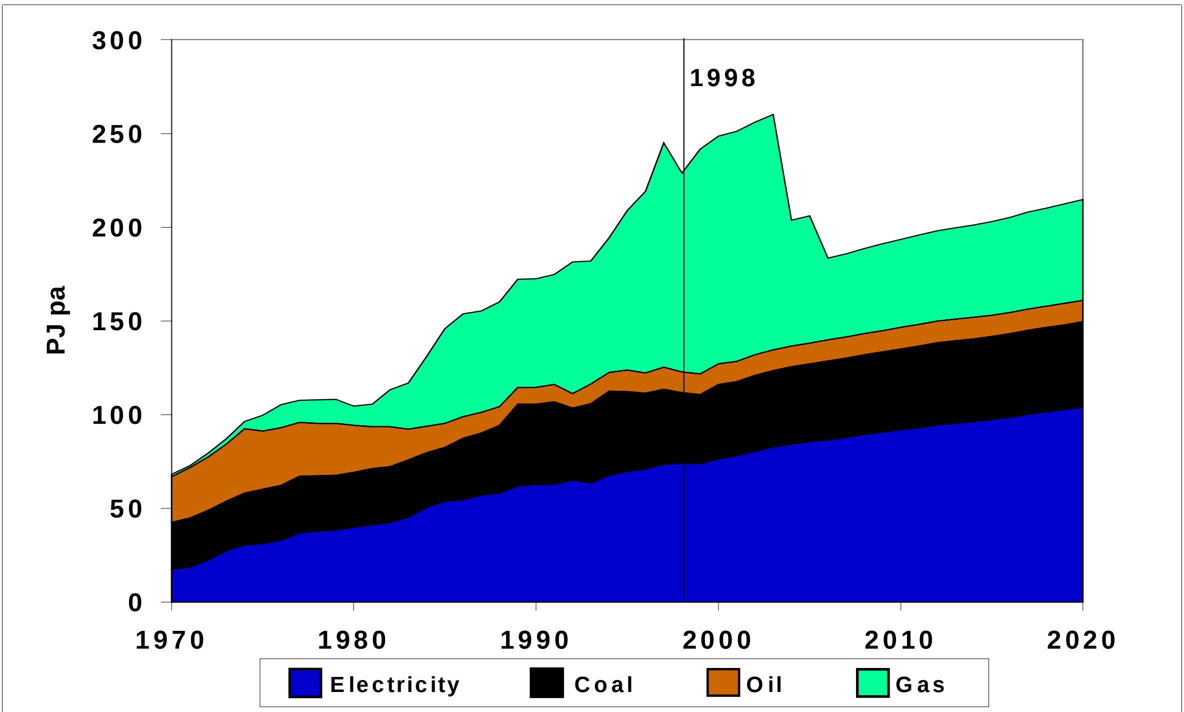
Total Industrial and Commercial

Total industrial and commercial consumer energy declines at around 0.3% pa, from around 229 PJ pa in 1998 to 215 PJ pa in 2020 (see Table Four). Little growth in the basic metals sector, and the closure of the petrochemicals plants (the dip in gas consumption around 2003 and 2005 in Figure 10), conceal growth in the consumer energy demand of the other industrial and commercial and forestry sectors, which grow at 1.5% pa and 2.5% pa respectively.

Table Four: **Total Industrial and Commercial Consumer Energy 1995-2020** *(PJ pa)*

March Years	**Electricity**	**Coal**	**Oil**	**Gas**	**Total**
1995	69.7	42.7	11.4	85.1	208.9
1998	74.0	37.7	11.0	106.2	228.9
2000	76.6	39.9	10.9	121.7	249.0
2005	85.6	41.5	11.2	67.7	206.0
2010	91.9	43.2	11.4	46.9	193.5
2020	104.1	45.6	11.3	53.9	214.8

Figure 10: **Total Industrial and Commercial Consumer Energy by Fuel 1970-2020**



Electricity consumption is projected to be the fastest growing fuel in the total industrial and commercial sector, growing at around 1.6% pa between 1998 and 2020. The consumer energy of coal grows at 0.9% pa between 1998 and 2020, oil at 0.1% pa, and gas declines at around 3.0% pa with the closure of the petrochemicals plants in 2003 and 2005[18]. As a result, electricity increases its share of the total industrial and commercial sector's consumer energy from 32% in 1998 to 48% in

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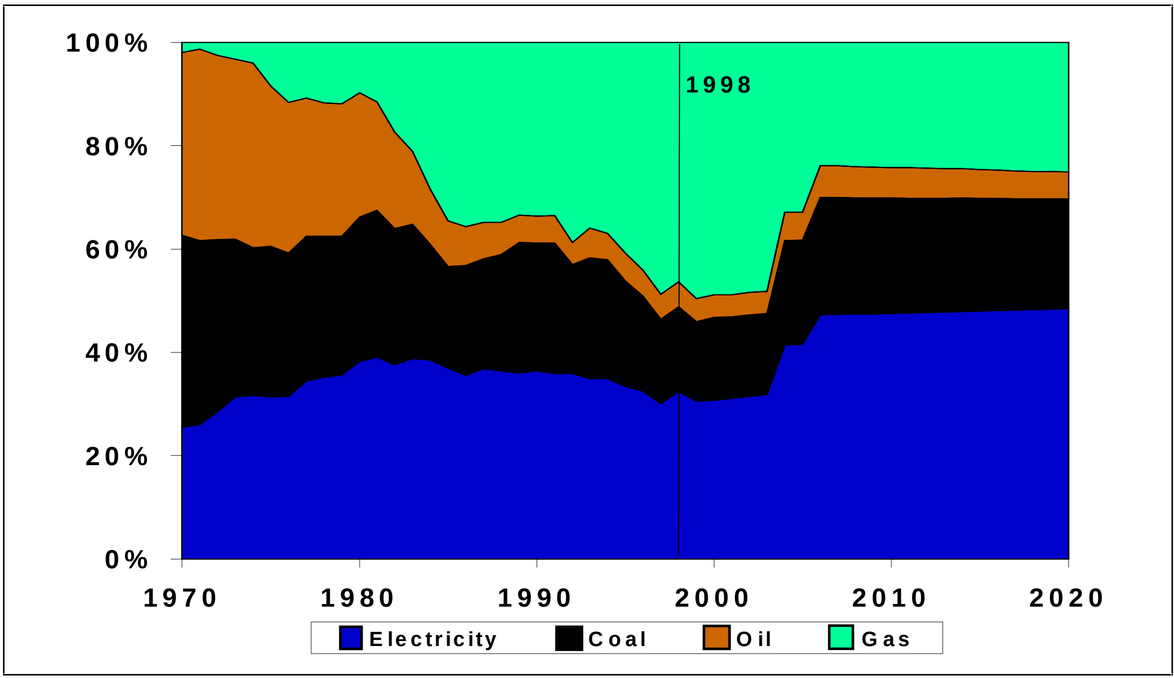
[18] *The methanol and ammonia/urea plants are classified under consumer energy, whereas the synthetic petrol plant is classified as a transformation activity. However, in 1998 both the Methanex plants produced only methanol.*

2020 (Figure 11). This is largely at the expense of gas, which declines from 46% to 25% as the petrochemicals plants close. Coal increases its share from around 16% in 1998 to 21% in 2020, while oil's share remains roughly static at 5%.

Figure 11: **Total Industrial and Commercial Fuel Shares 1970-2020**



The following sub-sections describe the projected contribution of the forestry, basic metals, petrochemicals, and other industrial and commercial sector's to the industrial and commercial sector's consumer energy demand growth.

Forestry

The forestry sector's energy requirements are expected to experience considerable growth over the outlook period, as an approximate doubling in the available wood resource occurs by 2020. Under the baseline scenario, 50% of the increase in forest harvest is assumed to be processed domestically, with the remainder being exported as logs. Of the 50% increase in the forest harvest processed domestically, half of this quantity goes to the energy intensive pulp and paper industry, while the remainder is turned into products which utilise less energy intensive processes, such as sawn timber, medium density fibreboard etc.

The forestry sector's projected energy use is shown in Table Five. Only electricity and gas consumption are included in the forestry time series of consumer energy (Table One and Table Four) due to the lack of accurate time series data on the forestry sector for the other fuels (coal and oil consumption, but not wood, are accounted for in the other industrial and commercial sector). However, the other fuels are presented here as an indication of the projected composition of forestry sector energy consumption.

Table Five: **Forestry Energy Use 1995-2020** *(PJ pa)*

	Electricity	Gas	Sub-Total	Coal	Oil	Wood and Other	Total
March Years	***(Included in Forestry Consumer Energy)***			***(Not included in Forestry Consumer Energy)***			
1995	11.6	8.4	19.9	2.1	1.7	33.0	56.7
1998	9.8	7.7	17.4	1.6	1.2	29.2	49.3
2000	13.1	8.9	22.0	1.8	1.3	34.0	59.1
2005	16.7	11.4	28.1	2.3	1.7	43.6	75.7
2010	17.1	11.8	28.9	2.4	1.8	45.4	78.5
2020	17.7	12.5	30.1	2.6	1.9	48.4	83.0

Electricity consumption is projected to grow at 2.7% pa, and gas consumption at 2.2% pa between 1998 and 2020. Coal consumption is projected to grow at 2.3% pa, and oil consumption at 2.2% pa between 1998 and 2020. Energy supplied internally, from sources such as pulping residues, wood wastes and hog fuel, is projected to grow at 2.3% pa and provide 58% of the forestry sector's energy requirements in 2020.

Basic Metals

The basic metals sector comprises Comalco's aluminium smelter at Tiwai Point, the BHP-New Zealand Steel mill, and the Pacific Steel mill. Projected increases in output from these plants are not expected to increase consumer energy demand significantly, as the energy impacts of moderate output growth are expected to be offset, to a degree, by improved efficiencies, and cogeneration projects.

Table Six: **Basic Metals Sector Consumer Energy 1995-2020** *(PJ pa)*

March Years	Electricity	Coal	Gas	Total
1995	19.0	15.1	1.9	36.0
1998	20.2	13.7	2.2	36.1
2000	19.1	16.1	2.0	37.2
2005	19.1	16.1	2.0	37.3
2010	19.2	16.1	2.0	37.3
2020	19.2	16.1	2.0	37.3

The basic metals sector's consumer energy is projected to grow at only around 0.1% pa between 1998 and 2020 (see Table Six). The consumer energy of electricity[19] and gas is projected to decline at 0.2% pa and 0.3% pa respectively between 1998 and 2020. The consumer energy of coal is projected to grow at 0.7% pa**.**

Petrochemicals

Gas used to produce methanol and ammonia/urea is classified under consumer energy, while gas used to produce synthetic petrol production is considered under energy transformation activities. The baseline scenario assumes that when the existing take-or-pay Maui contracts expire it will not be profitable for these petrochemicals plants to enter into the wholesale gas market to secure additional supplies. The Maui gas contract for the original synthetic petrol plant is set to expire in 2003, resulting in a reduction in gas available to Methanex of around 60 PJ pa. The original methanol and ammonia/urea plants Maui contracts are due to expire in 2005, leading to the closure of the associated plants and a further reduction in gas consumption of around 25 PJ pa.

Methanex New Zealand's recent contract with Contact for 130 PJ of gas could extend Methanex New Zealand's operations out to 2006 or 2007. However, the contractual restrictions on this gas are unclear given that it is to be sourced from Contact's Maui gas entitlement. As a result, until more information becomes available, Methanexs gas consumption is projected to end in 2005.

Other Industrial and Commercial

The other industrial and commercial sector is a residual sector. The major identifiable energy using industries, for which there is adequate historical data, have been subtracted from the total industrial and commercial energy demand to yield this sector.

Other industrial and commercial consumer energy demand is projected to grow as the economy expands, and as New Zealand increases the level of value added across the economy in areas where New Zealand has a comparative or absolute advantage. This will result in some industries and services expanding and others contracting. Table Seven presents the consumer energy projections for the other industrial and commercial sector.

Table Seven: **Other Industrial and Commercial Consumer Energy 1995-2020** *(PJ pa)*

March Years	**Electricity**	**Coal**	**Fuel Oil**	**Distillate**	**Gas**	**Total**
1995	39.2	27.6	6.9	4.5	28.1	106.3
1998	44.1	24.0	6.7	4.3	26.6	105.6
2000	44.4	23.8	6.7	4.2	26.8	105.9
2005	49.7	25.4	7.0	4.2	29.7	116.0
2010	55.7	27.1	7.2	4.2	33.1	127.3
2020	67.2	29.5	7.5	3.8	39.4	147.4

[19] *The electricity consumption in Table Six is presented net of in-house cogeneration at the BHP New Zealand Steel mill.*

In aggregate, growth of 1.5% pa in consumer energy is projected over the period 1998 to 2020 in the other industrial and commercial sector. The growth in electricity consumption is projected to be 1.9% pa between 1998 and 2020. Coal consumption is projected to grow at 0.9% pa, gas at 1.8% pa, and fuel oil at 0.5% pa. Distillate is the only fuel projected to decline over the period, at 0.6% pa.

Gas demand grows steadily, but is constrained by its increasing cost relative to electricity and coal, while coal demand grows only slowly, with much of this growth likely to come from the South Island where reticulated gas is not available. Electricity's share of the total grows from around 42% in 1998 to 46% in 2020, while coal falls from around 23% to 20%. Gas grows slightly from 25% in 1998 to 27% in 2020 and petroleum products decline from 10% to 8%.

Residential

The residential sector's projected consumer energy consumption is presented in Table Eight and Figure 12 and is projected to grow from 45 PJ in 1998 to 72 PJ in 2020, an average growth rate of around 2.1% pa. Electricity consumption is projected to grow at around 2.2% pa and gas at 2.6% pa between 1998 and 2020. Electricity is projected to slightly increase its share of residential sector energy from 86% to around 87% by 2020, while gas increases from 12% to 13%.

Figure 12: **Residential Consumer Energy by Fuel 1970-2020**

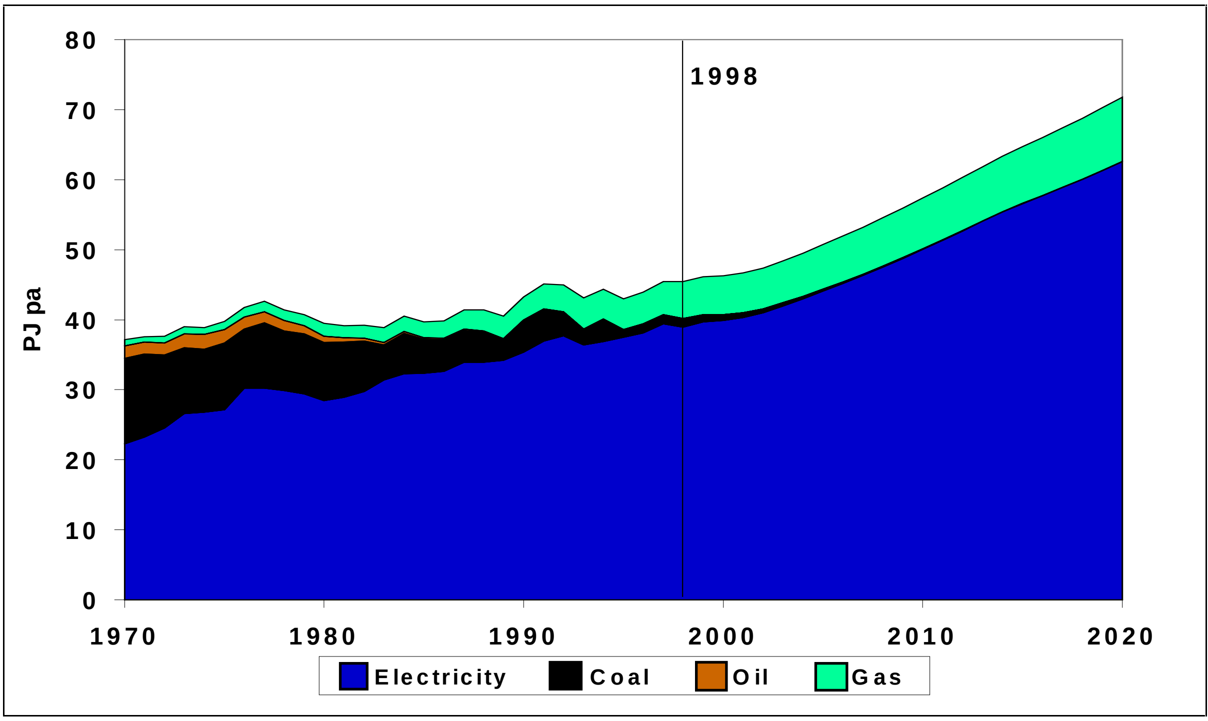


Table Eight: **Residential Consumer Energy 1995-2020** *(PJ pa)*

March Years	**Electricity**	**Coal**	**Gas**	**Total***
1995	37.5	1.0	4.4	43.0
1998	39.0	1.2	5.2	45.4
2000	39.9	0.8	5.5	46.3
2005	44.1	0.3	6.4	50.7
2010	50.0	0.1	7.2	57.4
2020	62.6	0.0	9.2	71.8

** A negligible amount of oil is also used in the residential sector.*

Consumer Energy Fuel Shares

The total projected growth in consumer energy by fuel is presented in Table Nine and illustrated in Figure 13. Electricity consumption grows strongly at around 1.8% pa between 1998 and 2020 as a result of strong demand from the forestry, residential, and other industrial and commercial sectors, whose consumption grows at around 2.7% pa, 2.2% pa, and 1.9% pa respectively between 1998 and 2020. Consumer energy coal growth is much more modest, averaging 0.7% pa between 1998 and 2020. The consumer energy of oil grows strongly at 1.9% pa, concomitant with strong transport demand growth.

Figure 13: **Total Consumer Energy by Fuel 1970-2020**

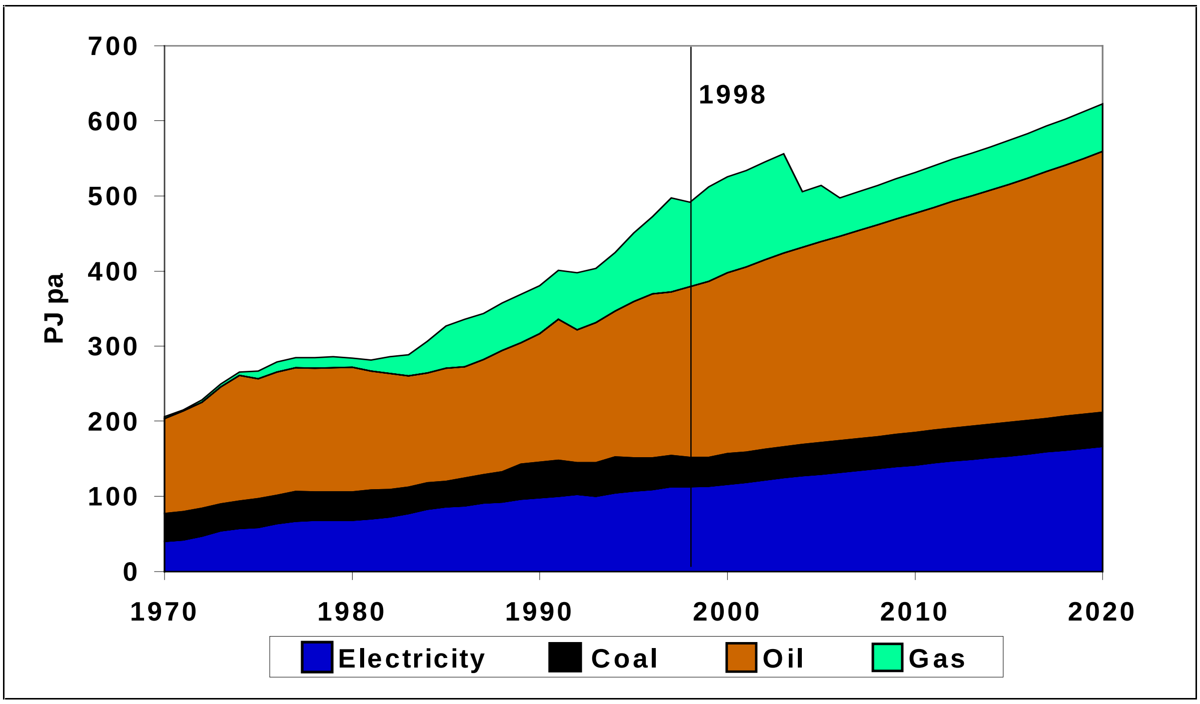


Table Nine: **Total Consumer Energy by Fuel 1995-2020** *(PJ pa)*

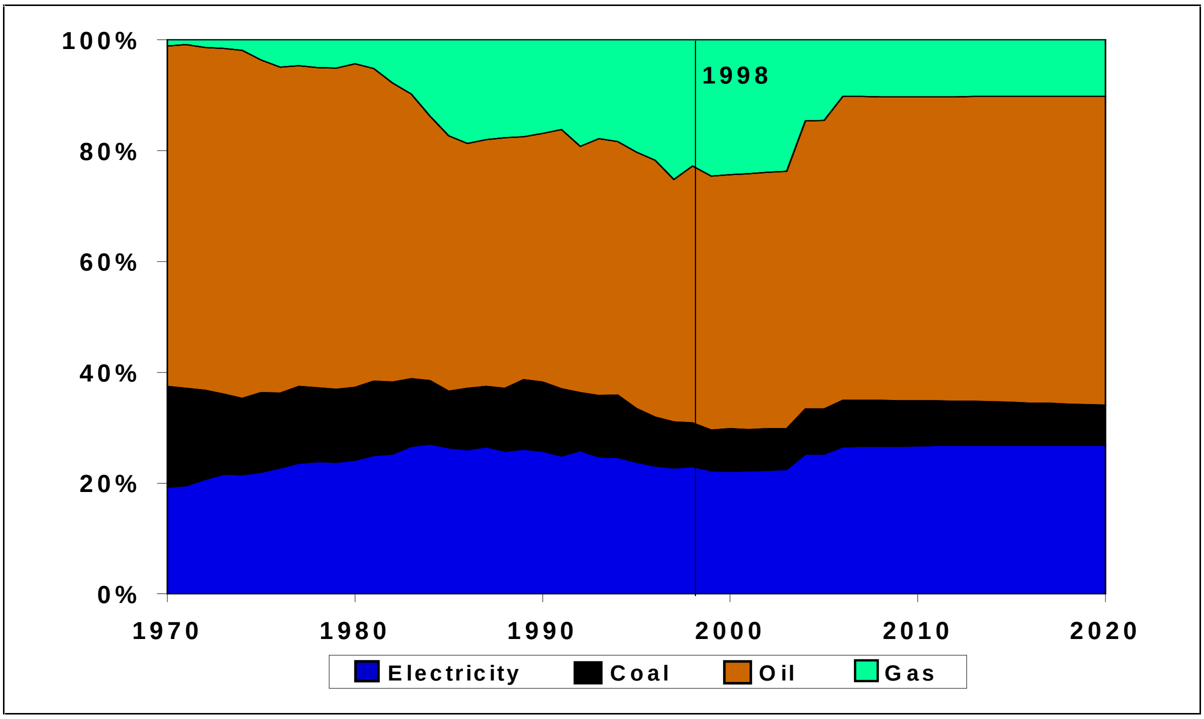
March Years	**Electricity**	**Coal**	**Oil***	**Gas**	**Total**
1995	107.2	43.7	208.5	91.1	450.5
1998	113.0	38.9	227.4	112.0	491.4
2000	116.5	40.7	240.0	127.7	524.9
2005	129.7	41.8	266.0	74.5	512.0
2010	142.0	43.3	290.5	54.5	530.2
2020	166.6	45.6	347.0	63.3	622.5

**Includes LPG, but not CNG, which is included under gas.*

Under the baseline scenario, declining gas reserves and the rising wholesale value of gas are assumed to force the closure of the petrochemicals plants at the end of their Maui contracts in 2003 and 2005. This causes a significant decline in the consumer energy of gas over the period 2003 to 2005. When considered with the growth in gas use in other sectors this results in the consumer energy of gas declining at an average of 2.6% pa over the period 1998 to 2020 (see Figure 13).

The effect these relative growth patterns have on fuel shares is presented in Figure 14. Oil increases its share of consumer energy from 46% in 1998 to 56% in 2020. Electricity increases from 23% in 1998 to 27% by 2020. Coal declines from 8% to 7% while gas declines from 23% to 10% as a result of the depletion of the Maui field and the resulting closure of the petrochemical plants.

Figure 14: **Total Consumer Energy Fuel Shares 1970-2020**



PROJECTED GROWTH IN PRIMARY ENERGY SUPPLY

The steady growth in consumer energy does not reveal some of the significant changes that are projected to occur in the composition of New Zealand's primary energy supply, as the Maui gas field depletes and the diversity of fuel sources for new electricity generation projects increases. The view presented here is only indicative of the likely changes, as only fuels with sufficient time-series data are modelled: specifically, direct geothermal and wood use are excluded. This is consistent with our treatment of consumer energy.

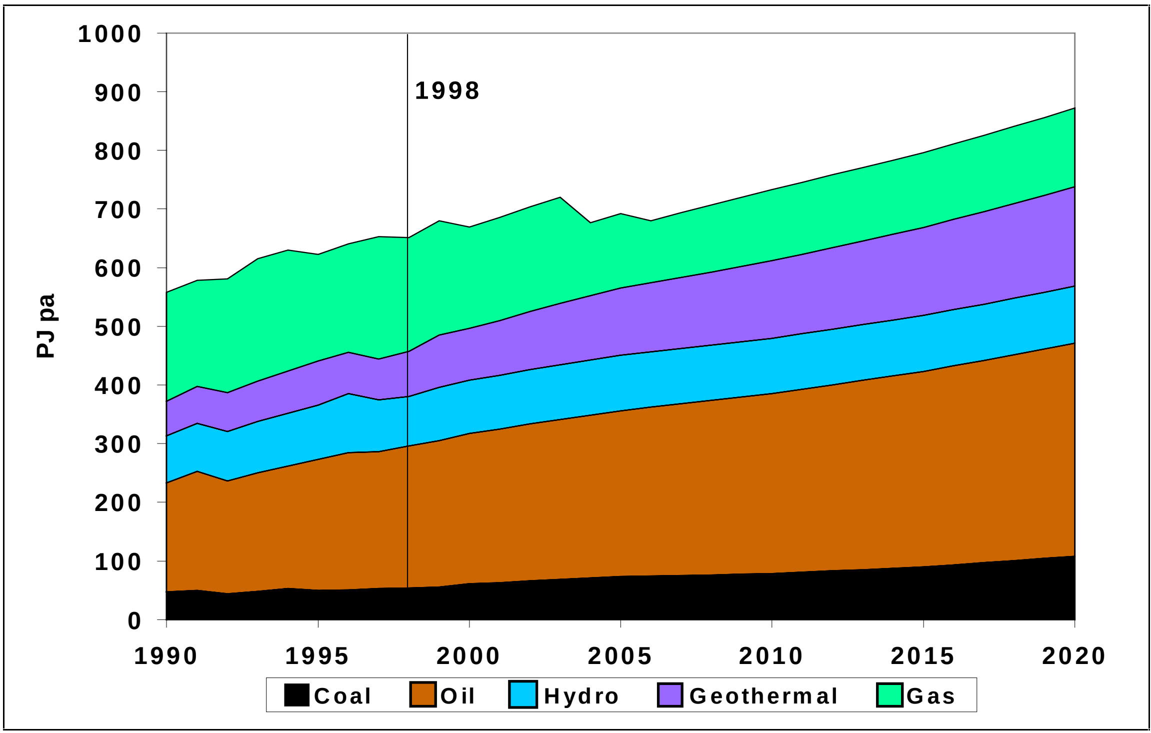
The total primary energy supply in New Zealand is projected to grow at 1.3% pa between 1998 and 2020, from 652 PJ pa to 872 PJ pa, and this is summarised by fuel in Table Ten and Figure 15.

Table Ten: **Total Primary Energy Supply 1995-2020** *(PJ pa)*

March Years	**Coal**	**Oil***	**Gas**	**Hydro**	**Geothermal**	**Total**
1995	50.0	223.5	181.6	92.2	75.4	622.7
1998	53.8	242.4	194.7	84.3	76.4	651.7
2000	61.4	255.0	172.5	91.0	88.8	668.6
2005	73.4	281.1	127.0	94.3	114.6	690.5
2010	78.4	305.9	121.4	94.3	131.9	731.9
2020	108.1	363.7	134.2	97.1	169.2	872.2

**Includes LPG, but not CNG, which is included as gas.*

Figure 15: **Total Primary Energy Supply 1990-2020**



Gas

As existing reserves, particularly of the Maui field, decline, gas is likely to be traded to its highest value uses. As a result, the wholesale price of gas is expected to rise over time to the long-run cost of new discoveries, reflecting the increasing scarcity of the resource.

This rising price profile is projected to have three major implications for the New Zealand energy sector:

- First, Huntly is projected to switch from gas to coal-fired generation by 2000, as the wholesale price of gas rises above the coal price[20].

- Second, the rising wholesale gas price profile is projected to make it unprofitable for the existing petrochemicals plants to enter into the gas market to secure additional supplies of gas once their Maui gas contracts expire. The original Maui gas contract for the synthetic petrol plant is set to expire in 2003, with the methanol and ammonia/urea contracts in 2005. Therefore, Methanex is projected to scale down its operations in New Zealand over the period 2003 to 2005.

- Third, gas's growth in the other industrial and commercial sector is projected to be constrained due to its rising price profile, and uncertainty regarding future availability of supplies.

The reduction in gas consumption, when the petrochemicals plants close, has a significant effect on the composition of primary energy supply. Gas consumption is presented in Table Eleven and Figure 16 and is projected to have peaked already. The primary energy supply of gas is projected to bottom out around 2006 at around 106 PJ pa before modest reticulated growth, and an increase in the use of gas at the new 300 MW gas combined cycle (GCC) projected to be built in 2010 slowly lifts consumption to around 134 PJ pa in 2020. The primary energy of gas supply on balance is projected to decline by around 1.7% pa between 1998 and 2020.

Table Eleven: **Primary Energy Supply of Gas 1995-2020** *(PJ pa)*

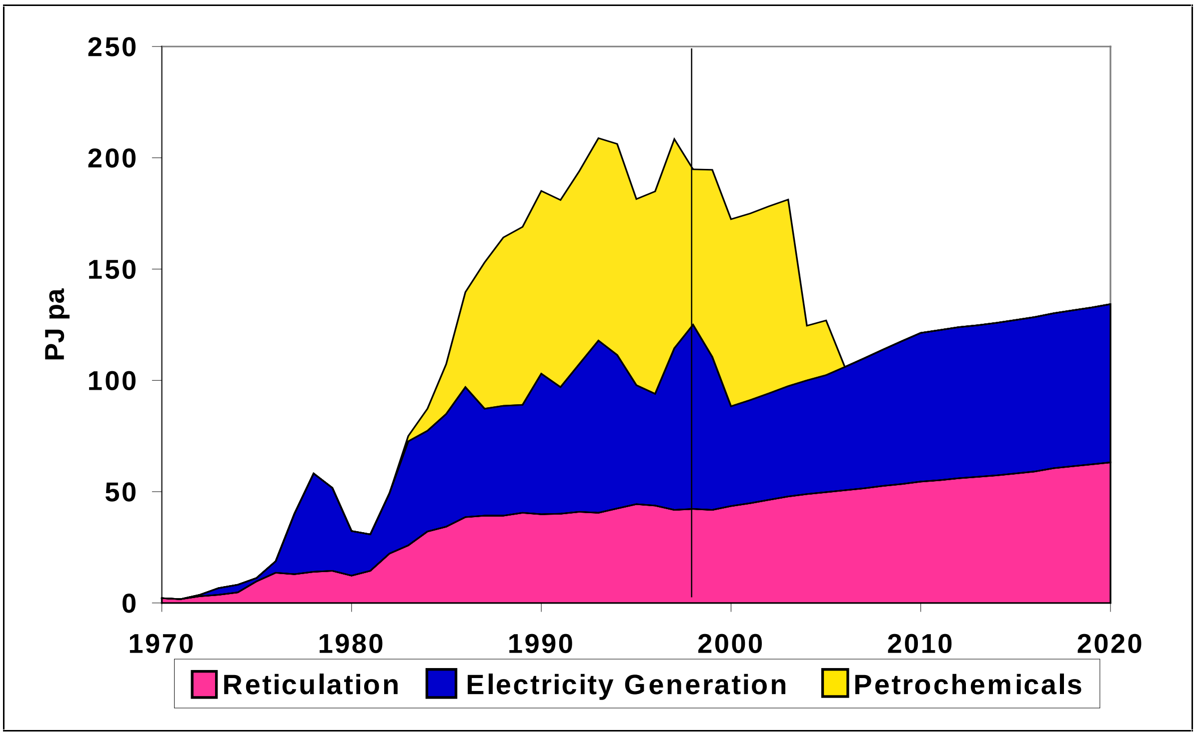
March Years	**Petrochem**	**Methanex**	**Electricity Generation**	**Reticulation***	**Total**
1995	5.5	78.3	53.4	44.4	181.6
1998	5.0	64.0	82.7	42.3	194.7
2000	5.0	78.9	44.8	43.8	172.5
2005	5.0	19.6	52.5	49.9	127.0
2010	0.0	0.0	66.9	54.5	121.4
2020	0.0	0.0	70.9	63.3	134.2

** Including CNG used for transport.*

[20] *There is a negligible difference in thermal efficiency between running Huntly on gas and on coal.*

The shift in gas consumption in electricity generation from the relatively inefficient Huntly and New Plymouth[21] power stations to advanced combined cycle power plants, such as the Taranaki combined cycle (TCC) and Otahuhu B, helps reduce gas demand to 2000. However, after 2000 the nearly 800 MW of GCC (1100 MW in 2010) is increasingly run as base load plant, resulting in gas consumption for electricity generation recovering, albeit to levels below those seen in recent years when Huntly and New Plymouth have been operating on gas.

Figure 16: **Primary Energy Supply of Gas by Use 1970-2020**



Coal

Coal is the largest beneficiary of the projected decline in New Zealand's gas reserves under the baseline scenario, with the primary energy supply of coal projected to grow significantly, from around 54 PJ pa in 1998, to around 108 PJ pa in 2020 (see Table Twelve). This represents growth of around 3.2% pa between 1998 and 2020. There is moderate growth in coal for industrial and commercial use, at 0.9% pa, as the gas price rises and fuel switching occurs.

The growth in coal use is mostly attributable to electricity generation. From 2005 to 2020, around 30-35 PJ pa is used by the Huntly power station (depending on demand and system capacity). Around 2010 new coal plant becomes economic, and around an additional 30 PJ pa is consumed with the introduction of almost 700 MW new coal-fired plant by 2020.

Currently around 80 PJ pa of coal is extracted in New Zealand, including coal for export. The projected growth in domestic consumption to 2020 will therefore put very significant pressures on the

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[21] *In addition to losing market share to the cheaper more efficient GCCs prior to 2005, the New Plymouth power station is assumed to be mothballed from 2005 on.*

New Zealand coal industry and its supporting infrastructure. It is unlikely that all this increased demand will be met by New Zealand production, given that significant new mine development would be required, potentially at a higher cost than imports. Thus a sizeable portion of future demand is likely to be sourced internationally. No quantitative assessment of the likely contribution of imports has, however, been made.

Table Twelve: **Primary Energy Supply of Coal 1995-2020** *(PJ pa)*

March Years	**Residential**	**Metals Manufacturing**	**Other Industrial and Commercial**	**Electricity Generation**	**Total**
1995	1.0	15.1	27.6	6.3	50.0
1998	1.2	13.7	24.0	14.9	53.8
2000	0.8	16.1	23.8	20.7	61.4
2005	0.3	16.1	25.4	31.7	73.4
2010	0.1	16.1	27.1	35.2	78.4
2020	0.0	16.1	29.5	62.5	108.1

Oil

The primary energy supply of oil is also projected to grow strongly from around 242 PJ pa in 1998, to around 364 PJ pa in 2020, driven almost exclusively by demand in the transport sector. Projections of the primary energy supply of oil are given in Table Thirteen.

Table Thirteen: **Primary Energy Supply of Oil 1995-2020** *(PJ pa)*

March Years		**1995**	**1998**	**2000**	**2005**	**2010**	**2020**
Industrial and Commercial	Diesel/ Fuel oil	11.4	11.0	10.9	11.2	11.4	11.3
Transport							
On/Off Road	Petrol	91.1	93.8	100.2	111.9	122.7	147.0
	Diesel	45.5	59.0	63.4	72.3	81.0	101.7
	LPG *	4.3	4.3	4.3	4.1	3.2	1.9
Rail	Diesel	2.2	2.3	2.3	2.3	2.3	2.3
Air	Domestic	11.4	11.7	12.2	13.3	14.3	16.6
	International	16.8	21.7	22.3	25.5	28.8	36.9
Sea	Domestic	8.9	9.1	9.5	9.9	10.4	11.4
	International	16.9	14.5	14.8	15.5	16.3	18.0
Refinery	Conversion/Use	15.0	15.0	15.0	15.0	15.0	15.0
Electricity Generation		0.0	0.0	0.0	0.1	0.5	1.7
Total		223.5	242.4	255.0	281.1	305.9	363.7

* *By convention, LPG is been included with oil.*

The most significant growth over 1998 to 2020, as noted earlier, occurs in land transport diesel and international air transport, which grow at around at 2.5% pa and 2.4% pa respectively. Petrol consumption grows a little more modestly at 2.1% pa.

The refinery is projected to use around 15 PJ of energy pa, as it operates at or around its maximum capacity. No allowance has been made for any possible expansion, or efficiency improvements, at the refinery.

Hydro and Geothermal

The primary energy supplies of geothermal and hydro experience quite different patterns of growth as electricity demand exceeds the economic capacity of the existing system. The primary energy supply projections of hydro and geothermal are presented in Table Fourteen.

Around 260 MW of new geothermal capacity is projected to become economic over the period to 2020. This sees the geothermal primary energy supply of steam grow from around 76 PJ pa in 1998 to around 169 PJ pa in 2020 (all of this is used in electricity generation). The very large growth in the primary energy supply of geothermal energy is due to the assumed efficiency of geothermal electricity generation being only 10%.

Table Fourteen: **Primary Energy Supply of Hydro and Geothermal 1995-2020** *(PJ pa)*

March Years	**Hydro**	**Geothermal**	**Total**
1995	92.2	75.4	167.6
1998	84.3	76.4	160.7
2000	91.0	88.8	179.7
2005	94.3	114.6	208.9
2010	94.3	131.9	226.1
2020	97.1	169.2	266.3

Hydro's primary energy supply experiences much more modest growth rates (see Table Fourteen), as the hydro base is considerably larger than geothermal and is assumed to be 100% efficient. The primary energy supply of hydro is projected to grow from around 84 PJ pa in 1998 to 97 PJ pa in 2020, as the result of an additional 400 MW of capacity.

ELECTRICITY GENERATION

Electricity demand is projected to grow at 1.8% pa from 1998 to 2020, from around 31,400 GWh pa (113 PJ pa) to 46,300 GWh (167 PJ pa). Table Fifteen and Figure 17 show the quantity, composition and timing of the new generation capacity requirements needed to meet demand growth from the economic optimisation of the SADEM model. The SADEM electricity simulation is a market clearing model that matches demand with existing capacity; it then assesses the value of additional capacity, depending on the nature of the new capacity options and demand (including the costs of shortage). Increments of the most economic new capacity can then be added to the system. The model is then iterated to ensure that the electricity prices determined by the supply model are consistent with demand at those prices.

New Zealand's electricity supply curve for new capacity is upward sloping, with most of the lower cost electricity generating options having already been exploited. The assumptions for new generating capacity which underpin the supply curve are given in Box Two, page 11. Consistent with this the wholesale electricity price is expected to rise over time to reflect the long-run cost of generation, as increasingly more expensive plant is built to satisfy demand. However, in the short run, the current supply bubble will put downward pressure on wholesale electricity prices.

The cost estimates in Box Two are based on an assumed level of generation (load factor). The new plant profile presented here is an assessment of what new plant would most economically meet demand growth, based on the cost characteristics of each individual plant and the nature of load growth. The least-cost order of plant in Box Two (for a stylised view of the world) is thus not necessarily the precise order in which new plant will be built to meet load growth.

Table Fifteen: **Projected Economic New Power Station Sequence** *(MW)*

March Years	**1998-2000***	**2001-2005**	**2006-2010**	**2011-2015**	**2016-2020**	**Total**
GCC	770	-	300	-	-	1070
Hydro/Hydro Efficiencies	-	210	-	75	110	395
Geothermal	80	80	50	70	60	340
Cogeneration	220	90	75	80	50	515
Coal	-	-	-	300	375	675
Wind	35	-	50	50	50	185
Distillate	-	-	-	85	40	125
Total	1105	380	475	660	685	3305

** Capacity commissioned, or already under construction.*

Between 1998 and 2020 around 3300 MW of new generating capacity is projected to become economic to satisfy demand growth[22] (presented in Table Fifteen and Figure 18). Taking into account the mothballing of New Plymouth, this represents a net increase in capacity of around 2700 MW between 1998 and 2020.

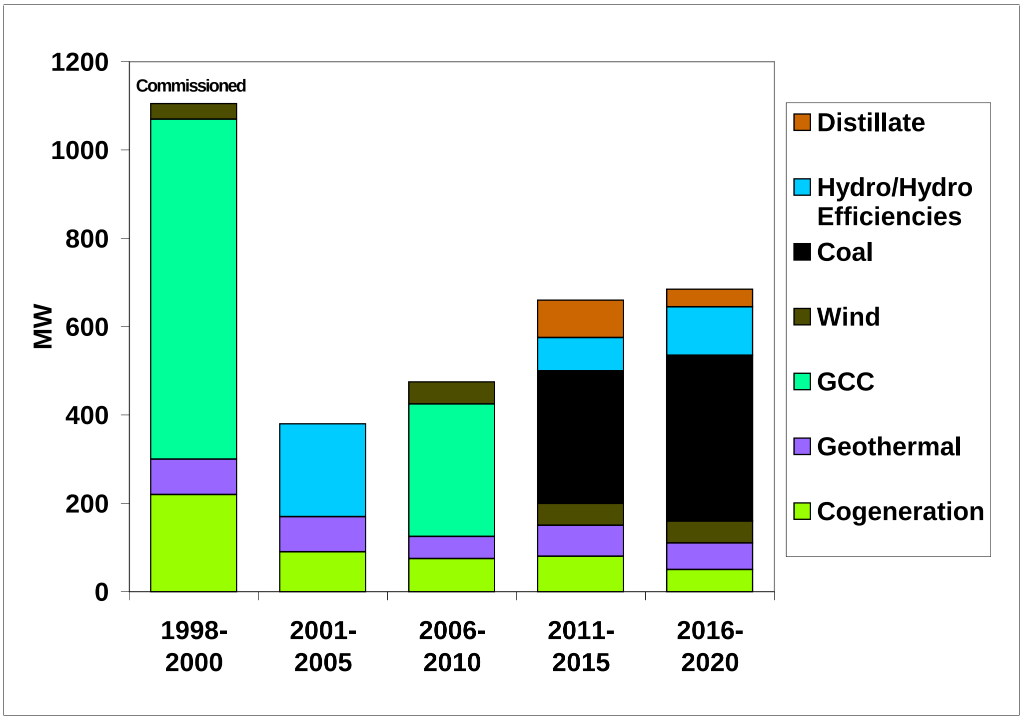
[22] *The growth in capacity to 2000 comprises plant that is already commissioned or committed.*

Around 1100 MW of the 3300 MW has recently been commissioned, is under construction, or has been built and is about to be commissioned. This 1100 MW represents a significant increase in capacity, over and above what would have been needed to satisfy demand growth, and has led to a supply bubble for the next few years.

To the year 2000, new plant recently commissioned or under construction is more than sufficient to satisfy demand growth. This new capacity is dominated by the Taranaki combined cycle, Otahuhu B, geothermal plants, and gas-fired cogeneration projects. The modest capacity increments required in 2005 reflect the slow erosion of the surplus capacity that arises from the large additions to capacity before 2000.

The profile of new cogeneration plant is based on an assumed level of penetration in the industrial and commercial sectors. Cogeneration developments are not driven primarily by electricity market considerations but by capital turnover in the industrial and commercial sectors, and the location of customers for the heat component of cogeneration. It is thus difficult to assess the quantity and timing of new cogeneration developments.

Figure 17: **Projected Economic New Power Station Sequence 1998-2020**



From around 2005 on, significant new baseload capacity is required from a mix of GCC, hydro, cogeneration, wind, and geothermal. By 2020, 125 MW of distillate plant becomes economic to satisfy peak demand as electricity consumption grows. By 2015 the short-run marginal cost (SRMC) of generation has risen sufficiently to make 300 MW of coal-fired generation economic as baseload plant, with an additional 375 MW in 2020.

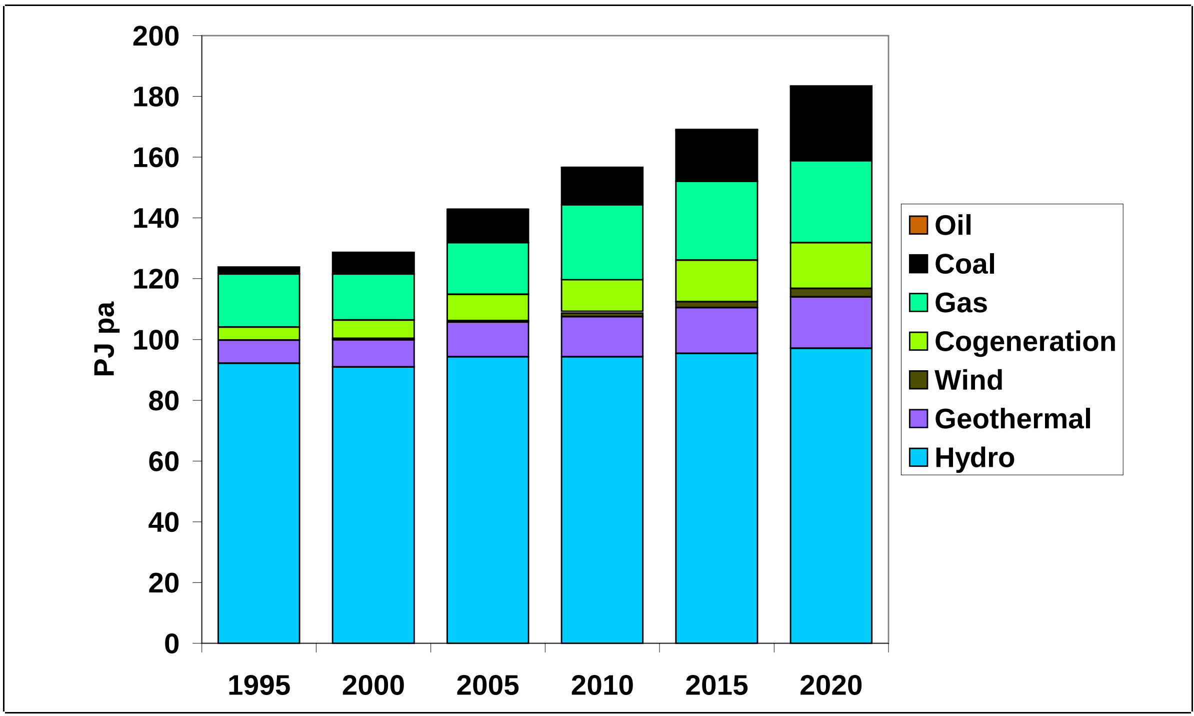
The projected generation from existing and new stations is presented in Table Sixteen and Figure 18. Significant changes in the composition of electricity generation occur between 1995 and 2000. Newly commissioned cogeneration and Huntly's switch to coal-fired generation mean a growing contribution from cogeneration and coal to our total generation requirement.

Table Sixteen: **Projected Electricity Generation by Fuel 1995-2020** *(PJ pa)*

March Years	1995	2000	2005	2010	2015	2020
Hydro	92.2	91.0	94.3	94.3	95.4	97.1
Geothermal	7.5	8.9	11.5	13.2	15.0	16.9
Cogeneration	4.3	6.1	8.6	11.0	13.6	15.1
Gas	17.6	15.1	17.1	24.7	26.0	26.9
Coal	2.3	7.2	11.0	12.2	16.8	24.2
Wind	0.0	0.5	0.5	1.2	2.0	2.8
Fuel Oil / Distillate	0.0	0.0	0.0	0.1	0.3	0.4
Total	123.9	128.7	142.9	156.6	169.2	183.5

Gas-fired generation dips in 2000 to only 12% of total electricity generation when Huntly switches to coal, before growing slightly to 15% in 2020 as new GCC capacity is built in 2010. Coal's share of electricity generation grows to around 13% in 2020. Geothermal's share grows to 9% in 2020, cogeneration to 8%, and wind from virtually nothing now to about 2% in 2020. Hydro declines to around 53% in 2020, despite an additional 400 MW of new hydro capacity.

Figure 18*:* **Projected Electricity Generation by Fuel 1995-2020**



Long-Run Technology Uncertainties

The analysis of new power station requirements undertaken in the electricity model is based on currently commercially available technologies. In this sense, it is conventionally conservative. The actual mix of new plant that will become economic over the longer term will deviate from this analysis, depending on which technologies improve their economics faster than others. One of the more significant uncertainties is what impact actions on climate change in New Zealand and around the world will have on the relative economics of renewable and thermal electricity generation.

In the next fifteen to twenty years, the supply curve (excluding cogeneration) contains significant quantities of renewables, with a number of geothermal, wind and hydro sites being the most competitive. Between 2005 and 2020 renewables are projected to account for 37% of all new capacity requirements.

The possibilities for new GCC plants are restricted by the uncertainty regarding future gas availability, and increasing prices as New Zealand's gas reserves deplete. Based on the estimated quantity and costs of currently commercially available technologies, the long-run cost of electricity generation is likely to be set by coal-fired generation, given its current economics and essentially unlimited supply in the New Zealand context. The technologies and costs of renewable energy will have to improve faster than coal's to gain a larger slice of new generation next century than currently projected.

ENERGY PRICES

Energy prices are central to the market clearing interactions of the SADEM model. This section presents the energy price assumptions for coal, oil, gas, and also the modelled electricity price series at the wholesale and retail levels. Coal and oil are internationally traded commodities, and the internationally traded prices provide a ready reference for our price assumptions. However, the domestic markets for gas and electricity in New Zealand are isolated, unlike in Europe for instance, where there is a limited developing market[23]. Gas and electricity prices are therefore determined solely by the interaction of demand and supply in the New Zealand market.

Oil, Coal, and Gas Price Assumptions

New Zealand has no influence over the international price of oil, either as a consumer, or a supplier. Forecasting oil prices since 1972 has been an extremely difficult task, and almost without exception, medium-term projections have been inaccurate. Given the recent volatility in prices this difficulty looks set to continue for the foreseeable future. The only way to allow for this uncertainty is to examine a set of scenarios and recognise that prices may range within a wide band. For the baseline scenario we assume prices decline from a possible high of around US$21/bbl for 2000 to US$19/bbl in 2002 before rising to around US$22/bbl in 2015 before stabilising in real terms. The weakening in oil prices to 2002 reflects the possible relaxing of OPEC's output quota, and its possible impact on prices, at some point in the next year or so. However, real supply side constraints are thereafter assumed to start to put upward pressure on prices. To explore the uncertainty that arises from the difficulty in projecting oil prices, we then vary the oil price assumption in two alternative scenarios. The baseline and high and low price scenarios have been developed after reference to projections by the International Energy Agency, US Energy Information Administration, and OPEC, and are broadly consistent with the projections given by these organisations.

Projections of internationally traded coal prices act as a cap on the domestic price of coal, allowing for transport costs. The baseline scenario assumes that New Zealand wholesale coal prices rise from around $2.60/GJ in 1998 to $3/GJ in 2010 in real terms (see Figure 19), remaining flat thereafter. Significant new investment in mine capacity will be required to source all of New Zealand's projected coal demand domestically[24], given the growth in demand, and the decline of some of New Zealand's existing mines over the outlook period. However, the outlook for internationally traded coal prices is likely to remain weak in the medium term, keeping pressure on domestic New Zealand coal prices. Additionally, competitive pressure from competing fuels, particularly gas in the North Island, will maintain pressure on coal prices.

New Zealand's gas reserves are expected to decline significantly early next century as the Maui gas field depletes. Currently there is little incentive to explore for gas, because the gas price is too low.

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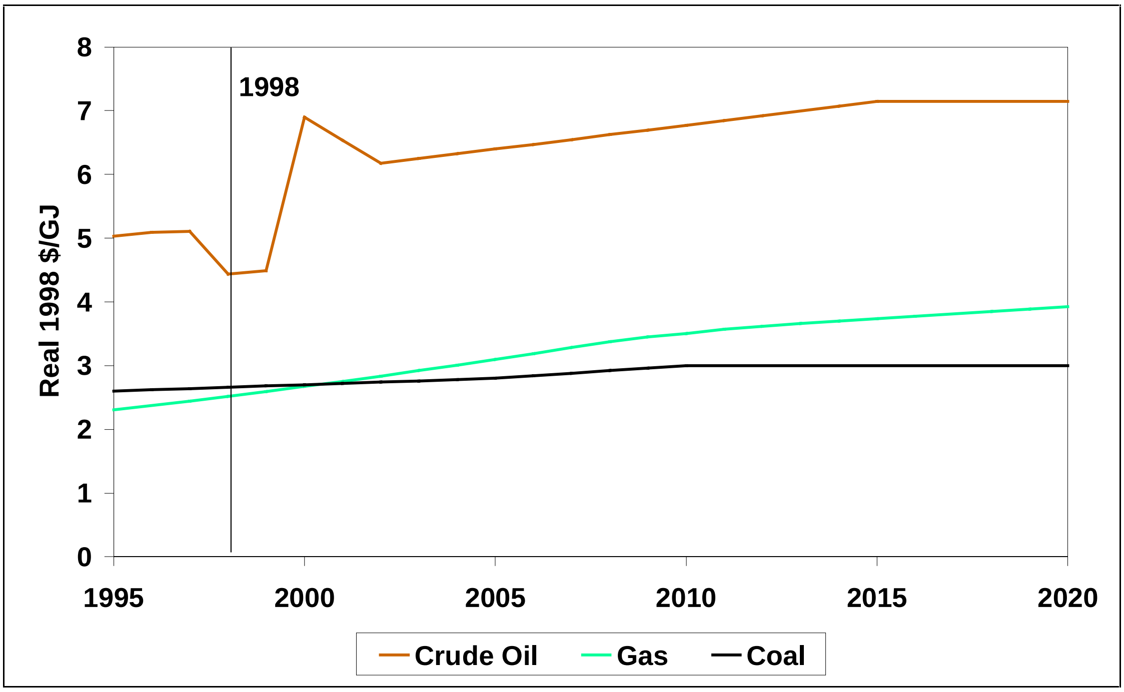
[23] *There is a small but growing world trade in LNG; however, the majority of LNG deliveries are under long-term contract, and the incidence of 'spot' cargoes is still rare. In any event, New Zealand does not have the required infrastructure to accept LNG deliveries, and it is unlikely it will be economic in the foreseeable future.*

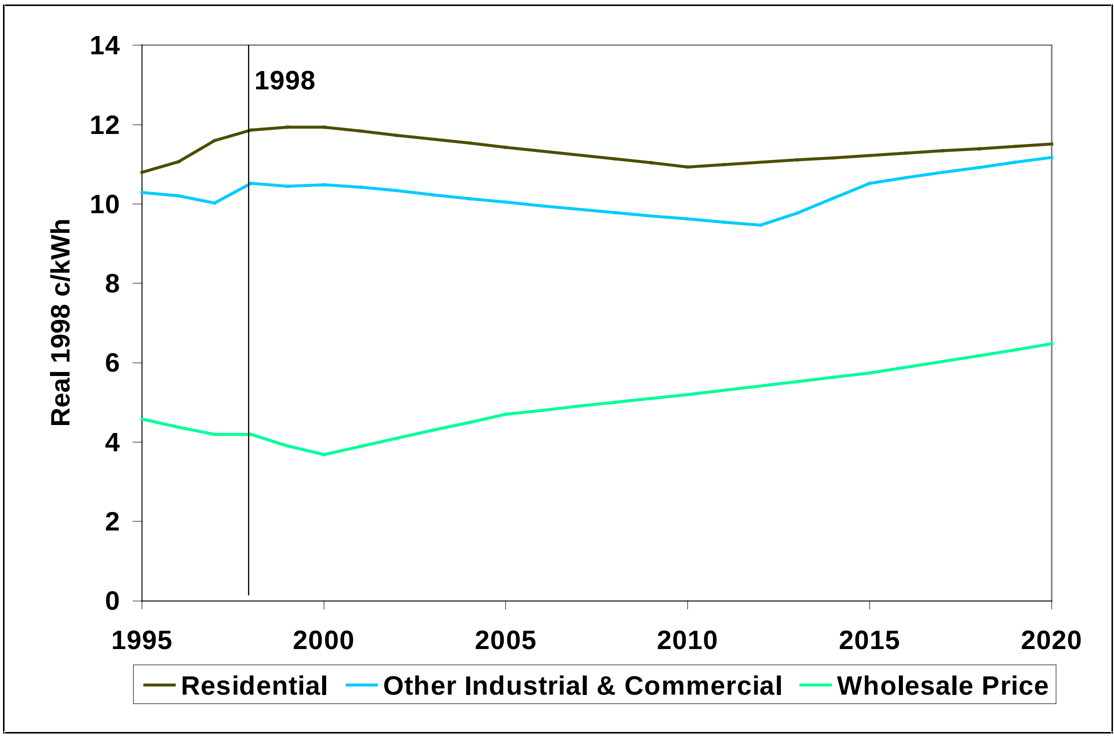
[24] *The SADEM model does not project the level of New Zealand production for coal, or oil. Much of New Zealand's coal requirements are, however, likely to be sourced domestically, prior to 2010. After this the construction of new coal-fired capacity will require significant imports of coal if New Zealand coal is not competitive with internationally traded coal.*

Figure 19: **Wholesale Energy Price Assumptions 1995-2020**



[25]. This is because before new capacity is required generators will not maintain a bidding strategy where prices remain above the cost of new entry for prolonged periods of time. The threat of new entry will effectively cap prices at the cost of new entry.

Figure 20: **Projected Electricity Generation Costs and Delivered Prices 1995-2020**



The baseline electricity expansion profile produces a real wholesale price that is illustrated in Figure 20. The wholesale price to 2005 is an expected average price (a mix of spot and contract prices), thereafter it is very close to the long-run marginal cost (LRMC) of generation[26]. This is due to a balanced expansion of capacity ensuring SRMC and LRMC are very close in most years after 2005. The baseline price declines as a result of excess capacity and increased competition following the split of ECNZ into three generators from around 4.2 c/kWh in 1998, to around 3.9 c/kWh in 2000. It then rises to around 6.5 c/kWh in 2020, as the wholesale price approaches the cost of coal-fired generation with the building of new coal-fired plant in around 2015 and 2020. However, the impact of movements in the wholesale price on the retail price are muted by transmission and distribution costs. This impact is heightened, because the SADEM model projects the per unit transmission and distribution cost to decline over the outlook period.

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[25] *Assuming the estimates of cost and quantity of new plant presented in Box Two on page 11.*

[26] *The long-run marginal cost (LRMC) of generation is not necessarily reached in the year that plant is built; it will vary around this cost depending on the composition of the system at that time and the 'lumpiness' of new capital. This is particularly significant for coal, which relies on economies of scale to reduce its costs.*

The real residential electricity price (see Figures 20 and 21) has risen since 1991 as tariffs have been rebalanced to remove cross-subsidisation and electricity companies have moved to a commercial footing. However, the real residential electricity price is projected to decline between 2000 and 2010[27] from its present high. Two factors are driving this outcome. Firstly, there is the pressure on wholesale prices mentioned above. Secondly, it is assumed that whatever regulatory framework is in place for distribution companies, it will be strong enough to put downward pressure on distribution costs and charges. The factors mentioned above mean that between 2000 and 2010 falling per unit transmission and distribution costs more than offset rises in the wholesale price that occur after the present supply surplus. After 2010 modest declines in the per unit transmission and distribution costs are not sufficient to offset the wholesale price increase, and delivered prices begin to rise[28].

The real other industrial and commercial retail electricity price declines steadily to around 2012 (see Figure 22) as per unit transmission and distribution costs decline faster than wholesale prices rise. However, after 2012 the rising wholesale price offsets the savings from declining per unit transmission and distribution costs, and the price begins to increase, surpassing its 1998 level by 2020 in real terms.

Delivered Energy Prices

To derive delivered energy prices, which are the prices to which consumers respond, requires the modelling of domestic transport, transmission, distribution and retail costs. The SADEM model uses a variety of assumptions to derive these delivered prices. Electricity and gas prices are modelled in the most detail, because more data is available on the supply chain of these fuels.

Delivered coal and oil prices to each sector are derived by assuming that the margins over import, or wholesale prices, are constant in real terms. It can be difficult to ascertain the correct level at which to set these margins when recent historical data have been volatile, or have followed a steady trend, as some judgement needs to be made about their likely long-run level. For electricity and gas the per unit transmission and distribution costs, are projected to fall as demand grows.

Delivered prices to residential consumers are presented in Figure 21. Coal prices for residential consumers are expected to drift slowly higher until 2010, and then remain constant, in line with our assumption for the underlying coal price. Gas prices for domestic consumers have risen in the last few years but are expected to stabilise around 2000 and decline slightly to 2010, as per unit transmission and distribution costs decline sufficiently to offset growth in the wholesale price. However, after 2010 the growth in the wholesale price of gas is likely to offset lower per unit transmission and distribution costs, leading to modest growth in the real delivered price of gas to residential users. The factors affecting residential electricity prices were outlined above. The result is that these prices follow a similar pattern to gas.

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[27] *Statistics New Zealand data indicates that the average residential price (calculated from quarterly movements) in 1999 was around 0.6% higher in real terms than it was in 1998. Figures 20 and 21 are consistent with this.*

[28] *The uncertainty around transmission and distribution costs on a per unit basis over time has become an important modelling issue with regard to retail prices. It is difficult to assess the marginal cost of additional electricity consumption on the transmission and distribution network. The price path presented here thus only presents one view of transmission and distribution costs.*

The delivered prices projected for the other industrial and commercial sector are presented in Figure 22. Electricity prices follow a similar pattern to that in the residential sector, although the delivered price does not begin to rise until around 2012. Gas and coal prices remain essentially flat throughout the projection period. Fuel oil and distillate prices follow the trend in the crude oil price assumption.

Figure 21: **Projected Residential Energy Prices 1995-2020**

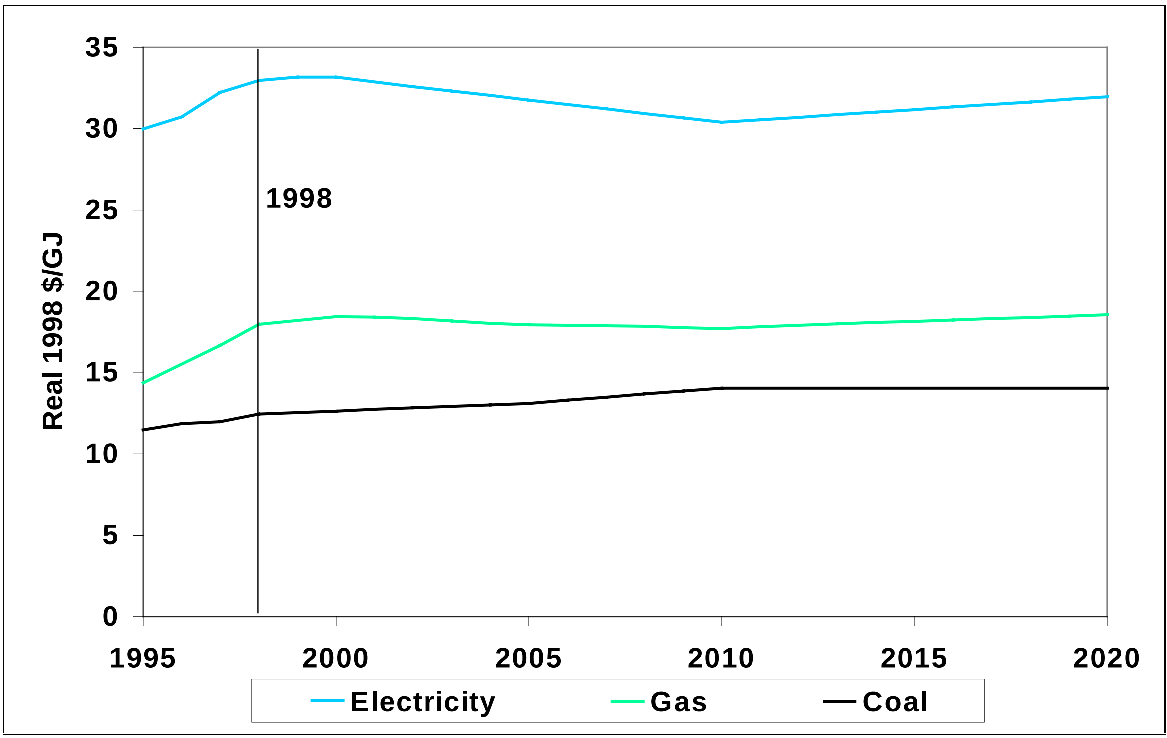
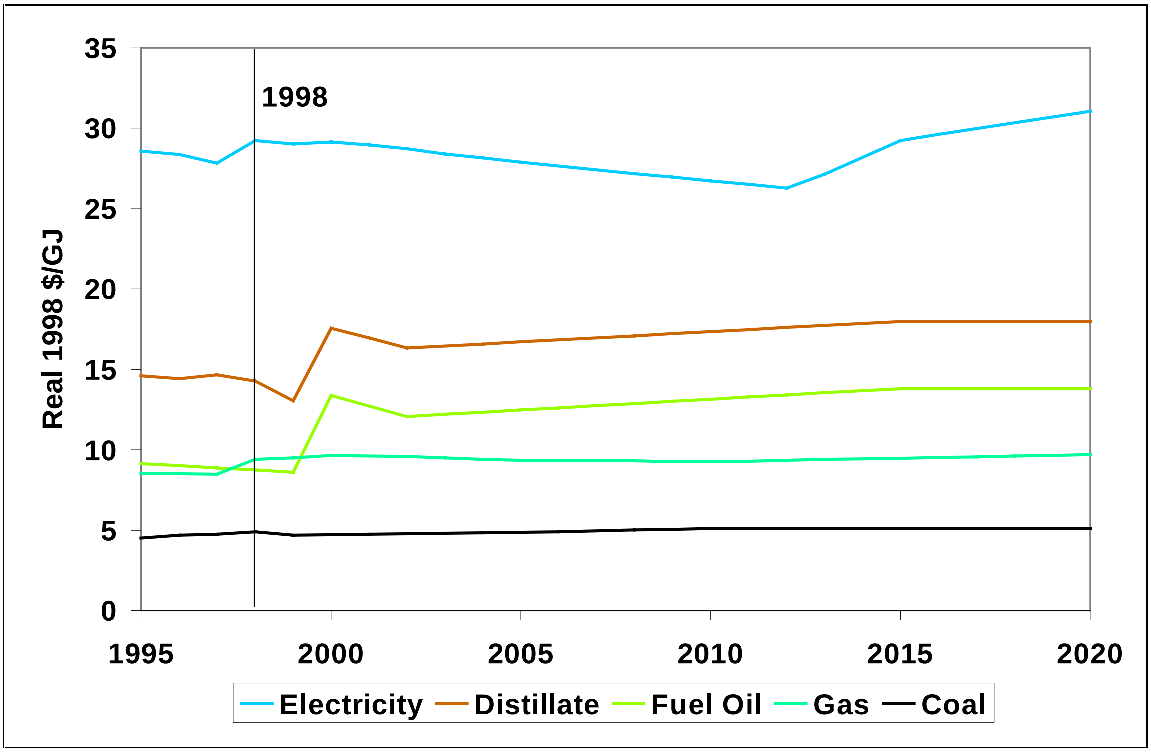


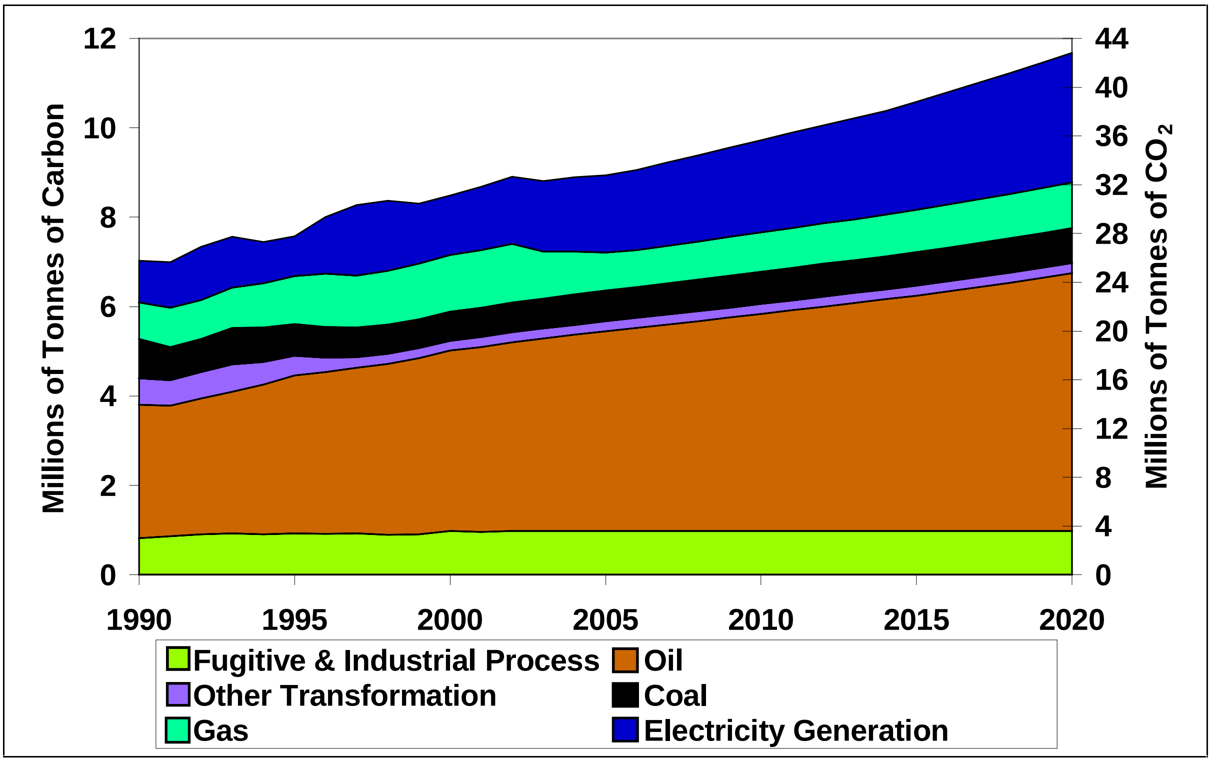
Figure 22: **Projected Other Industrial and Commercial Energy Prices 1995-2020**



CARBON DIOXIDE EMISSIONS

The energy sector contributes around 90% of New Zealand's gross human-made CO_2 emissions[29]. CO_2 emissions from energy sources and industrial processes[30] were about 25.5 million tonnes in the calendar year 1990[31]. Table Seventeen and Figure 23 present the projections of New Zealand's gross carbon dioxide emissions for the baseline scenario (see Box One on page 9) between the calendar years 1990 and 2020 by fuel type.

Figure 23: **Projected Gross CO_2 Emissions by Fuel 1990-2020** *(Calendar Years)*



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[29] *The terms 'carbon emissions' and 'CO_2 emissions' are used interchangeably in this Outlook. CO_2 emissions can be derived by multiplying carbon emissions by 44/12.*

[30] *Emissions from industrial processes are outside the ambit of the SADEM model but are conventionally included in CO_2 inventories and projections.*

[31] *Emissions are reported for calendar years throughout this Outlook. This is consistent with international reporting conventions. The calendar year 1990 is used for the base year comparisons of projections, rather than 1998, as this is the base year for New Zealand's reporting under the Framework Convention on Climate Change.*

Table Seventeen: **Projected Baseline Carbon Emissions by Fuel Type** *(Million Tonnes of Carbon pa)*

Calendar Years	**Coal**	**Oil** (excluding International Transport)	**Gas**	**Electricity Generation and Other Transformation**	**Industrial Processes and Fugitive Emissions**	**Total**
1990	0.77	2.98	0.72	1.66	0.82	6.95
1995	0.67	3.61	0.96	1.29	0.92	7.45
2000	0.65	4.00	1.27	1.55	0.98	8.46
2005	0.68	4.44	0.85	1.73	0.98	8.91
2010	0.72	4.84	0.88	2.29	0.98	9.70
2020	0.78	5.77	1.02	3.13	0.98	11.68

Table Seventeen and Figure 23 present the emissions projections by fuel. Between the calendar year 1990 and 1998[32], energy consumption has increased by around 3.4% pa in the transport sector. All fuel types have also seen increases, but at lower rates, except for the consumer energy of coal, which has declined. From a CO_2 emissions perspective, the increases in emissions from transport and the industrial sector have been counter balanced, to a limited extent, by reductions in emissions from the other transfromation sector. Weather has a significant impact on electricity generation, energy use and hence emissions. The historical data has not been normalised for weather, whereas the projections here assume average inflows and temperatures.

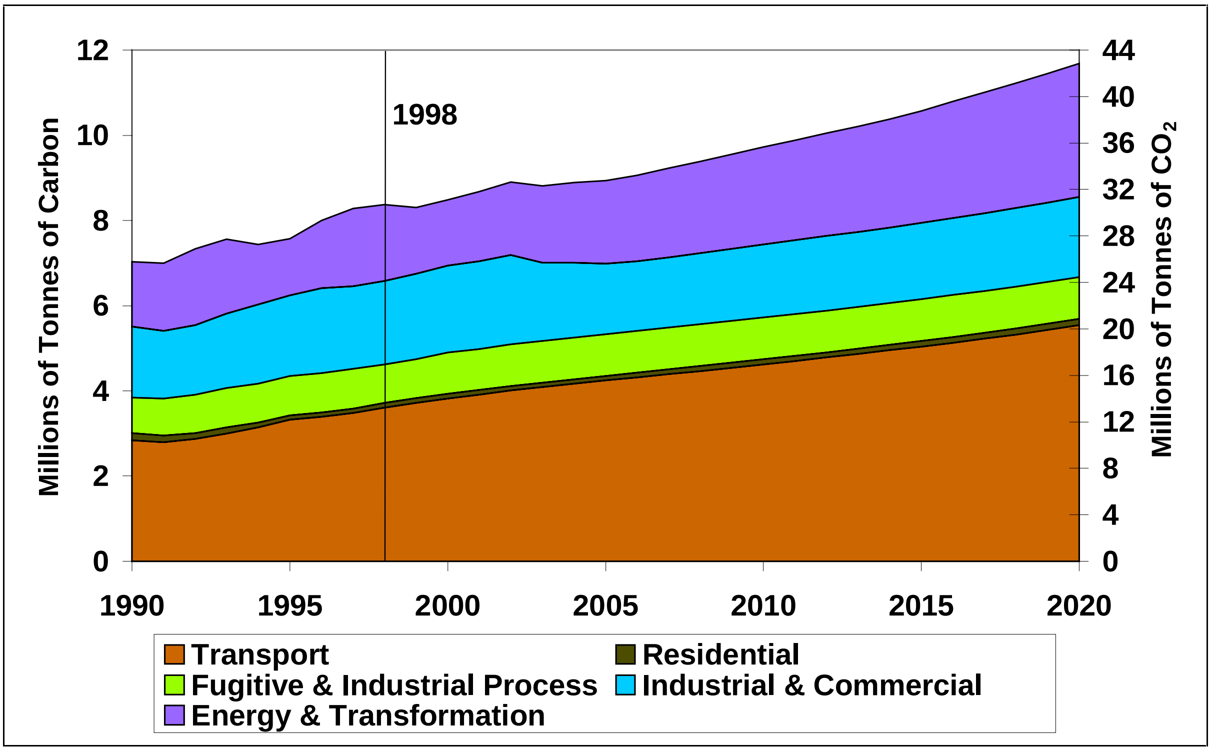
Table Eighteen: **Projected Baseline Carbon Emissions by Sector** *(Million Tonnes of Carbon pa)*

Calendar Years	**Residential**	**Industrial and Commercial**	**Transport**	**Electricity Generation and Other Transformation**	**Industrial Processes and Fugitive Emissions**	**Total**
1990	0.14	1.95	2.39	1.66	0.82	6.95
1995	0.15	2.10	2.99	1.29	0.92	7.45
2000	0.11	2.03	3.79	1.55	0.98	8.46
2005	0.11	1.65	4.21	1.96	0.98	8.91
2010	0.12	1.71	4.60	2.29	0.98	9.70
2020	0.15	1.89	5.54	3.13	0.98	11.68

Over the period 1990 to 2020, CO_2 emissions growth is projected to be around 1.7% pa in the baseline scenario. Table Seventeen and Figure 23 disaggregate this growth into emissions from electricity generation (coal, oil, and gas emissions) and other transformation, coal, oil (excluding international transport, which is reported separately as per current IPCC guidelines), gas and industrial process and fugitive emissions.

[32] *See* New Zealand Energy Greenhouse Gas Emissions 1990-1998, *Ministry of Commerce, 1999, for more details on historical greenhouse gas emissions in New Zealand.*

Figure 24: **Projected Gross CO_2 Emissions by Sector 1990-2020** *(Calendar Years)*



ALTERNATIVE GDP SCENARIOS

There is a significant observable link between energy usage and economic activity. Due to the critical nature of GDP growth to the projections, it is varied in runs of the model to produce a range of energy supply and demand projections to 2020. In terms of sensitivity analysis, variations in projected GDP profiles have the single largest influence on outcomes in the energy sector. In contrast, variations in areas such as projected crude oil prices, or the energy impacts of changing the wood processing assumptions in the forestry sector, have a less significant effect.

This section presents two variants on the baseline scenario. These are:

- a low GDP growth scenario which incorporates short-term GDP projections of GDP growth to 2002, and assumes 2% pa thereafter; and
- a high GDP growth scenario which incorporates short-term GDP projections of GDP growth to 2002 and assumes a 4% pa GDP growth rate to 2020.

Consumer Energy

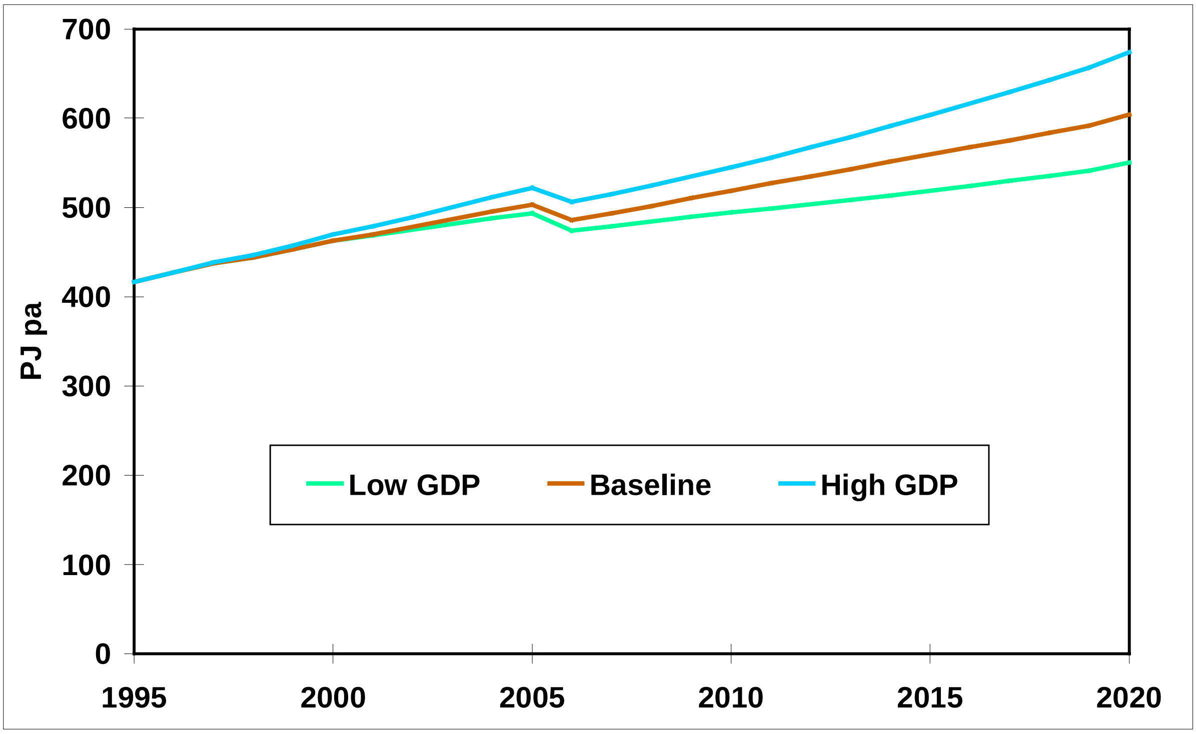
If 4% pa GDP growth were to be sustained between 2002 and 2020, projected consumer energy is 693 PJ (11% higher) in 2020 compared with 623 PJ for the 3% pa GDP growth baseline scenario. If GDP growth were to be 2% pa after 2002, projected consumer energy is 52 PJ (8.4%) lower at 567 PJ in 2020. The consumer energy profiles for the baseline, low GDP and high GDP scenarios are presented by sector in Table Nineteen and Figure 25.

Table Nineteen: **Low and High GDP Consumer Energy by Sector Relative to the Baseline Scenario**
(% Difference from Baseline)

March Years	**Residential**		**Industrial and Commercial**		**Transport**		**Total**	
	Low GDP	High GDP	Low GDP	High GDP	Low GDP	High GDP	Low GDP	High GDP
2005	-0.9%	+0.9%	-1.0%	+1.1%	-1.0%	+1.6%	-1.0%	+1.3%
2010	-4.6%	+4.8%	-3.3%	+2.7%	-3.7%	+4.8%	-3.7%	+4.1%
2020	-11.6%	+13.0%	-7.3%	+8.5%	-9.5%	+12.8%	-9.0%	+11.3%

In the longer term, the residential sector is the most responsive to GDP changes in the SADEM model, with demand in 2020 being around 12% lower than the baseline in the low GDP scenario and 13% higher in the high GDP scenario compared with the baseline. The transport sector is around 9% lower and 13% higher, respectively. The other industrial and commercial sector is the least responsive, with the low GDP scenario being 7% lower and the high GDP scenario being 9% higher than the baseline. This is consistent with the price and income elasticities reported in the last section of this report. The petrochemicals and basic metals sectors are not modelled as being responsive to these scenarios.

Figure 25: **Consumer Energy Profiles for Alternative GDP Scenarios 1995-2020**



RENEWABLE ENERGY SCENARIO

New Zealand is fortunate to be well endowed with significant renewable energy resources that are economic without government subsidies. Development in the past has focused on large hydro and geothermal resources for electricity generation; however, there is also extensive smaller-scale use of these two resources, and significant direct use of geothermal energy. Wood has also continued to play an important role in our economy, particularly for the energy needs of the forestry processing and residential sectors.

It is projected that the renewables share of our energy needs, particularly in electricity generation, will decline over the projection period to 2020, despite significant new renewable capacity being built. This is due to a number of factors, but perhaps the most important is that we have utilised most of the low-cost options available with traditional renewables technology and resources. GCC generating plants, given current gas prices, are very competitive when viewed against the next available renewables alternatives. However, once we have utilised the available gas resource, renewables again become the most economic option for new capacity for a significant tranche of capacity (see Box Two on page 11). However, coal-fired plant then appears finely balanced with a significant quantity of additional renewables capacity around 6 c/kWh.

This scenario examines what would happen to the mix of generation if the situation were such that coal-fired generation was more expensive than the alternative renewables capacity in Box Two, and that there were no new GCC plant built after Otahuhu B. There are a number of circumstances that might combine to create this situation. However, this is a hypothetical scenario for illustrative purposes only, and no particular combination is assumed. Huntly still switches to coal-fired generation by 2000, as it is not assumed anything affects the relative baseline economics of Huntly on coal.

Table Twenty below presents the results of this scenario for the electricity generation sector. Around 250 MW less capacity is required than in the baseline scenario over the period. This is mainly due to the reduction in demand as wholesale electricity prices reach around 8.2 c/kWh in 2020. Significant new distillate capacity, 400 MW, is projected to be economic when the baseline's 2010 GCC and new coal plants are not built. This is to help satisfy the growth in peak demand that the new thermal plants' flexibility helped satisfy in the baseline scenario. The main renewables beneficiaries in this scenario are hydro, geothermal and wind.

Table Twenty: **Projected Economic New Power Station Sequence in the Renewable Scenario** *(MW)*

March Years	**2000***	**2005**	**2010**	**2015**	**2020**	**Total**
GCC	770	-	-	-	-	770
Hydro/Hydro Efficiencies	-	210	170	-	170	550
Geothermal	80	80	50	200	110	520
Cogeneration	220	90	70	80	80	540
Coal	-	-	-	-	-	-
Wind	35	-	50	90	100	275
Distillate	-	-	-	200	200	400
Total	1105	380	340	570	660	3055

** Capacity commissioned, or already under construction.*

Electricity demand, due to the higher cost of generation, grows at 1.6% pa between 1998 and 2020, with electricity demand reaching 162 PJ pa in 2020. This compares to electricity growth of 1.8% pa in the baseline scenario over the same period. Total consumer energy consumption grows at the rate of 1.0% pa in this scenario over the period 1998 to 2020, compared to 1.1% pa in the baseline scenario.

Primary energy supply grows from 652 PJ pa in 1998 to 894 PJ pa in 2020, compared to 872 PJ pa in 2020 in the baseline scenario. The primary energy supply of oil, hydro and geothermal are all higher in 2020 than in the baseline scenario, while the primary energy supply of coal and gas are both lower in 2020, due to the reduced quantity of gas and coal fired-plant built in this scenario.

This scenario has a significant impact on CO_2 emissions, as the emissions from electricity generation are lower as a result of the absence of 300 MW of GCC plant and around 700 MW of coal-fired plant. CO_2 emissions in this scenario reach around 10.90 MtC in 2020 compared to the baseline scenario where emissions reach 11.68 MtC in 2020. This reduction does not come exclusively from the electricity generation sector. A very small reduction in emissions from the residential and other industrial and commercial sectors also contributes to this reduction in emissions compared to the baseline. This is driven by the increased electricity prices that are a consequence of foregoing the cheaper GCC and coal-fired generation options that contribute to satisfying demand growth in the baseline scenario between 2010 and 2020.

Wholesale electricity prices are projected to reach 8.2 c/kWh in 2020, around 27% higher than in the baseline scenario. Delivered residential prices are projected to be 21% higher than the baseline scenario in 2020, as transmission and distribution costs mute the impact of the rise in wholesale prices has on delivered prices.

Non-Traditional Renewable Energy Prospects

The scenario just described is based on the opportunities for currently commercially available renewables technologies to gain a greater share of new capacity requirements post 2000. These are largely what are described as traditional renewables: large-scale hydro and geothermal projects. The SADEM model does, however, also project quite a large contribution from wind generation.

Other non-traditional renewables have the potential to make a real contribution to New Zealand’s energy supply in the future. The development of and increasing information, awareness and understanding of new and emerging renewable energy technologies will increase their uptake in applications where they are competitive with traditional forms of energy supply, most likely in niche applications initially.

The SADEM model includes projections of the contribution that hydro, geothermal, wind and biomass energy (in the forestry sector) are likely to have over the next 20 years. However, there do not appear to be significant quantities of other new and emerging renewable technologies available at, or near, current energy costs. Therefore new and emerging renewable technologies will only be installed where site specific conditions make them economic. This is likely to be on a small scale initially, but as the costs of these emerging technologies are reduced, and energy prices rise, then the opportunities for uptake will increase.

Table Twenty-One outlines the indicative costs of some of the more competitive new and emerging renewable technologies and fuels. Solar technologies perhaps show the biggest potential after wind and biomass, as their installed costs will become very competitive with the delivered cost of electricity if the cost of solar energy continues to decline.

Dedicated fuel crops for wholesale electricity generation, or cogeneration, also have the potential to rival traditional energy sources. The lower cost projections of the fuel cost for biomass in Table Twenty-One are close to current fossil fuel prices. If the renewable technologies can match the capital costs (including fuel processing costs) and efficiency of traditional fossil fuel stations, then their economics will be comparable.

The Ministry's projections include the contribution of the non-traditional renewables of wind, and of wood and pulp residues in wood processing (for heat and electricity generation), because they are projected to become economic, given current technologies. It is possible that non-traditional renewables will play a larger role than projected, given the inherent uncertainty regarding future price levels, manufacturing costs and the relative rates of technological development of renewable and fossil fuel technologies.

Table Twenty-One: **Estimated Costs of New and Emerging Renewables**

	$/GJ	c/kWh
Solar		
Solar thermal for water heating		13 - 16
Photovoltaics (currently)		30 - 60
Photovoltaics (probable in 2005)		15 - 20
Biomass Fuels		
Forest arisings	3 - 8.7	
Wood process residues	0 - 6.4	
Short rotation plantations	1.6 - 5.0	
Energy crops	0.6 - 8.0	
Municipal solid waste	3.2 - 5.6	
Bioenergy Conversion Costs		
To convert into heat add to fuel cost	2.5 - 3.0	
To convert into electricity (5 - 100 MW) for fuel cost of:		
$0/GJ		7 - 9
$2/GJ		11 - 13
$5/GJ		14 - 16
Biogas from organic wastes		2 - 5
Biogas from green crops		11 - 18
Landfill gas		5 - 7
Water		
Small hydro <10 MW (315 MW available)		5 - 10
Wind		
Wind farms (best sites)		6 - 8

Source: EECA and Centre for Advanced Engineering, University of Canterbury, 1996, New and Emerging Renewable Energy Opportunities in New Zealand.

ALTERNATIVE OIL PRICE SCENARIOS

Varying the baseline assumptions on the long-run price of oil have their major impact on the transport sector and have only a small (direct) impact on the other energy consuming sectors. The primary effect is via the price mechanism and a smaller inter-fuel (price) substitution effect in those sectors where oil (products) compete with other forms of energy.

Impacts on the transport sector are muted, as the price of crude oil is not a dominant component of the final pump price of petroleum products, being around 16-33% of the pump price of petrol and around 35-55% of the pump price of diesel. When combined with the low price responsiveness of transport demand, changes in the profile of crude oil prices have relatively little impact on the demand for petroleum products.

Two alternative oil price scenarios have been considered – a high-price and a low-price scenario.

The high-price scenario assumes a price of around US$21/bbl in 2000, which then rises to $28/bbl in 2015 before stabilising for the rest of the projection period. This scenario has negligible effect on the demand for oil, reducing demand by around 1.0% compared to the baseline, with almost all the effect occurring in the land transport sector. As expected, new incremental distillate-fired peaking capacity becomes less attractive vis-à-vis other forms of meeting peaking demand, and slightly less capacity is built in the electricity expansion profile.

The low oil price scenario assumes the oil price falls from around US$21/bbl in 2000 to US$15/bbl in 2015 before remaining constant. This scenario suggests that oil demand would be around 1.3% higher by 2020. Land transport energy demand could be 1.8% higher than the baseline by 2020 with a 1.0% increase in aggregate consumer energy demand. With a lower aggregate price for energy, there are also small increases in the demand for the other energy types. However, the decrease in oil prices is not sufficient to induce more distillate fired electricity generation capacity than is economic in the baseline scenario.

ALTERNATIVE NEW GAS DISCOVERY SCENARIOS

The future level of gas discoveries is an uncertainty in any scenario of the New Zealand energy sector. Gas is a (relatively) clean, high value fuel, and plays an important role in our energy sector and economy. The depletion of the Maui gas field in around the next ten years represents a unique challenge for the New Zealand energy sector.

The baseline scenario assumes that new gas discoveries are around 80 PJ pa; however, two additional scenarios have also been explored. These are a high gas availability scenario, where 120 PJ pa of new gas discoveries is assumed and a low gas availability scenario, where around 40 PJ pa of new gas discoveries are made. These three scenarios together are designed to provide an illustration of how the New Zealand energy sector might develop under a range of gas discoveries assumptions.

Gas Prices and Reserves

Where the supply of gas is constrained by limited new discoveries, the price will rise as reserves are more rapidly depleted. Conversely, where supply is relatively more abundant, lower prices would be expected. Table Twenty-Two below presents the gas price assumptions for the low new gas discoveries, baseline, and high new gas discoveries scenarios. In the high new gas discoveries scenario the wholesale price rises only slowly to around $2.95/GJ in 2010. In the low new gas discoveries scenario prices still only reach $3.50/GJ in 2010, but after the depletion of the Maui field, at which time supply comes under more pressure, prices then rise more steeply reaching around $4.65/GJ in 2020.

Table Twenty-Two: **Alternative Wholesale Gas Price Assumptions 1998-2020** *($/GJ)*

March Years	**Low Gas Discoveries**	**Baseline Scenario**	**High Gas Discoveries**
1998	2.52	2.52	2.52
2000	2.67	2.67	2.52
2005	3.10	3.10	2.75
2010	3.50	3.50	2.95
2020	4.65	3.92	2.95

Neither, the high or the low gas discoveries scenario is considered to affect the assumption that the petrochemicals plants will close with the expiry of their Maui contracts in 2003 and 2005.

The reason there is no difference in the price profiles of the baseline and low new gas discovery scenarios prior to 2011 is because the lower level of new discoveries does not have a significant impact on gas availability relative to the baseline prior to the depletion of the Maui field.

In the baseline and high new gas discoveries scenarios the reserves-to-production ratio declines to around eight and nine years respectively in 2020. In the low new gas discoveries scenario the reserves-to-production ratio declines to around six years in 2020, implying that further price rises would be expected.

Consumer Energy and Primary Energy Supply

In the low new gas discoveries scenario, consumer energy is around 1% higher than in the baseline scenario in 2020, as slightly less gas use in the industrial and commercial sector is replaced, in part, by coal[33]. In the high gas discoveries scenario, consumer energy is fractionally less than in the baseline scenario in 2020. However, due to the more competitive price of gas in this scenario, gas increases its share of the consumer energy purchased in the residential and other industrial and commercial sectors.

The major differences occur in the projected primary energy supply in 2020. In the low new gas discoveries scenario, New Zealand's primary energy supply is around 3% higher, at around 897 PJ pa in 2020, compared to the baseline figure of 872 PJ pa. However, this moderate difference in total primary energy supply hides significant differences in the coal and gas figures. The primary energy supply of gas is around 29% lower at 96 PJ pa in 2020 in the low gas scenario, compared to the baseline figure of around 134 PJ pa. Most of this difference is attributable to electricity generation. Coal is the chief beneficiary, increasing its primary energy supply from around 108 PJ pa in 2020 under the baseline scenario, to around 169 PJ pa under the low gas discoveries scenario (around 56% higher[34]).

New Zealand's primary energy supply is around 868 PJ pa in 2020 under the high gas discoveries scenario, or around 0.5% lower than the baseline scenario. The primary energy supply of gas recovers from a low in 2006 to reach around 165 PJ pa in 2020 under this scenario. This is around 23% higher than the baseline scenario's figure.

Electricity Generation

The increase in gas prices in the low new gas discoveries scenario is insufficient to make the GCC that is economic in 2010 in the baseline uneconomic, but, only 260 MW becomes viable. The subsequent gas price rises relative to the baseline also affect the level of operation of all the gas plant. Compared to the baseline scenario, the low new gas discoveries scenario requires around 185 MW more coal-fired plant, around 30 MW less hydro, and no new distillate capacity. Total new capacity built is around 3255 MW, or 50 MW less than in the baseline scenario. However, there is actually around 75 MW more baseload capacity built in the low new gas discoveries scenario to satisfy slightly higher electricity demand (due to an increase in market share) than in the baseline scenario.

In the high new gas discoveries scenario, the total new capacity projected to be economic is coincidentally 3255 MW. The GCC plant in 2010 is economic at 300 MW, although we continue to assume that this level of new discoveries is still insufficient to support additional GCC capacity. Huntly does not switch to coal given gas prices do not pass the price of coal at $3/GJ. Slightly less coal-fired capacity is required, because Huntly and all the new GCCs can run slightly harder with a lower gas price. The level of new wind, hydro, geothermal, cogeneration and distillate capacity projected to be economic is almost identical to the baseline scenario.

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[33] *Gas use in the industrial and commercial sector yields twice as much useful energy (after losses in the conversion process) as coal does. Thus if coal replaces gas in this sector, around twice as much will be required to provide the same level of service.*

[34] *The disproportionate change is due to the lower assumed efficiency of new coal-fired plant, and the fact that Huntly is generating even harder on coal under this scenario at a lower efficiency than new coal plant.*

Carbon Dioxide Emissions

The importance of gas in the electricity and industrial sectors means that changes in the pattern of gas use have an important impact on carbon emissions. Table Twenty-Three below compares the carbon emissions under the low new gas discoveries, the baseline, and the high new gas discoveries scenarios.

Emissions are marginally higher in the low new gas discoveries scenario after 2005 as reduced gas-fired generation is replaced by increased coal-fired generation. This results in increased emissions given that coal contains almost twice the level of carbon and cannot operate at the efficiency of modern GCCs. This upward pressure on generation emissions is compounded by the projected increase in market share of electricity and coal in the other industrial and commercial sectors as a result of the relatively higher gas price in this scenario. By 2020 carbon emissions are therefore projected to be around 9.5% higher in the low new gas discoveries scenario than in the baseline scenario.

Table Twenty-Three: **Carbon Emissions under Alternative Gas Discovery Scenarios 1990-2020** *(MtC)*

Calendar Years	**Low Gas Discoveries**	**Baseline Scenario**	**High Gas Discoveries**
1990	6.95	6.95	6.95
1995	7.45	7.45	7.45
2000	8.46	8.46	8.19
2005	8.99	8.91	8.53
2010	9.85	9.70	9.28
2020	12.79	11.68	11.24

The high new gas discovery scenario results in lower emissions than in the baseline. This is predominantly due to Huntly not switching to coal, and more gas generation from the GCC plants at the expense of new coal-fired plant. This results in less than half the level of coal-fired generation in 2020, compared to the baseline in this scenario, and almost 44% more gas-fired generation in 2020. Overall carbon emissions are projected to be around 3.8% lower in the high new gas discoveries scenario than the baseline scenario in 2020.

ALTERNATIVE FORESTRY PROCESSING SCENARIO

New Zealand's exotic forest estate has grown steadily throughout the 1980s and 1990s. The level of new area planted each year is such that the projected wood harvest is set to double by 2020. The baseline scenario assumes that 50% of the growth in wood offtake, above 1998 levels, over the outlook period will be processed domestically, with an even split of this between pulp and paper and less energy intensive processing options assumed. The remaining 50% of the wood harvest is assumed to be exported as logs.

To examine a more optimistic domestic processing scenario it was assumed that all the increase in wood offtake above the 1998 level is processed domestically. It was still assumed that this would then be split 50/50 between pulp and paper, and less energy-intensive processing options (medium-density fibreboard, sawn timber etc).

Table Twenty-Four presents the projected energy consumption in the forestry sector if all the growth in forestry offtake over and above the 1998 level is processed in New Zealand.

Table Twenty-Four: **High Forestry Processing Scenario Consumer Energy Demand 1995-2020** *(PJ pa)*

March Years	**Electricity**	**Gas**	**Sub-Total**	**Coal**	**Oil**	**Wood and Other**	**Total**
	(Included in Forestry Consumer Energy)			***(Not included in Forestry Consumer Energy)***			
1995	11.6	8.4	19.9	2.1	1.7	33.0	56.7
1998	9.8	7.7	17.4	1.6	1.2	29.2	49.3
2000	13.6	9.2	22.7	1.9	1.4	35.4	61.4
2005	17.3	11.7	29.0	2.4	1.8	45.2	78.3
2010	21.8	17.3	39.1	3.5	2.6	67.4	112.5
2020	22.9	18.7	41.6	3.8	2.8	73.4	121.6

In 2020 energy demand in the forestry sector is projected to be 46% higher in total than in the baseline scenario. Electricity and gas demand, the only fuels to be included in the forestry consumer energy totals, is projected to be 38% higher. This is because electricity is only projected to be around 35% higher than the baseline in 2020. This compares to the other fuels (including those not included in the forestry sectors consumer energy), which are projected to be 48% to 51% higher in 2020 than in the baseline scenario.

Although, this scenario projects significantly higher forestry sector consumer energy in 2020, total consumer energy in 2020 is only around 1.8% higher than in the baseline scenario. Electricity demand in 2020 is around 2.9% higher than in the baseline. Around 95 MW of additional cogeneration capacity is installed, much of this in the forestry sector, while an extra 45 MW of coal plant is required to satisfy demand growth. An additional 45 MW of renewables capacity is also economic. This is balanced by the fact that 125 MW of distillate plant is now uneconomic. CO_2 emissions are projected to be virtually identical to the baseline in 2020, as the additional renewables and cogeneration capacity reduce electricity generation emissions, offsetting the emissions growth from increased gas consumption in the forestry sector.

ALTERNATIVE ENERGY EFFICIENCY SCENARIO

This section examines a high energy efficiency scenario, where energy efficiency is assumed to increase at a rate faster than in the baseline. Although, the baseline scenario includes the rate of so-called autonomous energy efficiency improvement (AEEI), it is interesting to examine the impact of a faster uptake of energy efficiency. The scenario proposed is not an estimate of what is possible; it is simply a presentation of the impact of a higher rate of energy efficiency improvement. Similarly, no assessment of the policies or measures, nor estimates of the economics or feasibility, of a programme designed to yield this level of energy efficiency improvement has been conducted. In any event, estimates of the cost and scope for increased energy efficiency over and above the AEEI level vary dramatically and are difficult to compare.

Improvements in energy intensity since around 1992 (excluding the effect of the petrochemicals plants) as measured by the amount of energy required to produce a unit of GDP are encouraging. However, it is not possible to accurately separate out what component of this improvement is due to improved energy efficiency, and what components are due to a wide range of other factors. In particular the improvement may be due to a shift in the mix of the economy to lower energy intensity activities vis-à-vis higher energy intensity activities, or to changes in the value of the economy's mix of outputs. Neither of these imply improved energy efficiency, but they do result in a lower energy intensity.

In the high energy efficiency scenario, we postulate a situation whereby the residential and other industrial and commercial sectors improve their energy efficiency sufficiently above the historical AEEI rate to reduce energy **consumption** by 0.75% pa[35]. Given the issues faced in the transport sector, it is assumed that the baseline consumption is reduced by 0.5% pa.

This scenario results in reduced sectoral energy demand, electricity system requirements, electricity wholesale price and carbon emissions as shown in the following tables. Table Twenty-Five presents the reduction in total energy consumption, and the reduction in consumption in by sector, that occurs in the high energy efficiency scenario when compared with the baseline scenario.

Table Twenty-Five: **Energy Efficiency Scenario Consumer Energy by Sector (vs Baseline)**

March Years	**Residential (-0.75% pa)**	**Industrial and Commercial (-0.75% pa)**	**Transport (-0.5% pa)**	**Total**
2005	-4.5%	-2.7%	-2.2%	-2.6%
2010	-8.4%	-5.6%	-4.0%	-4.5%
2020	-13.2%	-9.0%	-7.4%	-8.6%

[35] *It is necessary to reduce consumption directly, rather than increase energy efficiency, because there is no accurate time-series measurement of energy efficiency.*

Table Twenty-Six presents the reduction in energy consumption compared to the baseline by fuel.

Table Twenty-Seven identifies the reduction in new electricity capacity required, the change in the primary energy supply, and the change in CO_2 emissions relative to the baseline scenario. The 10% reduction in electricity demand relative to the baseline in 2020 means that substantially less new capacity is projected to become economic over the outlook period. Electricity demand growth remains sufficiently low to mean no new thermal plant (excluding cogeneration plant) becomes economic after 2000.

Table Twenty-Six: **Energy Efficiency Scenario Consumer Energy by Fuel (vs Baseline)**

March Years	**Electricity**	**Oil**	**Gas**	**Coal**
2005	-3.4%	-2.3%	-2.3%	-2.9%
2010	-6.3%	-4.2%	-6.4%	-5.5%
2020	-10.0%	-7.6%	-10.9%	-8.6%

This, and the reduction in consumer energy demand, leads to New Zealand's primary energy supply being projected to be around 10% lower than the baseline scenario in 2020. The lower thermal generation and consumer energy demand mean that carbon dioxide emissions are projected to be around 14% lower than the baseline scenario in 2020.

Table Twenty-Seven: **Energy Efficiency Scenario - Other Impacts (vs Baseline)**

March Years	**Electricity System**	**Primary Energy Supply**	**CO_2 Emissions**
2005	0	-3.0%	-5.1%
2010	-385 MW	-6.6%	-6.8%
2020	-1011 MW	-10.4%	-13.7%

CARBON DIOXIDE PRICE SCENARIOS

The baseline scenario assumes current policy settings, and specifically, no cost for emitting CO_2[36] (see pages 37 to 39 for the baseline CO_2 emissions). This section presents the effects on the energy sector of changing this assumption by modelling two CO_2 price scenarios. These scenarios are for illustrative purposes and **do not** represent government policy.

New Zealand is a signatory to the Kyoto Protocol ('the Protocol'). Subject to New Zealand ratifying the Protocol, and its entry into force, New Zealand's target will be to stabilise greenhouse gas emissions at 1990 levels, on average, over the first commitment period, 2008-2012.

It is important to note that the Protocol covers six greenhouse gases[37]. The analysis in this section covers only CO_2 emissions from the energy sector and industrial process emissions. The other five gases are not part of this analysis, neither are forest sinks, for which the Protocol makes provision. Accordingly, the material in this section does not relate directly to New Zealand's targets under the Protocol.

The scenarios for CO_2 pricing between 2005 and 2020 presented in this section indicate that, if the international price of CO_2[38] reached \$NZ13.9/tCO_2 in 2012, before levelling off, then energy and industrial process carbon emissions in 2020 would be around 13% lower than in the baseline scenario. If the price of CO_2 reached \$NZ34.7/tCO_2 in 2012, before leveling off, then carbon emissions in 2020 would be around 22% lower than in the baseline scenario. The low CO_2 price scenario results in a cumulative reduction in CO_2 emissions of 12.8 MtC below the baseline in 2020. The high CO_2 price scenario results in a cumulative reduction in CO_2 emissions of 30.5 MtC below the baseline by 2020 (each scenario has CO_2 pricing commencing in 2005).

It should be reiterated that the SADEM model is a partial equilibrium model of the New Zealand energy sector. Interaction with the wider economy, other sectors that emit GHGs, and the rest of the world are all outside the ambit of the model[39].

The model provides for much of energy demand to respond automatically to the changing price signals stemming from CO_2 pricing, ie, for those sectors where econometric techniques are used. However, it is less capable of providing a robust mechanism for assessing the short-run response to price signals in some of the large energy consuming sectors which are dominated by one or two

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[36] *However, the baseline does include the effects of existing climate change policy. This was implemented in 1994 by the previous government, and includes voluntary agreements with industry, energy market reforms and an energy efficiency strategy.*

[37] *The six greenhouse gases covered by the Protocol are carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulphur hexafluoride.*

[38] *The term 'price of* CO_2*' is used in this chapter (consistent with the terminology used in international policy development), although, emissions are reported in terms of carbon to be consistent with the rest of this Outlook.*

[39] *Refer to the* Introduction *(Page 1) for a fuller description of the SADEM model, its strengths and limitations.*

firms. In these sectors the magnitude of the response and the assumed 'lag' structure of the response (reflecting long-run capital stock replacement) has to be assessed and set manually[40].

Background

In January 1999, the then government released a Policy Options Statement[41] setting out the preferred long-term policy for the first commitment period (2008-2012) - domestic emissions trading interfacing with the international trading system. The statement also set out three policy options for the period prior to 2008. The statement has been used as a guide for devising the assumptions of the scenarios modelled in this section.

New Zealand's energy and industrial process emissions are projected to grow under the baseline scenario to reach around 2.8 MtC (10 Mt CO_2) more than 1990 levels in 2010. The inclusion in the Protocol of international emissions trading, means that countries do not necessarily have to reduce their emissions back to the target level. Instead, to supplement domestic reductions, countries can purchase emissions units in the international market to offset their emissions (in effect, pay for emission reductions to take place elsewhere). Another important point to note is that the inclusion of international trading is likely to result in a single international price for emissions during the target period. The prices used in the scenarios are based on estimates for the international price (further discussed below).

The two scenarios could represent an explicit price, ie, a CO_2 charge or tradeable permits, or an implicit price, the present value of the expected future price of CO_2 during the target period which firms would factor into current investment decisions if they were forward looking, and there was no uncertainty. Whether implicit or explicit, these scenarios assume there will be an effective price on CO_2 emissions, and hence an impact on the use of energy.

CO_2 Price Assumptions

This section outlines the methodology for determining the CO_2 price path for the period 2005 to 2020. To allow for the significant uncertainty involved in estimating where the internationally traded price of CO_2 over the period 2008-2012 might settle, two estimates of the price of CO_2 in 2010 are used. The low CO_2 price scenario assumes that the price of CO_2 is NZ$12/t$CO_2$ in 2010 (see Table Twenty-Eight), while the high CO_2 price scenario assumes that it is NZ$30/t$CO_2$ in 2010[42]. The high and low prices for emissions in 2010 are based on a range of values from international modelling studies reported in Ministry for the Environment (1999)[41].

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[40] *There are no 'leads' in any of the sectors, or models. Agents in the model only respond to price and income signals in the period in which they occur, ie, are introduced into the model, and subsequent periods where short and long run elasticities have been estimated. Implicit prices, which include discounted prices in the model in periods prior to their 'actual' introduction act as a proxy for forward looking agents.*

[41] *MfE* Climate Change: Domestic Policy Options Statement, *Ministry for the Environment, January 1999, Wellington.*

[42] *These are equivalent to $44/tC and $110/tC in 2010, for the low and high CO_2 price scenarios respectively.*

The price in 2010 is escalated to 2012 at 7.5% pa, reaching NZ$13.90/t$CO_2$ and NZ$34.70/t$CO_2$ for the low-price and high-price scenarios respectively. It is assumed that the price of CO_2 is then held constant at the 2012 level for the rest of the projection period[43].

The price of CO_2 between 2005[44] and 2010 is determined by assuming that the price of CO_2 in any year is kept constant in real terms at the 2010 level. This is achieved by discounting back from 2010 at a rate of 7.5% pa. The low CO_2 price scenario therefore has a price of NZ$8.10/t$CO_2$ in 2005 (see Table Twenty-Eight), whereas the high CO_2 price scenario has a price of NZ$20.30/t$CO_2$ in 2005.

Table Twenty-Eight: **Carbon Dioxide Price Scenarios** *(NZ$/t$CO_2$)*

March Years	**Low Carbon Dioxide Price Scenario** ***(NZ$/t$CO_2$)***	**High Carbon Dioxide Price Scenario** ***(NZ$/t$CO_2$)***
2000	0.0	0.0
2005	8.1	20.3
2010	12.0	30.0
2012	13.9	34.7
2020	13.9	34.7

Table Twenty-Nine presents the impact of the CO_2 pricing in 2012 when converted from an emissions basis (per tonne of CO_2) to an energy basis (per GJ). This conversion is based on the CO_2 content of each fuel. As a result, more carbon-intensive fuels face a larger rise in their costs[45]. However, the figures in Table Twenty-Nine do not represent the increase in the price of each fuel. This depends on the portion of this cost that is passed on to consumers, which in turn depends on the interaction of supply and demand.

Table Twenty-Nine: **Carbon Dioxide Price Scenarios Impact on Prices in 2012 with Inelastic Demand**

	Coal ***(NZ$/GJ)***	**Diesel and Fuel Oil** ***(NZ$/GJ)***	**Petrol** ***(NZ$/GJ)***	**Gas** ***(NZ$/GJ)***
Low Carbon Dioxide Price Scenario	1.37	0.96	0.93	0.73
High Carbon Dioxide Price Scenario	3.42	2.39	2.31	1.83

[43] *This assumption reflects the significant uncertainty regarding the possible targets for the second commitment period and the uncertainty regarding the supply (possible broader country participation) and demand (possible 'deeper' targets) of permits, with the likely balance unknown.*

[44] *2005 is used as a notional start date for domestic trading, or the start of an implicit price for CO_2.*

[45] *Electricity is a special case, because it is produced from a number of fuels, and the pricing of electricity is based on the marginal cost of generation, which is in turn capped in the long run by the cost of new entry capacity.*

Consumer Energy

Under the low CO_2 price scenario, New Zealand's consumer energy is projected to reach around 584 PJ pa in 2020, or around 6% lower than the baseline scenario. In the high CO_2 price scenario, consumer energy demand is projected to reach 556 PJ pa in 2020, or around 11% lower than the baseline. Table Thirty presents the percentage differences from the baseline of each of the two scenarios. However, because some sectors of the model need to be adjusted manually, the short-term adjustments implied by the model projections presented here should be treated with caution.

Table Thirty: **Consumer Energy Demand in the Carbon Dioxide Price Scenarios**

(% Difference from Baseline)

March Years	**Low Carbon Dioxide Price Scenario**	**High Carbon Dioxide Price Scenario**
	2005 Start	**2005 Start**
2005	-1%	-6%
2010	-2%	-9%
2020	-6%	-11%

Table Thirty-One presents the projected reduction in consumer energy demand relative to the baseline scenario for each CO_2 price scenario in 2010 and 2020 by sector. There is little reduction in transport demand, due to the low price responsiveness of the estimated petrol and diesel models (see the additional topics below) and the fact that the existing taxes and levies on petrol moderate the percentage increase in the price of petrol that would occur as a result of carbon pricing. Air and sea transport energy consumption is also little reduced as a result of CO_2 pricing at these levels.

Table Thirty-One: **Consumer Energy Demand by Sector in the Carbon Dioxide Price Scenarios**

(% Difference from Baseline)

March Years	**Residential**		**Industrial and Commercial**		**Transport**		**Total**	
	Low CO_2 Price	**High CO_2 Price**	**Low CO_2 Price**	**High CO_2 Price**	**Low CO_2 Price**	**High CO_2 Price**	**Low CO_2 Price**	**High CO_2 Price**
2010	-1%	-1%	-5%	-21%	1%	-2%	-2%	-9%
2020	-3%	-4%	-16%	-24%	-1%	-3%	-6%	-11%

The industrial and commercial sector is the sector most affected by the price changes induced by the rising price of CO_2. This is to be expected, given the relatively higher price responsiveness of the industrial and commercial sectors compared to the residential and transport sectors. It also reflects the impact of CO_2 pricing on the large carbon intensive industries.

In the residential and other industrial and commercial sectors, coal loses market share to the less carbon intensive fuels and electricity, while gas also loses some market share. However, under the high CO_2 price scenario, fuel oil is projected to gain market share in the other industrial and commercial sector, offsetting the decline in coal demand in the South Island, where gas is not an option for industrial users. Consumer energy demand for coal in 2020 is projected to be around 45% lower than in the baseline scenario in 2020 in the low CO_2 price scenario and around 70% lower in the high CO_2 price scenario. The consumer energy demand for gas in 2020 is projected to be around 19% and 37% lower than the baseline under the low and high CO_2 price scenarios respectively.

Electricity Demand and Supply

Electricity demand is projected to be only around 1% lower in 2020 than the baseline in each scenario. This reflects electricity's gain in market share at the expense of fossil fuels, particularly in the other industrial and commercial sector. However, there is a limit to the extent that electricity can be economically substituted for fossil fuels in many applications. This means that there will still be a core demand for coal, oil, and gas, albeit at reduced levels.

New electricity capacity requirements are projected to remain significant, although the balance of generation and new capacity change significantly under each of the CO_2 price scenarios when compared to the baseline scenario.

The low price for CO_2 scenario projects that around 200 MW less new capacity[46] than the baseline will be required over the entire outlook period (ie, the cumulative total), while the high CO_2 price scenario requires 260 MW less. However, this comparison becomes much closer when the little run 125 MW of distillate plant economic in the baseline is subtracted, as it is uneconomic in both CO_2 price scenarios. The remaining reduction in capacity requirements is due to the slightly reduced demand, the harder running of existing capacity, and the dedicated baseload nature of most of the new capacity[47] in the CO_2 price scenarios.

The increased cost of running existing thermal plant, and the increase in the cost of new thermal generation options, increases the price of electricity and allows more renewables options to become economic than in the baseline.

The low CO_2 price scenario projects that 65 MW more hydro capacity than in the baseline will be economic over the entire outlook period to 2020, 70 MW more geothermal, 95 MW more cogeneration, and 120 MW more wind. This is balanced by 375 MW less coal, 125 MW less distillate plant, and 50 MW less GCC plant.

The high CO_2 price scenario projects that 205 MW more hydro capacity than in the baseline will become economic over the entire outlook period to 2020, 150 MW more geothermal, 95 MW more cogeneration, and 140 MW more wind. This is balanced by 675 MW less coal, 50 MW less GCC, and 125 MW less distillate plant (see Figure 25 for a representation of economic capacity between 2000 and 2020).

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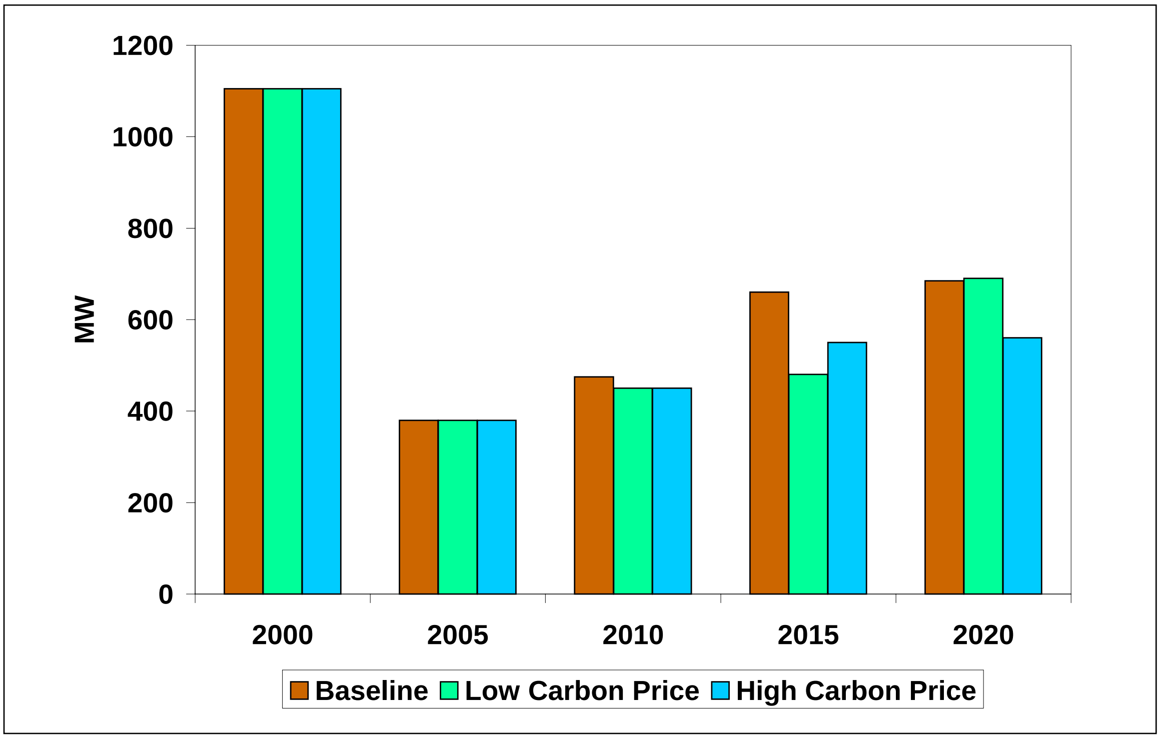
[46] *The electricity simulation is run every five years, examining supply and demand in 2000, 2005, 2010, 2015 and 2020, and interpolating between them.*

[47] *Coal is favoured ahead of other plant that could satisfy new capacity requirements in the baseline around 2015 and 2020, not only on price, but also for its flexibility in meeting mid-merit demand economically. As a result it is unlikely to operate purely in baseload mode as renewables plant generally do, reducing its load factor, and contribution to generation below that of renewables on a per MW basis.*

In 2015 (Figure 26) the low CO_2 price scenarios economic new capacity is reduced, as the coal plant that is economic in the baseline is delayed until 2020. The high CO_2 price scenario builds around 80 MW more capacity in 2015 than the low CO_2 price scenario. This is due to the high CO_2 scenario pushing more existing thermal plant from mid-merit to a peaking role. This makes additional renewable capacity economic earlier than in the low CO_2 scenario. Note in 2020 the corresponding reduction in new capacity that is economic in the high CO_2 scenario compared to the low CO_2 price scenario. The capacity in 2015 was not additional, only brought forward from 2020.

Figure 26: **Projected New Electricity Capacity: Carbon Dioxide Price Scenarios vs Baseline 2000-2020**



Primary Energy Supply

The reduced consumer energy demand and the changes in the composition of economic new electricity capacity projected under each CO_2 scenario have a significant impact on the projected primary energy supply.

In the low CO_2 price scenario New Zealand's total primary energy supply (Table Thirty-Two) is projected to be around 5% lower in 2020 than in the baseline scenario. Most of this reduction stems from lower coal and gas use in the residential, industrial and commercial, and electricity generation sectors. The increased new hydro and geothermal electricity generating capacity, projected to become economic in this scenario, leads to higher primary energy supply of these fuels in 2020.

Table Thirty-Two: **Primary Energy Supply in the Low Carbon Dioxide Price Scenario**

(% Difference from Baseline)

March Years	**Coal**	**Oil**	**Gas**	**Hydro**	**Geothermal**	**Total**
2010	-2%	-0%	-9%	0%	0%	-2%
2020	-37%	-1%	-14%	1%	9%	-5%

In the high CO_2 price scenario New Zealand's total primary energy supply (Table Thirty-Three) is projected to be around 6% lower in 2020 than in the baseline scenario. In this scenario, Huntly runs on coal only between 2000 and 2005; the switch from coal to gas accounts for the higher primary energy supply of gas between 2010 and 2020. This is also the reason why primary energy supply of coal is considerably lower than in the low CO_2 price scenario. The primary energy supply of hydro and geothermal are greater than the baseline, in line with the additional hydro and geothermal electricity generation capacity that is economic in this scenario.

Table Thirty-Three: **Primary Energy Supply in the High Carbon Dioxide Price Scenario**

(% Difference from Baseline)

March Years	**Coal**	**Oil**	**Gas**	**Hydro**	**Geothermal**	**Total**
2010	-75%	-1%	9%	0%	0%	-7%
2020	-87%	-3%	5%	3%	27%	-6%

Retail Energy Prices

Table Thirty-Four presents the actual retail price increases projected for the residential and other industrial and commercial sectors in 2020 under the high and low CO_2 price scenarios. Within each scenario, the electricity and gas prices increase by around the same amount in both sectors, in percentage terms. The reason for the similar electricity price increase is that the average electricity price in each of these sectors is very similar in 2020, resulting in similar price increases in actual and percentage terms. No significant consumption of coal, or fuel oil, is projected to occur in the residential sector in 2020, so no price changes are given for these fuels.

The price increases at the retail level for electricity and gas are muted by falling unit costs of transmission and distribution. Thus the increases in the wholesale prices for electricity and gas are higher than those at the retail level.

Table Thirty-Four: **Retail Energy Prices in 2020 for the Carbon Dioxide Price Scenarios**

(% Difference from Baseline)

	Coal	**Fuel Oil**	**Gas**	**Electricity**
	Low Carbon Dioxide Price Scenario			
Residential	-	-	14%	12%
Other Industrial and Commercial	34%	9%	14%	13%
	High Carbon Dioxide Price Scenario			
Residential	-	-	44%	25%
Other Industrial and Commercial	85%	22%	44%	25%

Carbon Dioxide Emissions

The CO_2 price scenarios reduce New Zealand's projected CO_2 emissions from energy sources and industrial processes below the baseline scenario. The extent of the projected reduction is presented in Table Thirty-Five and Figure 27.

Figure 27: **Gross CO_2 Emissions for the Baseline and Carbon Dioxide Price Scenarios 1990-2020**
(Calendar Years)

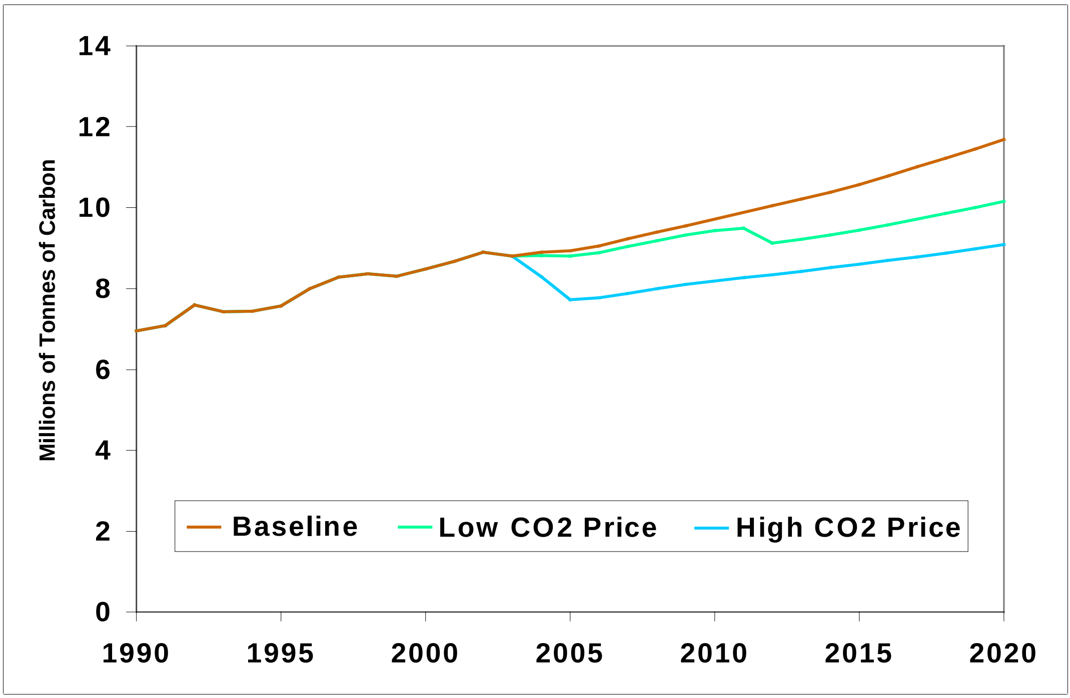


Table Thirty-Five: **CO_2 Emissions for the Carbon Dioxide Price Scenarios**

(% Difference from Baseline)

Calendar Years	**Low Carbon Dioxide Price Scenario**	**High Carbon Dioxide Price Scenario**
	2005 Start	**2005 Start**
2005	-2%	-14%
2010	-3%	-16%
2020	-13%	-22%

The low CO_2 price scenario reduces CO_2 emissions 13% below the baseline level in 2020, while the high CO_2 price scenario reduces CO_2 emissions 22% below the baseline in 2020. The low CO_2 price scenario results in a cumulative reduction in CO_2 emissions of 12.8 MtC below the baseline by 2020. The high CO_2 price scenario results in a cumulative reduction in CO_2 emissions of 30.5 MtC below the baseline by 2020. Emissions growth in the transport and electricity generation sectors is slowed by the introduction of a price for CO_2, but not stopped, offsetting over time some of the other sectors reductions in CO_2 emissions.

ADDITIONAL TOPICS

Price and Income Elasticities

Price and income elasticities represent the responsiveness of energy demand to changes in energy prices and income (all the current models use GDP as a proxy for income). An elasticity of 1 means that every 10% change in prices or income will result in a 10% change in demand. However, care needs to be taken in interpreting elasticities that are estimated using econometric techniques. First, they are based on the historical responses indicated in these sectors, but circumstances in the energy sector, or the economy, or of consumers generally, may change. Second, it is appropriate to use the elasticities only for changes in price or income that do not greatly exceed historical experience.

The long-run price and income elasticities for the residential, other industrial and commercial sectors, and transport fuels are summarised in Table Thirty-Six. Long-run elasticities are conventionally assumed to apply over a time period which allows for the replacement, or renewal, of the capital stock[48]. This is in contrast to short-run elasticities, which assume insufficient time to alter the capital stock. Short-run responses tend to be essentially behavioural and lower in magnitude than long-run responses, as they are constrained by the existing capital stock.

Table Thirty-Six: **Long-Run Price and Income Elasticities**

	Price Elasticity	Income Elasticity
Other Industrial and Commercial Sector	-0.24	0.65
Residential Sector	-0.19	0.80
Petrol	-0.19	0.62
Diesel	-0.13	1.26

In the other industrial and commercial and residential sectors, the price elasticity measures the responsiveness of effective energy demand to effective prices. Effective energy is the consumer energy of a fuel reduced by the assumed efficiency of the use of that fuel in that sector. The effective price of energy is higher than its base price if its efficiency of use is less than 100%. The models are thus trying to project the effective (underlying) demand for energy services. This allows a more valid comparison of the competing fuels, given their widely disparate efficiency of use when actually consumed.

The other industrial and commercial, residential sectors, diesel and petrol demand have similar price elasticities. With the exception of diesel demand, the same can be said for the income elasticities of these sectors. The demand for diesel has a significantly higher income elasticity than the other sectors. Diesel's high income elasticity is the result of spectacular growth in the demand for diesel in the 1990s. This growth is clearly unsustainable in the long run, and the model includes a dummy variable that acts to reduce the rate of growth in demand for diesel to more plausible rates in the longer term.

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[48] *The length of time required for the 'long run' is not defined but depends on the demand being analysed.*

Comparison of the 2000 and 1997 Energy Outlooks

The Ministry of Commerce SADEM model has been updated and developed incrementally over a number of years, and the differences in projections over the years therefore also tend to be small. Prior to this publication the Ministry has produced five major energy supply and demand Outlooks during the period 1991 to 1998. These publications are:

- *Energy Demand Forecasts – Some Initial Results*, Ministry of Commerce and NZIER, August 1991*;*
- *An Energy Baseline Forecast to 2020*, Ministry of Commerce and NZIER, September 1992*;*
- *Energy Supply and Demand Scenarios to 2020*, Ministry of Commerce and NZIER, July 1994*;*
- *New Zealand Energy Outlook*, Ministry of Commerce, February 1997; and
- *Energy Supply and Demand Forecasts for New Zealand – An Update*, Ministry of Commerce, March 1998.

The March 1998 update was presented to the 1998 New Zealand Petroleum Conference. This was then included in the conference proceedings but was not otherwise formally published. This section focuses on comparing the assumptions and projections presented in this outlook with the assumptions and projections of the February 1997 Outlook.

Generally speaking the underlying assumptions of the two Outlooks are very similar, the major difference being the coal and gas price assumptions[49]. Coal prices were assumed to reach $3.70/GJ in the 1997 Outlook, while it is anticipated to reach only $3.00/GJ in 2010, before remaining flat in this outlook. This is in line with a neutral to weak long-term outlook for internationally traded coal prices.

The other major difference occurs in the wholesale gas price path assumed. In 1997, it was assumed that gas prices would rise to around $5.30/GJ in 2020, with ongoing discoveries of around 85 PJ pa post 2005. It is currently assumed that more modest price rises will elicit new gas discoveries of 80 PJ pa post-2000. This reflects a more optimistic outlook for exploration and discovery in the petroleum and gas industry in recent years. It also tries to balance more evenly the possible premium that gas can achieve over coal in the higher volume, lower value, uses for gas in industry once the current supply surplus starts to decline.

The differences in the projections between the 1997 Outlook and this Outlook are not merely due to differing assumptions. There have been two years of actual developments in the energy sector, and the model parameters themselves have changed. Perhaps of the most significance have been the additions to electricity capacity and the reforms, restructuring and rationalisation of the electricity sector.

Table Thirty-Seven below presents a comparison of the 1997 projections and the current projections. Consumer energy is now projected to be around 3% higher in 2020 compared to the levels projected in the 1997 Outlook. This is due to higher oil and gas demand, which is partially offset by substantially lower coal demand. The substantially lower coal projection in this Outlook in is in part due to gas's increased share. Revisions to the historical data have also reduced the actual starting

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[49] *The only other assumption of note that is materially different is the exchange rate. This has declined significantly since 1997. It is now assumed to be US$0.54 = NZ$1 throughout the projection period, rather than US$0.65 = NZ$1.*

level of consumption from which we project coal consumption. The combination of the two effects has resulted in substantially lower projections for consumer energy coal consumption. However, we are still projecting modest growth in the consumer energy for coal over the outlook period. Electricity demand is still projected to reach around the same level in 2020 as was projected in the 1997 Outlook. The current sectoral projections are similar to the 1997 projections, with slightly higher residential and transport sector consumer energy use being offset by lower industrial and commercial sector consumer energy use.

Table Thirty-Seven: **Comparison of the 1997 and 2000 Outlook Projections for 2020**

	1997 Outlook	**2000 Outlook**	**% Difference**
Consumer Energy		*(PJ pa)*	
Total	604	623	+3%
Coal	58	46	-20%
Oil	323	347	+7%
Gas	58	63	+9%
Electricity	166	167	0%
Residential	67	72	+7%
Industrial and Commercial	225	215	-4%
Transport	312	336	+8%
Primary Energy		*(PJ pa)*	
Total	874	872	-0%
Coal	143	108	-24%
Oil	338	364	+8%
Gas	98	134	+37%
Hydro	96	97	+1%
Geothermal	200	169	-16%
New Electricity Capacity		*(MW)*	
Total	2610	3305	+27%
CO_2 Emissions		*(MtC)*	
Total	11.76	11.68	-1%
Coal	1.01	0.78	-23%
Oil *	5.80	5.77	-0%
Gas	0.91	1.02	+12%
Electricity Generation and Other Transformation	3.13	3.13	0%
Industrial Processes and Fugitive Emissions	0.91	0.98	+8%

** Excluding international transport.*

There have been a number of developments in the electricity generation sector since 1997, and the additional capacity projected to become economic between 1995 and 2020 is now projected to be around 700 MW more than in 1997. Most of this difference, given we have the same demand in 2020, can be explained by the current Outlook's assumption that New Plymouth (580 MW) will be mothballed in 2005. The remaining additional capacity is required, because there is more thermal plant projected to be economic in the current Outlook. Although, this is baseload thermal, it won't be run as hard as the renewable baseload plant included in the 1997 Outlook under normal circumstances, necessitating slightly more capacity to compensate.

Coincidentally, the projections for primary energy in 2020 are essentially identical. However, this masks the fact that the current outlook includes lower projections for coal (due to lower consumer energy, and lower generation at Huntly), and geothermal. The primary energy supply of gas is substantially higher, with more GCC capacity projected to come on stream than in the 1997 Outlook, and higher consumer energy demand. The primary energy supply of oil reflects the higher consumer energy consumption of oil for transport.

Carbon dioxide emissions are currently projected to be around 1% lower in 2020 than they were in the 1997 Outlook. Lower coal emissions stem from lower projected consumption. However, the fractionally lower oil emissions, despite an increase in projected consumption, are the result of slight downward revisions in the emission factors for oil. Coincidentally, emissions from electricity generation and other transformation activities are identical in 2020. Higher emissions from gas used in electricity generation are offset by lower emissions from coal used in electricity generation.