Energy Sector CO_2 Projections to 2020

(Interim Update)

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Energy & the Environment Group

Ministry of Economic Development

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1. Introduction

The scenarios presented in this paper are an interim update on the Energy Outlook 2003 and previous CO_2 projections in April 2004. The results are a product of modelling the complex interactions of the New Zealand energy sector. The scenarios are not attempts to project what will actually happen in the energy sector; rather, they provide an indication of a range of possible outcomes under a number of different assumptions.

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 and the Environment Group of the Ministry of Economic Development, using its Supply And Demand Energy Model (SADEM).

There are a number of important caveats underlying this analysis:

- The most significant is that the SADEM model has undergone significant revision and updating since the last Energy Outlook in 2003 and the most recent projections of CO_2 emissions in April 2004.

- A review by Covec and Infometrics has highlighted a number of areas where significant improvements are required. It is intended that these issues be progressively addressed and the model further revised leading up to the 4th National Communication (due January 2006) and the next Sustainable Energy Futures Report (previously known as the Energy Outlook) in mid-2006.

- The results presented here are therefore likely to change as a consequence and should be considered a provisional or interim update on Energy Outlook 2003.

This report summarises the CO_2 emission projections undertaken for the Climate Change Office (CCO). Non-CO_2 GHG (Greenhouse Gas) emissions from the energy sector are not directly modelled but are included by CCO in the main report.

1.1 Key Assumptions

The following assumptions (without future policy measures) behind the projections are explained more fully in the appendix:

- GDP growth using Treasury projections out to 2020. The high/low scenario has a +/- 0.7% variance around this projection.

- Oil prices rising from US$32.50/bbl in 2005 to US$40.00/bbl in 2025. The high/low scenario has a -/+ US$10.00/bbl around the 2025 projection (see appendix for details).

- Exchange rate of NZ$1.00 = US$0.67 in 2005, and then a constant of NZ$1.00 = US$0.60 from 2006 out to 2025.

- North Island delivered coal prices at a constant \$3.75/GJ. The high/low scenario has a -/+ \$0.25/GJ variance around this projection. It is assumed South Island coal demand at prices significantly lower than this is minimal.

- New gas available from discoveries averaging 60PJ pa from 2009 onwards.

- Methanex gas to methanol plant to close by mid-2006.

- No EECA/NEECS targets (i.e. no additional energy efficiency)

- A carbon tax of \$15/tCO_2 from April 2007.

- Carbon credits (from the Projects to Reduce Emissions [PRE]) for new renewable electricity generation installed before 2010.

- A price of \$6.50/GJ for gas for electricity generation in 2007.

These assumptions were modelled in a "Most Likely" scenario. As CP1 approaches and the price-based measures take effect, the measures scenario now becomes the "Most Likely" scenario. The measures in this scenario include the price effect of a carbon tax, and the modelled effect of carbon credits (from the Projects to Reduce Emissions mechanism) on new electricity generation.

Three scenarios were undertaken on the basis of low, medium, and high assumptions. The medium assumption was taken as the "Most Likely" scenario. The three key underlying variables that were changed to achieve these scenarios were GDP, and oil and coal prices.

2. Major Demand Sectors

Three major energy demand sectors are modelled; residential, industrial & commercial, and transport. Each sector has a number of models underlying it. Approximately two thirds of the total energy is modelled using a sophisticated multi-variate approach. About a fifth of the total energy is modelled based on forecasts directly from the industries concerned. The remaining portion is modelled using simple ordinary least square linear regression (OLS).

Table 1: Demand Sectors and Modelling Techniques

Major Sector	Sub-Sector	Model	Net Energy (PJ, 2004)	Percentage
Residential	Residential	Multivariate, GDP, Price, HDD, Lagged Demand	52	10%
Industrial & Commercial	Forestry	MAF forecasts	23	4%
	Metals	Company forecasts	40	8%
	Petrochemicals	Company forecasts	52	10%
	Other Industrial and Commercial	Multivariate, GDP, Price, HDD, Lagged Demand	105	20%
Transport	Petrol (Land)	Multivariate, GDP, Price, Lagged Demand	104	20%
	Diesel (Land)	Multivariate, GDP, Price, Lagged Demand	80	15%
	Aviation	OLS	48	9%
	Sea	OLS	22	4%
	Other	OLS	9	2%
TOTAL			533	100%

2.1 Residential Sector

This sector has been modelled based on time series information since 1961 for five fuels - electricity, gas, coal, coke, and oil. Over this period the fuel mix has changed from approximately a 40:50 electricity:coal domination to a 90:10 electricity:gas domination. The demand drivers used in this model are price, GDP, and Degree Days (DD).

Figure 1: 1961 Residential Fuels (PJ)

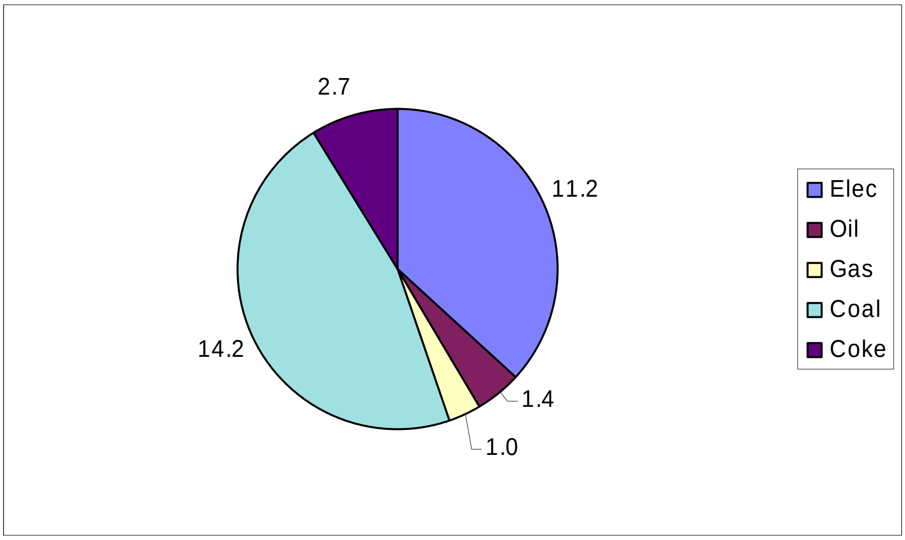
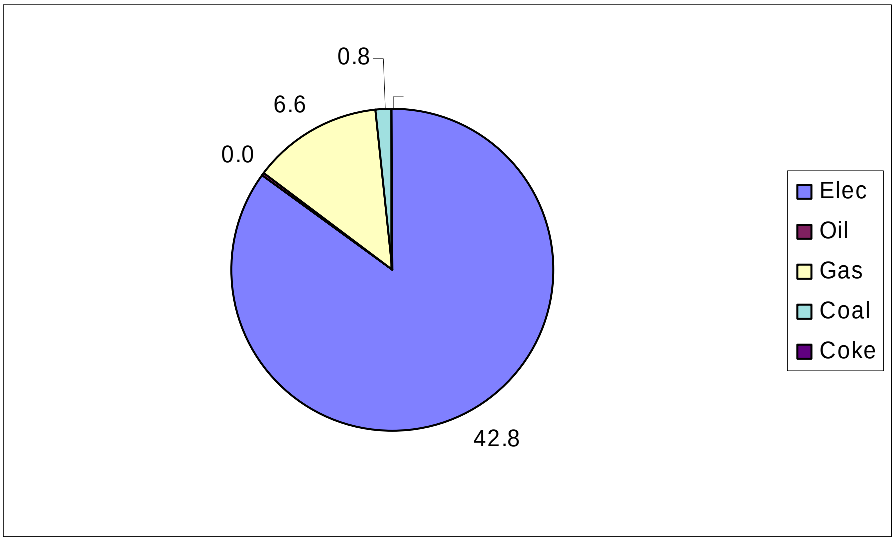


Figure 2: 2004 Residential Fuels (PJ)



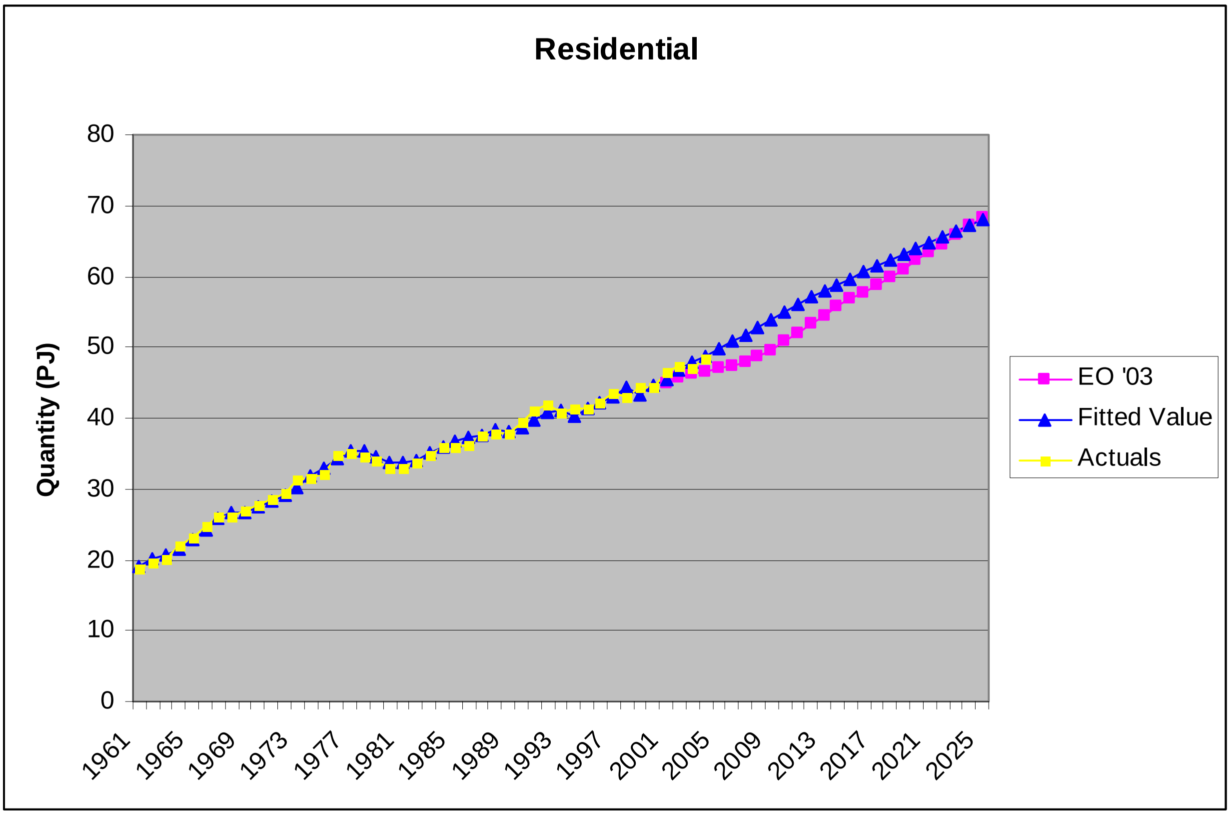
The above graphs illustrate the amount of energy consumed from each fuel, and the changes in the fuel mix over the past 40 years. The model however is based on the "effective energy" delivered. For electricity this is 100% of the fuels energy, however for coal it is just 30%, while gas falls at the higher end at 80%. This factor is reflected in the way fuel switching occurs between these options.

Projecting forward to 2025 the price of electricity is expected to increase slightly but the price of gas will increase markedly as reserves dwindle.

Degree Days (DD) are measured from two points. Heating degree days are recorded when the average temperature falls below 15°C, while cooling degree days are recorded when the average temperature rises above 21°C. Degree days are projected to reduce having a slightly suppressing effect in their contribution to demand. The two key drivers for this are long-term warming trends pushing up average temperatures, and the continuing regional shift of the population balance from the cooler south to the warmer north in particular Auckland.

Residential energy demand is projected to increase at an average of 1.9% p.a. from 2005 to 2025. Figure 3 highlights the difference between the current projection and Energy Outlook 2003.

Figure 3: Residential Energy Demand (PJ)



2.2 Industrial and Commercial Sector

This sector includes heavy industrial metals refining (BHP, Comalco, Pacific Steel), petrochemicals (Methanex and Urea), forestry processing (pulp and paper and milling), and "other industrial and commercial" (OI&C).

For the heavy metals sector, energy growth is projected to be negligible as there are unlikely to be additional amounts of relatively cheap electricity and gas that would make expansion of this sector economically attractive. For the petrochemicals sector a greater than 90% decline in gas use from 2003-2007 (principally Methanex) is expected due to the decline of known gas reserves causing sharply increased gas prices. For the forestry processing sector strong growth is expected due to increased harvesting from the maturation in 2010-2025 of forest plantings made in the late 1980's and early 1990's.

The OI&C sector has been modelled since 1961. During that period there has been strong growth in demand particularly in the electricity and gas components. The only exception to this was a period in the mid-1970's when the oil crisis created a temporary period of high prices. This has shifted the fuels mix from approximately 60% coal in 1961 to a mix of fuels dominated by 40% electricity in 2004. The demand drivers used in this model are price, GDP, and Degree Days (DD).

Figure 4: OI&C Fuels Mix 1961 (PJ)

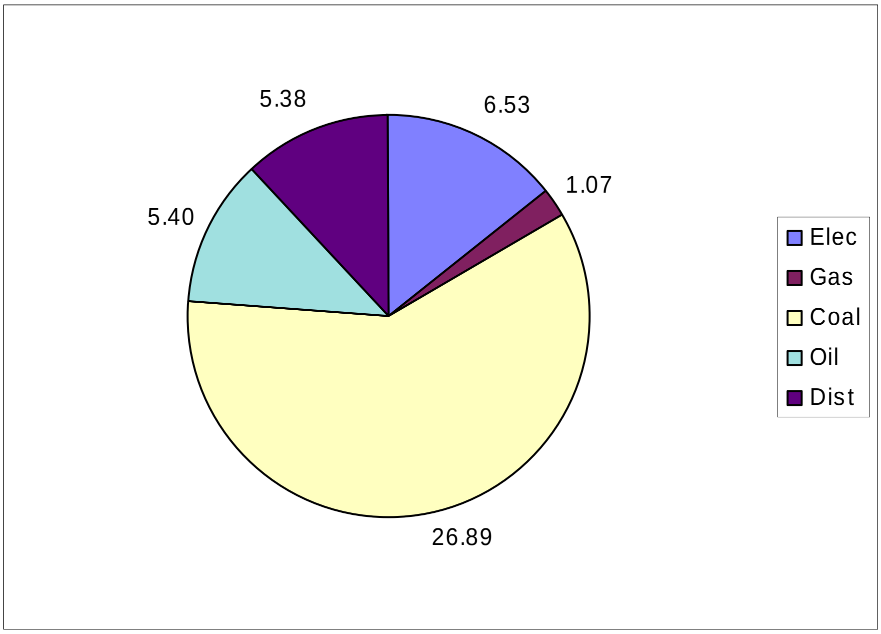
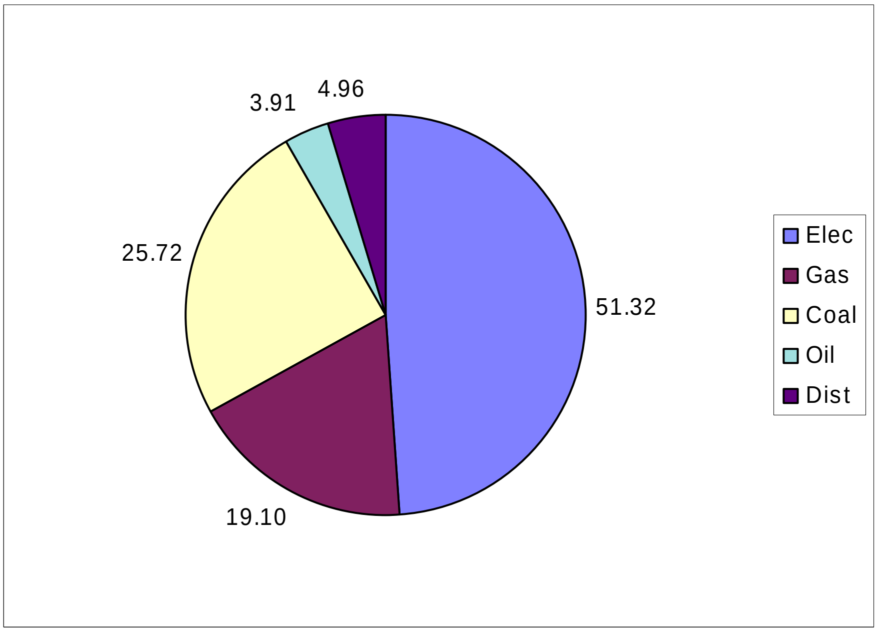
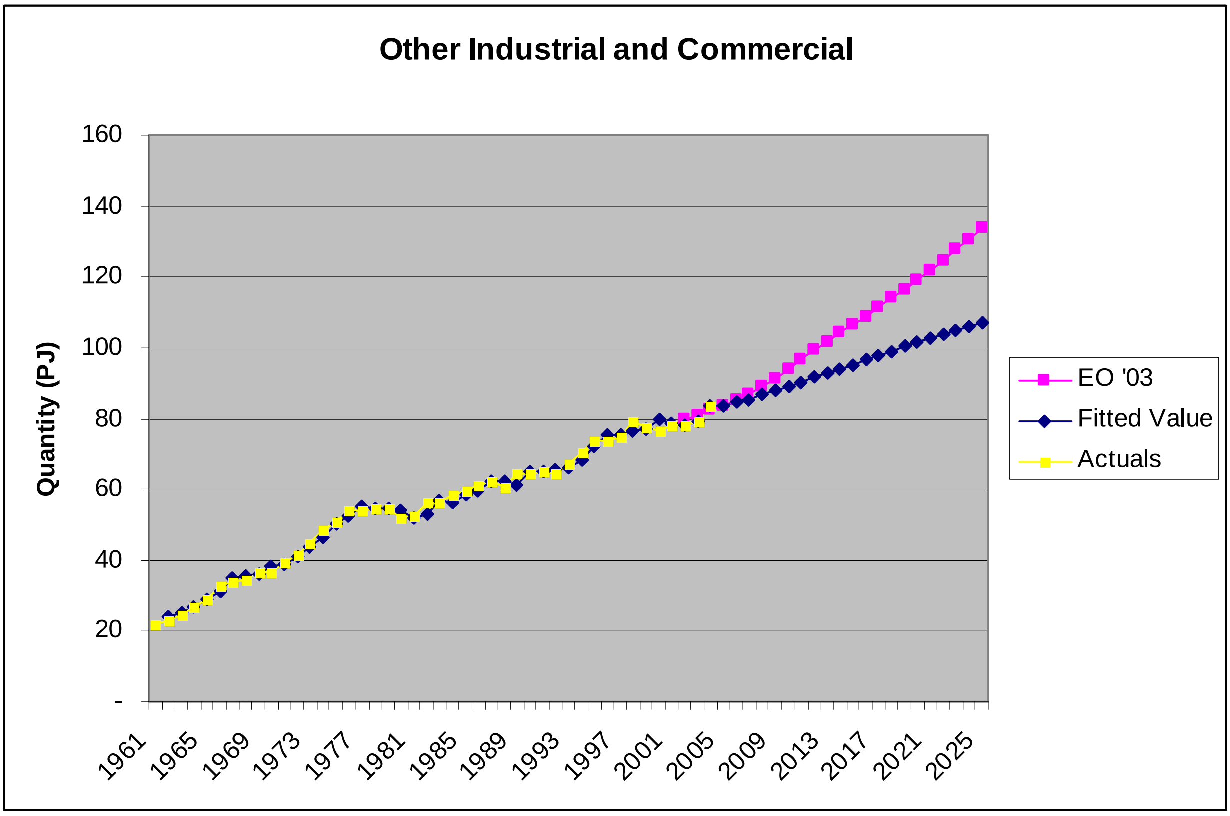


Figure 5: OI&C Fuels Mix 2004 (PJ)



OI&C energy demand is predicted to increase at an average of 1.2% p.a. from 2004 through to 2025. This is significantly less than was recorded for Energy Outlook 2003 due to clearer lines of allocation between OI&C and the Forestry and Metals sectors, and revision of electricity consumption actuals for 1999-2001.

Figure 6: Other Industrial and Commercial Energy Demand (PJ)



2.3 Transport Model

This model contains 5 sub-sectors namely petrol (land), diesel (land), aviation, sea, and other. Petrol (land) and diesel (land) make up 70% of energy in this sector and are modelled using a multivariate approach. Aviation is 18% and is modelled using a simple OLS approach.

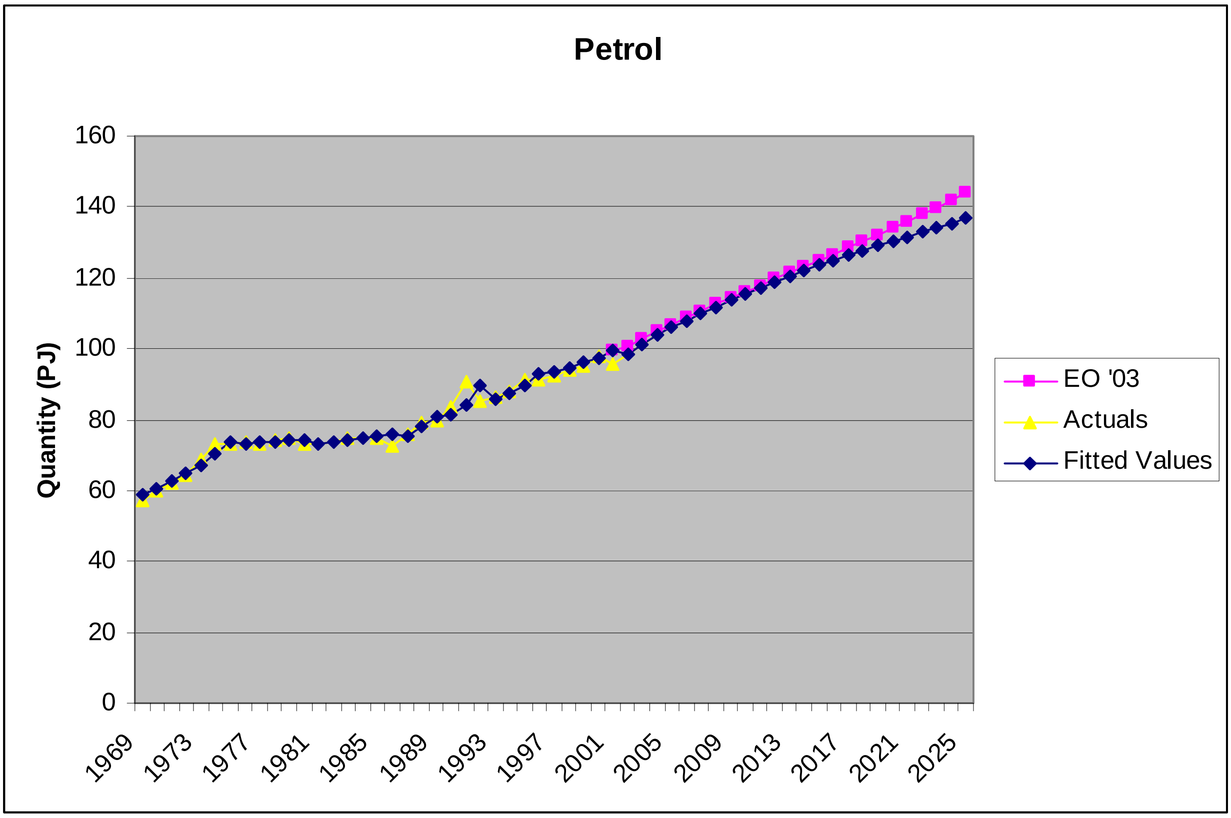
2.3.1 Petrol Model

Petrol is used almost exclusively (99%) for transportation purposes. Whilst the type of transportation has not been explicitly determined it can be assumed that most of it is for private cars.

The demand drivers used in this model are price and GDP. The sensitivity to price is however very small compared to GDP. For example a 0.6% drop in GDP would suppress demand by only 0.1%. The change in oil price needed to suppress demand by the same amount is an increase of US$2.20/bbl (7%).

Demand is predicted to increase at an average of 0.6% p.a. through to 2025.

Figure 7: Petrol (Land) Energy Demand (PJ)



2.3.2 Diesel Model

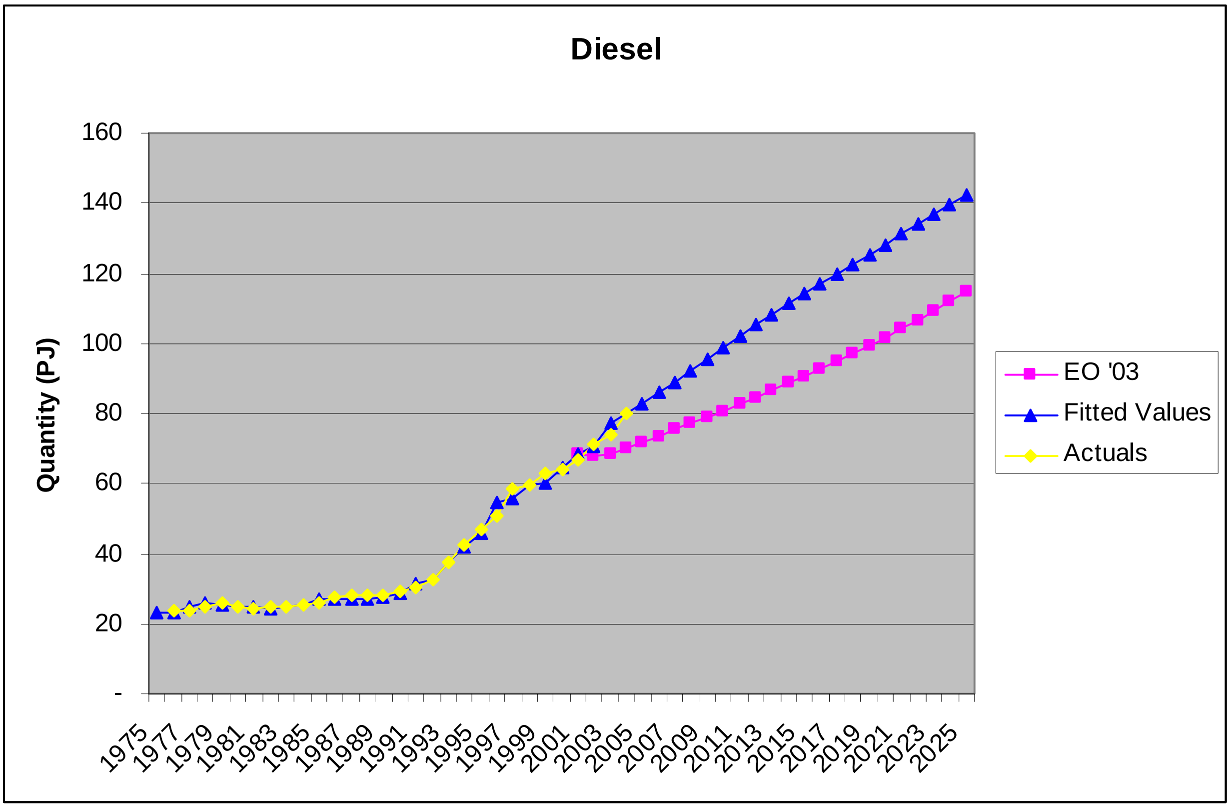
This model is based on diesel demand for land transportation purposes. Diesel demand for industrial and commercial purposes and domestic sea transport is removed from this model. These other sectors account for approximately 30% of diesel consumption. Domestic air transport (jet fuel) is also modelled separately. International transport (sea and air) is excluded from all GHG analysis.

Previously the Diesel model in Energy Outlook 2003 and the previous April 2004 CCO projections significantly underestimated demand. This model has now been substantially improved.

There is also some switching occurring from petrol to diesel for automotive purposes, which accounts for part of the difference in growth rates between the petrol and diesel models.

Diesel demand is predicted to increase at an average of 3.1% p.a. through to 2025.

Figure 8: Diesel (Land) Energy Demand (PJ)



3. Electricity Generation

3.1 Introduction

New electricity generation growth is predicted to be on average 1.4% p.a. for the "Most Likely" case (2004-2025). There are a number of issues relating to this lower figure particularly when compared to the Electricity Commission (EC) published demand data. The main differences are that SADEM:

- incorporates interaction between electricity demand and prices
- incorporates the effects of price competition between electricity and other energy sources across all sectors

These differences are being reviewed with the EC. Also the SADEM electricity module is being reviewed in association with Covec and Energy Link.

Furthermore on the generation side there has been significant year-to-year variability in emissions. This is primarily due to the annual variability of hydro inflows.

Electricity demand growth is modelled to be significantly lower than current growth (1.9% p.a. for 1999-2004) for a number of reasons:

- Electricity demand by the Industrial and Commercial sector is expected to be slightly suppressed. Current growth of 1.6% p.a. (1999-2004) is expected to drop to 1.4% p.a.

- No further electricity growth is expected for the Metals sector beyond 2009. Comalco in particular forecasts flat demand. Current growth is 0.5% p.a. (1999-2004).

- Forestry is currently growing very strongly at 6.4% p.a. (1999-2004). This growth rate is forecast to drop for 2004-2010 to 1.3% p.a. Forestry however is set to expand with a projected increase in wood harvested from 2010.

- Residential growth is projected to remain steady at 1.7-1.8% p.a.

Growth in electricity generation is essentially provided for by installation of, cogeneration, geothermal, GCC plant (e3p), wind and upgrades to existing hydro. New hydro doesn't feature in the modelling scenarios until after 2010. The merit order and new generation profiles are provided in Figure 9 and Table 2. Table 2 should be taken as illustrative. For each generation type there exists a range of capital development possibilities each with their own price and likely level of national availability at that price.

Figure 9: Indicative New Plant Generation Costs

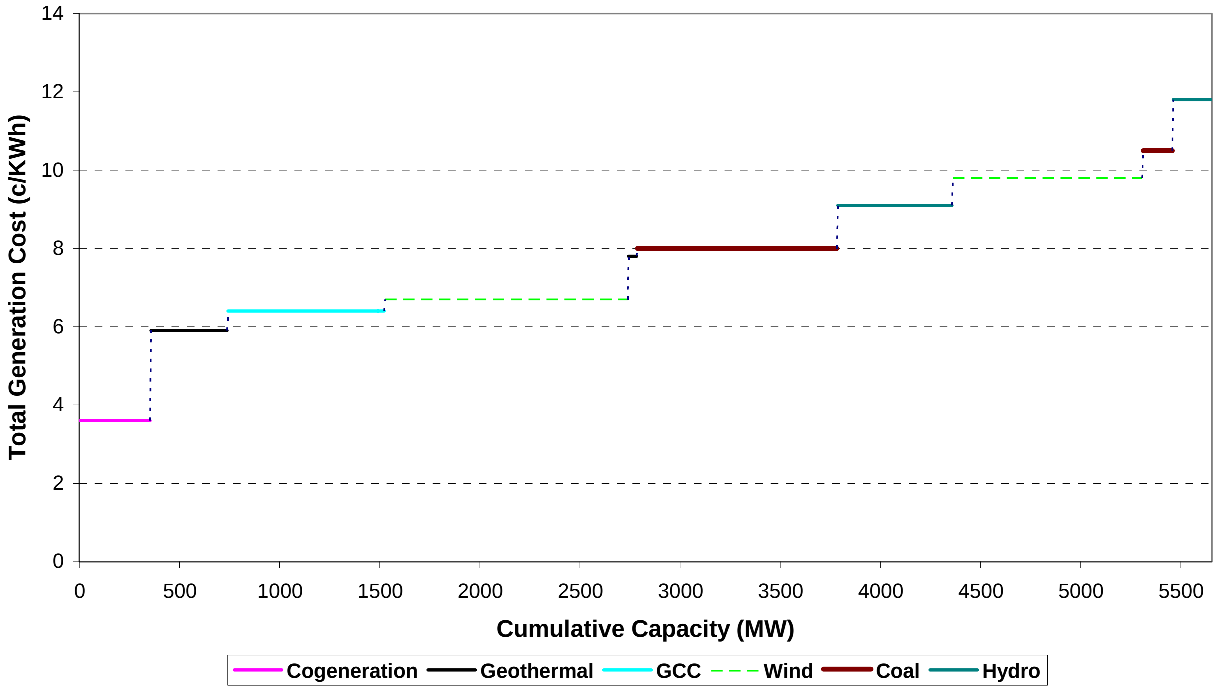


Table 2: Indicative New Plant Generation Profiles[1]

Generation Type	Total Cost *c/KWh*	Potential Capacity *MW*	Potential Supply *GWh pa*	Potential Average Load *%*
Hydro	7.5 to 9.0	575	3000	60%
	11.0 to 13.0	190	1000	60%
Geothermal	5.5 to 6.5	385	3000	89%
	8	45	350	89%
Cogeneration	2.5 to 5.0	350	1700	55%
Wind	6.5 to 7.0	1220	4800	45%
	9.0 to 11.0	950	3300	40%
Gas Combined Cycle	5.5 to 7.0	785	4800	70%
Coal (no carbon tax)	8.0	1000	7000	80%
	10.5 (FGD)	150	1050	80%
Distillate	18.5 to 24.0	no limit	no limit	75%

3.2 Wind generation

Wind generation as a resource is expected to become much more significant. Due to the high proportion of hydro currently established, New Zealand is significantly advantaged in that it is able to leverage off the "fuel reserve" (i.e. dam storage) for inter-seasonal and daily variability.

3.3 Gas generation

During the 1990's growth in gas fired electricity generation was strong at 4-5% p.a. Much of this was due to the ready availability of relatively cheap Maui gas. In addition the technological improvement in high temperature materials and bypass designs allowed a significant improvement in gas turbine efficiencies. Combined with steam generation units on the gas turbine offtake, known as gas combined cycle (GCC), efficiencies in the order of 50-55% are now obtainable. This compares well with coal

[1] "Availabilities and Costs of Renewable Sources of Energy for Generating Electricity and Heat", East Harbour, 2005 & "Fossil Fuel Electricity Generating Costs", East Harbour, 2004.

fired steam generation where efficiencies are typically only 30-40%. Also capital costs for GCC plant are less than for new coal plant per MWh of generation.

Considerable uncertainties exist around gas availability. Because New Zealand is isolated, gas is only currently available from fields developed locally. Current reserves are projected to last till 2020 but not at a level that will sustain the volume required for electricity generation. The level required for this is only likely to be sustainable to 2012-2015, unless there are significant new discoveries.

If an LNG (liquefied natural gas) terminal were to be developed it would mean that gas could be imported by ship. LNG is a capital intensive and expensive option, compared to domestic gas production. Although costs are reducing in this area as technologies improve.

3.4 Cogeneration

There is a further uptake in cogeneration, particularly with the availability of small scale turn-key plant and the recent increases in electricity prices. Cogeneration is a system for producing industrial heat, with electricity generated as an additional saleable product. Fuel for cogeneration modelled in these projections comes from natural gas and woody residues. Cogeneration has been especially popular in the wood processing industry where such residues occur, particularly in timber milling/kiln drying operations. And in the dairy industry where gas fired turbines generate electricity and provide large amounts of secondary steam for heating and sterilisation purposes.

3.5 Geothermal Generation

With the rising cost of electricity a number of existing and new geothermal fields are now becoming viable for development. Geothermal generation has been reasonably well established for some time and New Zealand is well mapped in terms of locating and developing this resource.

Greenhouse gas releases may become an issue for this form of generation. Each geothermal field has its own release characteristics which are principally dependant upon the temperature of the field. Once this pressure is released during generation much of the carbon dioxide absorbed in the geothermal water used to run the turbines is released to the atmosphere.

Geothermal generation is however relatively inefficient at 10-15% conversion due principally to the relatively low temperatures involved (200-250ºC).

GHG releases ranging widely in the order of 3% to 60% of that for a coal fired power station per MWh generated are typical. Currently the weighted average is about 11% (or 100tCO_2/MWh). However the current model only includes CO_2 emissions from existing, but not new, geothermal.

4. Results of Standard Runs

4.1 Results Comparison

Table 3 contains the “Most Likely” scenario projections out to 2020 (December year ending), using the medium assumptions and including the effect of a carbon tax and carbon credits (price based measures). The effect of price-based measures was modelled using SADEM. As CP1 approaches and the measures take effect, the measures scenario now becomes the “most likely” scenario. The following price-based measures were modelled:

- Carbon charges at \$15/tCO_2 from 1st April, 2007. SADEM is a price-equilibrium model. This tax is modelled using SADEM as a price increase for the fuels concerned, and the effect of this on demand and fuel switching is the result.

- Carbon credits for new ‘renewables’ electricity generation. The effect of this in SADEM is to lower the cost of entry (by up to 0.6c/kWh) of new ‘renewables’ generation effectively moving it up the order at the expense of fossil fuelled generation.

Table 3: “Most Likely” Scenario (Carbon tax (\$15/tCO_2) and modelled carbon credits)

	Electricity Generation	Other Transformation	Gas	Oil	Coal	Fugitive & Industrial Process	Total
2003	7.3	1.2	2.9	16.5	2.4	4.2	34.5
2010	8.3	1.2	2.2	18.9	2.6	4.8	38.0
2015	10.3	1.2	2.4	20.7	2.7	4.9	42.2
2020	10.6	1.2	2.5	22.5	2.9	4.4	43.9

Emissions are projected to increase by 10% (3.5MtCO_2) in 2010 over 2003 levels. There are several contributors to this. Oil is up by 2.4MtCO_2 mainly in the form of transport emissions. Electricity generation is up by 1.0MtCO_2 mainly due to coal fired generation at Huntly. And fugitive emissions are up 0.6MtCO_2 mainly due to venting of CO_2 from Kapuni which was previously sequestered in the production of methanol by Methanex. Correspondingly gas is down 1.0MtCO_2 principally due to the closure of Methanex.

Overall emissions in 2010 are projected to be 50% above 1990 levels.

4.2 Comparison with Previous Results

Table 4: Previous results provided to the CCO – April 2004

	Baseline Scenario - No Project Aqua; updated Treasury GDP forecast to 2008, then 2.5% pa. Figures are in Mt CO_2 p.a.						
	Electricity Generation	**Other Transformation**	**Gas**	**Oil**	**Coal**	**Fugitive & Industrial Process**	**Total**
2003	7.2	0.8	3.6	15.4	2.1	3.3	32.4
2010	6.8	0.8	3.2	17.5	2.3	3.7	34.3
2015	7.8	0.8	3.6	19.1	2.5	3.7	37.6
2020	11.0	0.8	3.9	20.9	2.8	3.7	43.2

In comparison the previous results provided to the CCO do not have these price-based measures (Table 4). This is explained in more detail as follows:

Starting Position Comparison - Year 2003:

When comparing tables 3 and 4, overall, there is an increase in emissions that occurred in 2003 from 32.4 to 34.5 $MtCO_2$ (6.0%). This is due to the following:

1. The April 2004 run was based on Energy Outlook 2003 which used actuals to 2001 and projections thereafter. Hence 2003 was based on a projection not actuals. This has now been corrected for in the May05 runs where 2003 data now represent actuals. This accounts for the small difference seen for “Electricity Generation” (0.1 $MtCO_2$).

2. “Other Transformation” now contains an extra 0.4$MtCO_2$. This derives primarily from gas and oil production losses from on-site flaring that were previously unaccounted for.

3. “Fugitive and Industrial Emissions” now contain urea production (0.4 $MtCO_2$) which was previously under gas. Any process that primarily exists to convert the fuel’s chemistry into a different form other than combustion must be reported as an “Industrial Process Emission”. Further reducing gas was some over reporting of emissions for the Forestry and Metals sectors.

4. Oil shows a significant increase (1.1 $MtCO_2$). This is due to the underlying diesel model in the April 2004 run being significantly underestimated. Somewhat offsetting this was double reporting of domestic marine emissions in the fishing sector (0.2 $MtCO_2$).

5. Coal was 0.3 $MtCO_2$ higher due primarily to higher than expected gas and electricity prices for this year. Fuel switching was undertaken by industrial users where possible.

Year 2010:

Overall there is a significant increase in emissions projected from 34.3 to 38.0$MtCO_2$ (11%). This is due to the following:

1. Electricity Generation" is 1.5 $MtCO_2$ more due to increasing prices in the gas sector making coal more favourable to burn at dual fuel stations (Huntly). This is partly offset by the effect of price-based measures.

2. Oil emissions are up 1.4$MtCO_2$ due to the effect of increased diesel consumption.

3. Correspondingly gas is 1.0 $MtCO_2$ less, and coal is 0.3 $MtCO_2$ more. Most of the gas reduction is due to Methanex closing.

4. Fugitive and Industrial Process emissions are up 1.1$MtCO_2$. This is accounted for by a number of factors including the venting of Kapuni CO_2 gas (previously sequestered by Methanex, 0.4 $MtCO_2$), transfer of Urea as above (0.4 $MtCO_2$), and an underestimate on the steel forecast emissions (0.3 $MtCO_2$).

Year 2020:

Overall there is an increase in emissions projected from 43.2 to 43.9 $MtCO_2$ (2%). This is due to the following:

1. "Electricity Generation" is 0.4$MtCO_2$ less. This gap has closed from that observed for 2010 (1.5$MtCO_2$ more) due to a reduction in projected demand in the Industrial and Commercial sector.

2. From 2018 the Kapuni gas field runs out. Kapuni gas contains approximately 50% CO_2 and this is usually vented to the atmosphere prior to use. The decommissioning of Kapuni results in a substantial reduction in "Fugitive and Industrial Process" of 0.5$MtCO_2$.

3. Overall projected "Electricity Generation" is showing less hydro potential in favour of wind and geothermal generation. This is largely due to Project Aqua not going ahead. The change from hydro to wind and geothermal for new generation has little effect on carbon emissions as neither technology is an emitter.

4. Switching between coal and gas for "Electricity Generation" is very sensitive to pricing and the factors underlying that. These factors include run out year (the year NZ depletes its gas resource, 2030 in the "Most Likely" case), starting price, new gas discovery rate, LNG (backstop) price, carbon tax, and changes in CCGT technical efficiencies. There is a great deal of uncertainty as to whether coal or gas will be used. The emission factors for coal and gas for electricity generation are significantly different by a factor of 2-3 times per GWh generated. Hence there is a lot of uncertainty regarding carbon emissions. For renewable generation there

is less sensitivity in this switching as generally once the capital investment decision is made and the generation installed, its production is limited only by the availability of the resource.

Figure 10: Carbon Dioxide Emissions in 2020 ($MtCO_2$ p.a.)

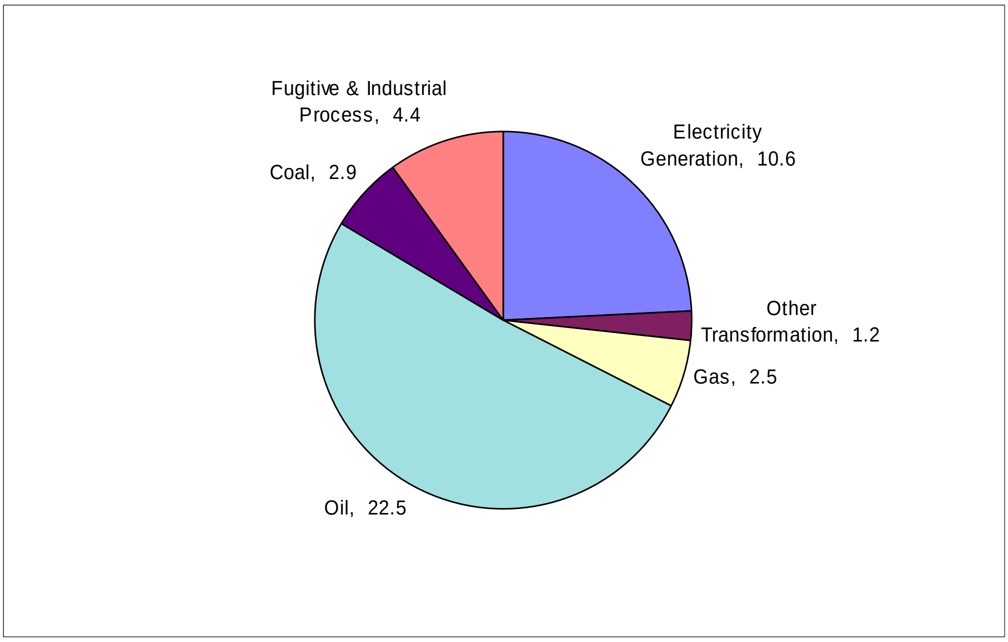
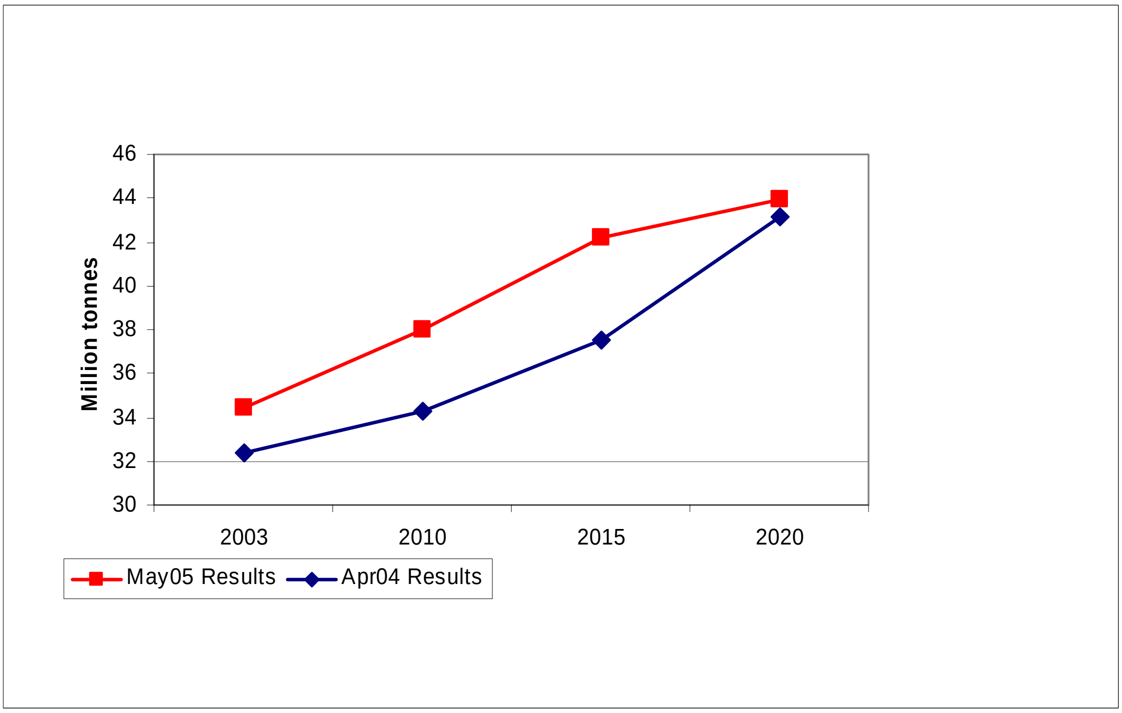


Figure 11: Carbon Dioxide Emissions – 2003-2020 ($MtCO_2$ p.a.)



4.3 Three scenario's – High, Most Likely (including price-based measures), and Low Emissions

Table 5: Most Likely Scenario (including price-based measures) - GDP medium (Treasury) forecast, medium oil prices, medium coal price. Figures are in $MtCO_2$ p.a.

	Electricity Generation	Other Transformation	Gas	Oil	Coal	Fugitive & Industrial Process	Total
2003	7.3	1.2	2.9	16.5	2.4	4.2	34.5
2010	8.3	1.2	2.2	18.9	2.6	4.8	38.0
2015	10.3	1.2	2.4	20.7	2.7	4.9	42.2
2020	10.6	1.2	2.5	22.5	2.9	4.4	43.9

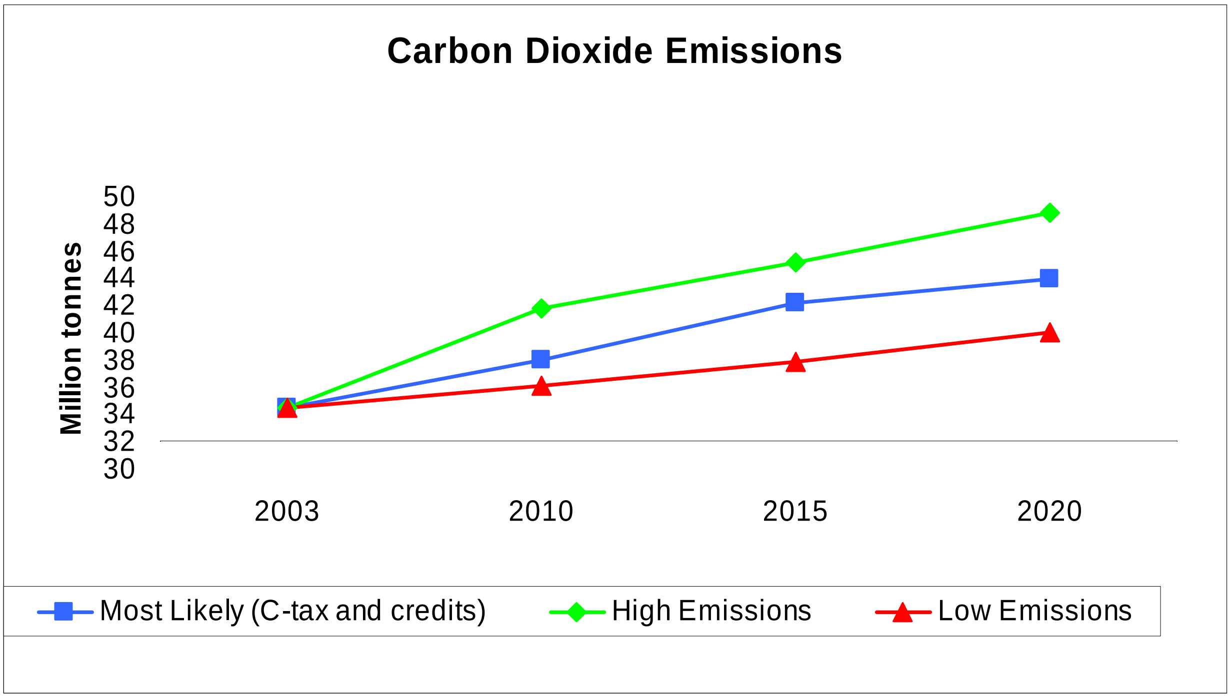
Table 6: High emissions Scenario (including price-based measures) - GDP high (Treasury + 0.7% p.a.) forecast, low oil prices, low coal price. Figures are in $MtCO_2$ p.a.

	Electricity Generation	Other Transformation	Gas	Oil	Coal	Fugitive & Industrial Process	Total
2003	7.3	1.2	2.9	16.5	2.4	4.2	34.5
2010	10.9	1.2	2.3	19.9	2.7	4.8	41.8
2015	11.1	1.2	2.5	22.5	2.9	5.0	45.1
2020	12.2	1.2	2.6	25.2	3.1	4.5	48.7

Table 7: Low emissions Scenario (including price-based measures) - GDP low (Treasury - 0.7% p.a.) forecast, high oil prices, high coal price. Figures are in $MtCO_2$ p.a.

	Electricity Generation	Other Transformation	Coal	Oil	Gas	Fugitive & Industrial Process	Total
2003	7.3	1.2	2.9	16.5	2.4	4.2	34.5
2010	7.4	1.2	2.2	18.1	2.5	4.8	36.1
2015	7.6	1.2	2.3	19.3	2.6	4.8	37.8
2020	9.3	1.2	2.4	20.2	2.7	4.2	40.0

Figure 12: High – Low Scenario's – 2003-2020



For the 3 scenario's there is an approximate +/- 10% spread for 2020 from the "Most Likely" scenario (40.0, 43.9, 48.7 $MtCO_2$).

5. Appendix – Assumptions

Where possible, source data for these assumptions are from government sources. The assumptions were also reviewed late 2004 by the Officials Committee for Sustainable Energy (OCSE), a committee consisting of inter-departmental representatives. Variations on three of these assumptions (GDP, oil/coal price) were selected to construct the low, medium (”Most Likely”), and high scenarios on the basis that they would have the greatest effect on emissions projections.

5.1 GDP

The GDP values used are the Treasury budget forecasts from 2004-2008 and the Treasury long range growth forecasts for 2009-2020[2]. A further study on historical data was undertaken, the historical variance plotted and scaled to the relevant time period of interest. This study found that +/-0.7% was the most likely variance over a 20 year period.

Year	Low emissions scenario	”Most Likely”	High emissions scenario
2005	1.7	2.4	3.1
2006	2.1	2.8	3.5
2007	2.6	3.3	4.0
2008	2.3	3.0	3.7
2009	1.9	2.6	3.3
2010	1.8	2.5	3.2
2011	1.7	2.4	3.1
2012	1.4	2.1	2.8
2013	1.3	2.0	2.7
2020*	1.0	1.7	2.4

*linearly ramped over the 2013-2020 period.

[2] The Treasury, Budget 2004, Fiscal Strategy Report, http://www.treasury.govt.nz/budget2004/fiscalstrategy/fsr04.pdf

5.2 Exchange rate

Values closely reflect the long term average since floating of the dollar in 1985.

Year	US$/NZ$
2005	0.67
2006 to 2020	0.60

5.3 Oil price

Data was originally sourced from IEA (see International Energy Agency: World Energy Outlook 2004). The IEA oil prices are based on real, long run prices, and do not reflect the current volatility in world oil markets. It is important to note that the price New Zealand pays for its oil is usually similar to the normally quoted West Texas intermediate traded on the NYMEX market. The key factor for prices for modelling is not the absolute level, but the rate at which prices increase over time.

Year	High Price Scenario	”Most Likely”	Low Price Scenario
2005	37.50	32.50	30.00
2006	38.13	32.88	24.00
2007	38.75	33.25	24.00
2008	39.38	33.63	24.00
2009	40.00	34.00	24.00
2010	40.63	34.38	24.00
2011	41.25	34.75	24.40
2012	41.88	35.13	24.80
2013	42.50	35.50	25.20
2014	43.13	35.88	25.60
2015	43.75	36.25	26.00
2016	44.38	36.63	26.40
2017	45.00	37.00	26.80
2018	45.63	37.38	27.20
2019	46.25	37.75	27.60
2020	46.88	38.13	28.00
2021	47.50	38.50	28.40
2022	48.13	38.88	28.80
2023	48.75	39.25	29.20
2024	49.38	39.63	29.60
2025	50.00	40.00	30.00

5.4 Coal Price.

Whilst South Island coal was found to be considerably cheaper by $2/GJ, when electricity transmission costs were factored in (2c/kWh or $1.70/GJ coal equivalent) this price advantage was found to be negligible.

Year	High price scenario	”Most Likely”	Low price scenario
2005 to 2020	$4.00	$3.75	$3.50

5.5 Gas.

A constant, new discovery rate of 60PJ p.a. from 2009 onwards is assumed. A price of $6.50/GJ for gas for electricity generation in 2007 is assumed, rising to $7.25/GJ in 2020 for the ”Most Likely” scenario. This is calculated on the basis of a current backstop price of $7.80/GJ for LNG, although this also increases over the outlook period.

5.6 Methanex

Methanex is the gas-to-methanol plant operating in Taranaki. Methanex is currently operating at 30-40PJ p.a of gas which is half the rate it was operating at previously. This plant is modelled to close by mid-2006, owing to the expiry of its Maui gas contract.

5.7 Energy efficiency measures

No EECA targets will be included in the ”Most Likely” scenario – the targets will be reported separately by the CCO under the policies section of the main report.

5.8 Projects to Reduce Emissions (carbon credits)

The effects of carbon credits from the Projects Mechanism are modelled for electricity generation in the “Most Likely” scenario and “High” and “Low” scenarios derived from this. These are modelled via a reduction in installed costs of the relevant type of low emission generation. Modelling analysis indicates an effective reduction in costs of up to 0.6c/kWh.

5.9 Carbon Tax

A carbon tax of $15/tCO_2$ from April 2007 is modelled. This is applied to all sectors except the heavy industry sector. For the heavy industry sector it is assumed that Negotiated Government Agreements (NGA) are applied and that these offsetting effects are already incorporated in the forecasts received for these sectors. The effect of NGA's are not modelled in any other sector.