Sustainable Aviation Fuels Road Map: Data assumptions and modelling

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ACRONYMS AND ABBREVIATIONS

ASAFUG	Australasian Sustainable Aviation Fuel Users Group
bbls	barrels (equivalent to 159 litres)
Bio-SPK	Biomass derived Synthetic Paraffinic Kerosene
^{o}C	degrees Celsius
CO_2e	Carbon dioxide equivalent
CSIRO	Commonwealth Scientific and Industrial Research Organisation
EIA	Energy Information Administration (of the United States Department of Energy)
FT	Fischer Tropsch
GDP	Gross Domestic Product
G/FT	Gasification / Fischer Tropsch
HDO	Hydrodeoxygenated oil
HRJ	Hydroprocessed Renewable Jet
IATA	International Air Transport Association
IEA	International Energy Agency
Kg	kilograms
L	litres (equivalent to 0.2642 US gallons)
MJ	mega joules (a measure of energy content)
RSB	Round table on Sustainable Biofuels
RSPO	Round table on Sustainable Palm Oil
SAFUG	Sustainable Aviation Fuel Users Group

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1. INTRODUCTION

This is a technical document in support of the Sustainable Aviation Road Map Study's *Flight path to green aviation* report. This document is designed to provide a brief description of the data used and assumptions and modelling processes which underpin the conclusions reached in that report. Providing such transparency makes it possible for the reader to explore the implications of alternative assumptions.

The report describes the main assumptions with respect to the biomass to jet fuel supply chain including the cost, type and volume of biomass resources available in Australia and New Zealand and the cost of alternative pathways for refining. These data assumptions are the most important drivers of the future of bio-derived jet fuel and are the main focus of the first section of the report. The remaining sections describe the scenarios that were explored and the modelling results.

The modelling was designed to consider competition for biomass within the transport sector and between the transport sector and the electricity sector. Accordingly, the assumptions relating to the remainder of the transport sector and to the electricity sector are outlined in two separate appendices.

2. BIOMASS TO JET FUEL SUPPLY CHAIN ASSUMPTIONS

2.1 Scope

This study would ideally cover all potential biomass and its uses in order to fully represent all of the options and interdependencies that could determine future outcomes. Due to the constraints of time, cost, relevance and available information there have been some exclusions, as described below:

- Palm oil was excluded on the basis that Australasia has limited climate zones suiting this species

- Grasses and halophytes were not included in the study because although some international yield data is available, there is virtually no data available on likely Australasian yields and suitable locations.

- Jatropha was not included in this study because it has a lower expected yield than pongamia (which would use similar land), is likely more labour intensive (in a region where we do not have low cost labour) and it is classified as a noxious weed with prohibitions on its cultivation in Australia.

- Wheat, canola, other rotation oil seeds such as juncea and the sugar juice component of sugarcane are all excluded on the basis that their use as biofuel feedstocks could impact on the food market which would eventually limit their supply through either rising food prices or through negative consumer sentiment

- Food prices and food market impacts on the biofuel sector were not considered because the study has only included non-food (second generation) biomass feedstocks that have limited impact on food production (via sharing rather than supplanting existing land use).

- The economic value and market demand for cosmetic, animal feed and other biofuel refinery co-products were not considered, so as to reduce the complexity of the study. Consequently, the economic viability of some biomass to fuel pathways may be better than projected. Specifically, co-product markets may be make a significant contribution to oilseed and algae producers.

- Only the hydrodeoxygenation and gasification / Fischer Tropsch biomass to jet fuel refining pathways have been included in the modelling. Data for alternative pathways was deemed to be insufficiently developed for inclusion.

2.2 Units

As this is an Australia/New Zealand-based study the units used are based on local conventions. This section is to assist in calibrating readers from different regions to the data units used.

All prices are in Australian dollars unless otherwise stated. However, Australian exchange rates at the time of this study were close to parity with US dollars.

A MMBTU is 0.9478 times a GJ. Therefore US prices expressed in $/MMBTU can be taken as very close to $/GJ which are often the preferred Australian units. Or you can divide or multiply through as appropriate for more accuracy.

A US gallon = 3.785 litres. A barrel is 159 litres.

Typical Australian fuel prices:

- East coast gas existing long term contract for large industrial user = $A3.5/GJ
- East coast gas new long term contract for large industrial user = $A5-7/GJ
- West coast gas (export market exposed) = $A10-15/GJ
- Petrol/gasoline price (at $1.10/L) = $A32/GJ
- Diesel price (at 1.10/L) =$28.5/GJ

Recent Australian diesel and petrol prices have ranges between $1.10 and $1.35/L in the cities. Divide through by energy content below and multiply by 1000 to convert different price levels to alternative $/GJ levels.

Indicative energy content values used in Australia based on ABARE (1997):

Jet fuel content = 36.8 MJ/L

Petrol (gasoline) content= 34.2 MJ/L

Diesel content= 38.6 MJ/L

Ethanol content = 23.4 MJ/L

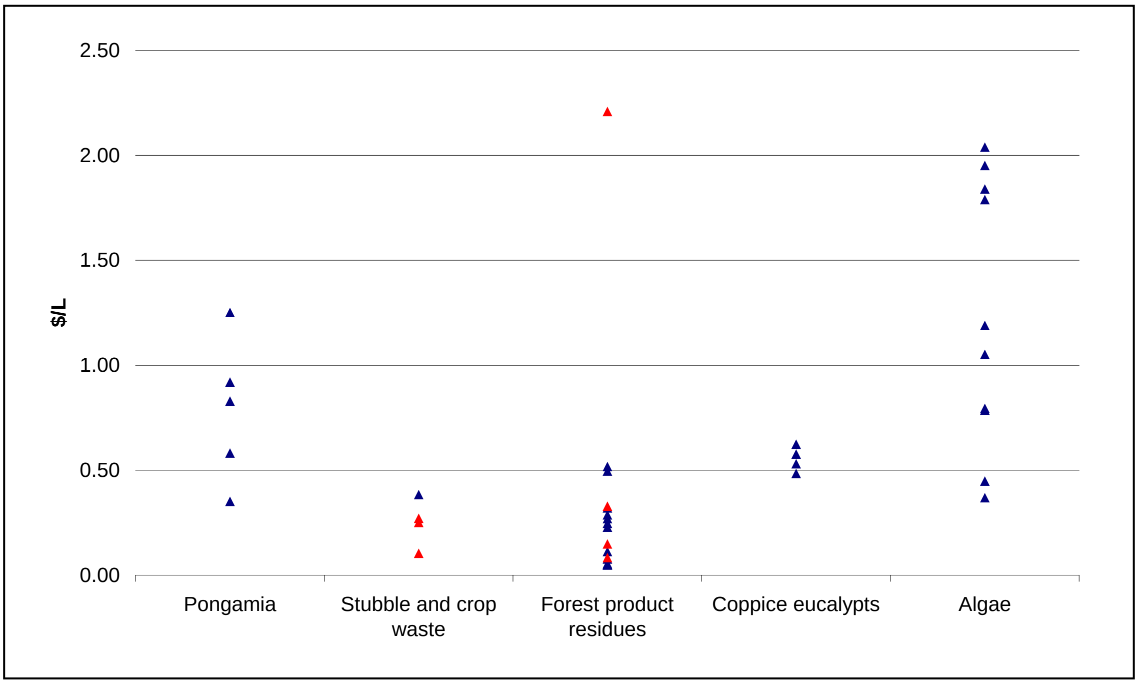
LPG content = 25.7 MJ/L

2.3 Cost of bio-derived jet fuels

Data for biofuels is from a mixture of CSIRO internal data, data in public documents and private industry sources. Ideally all data would be from publicly refereed sources. However, such an approach would mean that we would have no data at all in many cases. Data is more reliable where the biofuel feedstock is already in commercial scale production. For second generation non-food sources other than bagasse, forestry and crop waste, no significant production has occurred to date.

Figure 1 shows that existing crop residues and the majority of forest residues estimates are at relatively low cost. However, as we shall see later it can cost more to refine this type of biomass. Pongamia is the next lowest cost resource. Algae cost estimates span a wide range reflecting their relative production immaturity.

Figure 1: Estimates of the contribution to delivered cost of jet fuel of non-food biomass feedstocks (Australian estimates in blue, New Zealand in red).

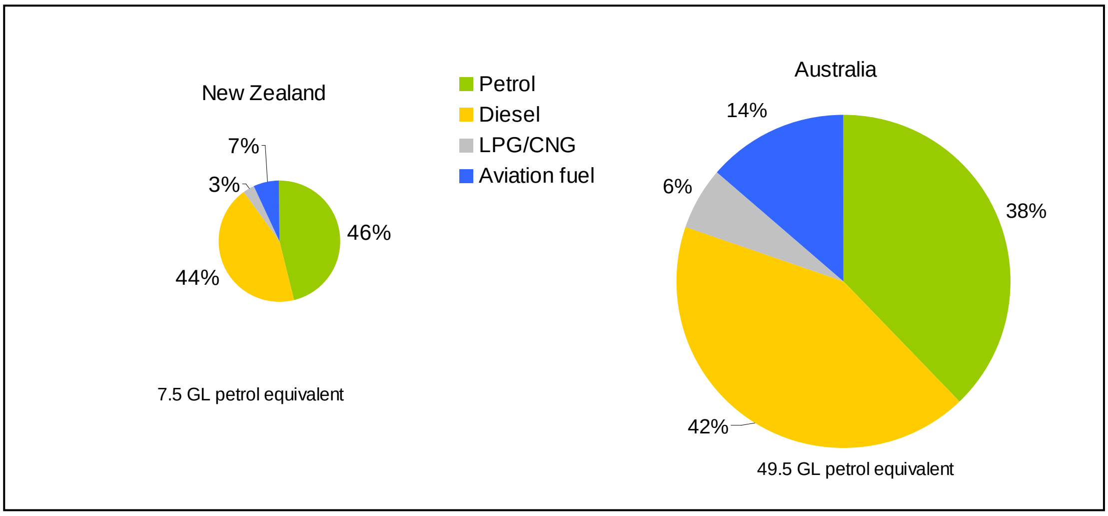


Notes:
All New Zealand data is from Hall and Jack (2008) and Hall and Gifford (2007)
Pongamia data is primarily from internet sources in relation to Indian experiences. An industry estimate for potential Australian production was provided by CleanStar
Stubble and forest product residues are CSIRO estimates from Farine et al (forthcoming) based on observed market prices for straw, various grades of bark, pulp log, chip and sawmill residues
Coppice eucalypts refers to new plantations incorporated into existing farming systems and is a CSIRO estimate
Algae data is from IATA (2009b), Campbell et al. (2009) and Darzins et al (2010). These sources also contain estimates up to $5/L not shown in the chart.

2.4 Volume of transport fuels consumed in Australia and New Zealand

The following figures show the amounts of fuels used in transport in Australia and New Zealand for the purposes of comparing these amounts to the volumes of biomass available that will be discussed in the proceeding section.

Figure 2: Fuel consumption in Australia and New Zealand



Source: ABARE (2010),

2.5 Volume of bio-derived jet fuels in Australia

The following figures show the amounts of biomass that is expected to be available in Australia at the costs shown in Figure 1 and Figure 3. Appendix A provides more details on how the estimates of sustainable quantities of bio-oils and lignocellulosic feedstocks were obtained, as well as commentary on sustainability issues relevant to Australia, and how these relate to the principles comprising the Roundtable on Sustainable Biofuels (RSB).Where cost information could be directly linked to volumes of a particular feedstock it has been. For example, within the forest biomass category we have data for the price and amounts of 15 subsets of forest products.

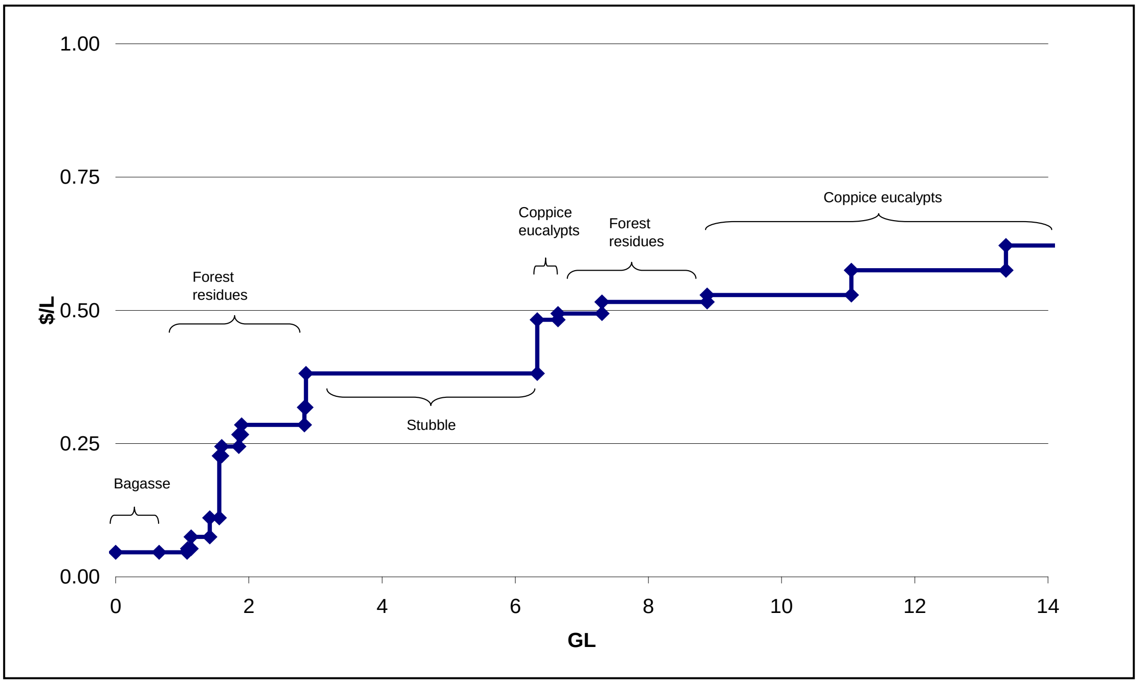
Where quantity and cost estimates are only available for the total resource, quantities have been allocated to the range of different cost estimates in a more or less even fashion. While somewhat arbitrary, it is expected this assumption is less erroneous than if the feedstock were assumed to be homogenous. In reality, each source of a given biomass feedstock will exist along a rising cumulative cost curve where factors such as climate, soil and access to infrastructure will determine its position.

Costs estimates associated with accessing these amounts of bio-derived jet fuel feedstocks will improve over time beyond those shown here. This issue is dealt with in the scenario analysis.

Note, as a point of reference in understanding the significance of the amounts shown, current aviation fuel consumption in Australia and NZ is around 6 GL/yr (Figure 2).

Figure 3 shows that the volume of aviation turbine fuel that could be produced from already existing lignocellulosic sources of biomass is around 8-9 GL/yr. New coppice eucalypt plantations, on the other hand, would take significant time to establish (establishment rates could be up to ~ 100000 ha/yr).

Figure 3: Cumulative volumes of jet fuel that could be sustainably produced from lignocellulose biomass resources in Australia and their contribution to jet fuel costs



Specific sustainability criteria applied to stubble are:

- Between 1-1.5 tons/ha of stubble are left on site for soil protection.
- The stubble is dispersed and often occurs at low density in the landscape - only the hotspots where 1 million ton of stubble might be available annually within a radius of 100 kms were included in the estimation

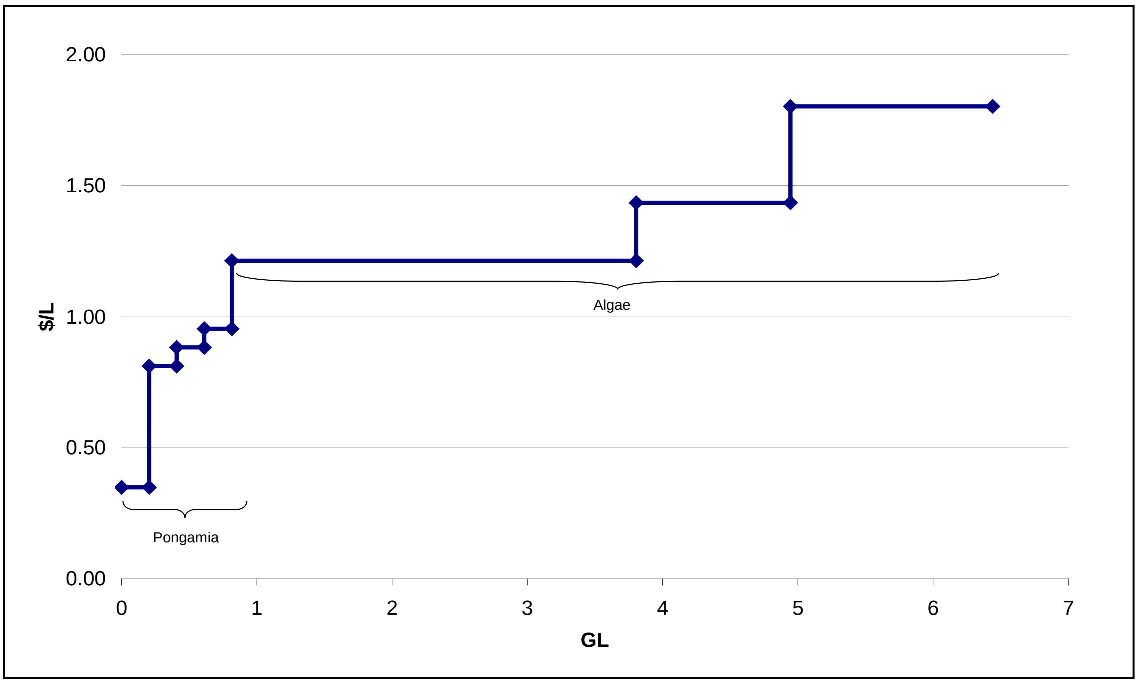
Specific sustainability criteria applied to forestry are:

- Sawlogs are not available for bio-energy
- Native forest wood is not available, except for sawmill residues
- Hardwood Pulp logs: The export fraction might be used for bio-energy (90% of the total)
- Softwood Pulp logs: The export fraction might be used for bio-energy (70% of the total)
- Plantation forest harvest residues: Branches, leaves and foliage are not available for bio-energy
- Plantation forest harvest residues: 100% residual (not harvested for either sawlogs or pulpwood) stem wood remaining in the forest might be available (assuming no whole tree harvesting)

Figure 4 shows the volume estimates for biofuel derived from plant oil resources. All of the volume shown would need to be developed over time. There is no existing pongamia or algae production.

The pongamia estimates are based on imposing climatic limits (based on an analysis of the climatic conditions where pongamia currently grows overseas) on the land mass of Australia (see Appendix A, and Farine et.al., in review, for further details). An oil yield of 2 t/ha per annum was then applied based on yield estimates in the limited data available in the published literature that range from 1.8-3 t/ha per annum. Some industry proponents suggest higher yields are possible, but these have not been validated by field trials. If irrigation is available that could potentially expand the total land available for pongamia. Industry experts have suggested irrigation may be required for up to three years to prevent tree losses in hotter and drier seasons.

Figure 4: Cumulative volumes of jet fuel that could be sustainably produced from oil resources derived from either pongamia or algae



Algae volumes are calculated from Campbell et al (2009) and Farine et al (forthcoming) where the main constraint considered was access to a concentrated source of carbon dioxide. Sources included were power stations, coal seam methane and human and animal waste processing facilities. Higher cost estimates for algae feedstock resources above $1.80/L were excluded as it is unlikely such resources would be deployed.

2.6 Volume of bio-derived jet fuel in New Zealand

Data for the volumes of biofuel available in New Zealand have been adapted from Hall and Gifford (2007) and Hall and Jack (2008). The data shown in Figure 5 is biomass that is currently available. Data shown in Figure 6 is biomass that is expected to be available in 2030.

New Zealand was also assumed to have the potential to grow algae feedstocks. The amount of 400 ML was estimated based on the ratio of carbon dioxide available in the New Zealand and Australian electricity sectors multiplied by the potential Australian algae production.

Figure 5: Cumulative volume of bio-derived jet fuel based currently available second generation biomass resources in New Zealand and their contribution to jet fuel costs

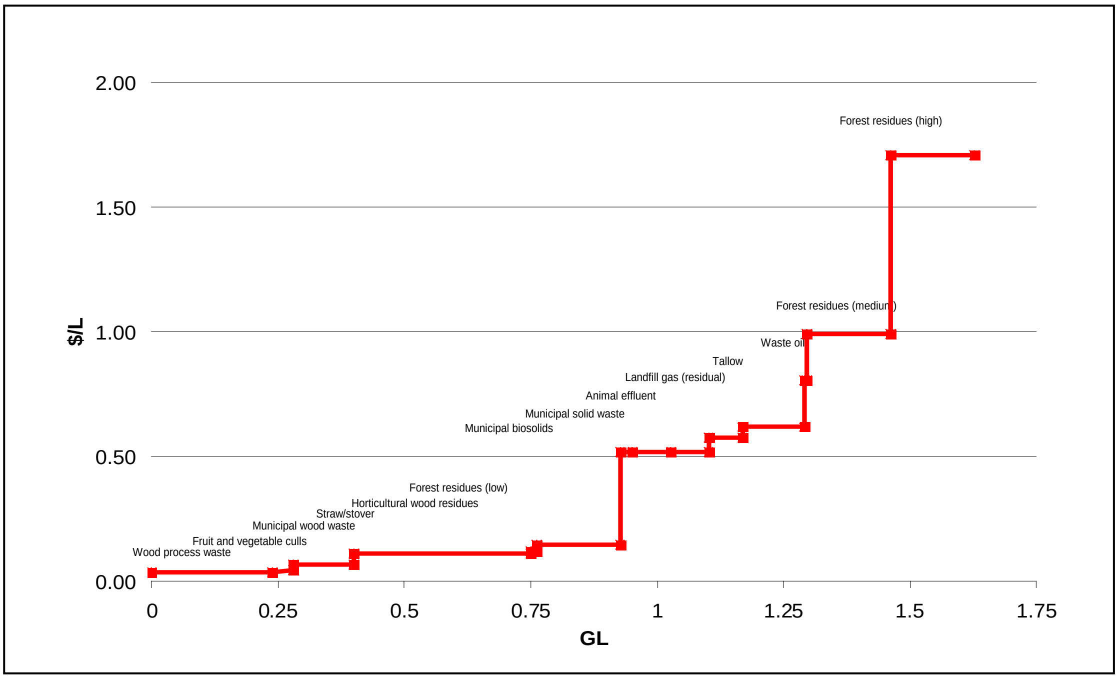
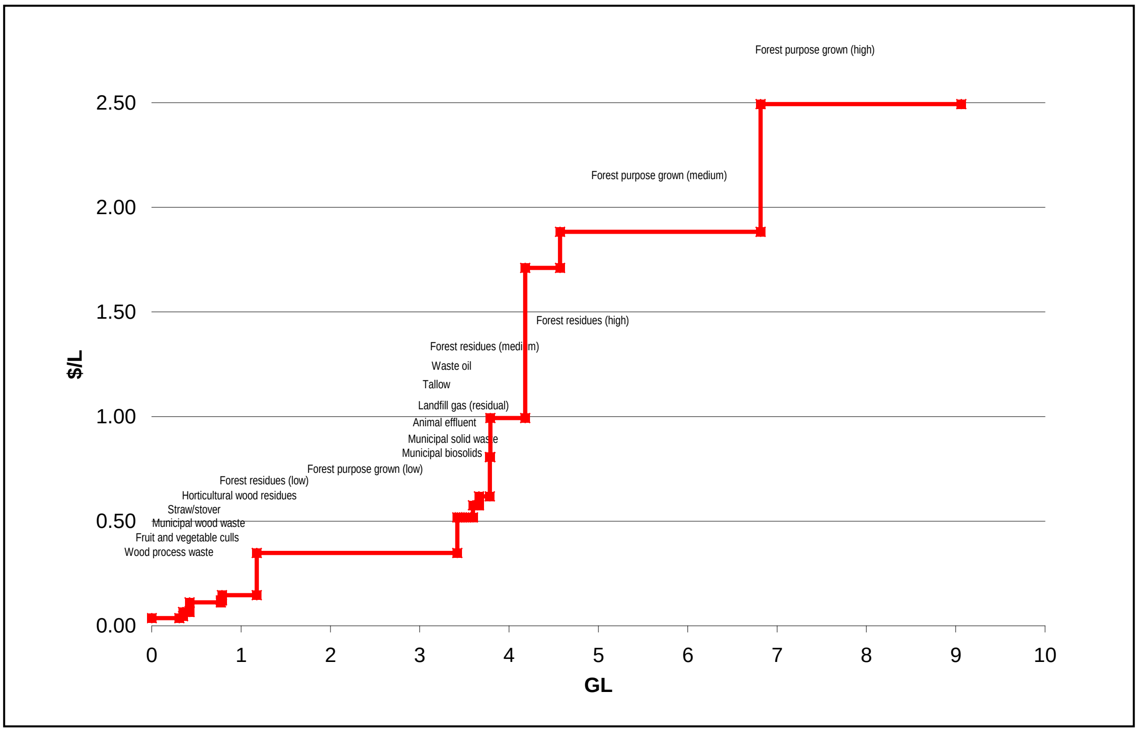


Figure 6: Cumulative volume of jet fuel available in 2030 that could be sustainably produced from biomass resources in New Zealand and their contribution to jet fuel costs



2.7 Summary of biofuel volumes

While we need to add further cost components to understand the total cost of bio-derived jet fuel, we can at this point summarise the implications of the data on biomass/biofuel volumes. Based on projected growth in fuel demand across the whole transport sector over the next decade to 2020 and assuming we are able access all existing biomass resources plus 10 percent of potential new resources that could be developed (such as algae, pongamia and coppice eucalypts) then Figure 7 shows the scale of potential biomass relative to total transport fuel demand. Relative to total transport demand fuel needs, biomass resources could supply 7 percent of that consumption. If all of this resource were available only to the aviation sector then it could supply 46 percent of the aviation sector’s fuel consumption.

In the long term, by 2050, all identified biomass resources would be able to be exploited if economically viable. However fuel demand will have risen further by that time. Nevertheless biomass resources will be equal to 20 percent of total transport needs by 2050. If available only to the aviation sector then it would be equal to more than its total fuel consumption in 2050 (Figure 8).

Figure 7: Scale of biomass resource relative to transport fuel demand, 2020

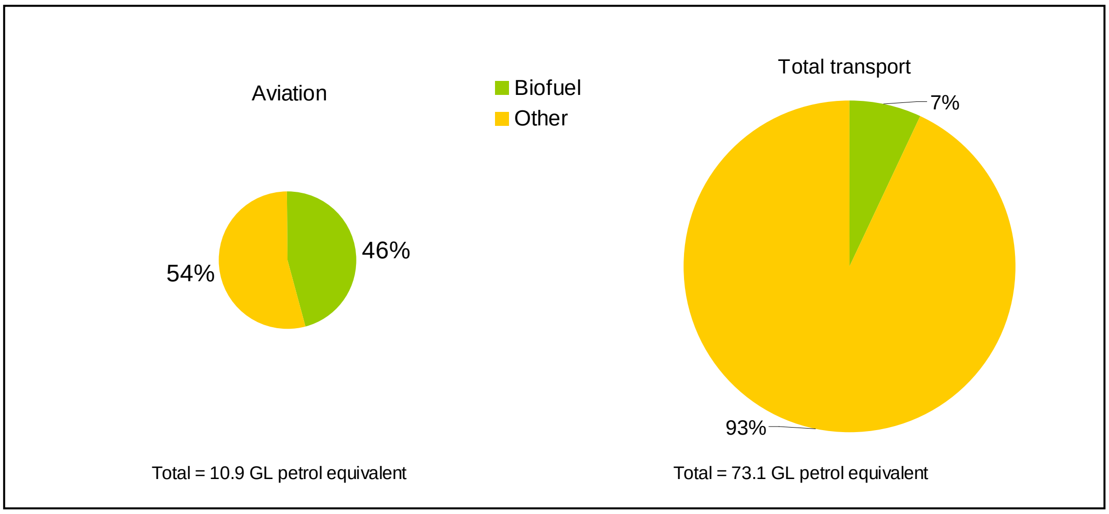
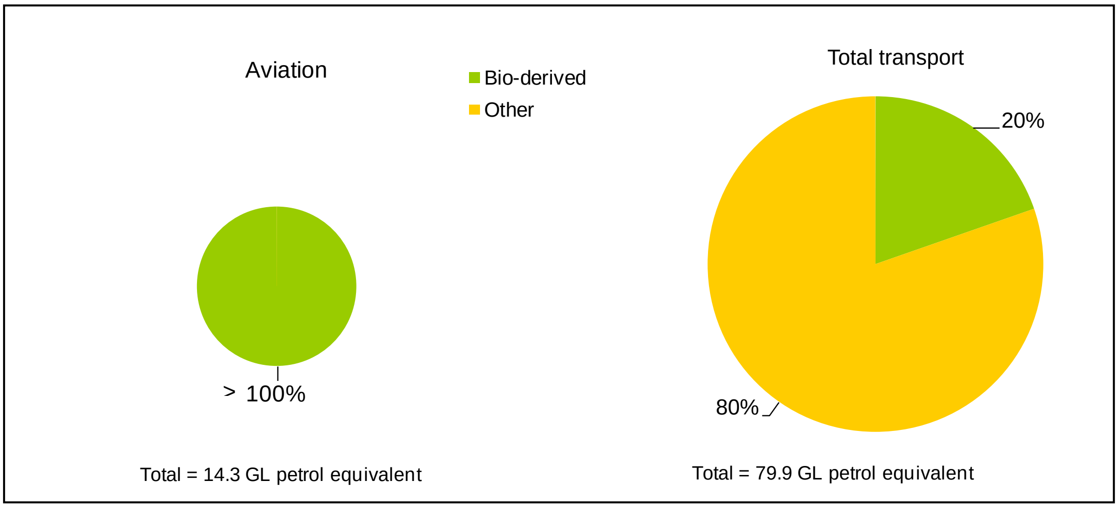


Figure 8: Scale of biomass resource relative to fuel demand, 2050



2.8 Biofuels refining

As discussed at the beginning of this section we have only included the hydrodeoxygenation (HDO) and gasification / Fischer Tropsch (G/FT) refining pathways due to lack of data on other processes. Before describing the assumptions for each of these two pathways the following describes the financial assumptions around converting the data into a form that is required for the modelling.

2.8.1 Units of measuring capital cost

Biofuel refining costs are presented in the literature in one of two ways. Either as a cost in millions of dollars for an amount of refining capacity (e.g. in million litres) or in dollars per litre of the delivered cost of fuel. In this report the costs of refining found in the literature or from other sources have all been converted to the latter form.

To convert up front refining capital costs to a component of delivered costs one must amortise the upfront payment into a payment per litre per annum. The standard formula for amortising an upfront payment into an annual payment is as follows:

$$AnnualPayment = UpfrontCost \times \frac{r\left(1+r\right)^{t}}{\left(1+r\right)^{t}-1}$$

where r is the rate of financing and t is the amortisation period. For this study a real annual cost of financing of 7 percent was assumed. This is based on evidence that the historical before tax return on investment in Australia is about 8-10 percent, roughly six percent above the riskless rate of return. The real cost of foreign funds has been 4-5 percent in the last decade (Commonwealth of Australia, 2007). However, there has been some recent volatility. See the end of this section for sensitivity analysis on the assumed cost of finance. The assumed amortisation period was 15 years.

This formula converts the upfront cost to an equivalent annual payment taking into account the time value of money. The final step is to divide through by the annual production rate to arrive at a figure in $/L produced. The annual capacity of a plant usually only reflects the maximum possible production rate. In reality the utilisation rate of the plant will be lower due to maintenance and other factors. As such we must multiply the annual production rate by the expected utilisation rate. In this case we assume a 90 percent utilisation rate.

$$DollerPerLitreCost = \frac{UpfrontCost \times \frac{r\left(1+r\right)^{t}}{\left(1+r\right)^{t}-1}}{AnnualProduction \times UtilisationRate}$$

It is also important to add an additional amount for interest lost during construction. This is the opportunity cost of having finances tied up in a real asset during its construction while it is not producing anything. If the funds were not tied up, at a very minimum they could have been earning interest in a bank deposit or been invested in an alternative revenue returning asset that has no production delays.

Therefore the formula is modified as follows:

$$DollerPerLitreCost = \frac{\left[\left(UpfrontCost \times (1+r)^{CP}\right) \times \frac{r(1+r)^t}{(1+r)^t - 1}\right]}{AnnualProduction \times UtilisationRate}$$

Where CP is the period when interest is lost during construction of the plant. This is not meant to represent the entire period from planning to full commissioning of a project. Rather it is the time between when the bulk of funds must be dispersed to plant and equipment suppliers and when production first commences. Using this simple formula we represent this period as a single upfront payment held over a short period as proxy for the reality which is more likely to be several smaller payments over a longer period. While our simpler approach is less accurate, it allows greater transparency. In any case, data in the open literature does not provide details of when all payments for each part of the plant will take place.

The values for CP parameter for HDO and G/FT are assumed to be 2 and 4 respectively.

Note formula provided need not use annual data. It could be applied to daily financing rates, amortisation period in days, production rate in days, etc but the result is the same so long as the time units are all consistent.

2.8.2 Biofuel refinery capital and operating costs

Data was sought in the open literature on theoretical and actual refining capital and operating costs. There was such a great uncertainty in theoretical G/FT plant costs that a decision was made to examine realised plant costs for gas and coal to liquids G/FT plants which are known in the literature as GTL and CTL plants. Whilst these plants do not use biomass as the feedstock they have some parts of the plant in common. A second major issue that needed to be overcome was to match costs with the likely scale of plants in Australia or New Zealand.

Table 1: Comparison of efficient and practical scales of two biomass to jet fuel refining processes

Plant type	**Efficient scale**		**Practical scale**	
	Output	**Biomass input**	**Output**	**Biomass input**
HDO	>400ML	0.4 Mt/yr pongamia oil	150-400ML	0.2-0.4 Mt/yr pongamia oil
G/FT	>2000ML	9.1 Mt/yr lignocellulose	400ML	1.8 Mt/yr lignocellulose

Table 1 shows that the most efficient scale for a G/FT plant (2000 ML) requires a very large biomass feedstock input. Based on knowledge of Australia conditions there would be no areas of Australia where you could access that volume of lignocellulose within a 100km radius. A more practical scale would allow for biomass input of 1-2 Mt per annum. In contrast, efficient scale HDO plant can be built at around the 400ML scale (bigger sizes will only deliver slight improvements).

Estimates of capital costs for existing or theoretical GTL and CTL plants are generally for plants in the 1200ML to 2000ML scale. Therefore we need a process for converting this data to take into account increases in cost with smaller scale. A commonly used formula in the refining industry is as follows:

$$ScalingFactor = \frac{\left(\dfrac{PlantSize_A}{PlantSize_B}\right)^{Rate}}{\left(\dfrac{PlantSize_A}{PlantSize_B}\right)}$$

The “rate” of increase (decrease) in costs as scale declines (increases) is usually in the order of 06.to 0.8 (Tijmensen et al, 2002). If we use 0.7 and apply this formula to scale a plant down from 2000 to 400ML then the calculated increase in costs is a factor of 1.62. If the scale down from 1200ML to 400ML then the scale factor is 1.39.

When we use the GTL and CTL plant data to calculate the cost of a biomass G/FT plant (also called BTL) then we need to not only take into account of the change in scale but also the differences in the plant components. An in-depth plant components analysis has not been conducted. However, an obvious point is that a GTL plant will not need to basify a solid fuel and therefore would be expected to have fewer components. CTL plants have this step in common with a biomass plant but as they are dealing with a different type of solid fuel costs will still differ.

To determine the appropriate factor for both scale and differences in feedstocks of G/FT plants the following data has been collected.

Table 2: Observed ratio of costs of GTL, CTL and BTL (biomass G/FT) plant capital costs

	GTL to BTL observed ratio	**CTL to BTL observed ratio**
IEA (2009b)	1.6	2.9
Kruetz (2010)		1.5

The IEA (2009b) data refers scaling down from a 2200 ML CTL to a 125 ML BTL plant (17 times difference). This large scale down perhaps explains why the Kruetz (2010) estimate is much lower at 1.5 and the IEA (2009b) GTL to BTL which we would have expected to have a greater difference at 1.6.

These estimates from the literature and the scaling factor formula are all in the range of 1-3 but there is not enough information to guide us in separating technological differences from scale differences. The factors chosen to be used in this study are 1.6 and 2 for CTL to BTL and GTL to BTL respectively based mainly on the scaling factor plus adding an additional penalty to the GTL to BTL adjustment factor to account for the additional gasification technology required to go from a gas to solid feedstock.

Table 3 shows the estimates of upfront capital costs, their conversion to amortised dollar per litre delivered capital costs and operating costs, where available, that have been gathered from various sources shown.

Table 3: Estimated capital and operating costs of jet fuel refining from biofuels using either the HDO or G/FT process

Biomass conversion processes	Reference / source	Qualifications	Up front Capital cost* $/L	Amortised Capital cost $/L	Operating Cost $/L
Gasification /Fisher Tropsch (G/FT)	IEA (2009b)	At $60/bbl oil, near term		0.41	0.07
	IEA (2009b)	At $60/bbl oil, long term		0.21	0.04
	IEA (2009b)	At $120/bbl oil, near term, 125ML	0.55	0.10	
	IEA (2009b)	At $120/bbl oil, long term, 750 ML	0.28	0.07	
	Wright, M.M and Brown, R.C. (2007)	681ML capacity	1.5	0.24	
	(S&T)2Consultants Inc (2007)	200ML	2.8	0.44	
	(Boerrigter 2006)	1900ML	0.9	0.14	
	Hatch (2008)	2310ML coal	3.2	0.50	0.10
	Hatch (2008)	1155ML coal	5.0	0.79	0.12
	Qatar Oryx project	2031ML gas	1.0	0.16	
	Qatar Pearl project	8124ML gas, (4 identical units)	4.9	0.78	
	Nigeria Escravos project	2031ML gas	4.9	0.78	
	Solena/BA project	90ML municipal biowaste	3.0	0.47	
	Anex et al (2010)	Nth plant	3.9	0.62	
	Anex et al (2010)	Pioneer (1st) plant	7.8	1.24	
Hydro-deoxygenation (HDO)	UOP Honeywell (2010)	Green field	0.73	0.10	0.11
	UOP Honeywell (2010)	Brown field	0.45	0.06	
	McKinsey/IATA (2009b)			0.11	0.13
	IEA (2009b)	At $60/bbl oil, near term		0.06	0.17
	IEA (2009b)	At $60/bbl oil, long term		0.03	0.14
	IEA (2009b)	At $120/bbl oil, near term		0.09	0.30
	IEA (2009b)	At $120/bbl oil, long term		0.04	0.26

* Costs have been scaled up by a factor of 1.6 if coal plant data and 2 if gas plant data to be comparable to BTL plant costs. Costs are in nominal terms

As discussed the G/FT refining pathway has the greater uncertainty even after adjusting for differences in feedstocks. Figure 9 demonstrates one possible reason for the variation. If we regard the IEA (2009b) and Solena/BA projects as outliers then the costs show an upward trend from around middle of the decade. This upward trend has been observed by CSIRO in power plant costs. CSIRO has observed that even for power stations where there has been very little technological change like black coal-fired power, plant costs have more than doubled. This is owing to increases in costs of raw materials such as steel and also shortages of engineering skills.

Figure 9: Estimates of G/FT costs order by time of publication

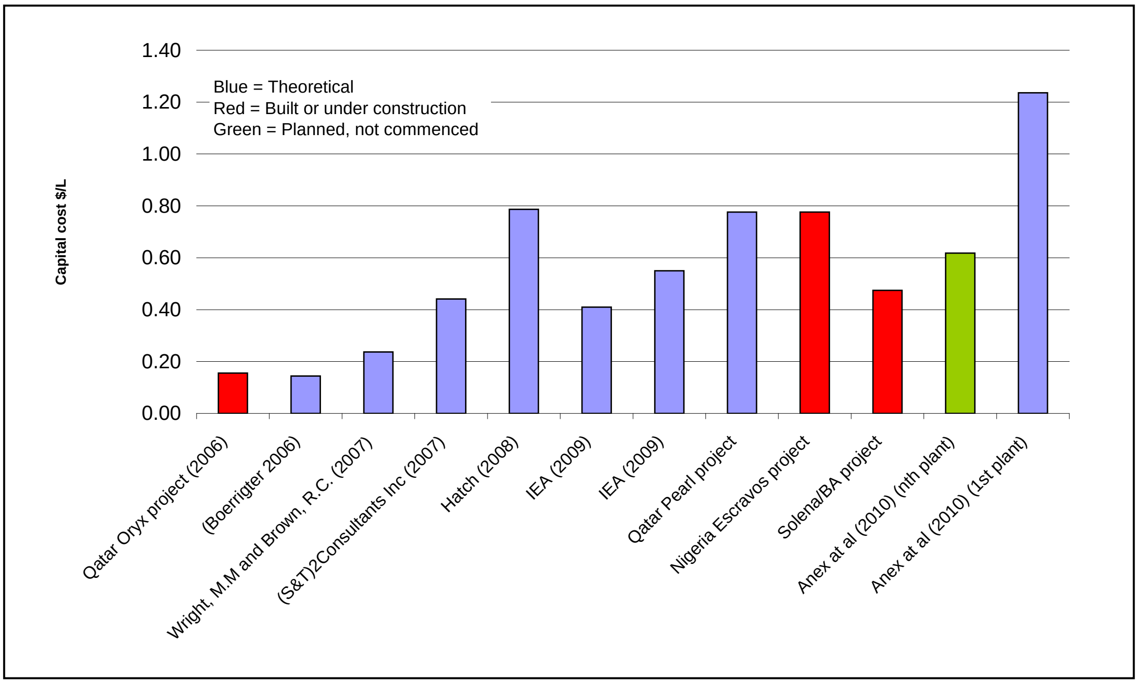
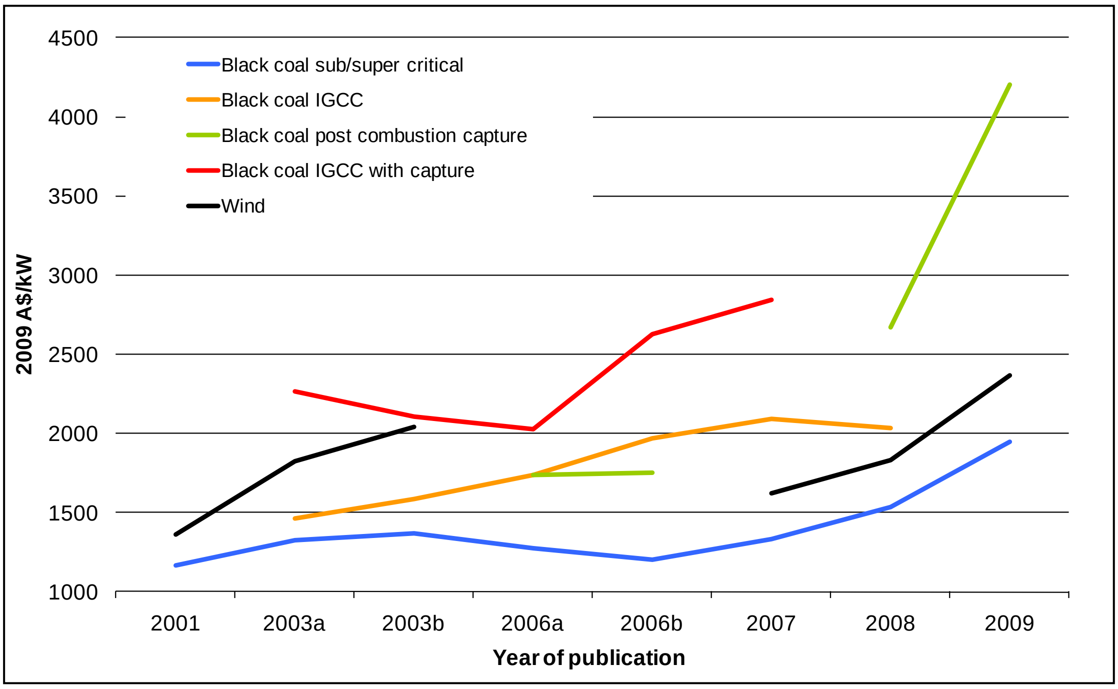


Figure 10: Trend in real power station costs based on CSIRO publications between 2001 and 2009



Given that the current trend towards higher commodity prices is yet to fully run its course, it would seem prudent to use the costs at the upper end of the range, even though the more recent project proposal from Solena/BA is at a lower cost. Consequently in the modelling we use $0.78/L for the G/FT capital cost. For the operating cost we assume the Hatch (2008) estimate of $0.12/L. For HDO we assume the UOP (2010) estimate of $0.10/L and operating cost of $0.11/L. Note that in both the G/FT and HDO cases we have assumed that they build their own hydrogen production infrastructure. The alternative would be for either plant type to purchase hydrogen from a co-located industrial facility. In that case capital costs would be lower but operating costs would be higher.

The feedstock costs for the refining process is based on the biomass costs already discussed divided through by the conversion efficiency. The assumed conversion efficiency for G/FT and HDO is assumed to be 45 and 65 percent respectively.

2.8.3 Alternative refining processes and potential for improvements over time

One alternative refining pathway is the fermentation of the plant sugars into fuel using patented yeast or other microorganisms. Capital and operating costs for the production of synthetic hydrocarbons from sugars are not yet available. However, IATA (2009b) reports that potential manufacturers have claimed that total delivered fuel costs will be between $0.23 and 0.56 per litre. This would appear to indicate that capital costs are very low indeed for this process.

Another alternative experimental refining pathway is fast pyrolysis techniques that use additional catalytic upgrading to produce jet fuels. The Renewable Oil Corporation in Australia is one of the proponents of this approach. Current data indicates it may be half the capital cost of the G/FT pathway. It can also use any type of biomass including lignocellulose inputs.

Since neither of these processes have been commercially demonstrated and data remains limited due to commercial considerations they could not be included in this study. However they are important to note because they indicate that refining cost could significantly decline in the future if these experimental process are proven at commercial scale.

For the existing HDO and G/FT processes we assume that both of them halve their capital costs over the next two decades. In the case of HDO this is justifiable because it is a relatively new technology and so there is considerable scope to improve it. It is perhaps less justified in the case of G/FT which is more established as a refining technology. However we apply the same rate of technological improvement to the G/FT pathway to acknowledge two potential developments.

The first potential development is that the Solena/BA technology may be capable of achieving its proposed costs at its proposed low scale.

The second potential development is that if the fast pyrolysis process proposed by organisations such as the Renewable Oil Corporation achieves its expected cost then even if the G/FT pathway costs do not decline, the costs of lignocellulose refining will be able to be halved via this alternative pathway. In this sense the future cost of G/FT in the modelling becomes a proxy for both G/FT and any other alternative lignocellulose refining options.

2.9 Transport and distribution costs

The IEA (2009b) publishes costs for transport and storage of refined fuel of $0.02/L and $0.04-0.05/L respectively.

Transport of biomass feedstock to the refinery should be of similar order if the feedstock is in oil form. However, for bulky lignocellulosic feedstocks the costs will be higher. CSIRO has estimated these costs for different feedstocks and distances. Transport costs for higher density feedstocks travelling only 10 kilometres could contribute as little as $0.05/L to delivered jet fuel costs. However, low density feedstocks travelling 250 kilometres would add over $0.40/L to costs (Table 4).

Table 4: Estimates of lignocellulosic feedstock transport costs from source to refinery

	Softwood Plantations			**Crops**	**Hardwood Plantations**			**Sawmill residues**			
Km	**Logs**	**Chips**	**Residues**	**Stubble**	**Logs**	**Chips**	**Residues**	**Chips**	**Bark**	**Sawdust[1]**	**Shavings**
10	$0.07	$0.05	$0.09	$0.05	$0.05	$0.04	$0.08	$0.05	$0.03	$0.05	$0.03
50	$0.11	$0.10	$0.13	$0.09	$0.09	$0.08	$0.12	$0.09	$0.06	$0.09	$0.05
100	$0.19	$0.18	$0.19	$0.14	$0.15	$0.14	$0.18	$0.16	$0.11	$0.17	$0.09
150	$0.26	$0.25	$0.26	$0.19	$0.21	$0.20	$0.24	$0.24	$0.16	$0.25	$0.13
200	$0.34	$0.33	$0.32	$0.25	$0.27	$0.27	$0.29	$0.31	$0.21	$0.33	$0.17
250	$0.42	$0.41	$0.38	$0.30	$0.34	$0.33	$0.35	$0.39	$0.26	$0.40	$0.21

1 Green sawdust

Source: Farine et al (forthcoming)

2.10 Cost summary

Figure 11 indicates the sum of the biomass, refining and transport costs that have been discussed to show the current total delivered cost of jet fuel via the two refining pathways. For biomass the mid-range of costs have been assumed in order to use a single value. The data indicates that feedstocks are the biggest cost issue for the HDO pathway. For G/FT the capital cost of the plant is the largest cost. Transport and feedstock are around equal second. While feedstock is relatively low cost for G/FT the conversion efficiency is poor and transport costs are high.

Figure 12 and Figure 13 plot the component costs in what can be described as a ‘tornado chart’. These charts show the change in the delivered cost of bio-derived jet fuel from the two refining pathways form a 50 percent increase or decrease in a given cost assumption. These charts show in a more precise way the relative percentage sensitivity of the delivered fuel costs to component costs. Much the same conclusion can be drawn. However, there is one additional component added to these chart which is the cost of finance. The cost of finance is often a much debated input into any cost analysis. While components such as risk free rate of interest are well known there is much debate around what return on equity should be targeted and any additional risk weighting. The charts show that the impact of using a different cost of finance would have made very little difference to the calculated delivered cost of HDO bio-derived jet fuel. However, it does have a significant impact on the cost estimates for G/FT bio-derived jet fuel.

Figure 11: Comparison of cost of jet fuel from the HDO and G/FT pathways

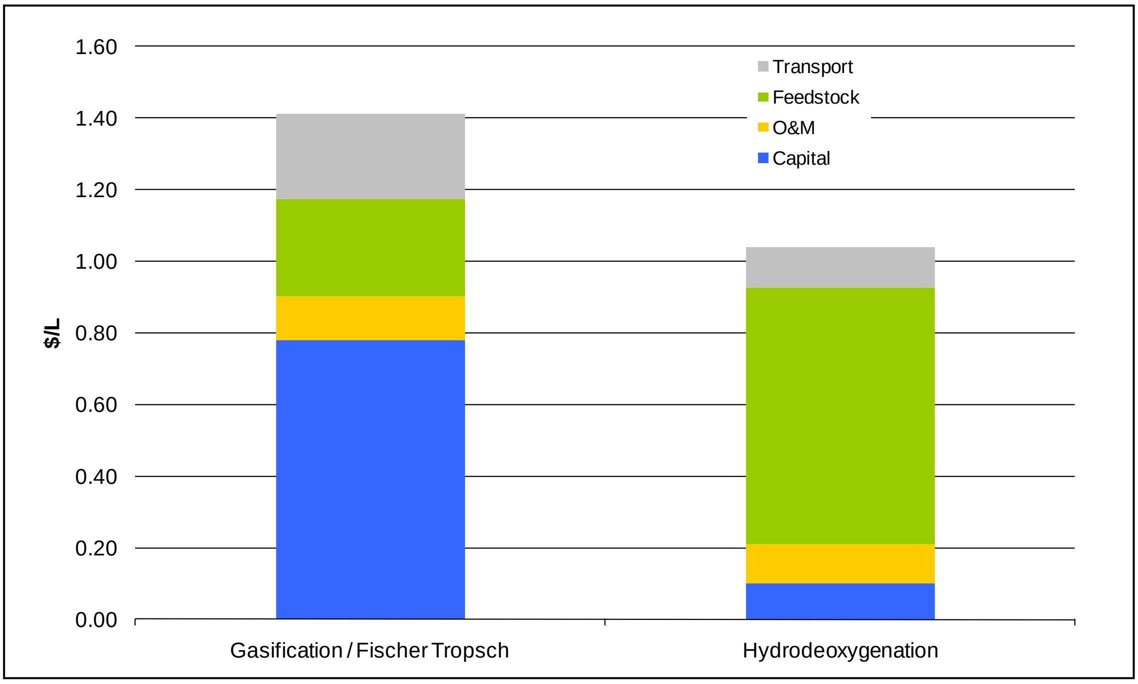


Figure 12: The impact of a 50 percent change in a given cost assumption on the delivered cost of bio-derived jet fuel from the G/FT refining pathway

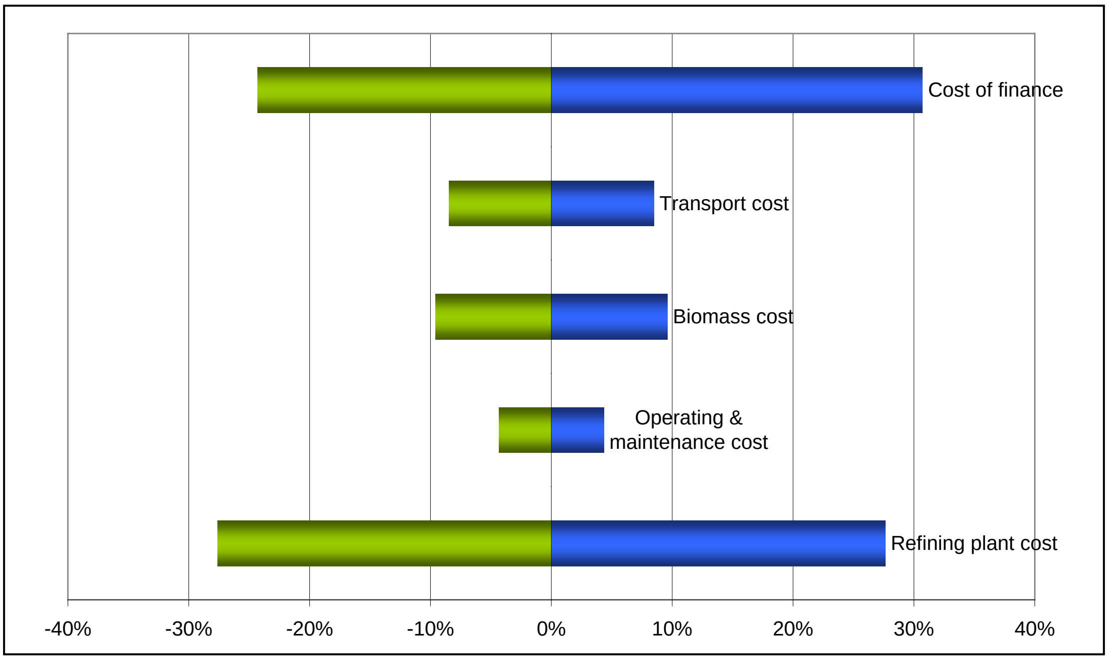
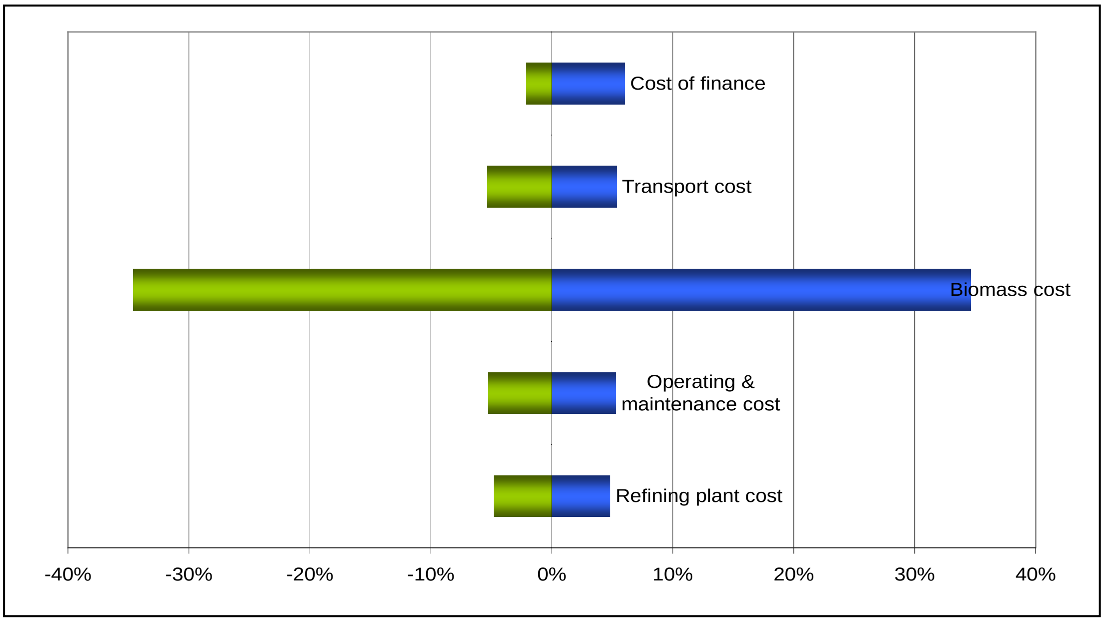


Figure 13: The impact of a 50 percent change in a given cost assumption on the delivered cost of bio-derived jet fuel from the HDO refining pathway



2.11 Timing of first bio-derived jet fuel production

The table below indicates the earliest possible dates at which the various biomass production feedstocks could be available for use (ignoring refining constraints).

From a refining point of view, HDO refining plant could be constructed in the least time due to its low capital intensity. Various G/FT plants have historically taken many years (5-10) to plan and construct due to their high capital intensity (around 8 times that of HDO). Consequently G/FT plant construction will not be the first choice for refining plant if it can be avoided.

On the other hand, the feedstocks for G/FT are readily available at present or within a year. Non-food biologically derived oil feedstocks required for HDO will need to be built up from a zero base. Pongamia will take between 5-10 years before new plantations reach maturity (Table 5). Algae may be able to be produced sooner. There could be scope to commence a HDO plant with some first generation food-based biomass feedstocks inputs while second generation feedstock are being developed.

Table 5: Earliest possible production of biomass resources ignoring refining constraints

Feedstock	Earliest timing	Comments
Forest residue	2011	Currently in production but there may be delays in securing contracts as current volumes may be directed at other uses
Coppice eucalypts	Beyond 2015	Coppice eucalypts can be harvested after as little as 3-5 years, but the major delay will be in establishing its profitability and then the time it takes for many independent producers to scale up (maximum annual establishment rate is probably about 100000 ha/yr)
Pongamia	2020	First seed from the trees at about age five year but fully mature in 10 years. Only very small amounts available because current estate is small and establishment rate likely to be slow.
Algae	2013	Small amounts initially - municipal solid waste infrastructure would allow fast start up due to existing infrastructure. New race way ponds at power station sites will take longer
Stubble	2011	Requires negotiation of contracts with farmers, and improved systems for collection and transport

2.12 Life cycle emissions

The bulk of life cycle greenhouse gas emission analysis of biofuels has been targeted at road fuels rather than Jet fuels.

In life cycle emission accounting combustion emissions are not counted since they are offset by the process of re-growing the biomass. The large source of non-combustion emissions are in relation to the energy used in biomass recovery and processing unless the biomass production involves land clearing in which case emissions associated with land use change often becomes one of the largest components.

Table 6 shows some estimated full fuel cycle emissions from Stratton et al (2010). These include emissions from the whole life-cycle. Farine et al (forthcoming) also makes available more limited data for only the biomass production and transport stages. That data indicates emission factors for forest residues (not covered by Stratton et al (2010)) in the range of 1.1 to 6.5 g/CO_2e.

Table 6: Life cycle emissions of jet fuel by source in gCO_2e/MJ.

Crude oil	Oil sands	Oil shale	Natural gas	Coal	Canola	Algae	Jatropha	Switch grass	Salicornia
87.5	103.4	121.5	101	97.2-194.8	54.9	50.7	39.4	-2-17.7	5.8-47.7

Notes: Source is Stratton et al (2010). The coal data range refers to with and without carbon capture and storage. Switch grass and Salicornia data ranges reflect possible credits for land use change since these may add biomass to regions that did not have existing biomass.

The conclusion from this data is that bio-derived jet fuels could contribute to emission reductions of 40-100 percent over conventional oil based jet fuel. There is too little research to firmly ascribe an emission factor to each feedstock particularly when many of the varieties and production systems have not be trialled at scale in Australia or New Zealand.

The approach taken in the modelling here will be to ascribe a zero emission rating to bio-derived aviation fuel. This is in accordance with the likely way in which the aviations sector will need to report its emissions. However, this does not in any way suggest that upstream emissions should be ignored. One approach suggested by the Round Table for Sustainable Biofuels, an international body assisting in developing consensus around the sustainable use of biofuels, is that end users should aim to ensure that their bio-derived fuel consumption should contribute to at least a 50 percent reduction on average in total lifecycle emissions relative to oil based fuels.

2.13 Water and other resource constraints

Water use during biomass production will be the major issue that needs to be managed. Water scarcity varies greatly at specific locations across Australia and NZ, and is both a function of water supply and demands. Where expansion of biomass production for bio-energy is proposed, the potential impacts on water security will need to be carefully assessed and managed at both local and catchment scales.

Algal production also requires significant amounts of water, but in many cases fresh water is not required.

Refinery requirements for water can also be significant, and this may affect the location of new facilities. The G/FT process requires significant volumes of water. The Qatar project plant which was chosen as the default current costs for G/FT includes construction of a desalination plant. The more experimental fast pyrolysis refining pathway requires no significant water quantities.

The land constraints for biomass production have been addressed in the creation of the biomass volume data already presented. In creating that data CSIRO has pre-selected only feedstocks which have minimal impact on existing land use.

One major constraint that should be mentioned is that algae must have a concentrated and constant source of CO_2. Algal biomass production must therefore be confined to sites near or within economic piping distance of a power station or other CO_2 producing industrial site.

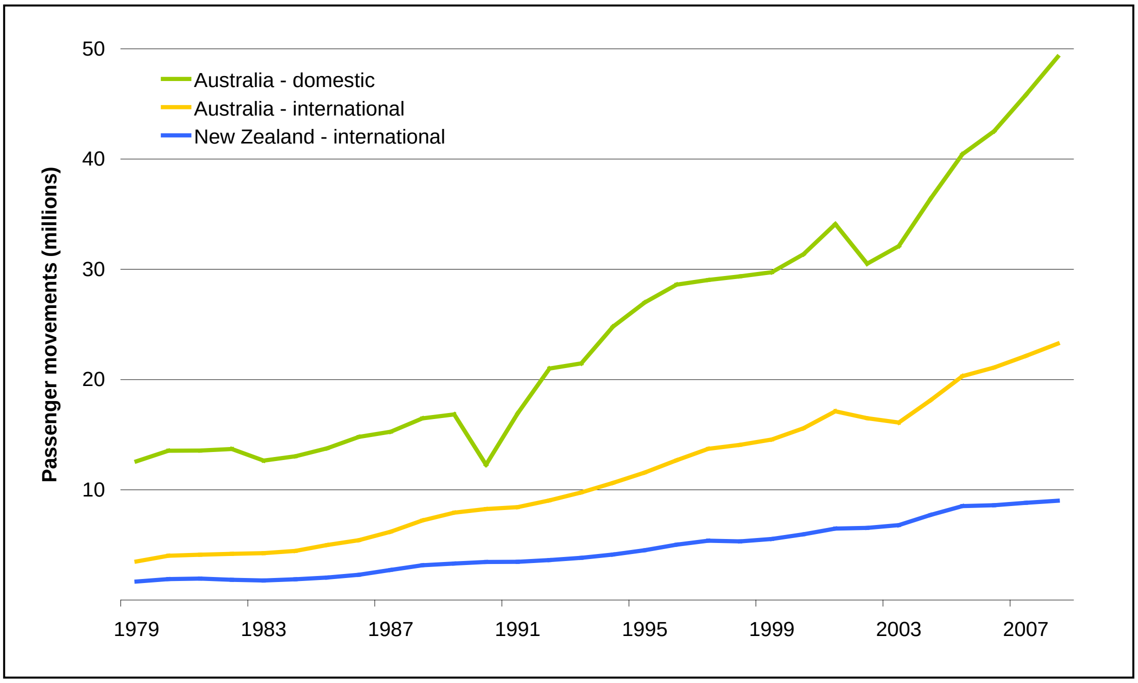
2.14 Aviation demand

There are a number of national and international organisations in New Zealand and Australia that project annual growth in total aviation demand in either passenger or freight terms. Four projections are shown below:

- Airbus (2009): 5.0% passenger kilometres (Australia and New Zealand)
- Boeing (2009): 5.1% passenger, 6% cargo (Australia and New Zealand)
- IEA (2009b): 4% global in passenger kilometres with non-OECD making up greater proportion of growth (5% non-OECD average)
- BITRE (2009a): 4.2% (passengers in Australia)

These projections relate to period to 2030 and are in line with or slightly lower than historical growth which was around 6 percent.

Figure 14: Historical demand growth in Australia and New Zealand (domestic data not available for New Zealand)



Source: BITRE (2009b). Note times series for New Zealand domestic not available. However it was equal to around 10.3 million passenger movements in 2008.

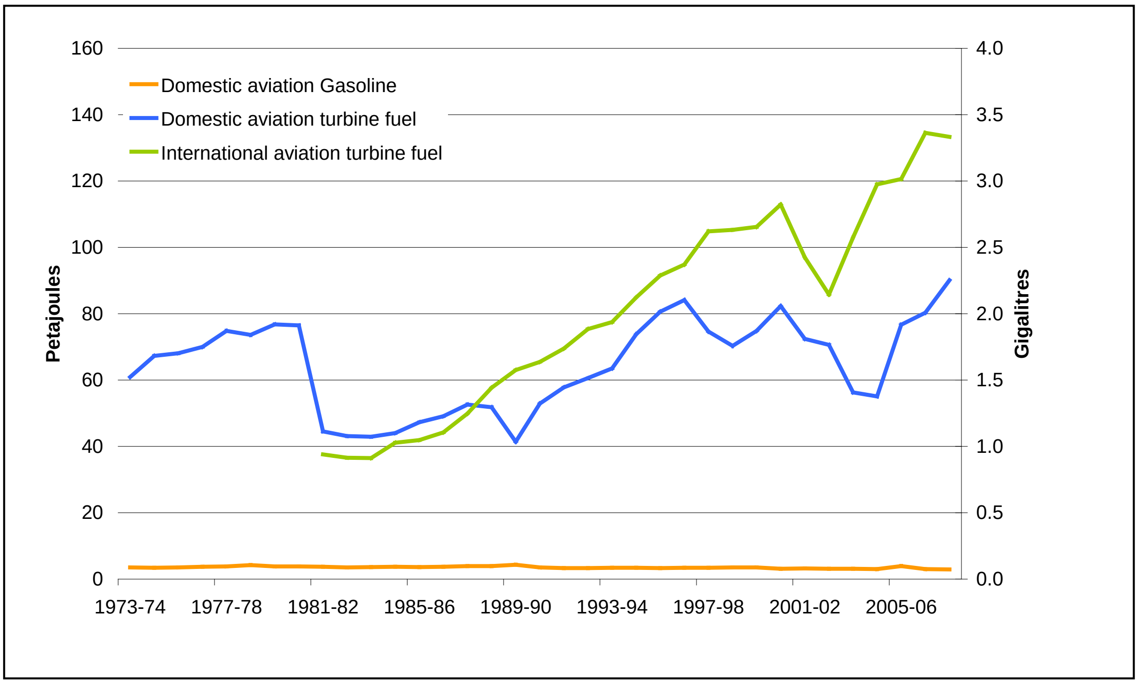
The demand projection for Australia under no carbon price has been derived from the MMRF model of the Centre of Policies Studies but it is in line with these other projections at around 5%. MMRF is also able to calculate how this projection changes as carbon prices are introduced.

New Zealand projections have been based on the above studies and forecasts available from two of its airports. Carbon price responsiveness is assumed to be similar to the projected Australian experience.

2.15 Developments in aviation fuel consumption

As can be seen in Figure 15 we can are primarily concerned with aviation turbine fuel or jet fuel as this makes up the vast majority of aviation fuel consumed. Given the significant projected growth in demand for aviation transport services we need to understand how fuel efficiency might change in order to project total fuel consumption.

Figure 15: Historical Australian aviation sector fuel consumption



The assumptions for energy efficiency improvements in this study are drawn from IEA (2009b) which has projected around 50 percent improvement in fuel efficiency due to a variety of factors (Table 7). Individually these factors are inaccurate in representing the potential fuel saving measures in the Australian and New Zealand region. This region has different issues to other regions due to fleet make-up, distances, and population density. However, while the individual components are likely misrepresentative, we apply the headline figure of 40-50% savings to calibrate future fuel consumptions savings in the absence of detailed regionally specific data in the public record.

Table 7: Projected improvements in aviation fuel efficiency by source

Type of improvement	Percentage fuel intensity reduction
Airframe aerodynamics	20-30%
Airframe light-weighting	20-30%
Engine technologies	15-20%
Air traffic management and operations	7-12%
Total	40-50%

Source: IEA (2009b)
Note: The total accounts for non-additive effects of combining measures

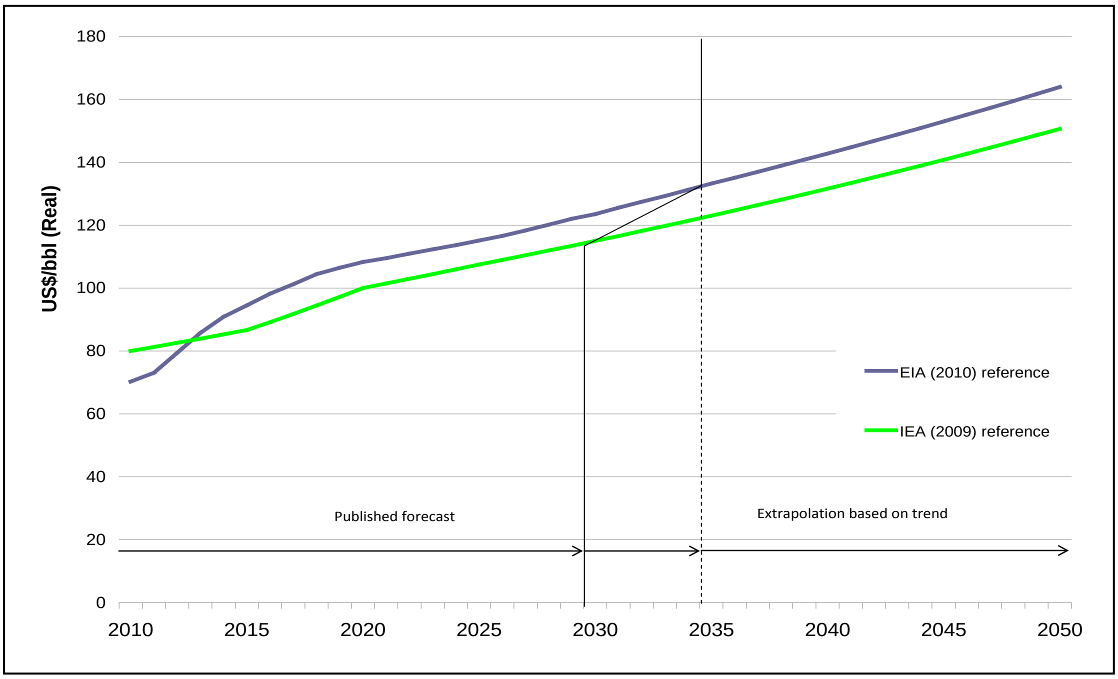
3. REFERENCE CASE

The carbon price, the oil price, technological change and government intervention were all identified as being strong drivers of the future uptake of bio-derived jet fuel. A good basis for designing scenarios is to construct a reference case which incorporates things which are likely to happen and to construct scenarios of events that are uncertain but plausible. They may be events which are outside of our control or events that we could choose to create. The reference case can then be used to compare the impact of those events or actions.

The reference case contains all of the data assumptions outlined in this document. In addition it assumes the International Energy Agency's reference case oil price (IEA, 2009). This oil price was chosen because it is widely accessible and well known. It also accords well with the slightly more recent Energy Information Administration's forecast (EIA 2010). Our modelling extends to 2050 so for both sources these projections have been extrapolated in Figure 16.

As oil prices increase it is assumed that the price of jet fuel increases slightly faster. This reflects the fact that jet fuel partially competes with diesel production. There is some flexibility but generally a refiner will need to make a choice about what fraction of jet fuel to produce and the trade-off is less diesel. Given the diesel market is so much larger and generally associated with less discretionary end-use consumption, it is reasonable to expect that jet fuel users will have to pay a small premium over other fuels on an energy equivalent basis as oil supply tightens in coming decades.

Figure 16: Reference case oil price projections



3.1 Modelling results

The modelling framework applied is described in Appendix D. It is an economic framework which allocates resources based on costs and profit maximisation via market mechanisms subject to any policy constraints that are in place.

Under our reference case assumptions the modelling projects that available biomass supplies will expand into the electricity and road transport sectors up until 2020. The aviation sector is projected to commence uptake of bio-derived jet fuel from 2025 after which the share of bio-derived jet fuels rapidly expands to just under 50 percent by 2050.

The preference for biomass to grow significantly in the road sector in the next decade reflects two factors. The first is that it is lower cost to make road fuels from biomass than jet fuels. All else being equal a biofuel producer can get a better return from their product in the road market. The second factor is that the government in both Australia and New Zealand provide additional incentives for biomass to be converted to road biofuel through lower biofuel excise rates and mandated road biofuel uptake targets (primarily New South Wales). Note, in Australia the excise differences are strongest in the passenger segment. In the freight sector, additional oil-based fuel excise rebates mean that the incentives to take up biofuels are not as strong.

The increasing share in the electricity sector mainly reflects a short term trend as both Australia and New Zealand put in place policies that encourage renewables (e.g. Australia's expanded 20 percent Mandatory Renewable Energy Target). However, biomass electricity is not specifically targeted and the level of biomass generation in both countries does not expand over the long term due to competition from other renewable and low emissions electricity technologies.

The momentum shifts from the road sector to the aviation sector in the period from 2025 (Figure 17) for several reasons:

1. The excise differences between the sectors are less over time because they are set in nominal terms and are therefore eroded by inflation

2. The road sector commences a significant shift toward full or partially electrified vehicles reducing growth in liquid fuel demand (Figure 18 and Figure 19).

3. Biofuel availability has expanded

4. The cost of refining jet fuels has reduced relative to the cost of refining road fuels

5. Synthetic road liquid fuels from fossil sources such as coal and gas are available and are low cost

6. Other low cost electricity generation technologies are available and existing renewable electricity schemes expire

Figure 17: Share of bio-derived fuel uptake in the aviation, road and electricity sectors in Australia and New Zealand

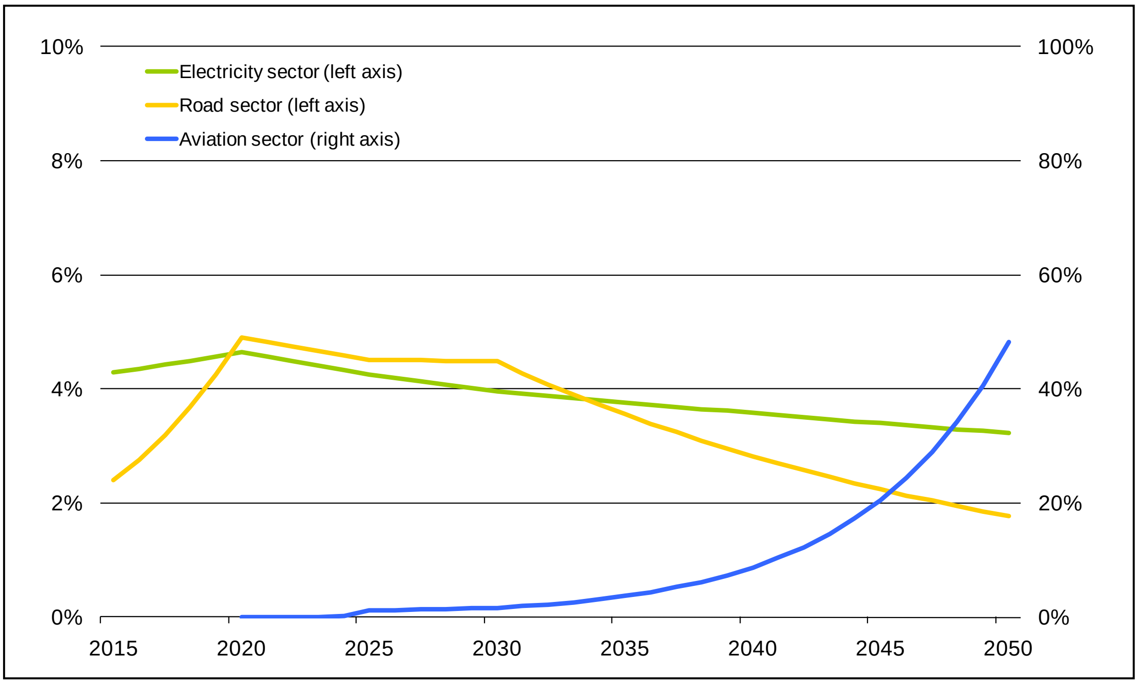


Figure 18: Projected fuel consumption by fuel in the Australasian road sector: reference case

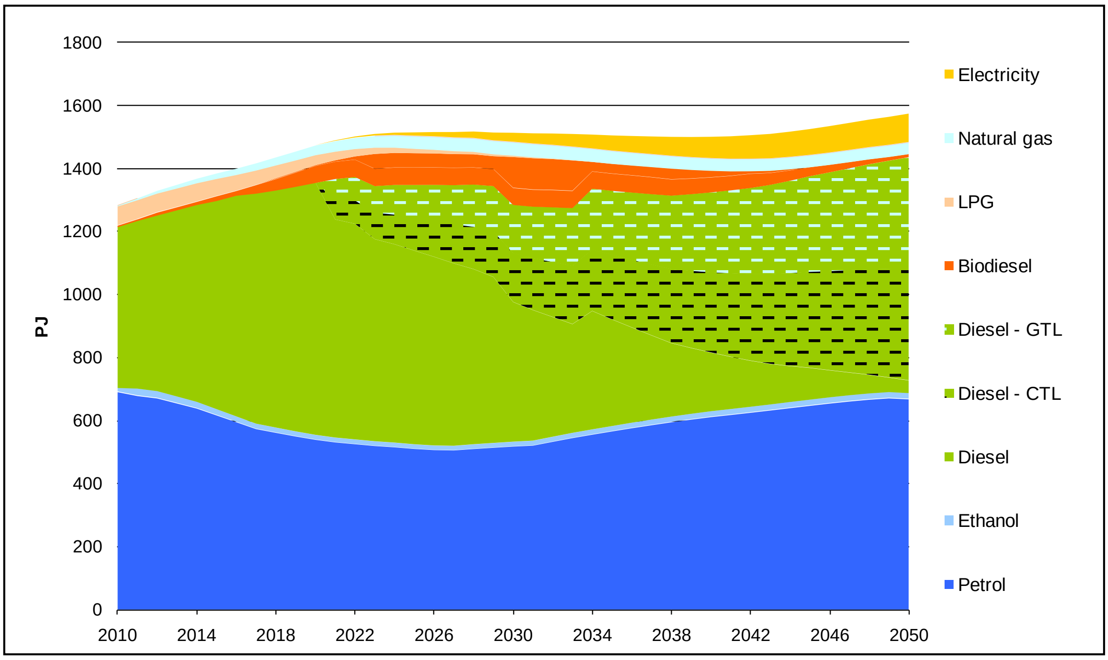
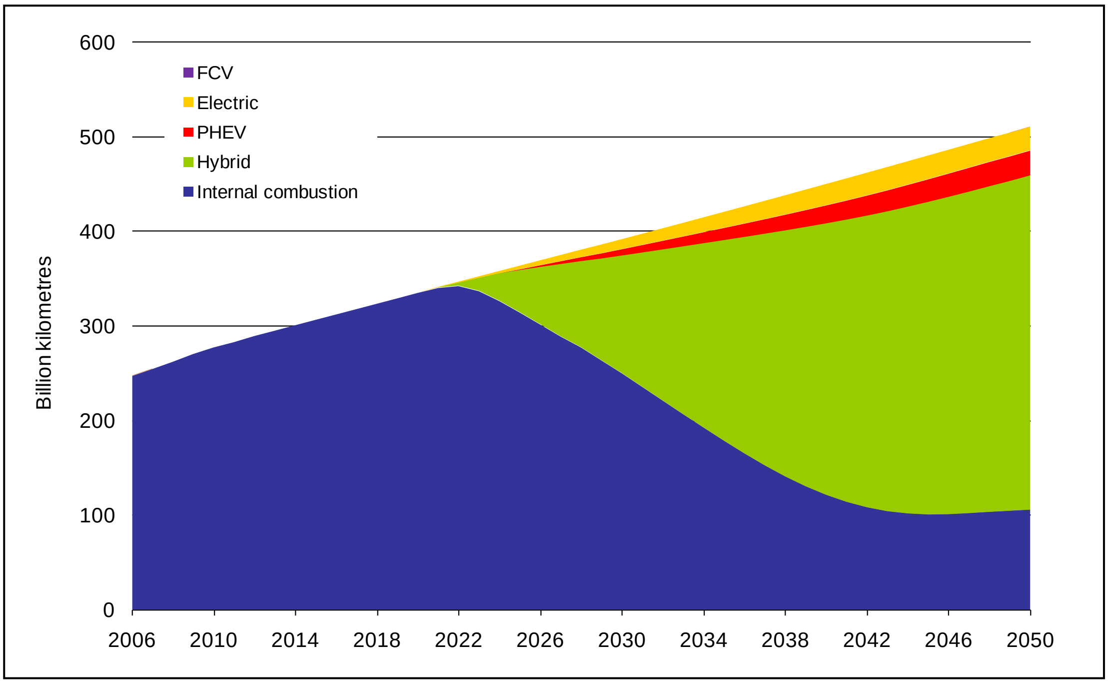


Figure 19: Projected kilometres travelled by engine type in Australasian road sector: reference case



4. SCENARIOS

Three scenarios have been modelled to explore alternative future outcomes. They are described as follow:

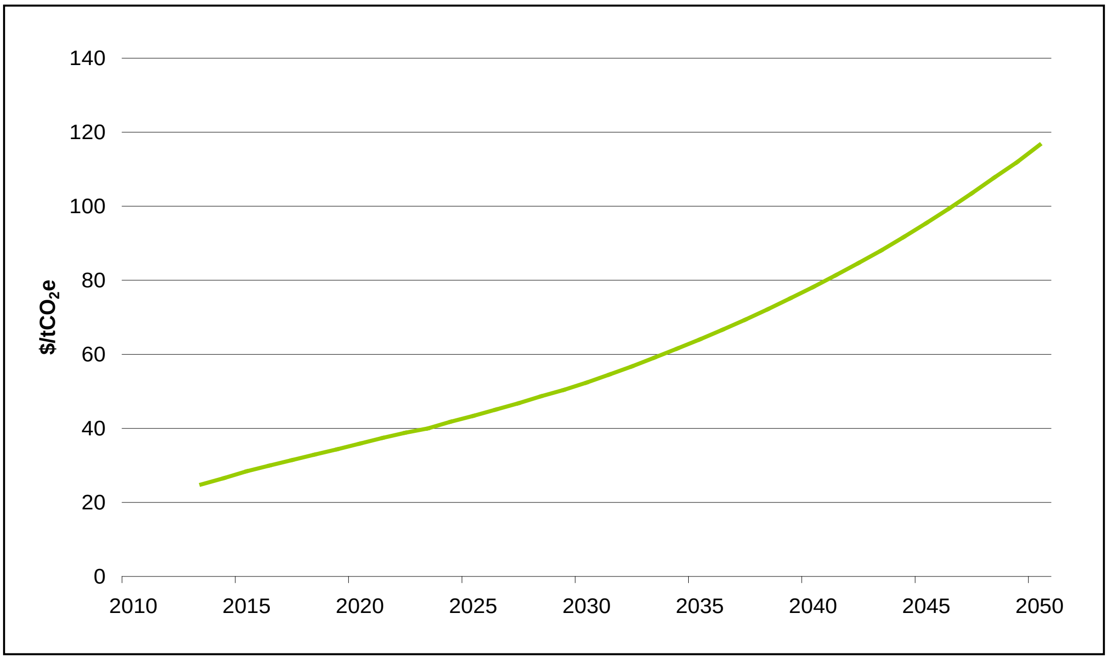
- CPRS-5 carbon price scenario: In this scenario a carbon price mechanism is assumed to be introduced and its level is based on the CPRS-5 carbon price projection estimated in the Commonwealth of Australia (2008) report *Australia's Low Pollution Future*. Under this scenario the carbon price mechanism is assumed to commence in 2013 and result in a \$A25/tCO_2e carbon price increasing at around 4 percent per annum to \$116/tCO_2e in 2050 (Figure 20).

- Low cost scenario: In this scenario the future cost of biomass is assumed to be 20 percent lower than under the reference case. This assumption is to take into account the possibility that the realised cost of biomass production methods could be lower than expected. Since many of the biomass sources included in the modelling have yet to be harvested at large scale there could be significant opportunities for improving production efficiency.

- Level playing field scenario: This scenario recognises that under current excise arrangements parts of the road sector enjoy a greater incentive to purchase biofuels than long haul transport mining, aviation and sea transport. Under the level playing field scenario the rebate to road biofuels is phased out. This action is in no way advocated by CSIRO or anyone in the Sustainable Aviation Fuel Road Map study. It is merely a modelling device to assess the extent to which current government interventions designed to encourage road biofuel use present a barrier to uptake of biofuels in the aviation sector.

- Road map scenario: This scenario was developed to ascertain *if* incentives were put in place or other favourable factors came to fruition to divert a portion of biofuels into the aviation sector, then what positive impacts for the region would flow from that outcome. The road map scenario assumes the construction and operation of two commercial scale refineries by 2020, the first in 2015. The Australasian aviation industry is assumed to achieve a 5 per cent bio-derived jet fuel share by 2020. Beyond 2020, bio-derived jet fuel production was assumed to steadily increase to reach a 50 per cent share in 2050.

Figure 20: The CPRS-5 carbon price level from 2013 to 2050



4.1 Modelling results

The modelling results of the three scenarios are compared against the reference case in Figure 23. Under the Low cost and Level playing field scenarios uptake of bio-derived jet fuels is accelerated by around five years compared to the reference case

In the CPRS-5 carbon price scenario, the carbon price has the effect of making biomass more attractive to all end-users relative to fossil fuels by penalising higher emission fuels. The uptake of biomass in aviation is higher relative to the reference case. It also expands uptake in the electricity and road sectors which both reduce their share of fossil sources of energy in favour of biomass and any other available technologies. They also take up other available low emission options such as vehicle electrification in road transport and wind, solar and geothermal power in the electricity sector.

Figure 21: Projected fuel consumption by fuel in the Australasian road sector: Carbon price scenario

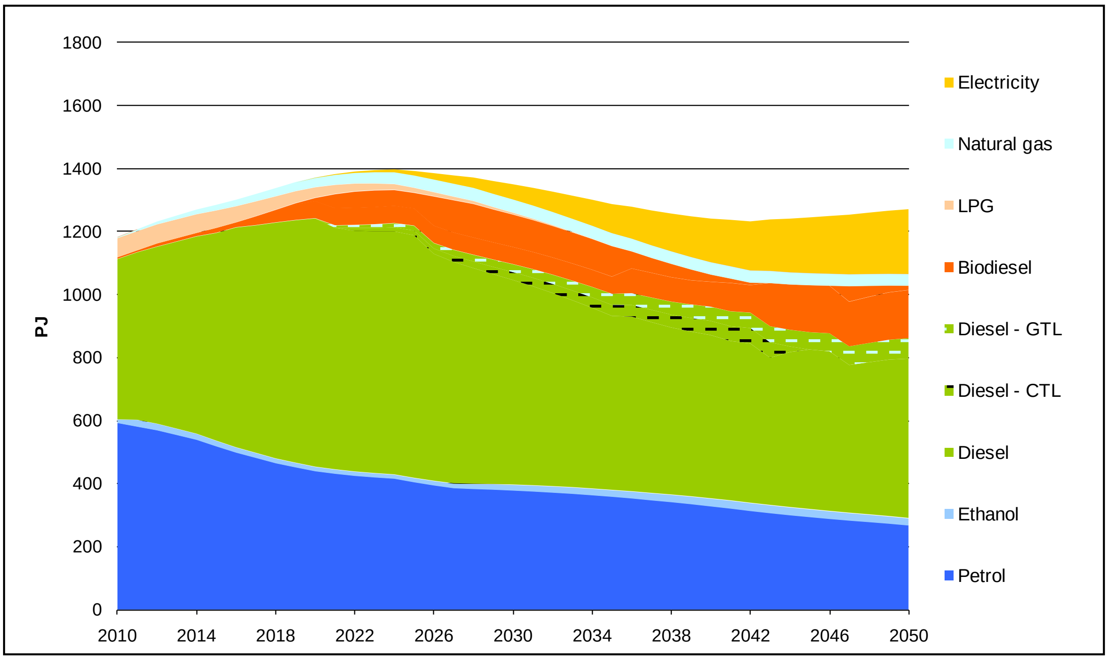
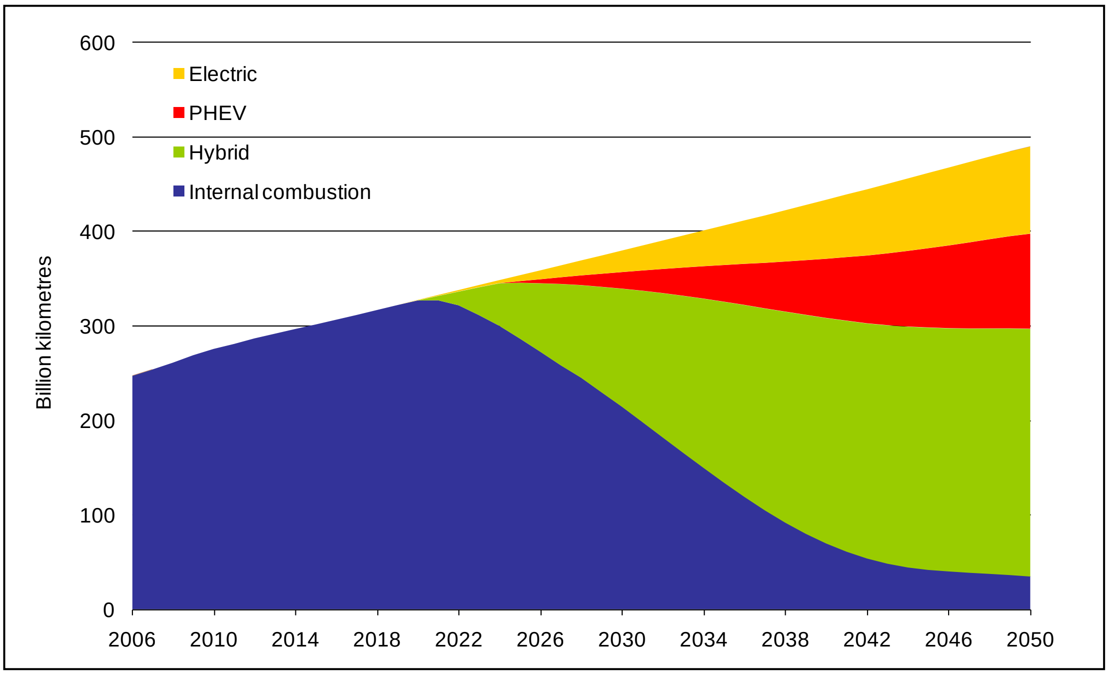


Figure 22: Projected kilometres travelled by engine type in Australasian road sector: Carbon price scenario

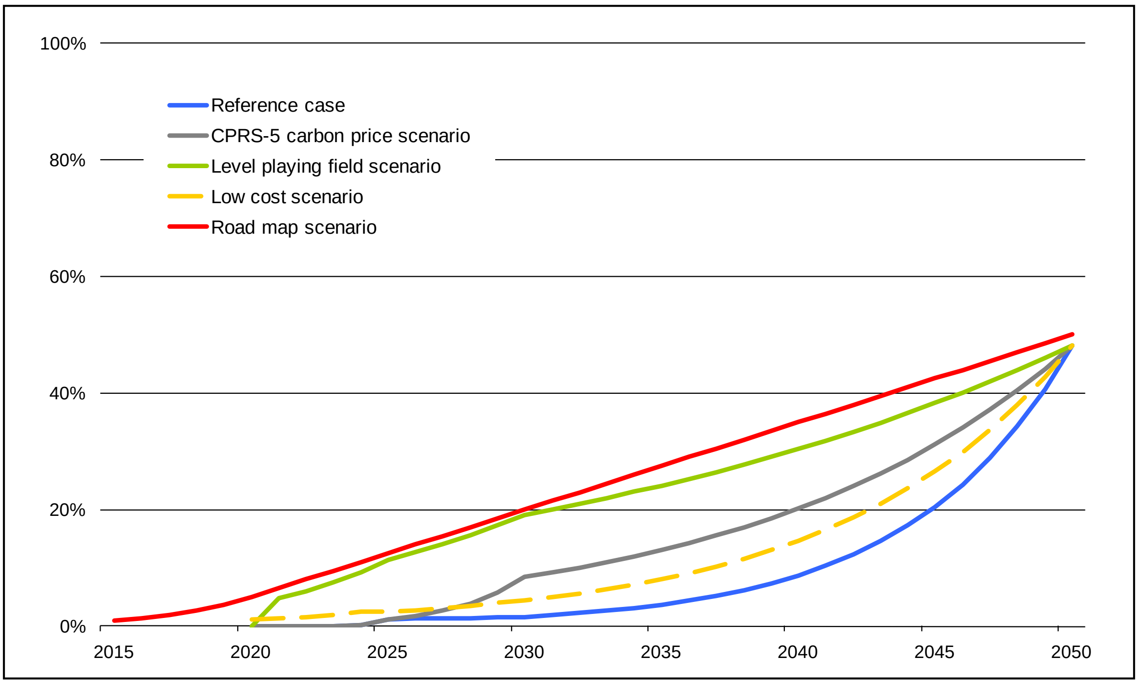


However, under the carbon price scenario real Australian GDP and aviation sector output are around 2 and 3 percent respectively below reference case levels based on the MMRF model outputs. Therefore there is a significant economic trade-off to achieving greater bio-derived jet fuel uptake via this mechanism. The reduction in economic activity under this scenario was to be expected given that a carbon price has broad impacts not just directly through the increased cost of fossil fuels but on demand for aviation from other sectors of the economy.

The demand impacts of the remaining scenarios were not explored since they have less significance across the economy. Reference case demand levels were assumed to prevail.

Like the carbon price scenario, lowering the cost of biofuels has the effect of “expanding the pie”. That is, it increases the volume of economically viable biomass available to all sectors so that competition for biomass is less intense. However, none of the scenarios lead to any significant bio-derived jet fuel uptake before 2020. Before 2020, most biomass continues to be directed to the electricity and road transport sectors due to the factors already discussed under the reference case.

Figure 23: Projected share of bio-derived jet fuel under the reference case and alternative scenarios



Under the Level playing field scenario the uptake of bio-derived jet fuels is also brought forward by around 5 years, which is similar to the effect of the Low cost scenario. Again, there is no uptake prior to 2020. The creation of a level playing field does not completely overcome all barriers to the uptake of bio-derived jet fuels because it is still a lower cost process to produce road biofuels relative to bio-derived jet fuels and some road sectors already pay no effective excise.

Under the Road map scenario bio-derived fuel uptake follows the path it has been designed to. The previous scenarios indicate that a level playing field, carbon pricing or lower biomass costs could contribute to achieving this path in the period from 2020 onwards. However, prior to 2020 it is likely that some sort of additional incentive or technological improvement would be necessary to support commercialisation during this period.

The purpose of modelling this scenario was to determine what impacts bio-derived jet fuel uptake of this order would have on jet fuel imports and greenhouse gas emissions. Figure 24 shows the value of jet fuel imports each decade from 2020 under the road map scenario compared to the case if the industry only imported oil-based jet fuel. It indicates that while the industry is commencing around 2020 the bio-derived jet fuel sector will save Australia and New Zealand around $0.5 billion. However, that amount will rapidly increase each decade to 2050 where it will reach $9 billion per annum.

Figure 24: Projected value of jet fuel imports under the road map scenario compared to oil-based jet fuel only

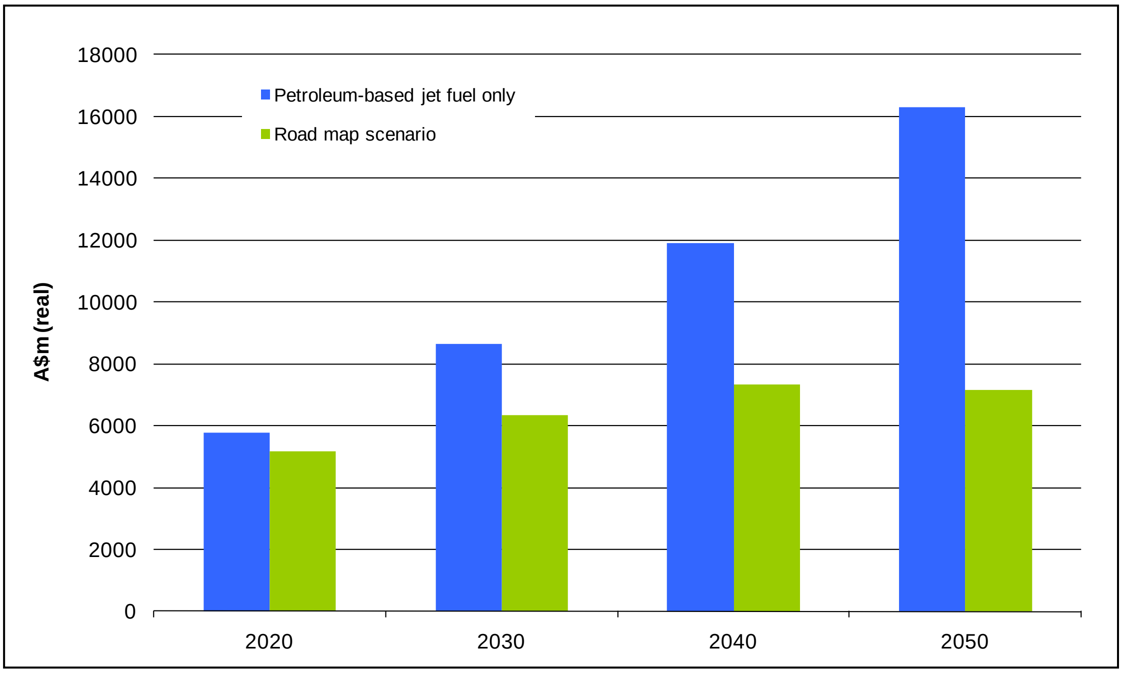
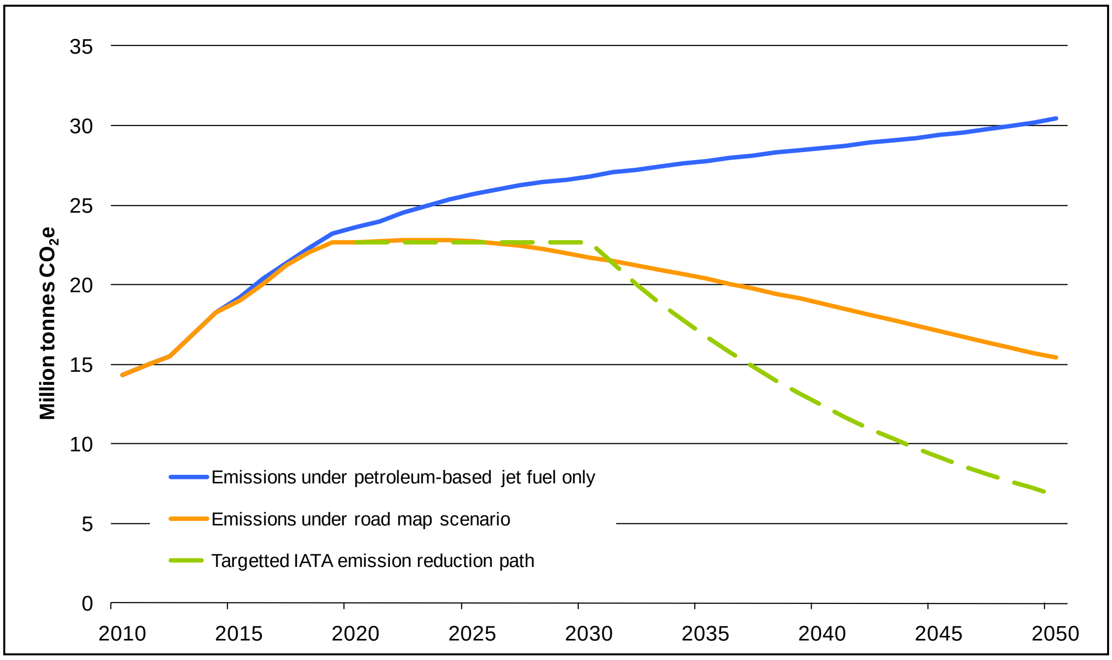


Figure 25 shows the impact of the Road map scenario on aviation sector emissions. The chart shows three emission paths. The first is the level of emissions that would be achieved if the Australian and New Zealand aviation sectors only used oil based fuels indefinitely. The second is the greenhouse gas emissions achieved under the Road Map scenario. The third is the International Air Transport Association’s published industry target as a proportion of Australasian emissions (IATA, 2009a). The projections indicate that the uptake of bio-derived jet fuels does contribute significantly to the global industry aspirations.

It should be noted that the emissions projected under the road map scenario are assuming a zero rating for bio-derived jet fuels. This is in keeping with expected reporting arrangements under any potential carbon accounting scheme. However, if we were to include upstream emissions associated with bio-derived jet fuel production and transport the emission shown could be between 0 and 50 percent higher. Not enough relevant full fuel cycle emission data is available at this point to ascribe a greater level of certainty than this range.

Figure 25: Projected Australasian aviation sector greenhouse gas emissions under the road map scenario compared to petroleum-based jet fuel only and the targeted IATA emission reduction path



5. APPENDIX A: METHODS AND ASSUMPTIONS USED TO ESTIMATE THE SUSTAINABLE PRODUCTION OF FEEDSTOCKS.

In addition to the following material, readers are referred to Farine et.al.(forthcoming) for a more detailed treatment of the production of biomass feedstocks for bio-energy production in Australia.

As part of the Road Map process, Australian biomass feedstocks suitable for the production of bio-derived jet fuel through different production technologies were identified and quantified. These feedstocks were plant and tree oils derived from agricultural oil-seed crops grown in the existing Australian production system such as canola and mustard (*Brassica juncea*) and in potential new production systems for algae and the oilseed tree Pongamia (*Pongamia pinnata*). The bio-oils derived from these would form the basic feedstock for the production of sustainable aviation fuel through the hydrodeoxygenation process. Alternatively, lingocellulosic feedstocks could be use in the Gasification/Fischer-Tropsch process or possibly through a biochemical conversion process to produce sustainable aviation fuel. Such feedstocks include residues from existing agricultural systems (stubble and bagasse), forest residues and pulpwood, and new energy crops such as coppicing eucalypts integrated into existing farming systems.

The total amount of each of the identified feedstocks was calculated based on available data (Farine et. al., forthcoming). Four key parameters were used for this calculation: the area of land used to grow the feedstock; the total amount of biomass grown annually: the amount of biomass harvested annually, based on actual harvest figures for some feedstocks (e.g. agricultural and forest products) or estimates for others (agricultural and forest residues); and the proportion of the harvested biomass that could be diverted for the production of bio-derived jet fuel. Technical and sustainability constraints to the use of each feedstock were applied.

For the potential new feedstock industries (algae, pongamia and coppicing eucalypts), data were sought on the likely suitable land area available for production based on growth requirements, and rates of biomass production to enable the estimation of annual production and harvest. As dedicated energy crops, it was assumed that all biomass could potentially be used for the production of aviation fuels.

Because of SAFUG’s commitment to meeting the RSB Standard, the feedstock production systems for lignocellulose (agricultural residues, forest products and residues, integrated farm forestry i.e. coppicing eucalypts), and for plant oils (canola and mustard, pongamia and algae) were assessed against the environmental and social principles embedded in the RSB Standard, Version 1.0. During this process, account was taken of possible mitigating actions that could be applied to address sustainability concerns.

5.1 Sustainability and other production constraints as applied to each feedstock.

Agricultural oil-seed crops – canola and mustard

Neither canola nor mustard oilseeds were included in the feedstock estimates. Current canola production in Australia is for the food market. Any increase in production of feedstock for bio-derived jet fuel would require expansion of arable land which could have negative conservation impacts, or, result in diversion of crop or modified pasture lands with subsequent negative impact on food production. While this may not contravene RSB's Principle 3 which is based on maintaining local food security, it could still mean competing with food in the production of bio-derived jet fuel.

Though some mustard is grown in cereal rotations in the lower rainfall cropping areas and used locally for the production of biodiesel, national production figures are not available and it was not included in the feedstock estimates. In terms of sustainability, it was considered that, as for canola, increased mustard production for bio-derived jet fuel could affect food production.

Algae

To estimate the future production of algal biomass and algal bio-oil in the absence of established industrial-scale facilities, a system based on growing algae in 400 ha raceway ponds with supplementary CO_2 was analysed (Farine et.al., forthcoming). It was assumed that each facility would be situated at one of thirteen sites identified in Australia where there is sufficient available CO_2 (e.g. at a coal-fired power station), available land and access to sea water or waste water.

Though water was considered to be the primary sustainability issue, the potential outcomes in "maintaining or enhancing the quality and quantity of surface and ground water" (RSB Principle 6: Water) could be variable. On the positive side, the use of sea water would avoid impacting on local, fresh, surface or ground water supplies, while the use of municipal waste water containing phosphates and nitrogen could assist in stimulating algal growth and the renovation of waste water. Negative sustainability impacts are the potential for discharge of contaminated water from the algal ponds, and a biosecurity risk if selected biofuel algal strains escaped into the environment.

Pongamia

In the absence of an established pongamia bio-oil industry in Australia, both the area of land suitable for growing the oilseed tree *Pongamia pinnata* and the annual oil production had to be estimated. A model was used to identify the likely areas best suited to growth of Pongamia (Farine et. al., in review). Only areas of medium and high growth potential were considered as prospective in our analysis. In the absence of empirical data on rates of oil production under Australian conditions, a production rate of 2t/ha/yr was assumed based on review of available literature. Oil yield was multiplied with the available land area to provide an estimate of the potential total feedstock production in Australia. All land meeting the growth requirements for medium and high categories of growth was included in the calculation. Requirements for good growth and seed set suggest that commercial growth may be restricted mostly to tropical and sub-tropical areas of Australia. The land area identified covers a range of current uses from irrigated, modified grazing and cropping land, to grazed natural vegetation and land held under native title.

Experience suggests that irrigation might be required during the establishment of pongamia plantations. Use of irrigation and land designated as irrigated, cropping and modified grazing for pongamia plantations would depend upon the economics of the water market and of replacing high value agriculture with oilseed trees. Further, any use of these lands could affect local and national food production. Clearing of native vegetation for replacement with pongamia plantations would be constrained by State and Territory legislation and policy. If this did occur, it would have negative impacts on conservation and biodiversity and, when included in the life cycle analysis of GHG emissions for biofuels from feedstock sourced from such land, seriously impact on any reduction in GHG emissions associated with the use of the biofuels.

In terms of the RSB Principles and SAFUG's commitment, use of some of the land identified as suitable for pongamia production in Australia might affect food security, biodiversity and the GHG balance of the fuel produced.

Crop stubble

Estimates of the annual production of stubble from wheat, oats, barley, triticale, sorghum, canola and lupins was calculated using published harvest indices (Farine et al., forthcoming) combined with statistics on grain production. Technical and environmental constraints were applied to estimate the amount of stubble available for harvest as follows:

- Twenty percent of the above ground non-grain biomass in the form of chaff and small fragments would not be harvestable due to technical harvesting constraints.
- Stubble could not practically be cut lower than 12.5 cm from the ground, and
- At least 1 t/ha of the stubble in the southern cropping regions and 1.5 t/ha in the northern cropping regions would be retained to protect soils from the risk of wind and water erosion.

The stubble harvest estimates were further considered spatially and "hot spots" where 1 Mt/yr was available within a 100 km radius were identified. The total amount of stubble available in these areas was taken as that potentially available for the production of bio-derived jet fuel.

There is on-going debate about the impacts of harvesting stubble on soil carbon balance, infiltration and evaporation of water, and soil health. Replacement of nutrients removed in the harvested stubble, and the rotation of grain crops with legume and pasture phases address some of these issues, contributing to the on-going production of food in conjunction with the harvesting of stubble. Better economic outcomes for grain farmers and their local communities could occur through the diversification of income streams from both grain and stubble, and thus would lower risks associated with grain cropping.

Bagasse

Bagasse is the residue produced after crushing and extraction of juice from cane at sugar mills. Currently much of the bagasse is used for the co-generation of electricity and heat within the mills. It is estimated that current plant are half the potential efficiency of new plant.

If upgraded, 50% of the bagasse currently used for heat and power could become available for production of bio-derived jet fuel. Any sustainability issue would be related to the production of sugar cane, and not specifically to the uses of bagasse as such.

Forest residues and pulpwood

Estimates of feedstocks from current forest production systems (native forest, hardwood and softwood plantations) were based on published figures of current Australian plantation areas and annual wood production (see Farine et.al., forthcoming for further details). For native forests, only sawmill residues were considered, not in-forest residues or pulpwood; whilst for plantations all three of these biomass components were considered. In-forest residues and sawmill residues were calculated from known residue fractions that relate to sawlog and pulplog production. Future supplies of biomass from the existing young and actively growing plantation forest estate were estimated using forest growth models (e.g. 3-PG2) and spatial layers of forest type and extent.

Constraints were then applied to the use or diversion of the different forest biomass fractions to calculate the overall amount of woody feedstock available for the production of bio-derived jet fuel.

In-forest residues potentially available for harvest were limited to the stemwood fraction below a designated diameter, with all the branches and foliage left *in situ* to provide return of nutrient and organic matter to the soil. Depending upon the price, it was estimated that some of the plantation pulplogs and chip that is currently exported could be diverted to the production of bio-derived jet fuel, but no high-value sawlogs were included.

The combination of sustainable plantation management as set out in Plantation Codes of Practice, together with application of the constraints described above, address most of the sustainability issues. Additional benefits may accrue from a reduction in the burning of in-forest and sawmill residues and the creation of some additional regional jobs.

Coppice eucalypt systems

Short rotation coppice eucalypt systems have been established and trialled for the reduction of dryland salinity, the restoration of biodiversity, carbon sequestration and the production of bio-energy in Western Australian cropping areas over the past two decades. Research into the system indicates an optimal method of integration of short rotation coppice eucalypts into crop paddocks is to use strip plantings 2 – 6 trees wide, 40 meters apart, which could be harvested on a 5 year rotation. Such a system uses approximately 5% of the total cleared land.

The estimate of the potential total feedstock from this source is based on the use of 5% of the cleared cropping and modified grazing lands in Australia. Though the original use of coppicing eucalypt strips in crop areas was to improve the sustainability of these agricultural landscapes, scaling up of this system would lead to some short-term reduction in food production but in the long-term may improve it via a reduction in wind and water erosion, the provision of shelter for livestock and the restoration of on-farm biodiversity. There may also be some impact on surface and ground water availability, although this could be offset through the reduction in areas of salinity due to rising groundwater.

As with stubble, the addition of a new farming enterprise would improve financial sustainability through the diversification of risk.

5.2 Analysis of each feedstock production system against the RSB Principles (RSB Standard Version 1.0).

Table 8 summarises an analysis of the impacts of production and use of each feedstock. A combination of colours (green +ve; yellow - variable or mitigated, and red –ve) and comment comprise each cell of the table .

RSB Principles 1) Legality, 2) Planning, Monitoring and Continuous Improvement and 11) Use of Technology, Inputs and Management of Waste were not included on the basis that they would either be a normal part of production best-practice, covered by Australian law, or not relevant to the part of the value chain for the production of biomass feedstock. For RSB Principle 3, GHG Mitigation, in the absence of Australian information, the Partner Project 28 Report "Lifecycle Greenhouse Gas Emissions from Alternative Jet Fuels" has been used (Stratton , 2010). That report assesses alternative jet fuels based on life cycle GHG emissions relative to baseline conventional jet fuel and provides Low, Baseline or High figures. The percentage reduction in GHG emissions listed in Table 8 are based on the Baseline figures in the report.

Table 8: Application of RSB Principles to potential bio-derived jet fuel production feedstocks in Australia

RSB Principle by Number	**Agriculture residues - e.g. removal of stubble from field**	**Forest products and residues**	**Plantation mallee**	**Oilseeds e.g. canola or B. juncea as rotation crops**	**Pongamia**	**Algae**
3. GHG (% reduction in GHG emissions cf. fossil jet fuel) (i)	+ve; 90% reduction based on US corn stover.	+ve: 85% reduction based on US forest residues	+ ve: estimate only - information n/a	+ve; 37% reduction based on UK cultivation of canola, no LUC	+ve; 55% reduction based on jatropha	+ve; 42% reduction based on reference baseline level for algae
6. Food Security	N/A	N/A	Variable: -ve; integrated into crops/pasture: +ve; long-term reduction of salinity	-ve; canola oil used as a common cooking oil - impact on availability and price	-ve; limited available suitable high-rainfall land	N/A
7. Conservation (Biodiversity)	Mitigated by leaving > 50% of stubble residues. (ii)	Mitigate by application of Plantation Code of Practice.	+ ve: re-vegetation of cleared land with native species;	- ve; negative for conservation if cropping expanded into native pastures	-ve; a) Monoculture plantations – reduces biodiversity; b) pressure to clear tropical native vegetation.	Variable: +ve clean up domestic waste water; -ve) a) contaminated discharge water; b) biosecurity algal spp.
8. Soil	Mitigated by leaving > 50% of stubble residues. (ii)	Mitigate: Leave foliage and branches for nutrient retention	+ ve; Long-term salinity mitigation	+ve; Brassica spp rotations reduce crop disease	Mitigate: Needs establishment management; e.g. contour planting to avoid erosion	N/A
9. Water	Mitigated by leaving > 50% of stubble residues. (ii)	Mitigate by careful management (Need to modify plantation CoP)	Variable: Scale and location dependent. Mitigation by integration into CMA and local plans	N/A	Mitigate: Integration into CMA and local plans; use of irrigation constrained by water market	Variable: +ve clean up domestic waste water; -ve a) volume of water used; b) contaminated discharge water
10. Air	+ve: Less in-field burning	+ve; Less in-field burning of forest residues	N/A	N/A	N/A	N/A ?: Pond odours
4, 5, 12 - RSB Social Principles – Labour, Land Rights, Rural and Social Development	+ve: Production diversification reduces risk; additional jobs	+ve: Additional jobs	Variable: - ve; LUC displaces food/fibre production: + ve; a) Regional development; b) diversification reduces risk	-ve; a) Impact on cooking oil availability and price; b) large-scale diversion of oil to jet fuel could reduce regional biodiesel production	+ve; New plantations and regional crushing plants would contribute to rural development and jobs.	Variable: -ve a) pond odours; b) aesthetics of salt water coastal ponds. +ve cleaning/recycling of waste water

i)Percentage reduction in GHG emissions compared to fossil jet fuel from Stratton, R. W., Hsin Min Wong., Hileman, J. I., (2010). Life Cycle Greenhouse Emissions from Alternative Jet Fuels, Partnership for Air Transport Noise and Emission Reduction.. ii) Mitigation of impacts of stubble removal for bio-energy from Herr *et al*, (2010) The impacts of using stubble for bio-energy in Australia. GRDC Phase 2 Report (in review).

5.3 Conclusions

- For lignocellulosic feedstocks derived from existing agricultural and plantation residues, there are either positive outcomes against the RSB Principles e.g. the reduction of GHG emissions compared to fossil jet fuels, or the impacts of the use of the residues can be mitigated through leaving residues for soil protection and nutrient re-cycling, or careful planning to manage water use impacts.

- The use of designated lignocellulosic energy crops either as block or as strip plantings of coppicing eucalypts within agricultural lands, is broadly compatible with the RSB Principles.

- A significant number of potentially negative impacts from the production and use of bio-oil from existing production systems e.g. the use of canola or juncea as break-crops within the existing winter cereal rotations and/or from new plantations of Pongamia were identified.

- For canola, these were linked to food security. The increased use of canola for biodiesel in Europe has been linked to increases in food prices. Further, increasing the extent or frequency of canola crops in cereal rotations would lower the production of cereals. This could affect food security either directly through reduced availability of cereals for human use or indirectly via effects on intensive livestock industries.

- For Pongamia, negative impacts were associated with food security, water use and possible impact on biodiversity. Suitable land with high rainfall, or available irrigation water in the sub-tropical and tropical areas of Australia is either already being used for food production or is protected from use through State and Territory native vegetation legislation.

- It would appear that there are few potential negative impacts from the likely systems used for the production of bio-oil from algae. However, it should be noted that there are some unknowns amongst the variables such as water use, the discharge of contaminated water and biosecurity.

6. APPENDIX B: ROAD TRANSPORT SECTOR ASSUMPTIONS

6.1 Road vehicle type configuration

An important consideration in the transport model is how to represent the vehicle and aircraft type combinations that are of interest. In theory, one could construct a model of the Australian transport sector which included every make of existing vehicle type and possible future types. In practice, modellers will always seek to reduce the size of the technology set in order to make the model manageable in terms of data, model structure and mathematical solution speed and reliability.

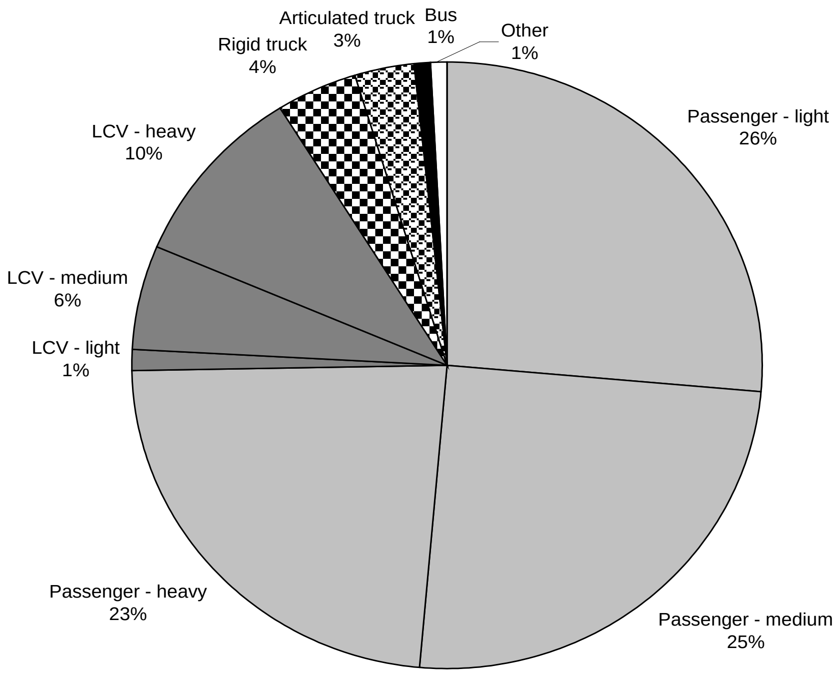
For road transport, the proposed vehicle aggregation is as follows. Passenger and light commercial vehicles will be represented in three weight categories:

- Light: less than 1200 kg
- Medium: 1200 to 1500 kg
- Heavy: 1500 to 3000 kg.

The remaining vehicle types will be rigid trucks, articulated trucks and buses. Motor cycles and campervans will not be specifically modelled but accounted for as a constant in the emission profile.

Fleet data for Australia was sourced from the *Australian Bureau of Statistics* and the vehicle weight categories for both countries are based on data therein. However New Zealand fleet characteristics – number of vehicles, fuel type, kilometres travelled – are sourced from the *New Zealand Ministry of Transport*.

Figure 26: Current share of kilometres travelled within the Australian road transport task by vehicle type, 2006



Source: ABS (2007)

6.2 Road fuel coverage

Within the current version of ESM, the road transport fuel options are:

- Petrol – aggregating unleaded, lead replacement and premium (PET)
- Petrol with 10 per cent ethanol (E10)
- Ethanol blend with up to 85 per cent ethanol and 15 per cent petrol (E85)[1]
- Diesel (DSL)
- Diesel with 20 per cent biodiesel blend (B20)
- 100 per cent biodiesel (B100)
- Liquefied petroleum gas (LPG)
- Compressed and liquefied natural gas (CNG and LNG)

[1] Consistent with experience overseas, there is expected to be seasonal variation in the ethanol content as ambient temperature affects performance of the fuel. This translates to lower ethanol content during the winter months.

- Hydrogen produced from renewables (H_2)
- Gas to liquids (GTL) diesel
- Coal to liquids (CTL) diesel with upstream CO_2 capture and storage
- Electricity (ELE).

This is obviously not a complete list of possible fuels but covers those which are generally of greatest interest for further study.

More categories of hydrogen production might be desirable. However, given the greatest cost associated with hydrogen is not the fuel but the cost of the storage system (and potentially the engine if a fuel cell is required), including additional cheaper hydrogen sources will make little difference in the modelling.

Compressed natural gas (CNG) is assumed to be used in all natural gas vehicles except for articulated trucks which use Liquefied natural gas (LNG).

The allowable road mode and fuel combinations for road transport in ESM are shown in Table 9.

Table 9: Allowable road mode and fuel combinations

	PASL	PASM	PASH	LCVL	LCVM	LCVH	RGT	BUS	ART
PET	X	X	X	X	X	X			
E10	X	X	X	X	X	X			
E85	X	X	X	X	X	X			
DSL	X	X	X	X	X	X	X	X	X
B20	X	X	X	X	X	X	X	X	X
B95	X	X	X	X	X	X	X	X	X
LPG	X	X	X	X	X	X			
CNG	X	X	X	X	X	X	X	X	
LNG									X
H_2	X	X	X	X	X	X	X	X	
GTL	X	X	X	X	X	X	X	X	X
CTL	X	X	X	X	X	X	X	X	X
ELE	X			X			X	X	

Notes: PASL: light passenger vehicles; PASM: medium passenger vehicles; PASH: heavy passenger vehicles; LCVL: light commercial vehicles; LCVM: medium commercial vehicles; LCVH: heavy commercial vehicles; RGT: rigid trucks; BUS: buses; ART: articulated trucks.

6.3 Road engine type configurations

The engine configurations allowed for road transport are:

- Internal combustion (ICE)
- Mild hybrid internal combustion-electric (HYB)
- Plug-in hybrid electric (PHEV)
- Full (100 percent) electric (EV)
- Fuel cell (FCV).

Fully electric vehicles (EVs) were deemed to be only available in the light passenger and light commercial vehicle types due to range and power limitations. Conversely, hybrids were allowed in all other categories. Medium and heavy passenger and light commercial vehicle categories are available as PHEVs (internal combustion engine and electric motor on board capable of driving for extended periods) as are rigid trucks and buses. Articulated trucks were limited to mild hybridisation (for example, engine stop and fast start capability). The fuel efficiency section outlines what this means in performance terms.

FCVs use fuel cells to convert the chemical energy contained in hydrogen into electricity, which is used to power an electric motor that drives the wheels and support other vehicle functions. FCVs are currently available in some jurisdictions overseas in limited numbers.

As fuel cell systems improve and FCVs are proven technically, the refuelling and fuel infrastructure issues are likely to become the main barriers to commercialisation. Fuel cell system costs have declined but are still very expensive compared to conventional ICE vehicles (see Section 6.4.1).

Table 10 maps the allowable road mode and engine combinations for road transport in ESM.

Table 10: Allowable road mode and engine combinations

	PASL	PASM	PASH	LCVL	LCVM	LCVH	RGT	BUS	ART
ICE	X	X	X	X	X	X	X	X	X
HYB		X	X		X	X	X	X	X
PHEV		X	X		X	X	X	X	
EV	X			X			X	X	
FCV	X	X	X	X	X	X	X	X	

6.4 Road transport costs

One of the key functions of ESM is to determine the uptake of fuel and engine technologies. These can be imposed but the default process is for the model to choose the least cost response to whatever drivers are in force (such as carbon pricing). In order for the model to give a plausible answer it must, as a minimum, be provided with data to compare the relative economic merits of the vehicles that would be under consideration by the consumer (or investor).

6.4.1 Vehicle costs

Table 11 sets out the major categories of non-fuel costs and sources of data for them. Basic vehicle costs are only meant to be representative of the median vehicle in their vehicle category. There is a wide margin of error. However, it cannot be easily avoided given the need for aggregation (see previous section). Maintenance costs are calculated via bottom up analysis of the minimum maintenance expenditure required to renew registration of the vehicle (e.g. tyre change every two years, minimal oil and battery replacement). In addition to regular maintenance, major part replacement is assumed to become part of the maintenance cost of older vehicles (> 5 years).

For some alternative fuels, there is little or no information available with respect to additional vehicle cost for the alternative fuel to be incorporated. In these cases, estimates have been made based on the ratio of costs in the next most relevant vehicle category.

In constructing non-fuel costs, the data has relied on a wide variety of predominantly web based sources and may be poor in some cases. To test the validity of the data it is compared with the NRMA's *Private Whole of Life Vehicle Operating Costs Report*.

Table 11: Non-fuel cost categories in total road travel cost

Non-fuel cost category	Data source
Basic vehicle cost	ICE (Passenger and light commercial): NRMA *Open Road*. ICE (Trucks and buses): Manufacturers websites. EVs/PHEVs: IEA (2009b); Electrification Coalition (2009). FCVs: IEA (2009b); ANL (2009).
On-costs above basic vehicle cost to accommodate alternative fuel	Various manufacturer websites
Insurance – third party and comprehensive	Insurance companies (e.g. AAMI, NRMA)
Registration	State government transport authority/department websites
Maintenance	Web sources on tyres, oil, batteries and servicing

The comparison is shown in Table 12. To simplify the comparison we have used the same fuel costs as quoted in the NRMA report which was an unleaded petrol price of 125.8c/L.

Table 12: Comparison of whole of life transport cost estimates for Australian petrol passenger vehicles (c/km)

Category	NRMA estimate	CSIRO estimate
Small/light	48.5	41.9
Medium	63.6	60.6
Large/heavy	69.9	76.3

NRMA has based the above estimates on the Holden Viva, Holden Epica and Mitsubishi 380 for the light, medium and large vehicle categories respectively. The CSIRO estimates differ in absolute terms mainly in the light and large vehicle categories but this was to be expected. Our estimates represent an average of vehicle costs in defined weight categories. For the light vehicle category, the Viva would be at the high end of our weight range so that our estimate would be expected to be lower than NRMA's. Similarly, the Mitsubishi 380 would be at the low end of the weight range so that our estimate would be expected to be higher.

Costs of rigid trucks are 95-140c/km. Costs for articulated trucks are 100-180c/km. Costs for buses are 175-250c/km. There are fewer references for comparison of these costs.

It is assumed that all internal combustion vehicle purchase costs and all other non-fuel costs rise with the level of inflation and therefore remain constant in real terms. By comparing older issues of NRMA's *Open Road*, this assumption holds true for the last 4 years for medium and heavy passenger vehicles. There was a real reduction in vehicle purchase costs for some light vehicles but this is assumed to have run its course. Going further back to the 1980s there is a definite trend of declining real costs, however it is assumed that trend will no longer apply due to changed world resource supply and demand conditions. The major risk is that strong growth in demand for metals worldwide may cause the price of vehicles to rise faster than inflation for a period before metal production accelerates to meet demand.

For other vehicles, notably for hybrid vehicles (HVs), plug-in hybrid electric vehicles (PHEVs), fully-electric vehicles (EVs) and fuel cell vehicles (FCVs), costs are assumed to fall. This is discussed in Section 6.5.

6.5 Treatment of technological change in the transport sector

There are significant uncertainties in terms of the timing and extent of the assumed reductions in the costs of non-ICE vehicles. Achieving these cost reductions relies on adequate supply of minerals and other raw materials, successful further development of battery and other technologies and realisation of global production economies of scale.

The cost assumptions for three points in time, 2010, 2030 and 2050 are shown in Table 13. The assumption regarding hybrid vehicles (HVs) is that over two decades mild hybridisation of vehicles will become standard and will not involve significant additional cost.

Similar to HVs, PHEVs are expected to always cost a premium over a standard internal combustion vehicle in the same vehicle category. Starting from a relative cost gap of around $14,000 to $18,000 for passenger and LCVs, costs are expected to narrow to less than an additional $3,000 by 2030.

For light EVs the price gap is around $12,000 in 2010 meaning that the vehicles are around 2.5 times more expensive than an equivalent ICE. However, global deployment is limited and in Australia only retrofitted EVs are available. Therefore, we assume no improvement in this gap until mass production built for purpose vehicles are available. This is assumed to occur during the next two decades. By 2030, the price gap has halved and reaches around $4,000 by 2050.

For FCVs, the vehicle cost in 2010 is notional as no FCVs are available in Australia, and the estimate is based on a relative cost to an ICE from ANL (2009). Although the costs of FCVs decline over time, the rate of decline to 2030 is significantly less than EV/PHEVs. FCVs face greater technical hurdles and a lack of fuel distribution and production infrastructure when compared to EV/PHEVs. Accordingly, the likelihood of FCVs emerging as a future low carbon option is less evident than the probability to see a switch towards EV/PHEVs (IEA, 2009b).

Table 13: Assumed current and future representative vehicle costs, $,000

	Passenger vehicles			**LCVs**			**Trucks**		**Bus**
	Light	**Medium**	**Heavy**	**Light**	**Medium**	**Heavy**	**Rigid**	**Art'd**	
2010									
ICE*	14	25	41	14	25	41	61	300	180
HYB	N/A	28	44	N/A	28	44	100	370	260
PHEV	N/A	39	59	N/A	39	59	107	N/A	271
EV	36	N/A	N/A	36	N/A	N/A	121	N/A	300
FCV	51	85	140	51	85	140	209	N/A	616
2030									
ICE*	14	25	41	14	25	41	61	300	180
HYB	N/A	26	42	N/A	26	42	63	305	185
PHEV	N/A	27	44	N/A	27	44	67	N/A	193
EV	20	N/A	N/A	20	N/A	N/A	77	N/A	212
FCV	30	52	84	30	52	84	124	N/A	362
2050									
ICE*	14	25	41	14	25	41	61	300	180
HYB	N/A	25	41	N/A	N/A	41	61	300	180
PHEV	N/A	26	43	N/A	26	43	67	N/A	192
EV	18	N/A	N/A	18	N/A	N/A	73	N/A	204
FCV	22	40	50	22	40	50	98	N/A	288

* The standard internal combustion engine (ICE) vehicle is considered to be a representative base vehicle for the category and weight class given.

Sources: NRMA; IEA (2009b); Electrification Coalition (2009); ANL (2009).

6.6 Road fuel costs

The assumed oil price determines the changes in retail prices for the fossil fuel categories with some differences according to relative energy content.

6.6.1 Synthetic fuels

Synthetic liquid transport fuels are currently being produced globally, mainly through an indirect liquefaction process of coal or gas, the Fischer-Tropsch (FT) synthesis. The FT process has four main steps. The first step is the creation of synthesis gas, which is a mixture of hydrogen and carbon monoxide. When natural gas is the feedstock, this step can be accomplished by one of two well-established commercial methods: partial oxidation or steam reforming. When coal or biomass is the feedstock, this step is accomplished by gasification, during which the feedstock is reacted with steam at elevated temperatures and moderate pressure. The synthesis gas leaving the coal gasifier contains large amounts of CO_2 as well as small amounts of gaseous compounds derived from impurities, such as sulfur, that are present in the feedstock. Both CO_2 and the impurities have a detrimental effect on FT synthesis. The second main step in the FT process removes these undesired compounds from the synthesis gas stream. When coal or biomass is the feedstock, a result of this second step is the release of a concentrated stream of CO_2 to the atmosphere (which could be captured and stored in the future). When natural gas is the feedstock, depending on the process employed, synthesis-gas preparation either consumes or causes negligible emissions of CO_2 (Hileman et al., 2008).

The third step is the FT synthesis. During this step, the synthesis gas is passed over an iron- or cobalt-based catalyst to form a broad mixture of hydrocarbons ranging from gases (such as ethane) to waxes (longer hydrocarbons). By altering the reaction conditions (catalyst, temperature, pressure, and time), the distribution of carbon lengths of the resulting hydrocarbons can be shifted to maximise, for example, production of middle distillates. But a broad distribution of products is an inherent output of the FT process. Under certain process design schemes, additional CO_2 is formed during the FT synthesis step (Bartis et al., 2008).

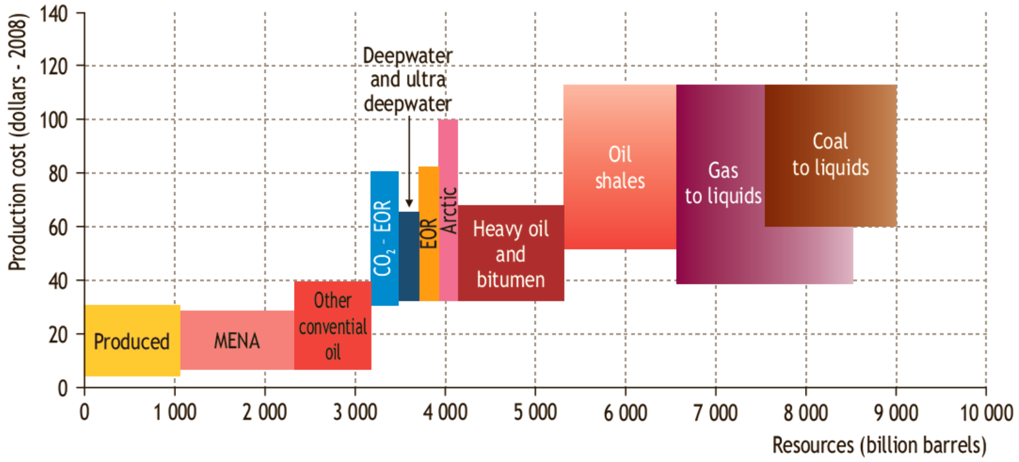
After leaving the FT section of the facility, the hydrocarbon product is upgraded to liquid fuels using well-established methods in common use in petroleum refineries. The outputs of the process can be narrowed to middle distillates and naphtha, both of which have a near-zero level of sulfur. In general, about one-third of the liquid fuel output of an FT plant is naphtha. The FT naphtha has value as a petrochemical feedstock. It can also be upgraded to gasoline suitable for automobile use (Hileman et al., 2008).

An alternative option for coal is direct liquefaction. Direct liquefaction involves breaking the coal structure into smaller molecules that resemble the constituents of petroleum. This can be achieved by heating the coal, but it is preferable that hydrogen also be added so that undesirable elements such as sulphur and nitrogen are removed from the molecules and the product is less aromatic. A catalyst is usually added so that the severity of the operating conditions is reduced, plus delivering higher yields of better quality products. The liquids produced can vary significantly in properties depending on the feed coal and process operating conditions, so some adjustments may be required to optimise the yield of diesel product and significant a gasoline yield would also be expected.

Due to available data, this report will only consider indirect liquefaction via the FT process.

The IEA (2008) estimates the production cost of coal to liquids (CTL) and gas to liquids (GTL) liquid fuels in the range of USD60-110/bbl and USD40-110/bbl, respectively. Figure 27 compares these production costs to other conventional and unconventional oil resources.

Figure 27: Cost-quantity curve for the supply of fossil based liquid fuels



Source: IEA (2008)

Note: The curve shows the availability of oil resources as a function of the estimated production cost. Cost associated with CO_2 emissions is not included. There is also a significant uncertainty on oil shales production cost as the technology is not yet commercial. MENA is the Middle East and North Africa. The shading and overlapping of the gas-to-liquids and coal-to-liquids segments indicates the range of uncertainty surrounding the size of these resources, with 2.4 trillion shown as a best estimate of the likely total potential for the two combined.

The cost of CO_2 capture and storage for CTL diesel is assumed to be $20/t$CO_2$-e. The discussion in Section 7.1.2 below finds from several studies that the cost of CO_2 storage is projected to be $10/ t$CO_2$-e. The balance of costs, that is the capture component, is also assumed to be $10/ t$CO_2$-e on the basis that capture technology will likely be demonstrated at very large scale in the electricity sector first and will therefore be available at reasonable cost to other sectors.

Both CTL diesel and GTL diesel are assumed to be available only after 2020.

6.6.2 First generation road biofuels

For first generation biofuels, biodiesel and ethanol, the cost will be based on the volume of demand as per the cost-quantity curves in Figure 28 and Figure 29. These curves are derived from O'Connell et al. (2007) and have been updated further to take account of price movements but will continue to fluctuate over time. Due to competition with the food production industry, it is assumed that only 5 per cent of this volume is available within the next decade. The exception is all used cooking oil and all tallow not exported is assumed to be available for biodiesel.

Figure 28: First generation biodiesel cost-quantity curve

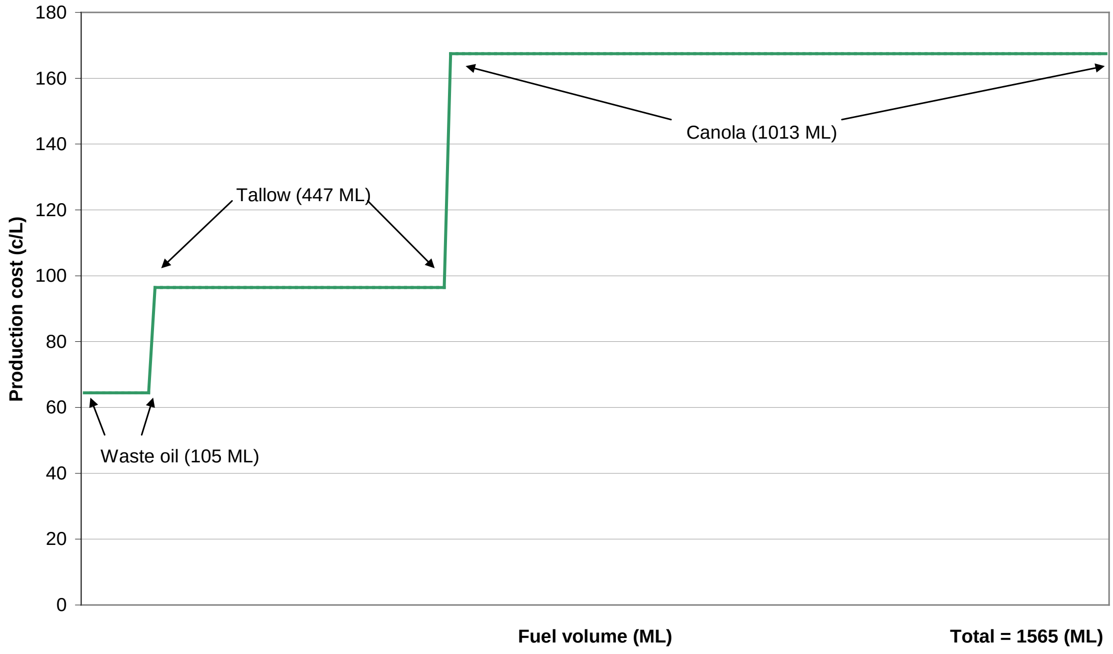
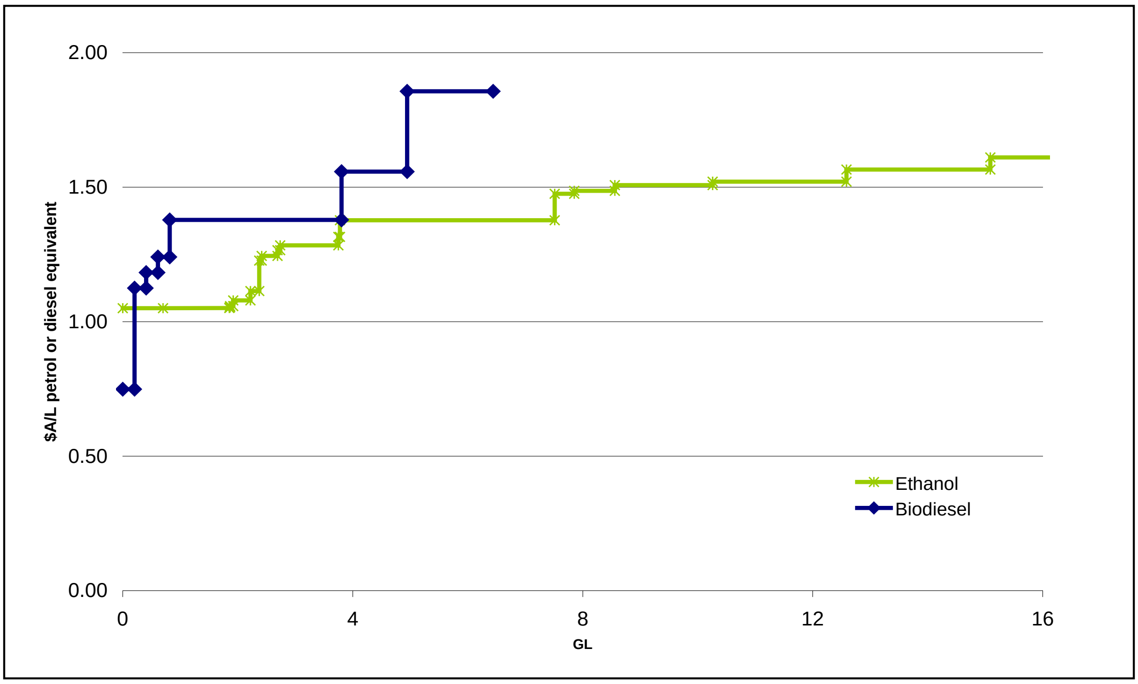


Figure 29: First generation ethanol cost-quantity curve

It should be noted that the timing around the availability of second-generation biofuel is subject to considerable uncertainty.

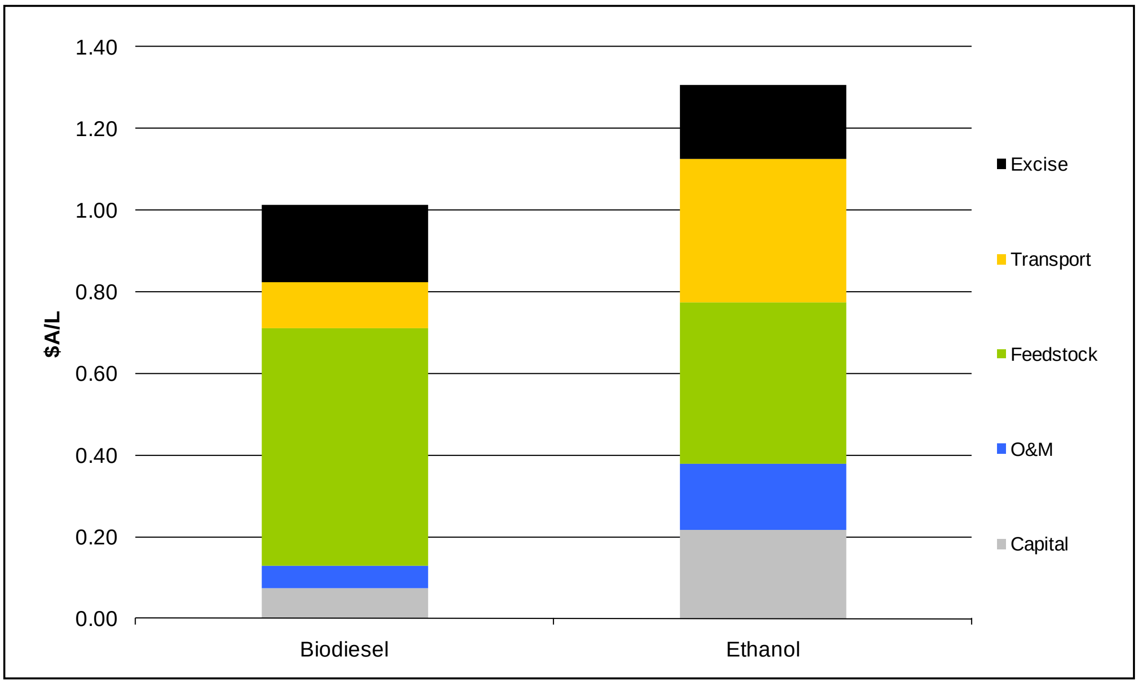
6.6.3 Second generation road biofuels

Figure 30: Cost curve for second generation road biofuels



The cost curve as a function of biomass availability and components costs for the production of second generation road biofuels are shown in Figure 30 and 31 respectively. The charts use the same second generation biofuel supply data as discussed in the first section of this report. However the refining costs and biomass conversion efficiencies for producing these road fuels differ to those used to produce jet fuels.

Figure 31: Component costs for second generation production of ethanol and biodiesel (based on excise rates that will prevail in 2015)



6.7 Road fuel efficiency

The efficiencies of fuels not currently in use and therefore not reported in ABS (2007) were calculated based on the relative energy content (Table 14). In some cases there is considerable uncertainty since energy content can vary, particularly for biofuels due to different feedstocks.

Table 14: Properties of selected fuels (/L, or /m^3 for CNG and H_2)

	LHV (MJ/kg)	Density (kg/L or kg/m^3)	LHV (MJ/L or MJ/m^3)
Petrol	42.7	0.75	32.0
Diesel	42.5	0.84	35.7
LPG	46.1	0.53	24.4
CNG/LNG	45.1	0.78	35.2
B100	40.2	0.84	35.3
B20	42.0	0.84	35.3
E85	29.2	0.78	22.8
E10	41.1	0.75	30.8
H_2	120.0	0.09	10.8
GTL diesel	40.0	0.84	33.6
CTL diesel	40.0	0.84	33.6

Note: The Lower Heating Value (LHV) is used instead of the Higher Heating Value (HHV) as the latent enthalpy of vaporisation for water vapour exhaust gas is not recovered in useful work.

Source: Graham et al. (2008)

The energy content of reported fuels was used to determine generic energy consumptions for Spark Ignition (gasoline) or Compression Ignition (diesel) internal combustion engines. Each alternative fuel was associated with the energy consumption of either the SI or CI combustion process, and alternative fuel efficiencies were then determined according to the properties of the individual fuel.

The assumed relationship between fuel type and combustion process is presented in Table 18. For light duty vehicles, buses and rigid trucks, all variants of diesel fuel were assumed applicable to CI engines, the remainder to SI engines. For articulated trucks it was assumed that all fuels with the exception of gasoline and E10 were applicable to CI engines as performance requirements in this sector determine that CI diesel is dominant, and alternative fuel programs accordingly utilise the CI diesel architecture.

Table 15: Combustion process according to fuel

	Petrol	Diesel	LPG	CNG	B100	B20	E85	E10	H_2	GTL	CTL
Passenger Cars											
Light	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Medium	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Heavy	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
LCVs											
Light	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Medium	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Heavy	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Trucks & Buses											
Rigid	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI
Art'd	SI	CI	CI	CI	CI	CI	CI	SI	CI	CI	CI
Buses	SI	CI	SI	SI	CI	CI	SI	SI	SI	CI	CI

Note: Articulated trucks using LNG

In some instances it is recognised that alternative fuel characteristics will adversely or beneficially affect the combustion process and in such cases the energy consumption is factored. The factoring is adjusted over time, as both the properties of alternative fuels and the deployment of appropriate engine technology are assumed to evolve.

6.7.1 Greenhouse gas emission factors

Direct and fugitive emission factors for the main fuels we use today have been calculated from values provided in *National Greenhouse Accounts (NGA) Factors* (DCC, 2009) with some adjustment for upstream or indirect emissions and for less common fuels from CSIRO internal data. The full fuel cycle emission factors (direct plus indirect emissions) gives the quantity of emissions released per unit of energy for the entire fuel production and consumption chain.

The full fuel cycle emission factors in grams per kilometre for road vehicles are shown in Table 16**Error! Reference source not found.**. It can be expected that estimates of upstream emission factors will change over time. For example, the science is still being developed around the impact of extracting fuels from biomass. The emission factors for biofuels in Table 16 are drawn from DCC (2008). A second example is that the conversion process for coal and gas to liquids are still being actively improved. One final example is that some fossil fuels, such as oil, may become more difficult to extract, therefore requiring more use of energy upstream. Ideally these changes should be incorporated. However, currently there is not enough reliable data to do so. Downstream or direct emission factors can be expected to improve because of improvements in fuel efficiency - this is incorporated in the modelling.

Table 16: Full fuel cycle CO_2-e emission factors for each fuel and road vehicle category (g/km)

	Passenger Vehicle			LCVs			Trucks		Bus
	Light	**Med.**	**Heavy**	**Light**	**Med.**	**Heavy**	**Rigid**	**Art'd**	
Petrol	215	240	329	245	274	375	N/A	N/A	N/A
Diesel	175	196	268	200	223	306	800	1493	738
LPG	195	218	298	222	248	340	836	N/A	N/A
CNG	203	227	311	232	259	355	873	1426	806
B100	21	23	32	25	26	36	104	198	101
B20	131	147	201	157	168	229	664	1183	609
E85	170	190	260	194	217	296	N/A	N/A	N/A
E10	213	238	326	242	271	372	N/A	N/A	N/A
BTL Diesel	42	46	64	50	52	72	208	396	202
GTL Diesel	175	196	268	200	223	306	800	1493	738
CTL Diesel	199	222	305	226	254	347	908	1694	837
Hydrogen (ren.)	0	0	0	0	0	0	0	0	0

Note: Electricity fuel is not assigned an emission factor because its emissions are determined by the emission intensity of electricity generation which varies by scenario..

Source: DCC (2008); Graham et al. (2008).

6.7.2 Efficiency improvements over time

The change in fuel efficiency over time is based on judgement of the balance of two competing forces. The first is improvements that have already or are likely to be achieved internationally where fuel excise rates are several times those in Australia. The second is the historical lack of improvement in fuel efficiency owing to:

- Greater non-propulsion use of energy within the vehicle for amenities such as air conditioning (itself a function of growing wealth and consumer expectations)
- The trend towards large vehicles within some weight categories (particularly 4WDs/SUVs in the large vehicle category), and

- The robustness of households to fuel price changes owing to the small proposition of fuel costs in the household budget (amounting to no more than 2-3 per cent of average adult annual income).

It is assumed that vehicles equipped with SI engines will improve in efficiency by 25 per cent and CI engines by 14 per cent from 2006 to 2050, independently of changes related to fuel type and hybrid drivetrain. These improvements are proposed to arise from increased efficiency of vehicle and engine technology in new vehicles, and the extent to which the existing fleet is modified by the addition of new vehicles.

Whilst equivalent vehicle improvements are assumed for both SI and CI vehicles, it is proposed that there is significantly greater scope to enhance the operating efficiency of the SI engine and that by 2050 the efficiencies of SI and CI engines will converge, with differentiation according only to the combustion characteristics of alternative fuel types. The efficiency of the SI engine is proposed to be increased through the following:

- Optimisation of engine gas exchange processes and reduction of pumping work through the deployment of advanced valvetrains

- Increase of compression ratio towards optimum values enabled by the use of direct injection and advanced valvetrains

- Reduction in engine friction and the operation of engines in regions of highest efficiency enabled by down-sizing, in turn achieved by higher specific output with boosting, and

- Operation at extended lean and dilute limits facilitated by advanced combustion processes, and enabled in part by the availability of lean emission after treatment and low-sulfur fuels.

For the REF scenario, it is implicitly assumed all improvements that are technically feasible, but costly to introduce in the near future, will come on line slowly toward 2050, once the costs have been reduced sufficiently to make them competitive.

Table 17 presents assumptions about road vehicle fuel intensity by fuel type for conventional ICE vehicles.

Combined with non-engine efficiency improvements, fuel intensities for ICE’s were assumed to decline up to 37 per cent between 2006 and 2050. Hybrid electric vehicle fuel intensities were developed based on their performance relative to ICE only vehicles.

It is assumed that the mild hybrid category has a 5 per cent improvement in fuel efficiency starting in 2006 increasing to 30 per cent by 2050 for all non-articulated truck road categories. Articulated trucks improve to only 10 per cent better than conventional articulated trucks. Mild hybrids draw no electricity from the grid.

The assumptions for PHEVs, which do draw electricity from the grid, are more complicated. Total fuel efficiency is calculated on the basis of the percentage of time in which it uses the electric drive train. When using the ICE drivetrain it has the ICE-only efficiency for that year. When using the electric drivetrain it has the following efficiencies:

- Light passenger: not applicable
- Medium passenger: 0.22kWh/km
- Heavy passenger: 0.31kWh/km
- Rigid truck: 0.85 kWh/km
- Bus: 0.8kWh/km.

These electric drivetrain efficiencies are held constant over time on the basis that any improvements are used up to provide better amenity (passenger and luggage room, safety, comfort, performance and instruments) rather than fuel savings.

The percentage of time using electric drivetrain in total annual kilometres is assumed to be 50 per cent initially in 2006, increasing to 80 per cent by 2035 as battery technology improves and allows for longer use of the electric drivetrain. For the remainder of kilometres the ICE drivetrain is in use. As such, a weighted average of the efficiency of these drivetrain gives the average annual efficiency for any given year.

In all cases, for fuel intensities in intervening years, constant compound growth rates were derived from the two end points. The implied annual growth in fuel efficiency to 2050 for each class is slightly slower than that over the last 30 years (consistent with an apparent slowdown in this growth since the 1980s).

EVs are only applicable for light vehicles, rigid trucks and buses using the electric drivetrain 100 per cent of the time at 0.2 kWh/km, 0.85 kWh/km and 0.8 kWh/km, respectively. Again, these efficiencies are held constant over time on the basis that any improvements in electric drivetrain efficiency are used up to provide better amenity.

Note, at a residential electricity price of 12c/kWh, the cost of electricity as a fuel for light vehicles is 4.2c/km. This is slightly more than a third of the cost of fuel for a petrol vehicle in the same weight class of 11.5c/km at a petrol price of 128c/L (retail petrol prices include fuel excise of 38.143 cents per litre and GST).

The fuel efficiency of FCVs is approximately double that of an ICE drivetrain.

Table 17: Assumed fleet average fuel efficiency by engine type (L/100km), conventional vehicles

	Petrol		Diesel		LPG		CNG/LNG (m^3/100km)		B95		B20		E85		E10		H_2 (m^3/100km)		BTL/GTL/CTL diesel	
	2006	2050	2006	2050	2006	2050	2006	2050	2006	2050	2006	2050	2006	2050	2006	2050	2006	2050	2006	2050
Passenger Cars																				
Light	9.1	6.8	6.3	5.4	12.1	8.6	8.0	5.5	7.7	6.3	6.5	5.6	12.8	8.6	9.5	7.1	36.7	23.3	6.6	5.7
Medium	10.2	7.6	7.1	6.1	13.6	9.6	9.0	6.2	8.6	7.1	7.3	6.3	14.3	9.6	10.6	7.9	41.1	26.1	7.4	6.4
Heavy	14.0	10.4	9.7	8.3	18.6	13.2	12.3	8.5	11.8	9.7	10.0	8.6	19.6	13.2	14.5	10.8	56.3	35.7	10.1	8.7
LCVs																				
Light	10.4	7.8	7.2	6.2	13.8	9.8	9.2	6.3	8.8	7.2	7.4	6.4	14.6	9.8	10.8	8.0	41.8	26.6	7.5	6.5
Medium	11.6	8.7	8.1	7.0	15.5	11.0	10.3	7.0	9.8	8.1	8.3	7.2	16.4	11.0	12.1	9.0	46.9	29.7	8.4	7.2
Heavy	15.9	11.9	11.1	9.5	21.2	15.0	14.0	9.6	13.5	11.0	11.4	9.8	22.4	15.0	16.5	12.3	64.2	40.7	11.5	9.9
Trucks & Buses																				
Rigid	39.2	29.3	28.9	24.9	52.2	37.0	34.5	23.7	35.2	28.8	29.8	25.6	55.1	37.0	40.6	30.3	157.8	100.1	30.1	25.9
Art'd	73.1	54.6	54.0	46.4	85.2	69.7	83.4	68.3	65.7	53.8	55.6	47.8	89.9	69.6	75.8	56.6	257.6	199.4	56.2	48.4
Buses	36.2	27.0	26.7	23.0	48.1	34.1	31.9	21.9	32.5	26.6	27.5	23.6	50.8	34.1	37.5	28.0	145.6	92.4	27.8	23.9

Sources: Graham et al. (2008); BITRE/CSIRO (2008).

7. APPENDIX C: ELECTRICITY SECTOR ASSUMPTIONS

7.1 Environmental parameters

7.1.1 Greenhouse gas emission factors

Direct and fugitive emission factors for the main fuels we use today have been calculated from values provided in *National Greenhouse Accounts (NGA) Factors* (DCC, 2009) with some adjustment for upstream or indirect emissions and for less common fuels from CSIRO internal data. The full fuel cycle emission factors (direct plus indirect emissions) gives the quantity of emissions released per unit of energy for the entire fuel production and consumption chain.

Within ESM, GHG emission factors for fuels used in electricity generation are also input on a full fuel cycle basis. Combustion emission factors by State and fuel are presented in Table 18. Australian combustion emission factors for coal differ by State due to different coal properties. Emission factors for coal are sourced from DCC (2008) with natural gas, biogas and biomass emission factors sourced from DCC (2009). New Zealand emission factors are assumed to comparable to the Eastern Australian States.

Table 18: Australian combustion emission factors (kg CO_2-e/GJ of fuel), by state and fuel

	NSW	**VIC**	**QLD**	**SA**	**WA**	**TAS**	**NT**
Black coal	89.3	N/A	91.1	95.9	93.1	N/A	N/A
Brown coal	N/A	93.2	N/A	N/A	N/A	N/A	N/A
Natural gas	51.3	51.3	51.3	51.3	51.3	51.3	51.3
Uranium	0	0	0	0	0	0	0
Biogas	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Biomass	1.8	1.8	1.8	1.8	1.8	1.8	1.8

Sources: DCC (2008, 2009)

Table 19 shows that fugitive emission factors for coal differ by State with natural gas differing also by end-user. Fugitive emission factors for coal differ by State due to the type of mine (underground or open cut), and the extent to which methane escapes post-mining from gassy mines. Fugitive emission factors for coal are sourced from DCC (2008).

Natural gas is usually supplied at either high or low pressure, depending on the scale of use. Major users are those supplied at high pressure and with an annual usage of more than 100,000 gigajoules. Small users are defined as consuming less than 100,000 gigajoules per year. The main difference is due to the energy required to transport natural gas by pipeline from the gas field to the major demand centres (e.g. capital cities). Fugitive emission factors for natural gas are sourced from DCC (2009).

Table 19: Australian fugitive emission factors (kg CO_2-e/GJ of fuel), by state, fuel and end-use

	Large end-user							Small end-user						
	NSW	**VIC**	**QLD**	**SA**	**WA**	**TAS**	**NT**	**NSW**	**VIC**	**QLD**	**SA**	**WA**	**TAS**	**NT**
Black coal	8.7	N/A	2.0	0.9	2.3	N/A	N/A	8.7	N/A	2.0	0.9	2.3	N/A	N/A
Brown coal	N/A	0.3	N/A	N/A	N/A	N/A	N/A	N/A	0.3	N/A	N/A	N/A	N/A	N/A
Natural gas	15.7	4.4	3.2	13.2	4.1	4.4	4.4	16.4	4.5	3.5	13.9	4.4	NE	4.4
Uranium	0	0	0	0	0	0	0	0	0	0	0	0	0	0

NE: Not estimated.
Sources: DCC (2008, 2009)

7.1.2 Geological storage of CO_2

In determining the potential for the geological storage of CO_2, the GEODISC program assessed over 100 potential environmentally sustainable sites for CO_2 injection (ESSCIs) by applying a deterministic risk assessment based on five factors: storage capacity; injectivity potential; site details; containment; and natural resources. Utilising this approach, Australia has a CO_2 storage potential in excess of 1600 years of current annual total net emissions. However, this estimate does not account for various factors such as source to sink matching. According to Bradshaw et al. (2004), if preferences due to source to sink matching are incorporated, Australia may have the potential to store a maximum of 25 per cent of current annual total net emissions, or approximately 100 to 115 Mt CO_2 per year.

More recent analysis for Victoria assessed the cost and potential for the geological storage of CO_2 in the offshore Gippsland basin from the Latrobe Valley (Hooper et al., 2005). The study determined that up to 2000 Mt may be stored over a forty year period (50 Mt per year) and estimated the cost of CO_2 transport and storage via a 200 km pipeline at $10.50/t. For Western Australia, analysis by Allinson et al. (2006) identified three potential storage sites in the Perth basin capable of storing 25 Mt per year for twenty five years with the cost of CO_2 transport and storage ranging from $10 to $15/t.

Consistent with the methodology in the studies cited above, it is assumed that new pipelines are required to transport CO_2 from source to sink, although existing gas distribution infrastructure could be an option depending on location. It is assumed that the fixed costs of constructing the pipelines are not paid upfront but as an annual fee which is part of generator's variable cost of transporting and storing carbon. Generators therefore pay for the fixed cost of building pipelines over the life of the carbon capture and storage operation. Given the lack of detailed information which would facilitate the construction of CO_2 transport and storage cost curves for all States, a disposal cost of $10/t has been applied to any CO_2 stored.

The amount of CO_2 that can be sequestered nationally per year has been capped at 115 Mt as estimated by Bradshaw et al. (2004).

7.2 Electricity generation fuel prices

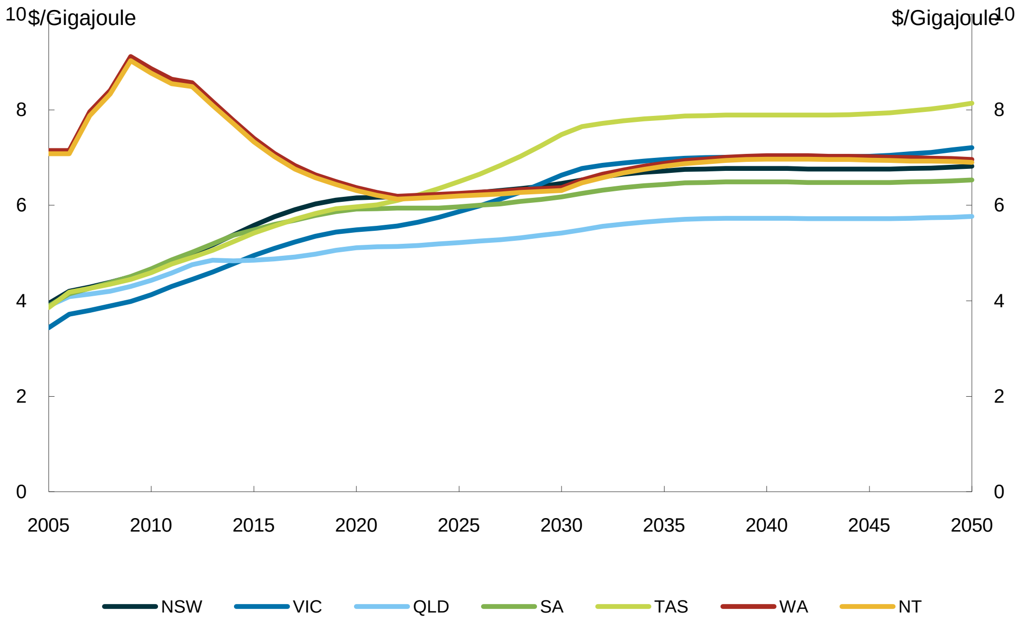
7.2.1 Coal

Brown and black coal prices for the projection period are taken from MMA (2008).

7.2.2 Natural gas

Natural gas is seen as a transition fuel to assist the electricity sector in transitioning from a high GHG emission intensity to more moderate GHG emission intensity in the medium term. The assumed Australian natural gas prices employed in the modelling are shown in Figure 32.

Figure 32: Domestic Australian natural gas prices (city node)



Source: MMA (2008)

Prices for Western Australia and the Northern Territory are assumed to track the export price for liquid natural gas (LNG). The projected East coast gas prices assume moderate LNG penetration in Queensland. Prices at the Gladstone port are predicted to reach export parity in 2025 with the southern State prices converging with the Queensland price by around 2030.

The price of natural gas in other States is assumed to be largely driven by domestic demand and longer term supply contracts which do not completely track international market volatility.

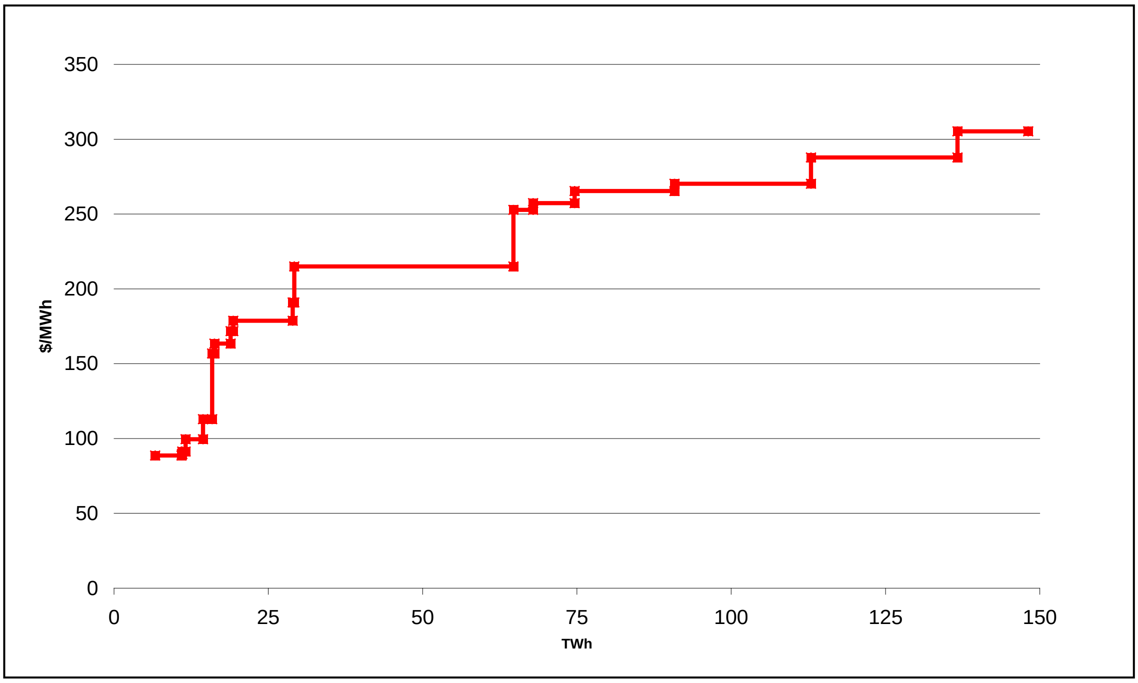
7.2.3 Uranium

Uranium, an international commodity, was assumed to have an international price, increasing mildly in real terms from around \$0.75/GJ in 2006 to around \$2.15/GJ in 2050.

7.2.4 Biomass

The following chart shows the cost of biomass from electricity if we assumed a capital cost of $3000/kW and use the second generation biomass cost-quantity curve outlined in the first section of this report

Figure 33: Electricity cost curve based on second generation biomass cost-quantity data



7.3 Electricity demand

Projections of future electricity demand by State are available from ABARE (ABARE, 2006). ABARE's regular national projections relate only to business as usual scenarios. They are based on future projections of economic growth, improvements in energy efficiency and some efforts to identify near term energy intensive projects, such as those associated with alumina refineries. ABARE projects the average growth rate for Australia to 2030 to be around 1.9 per cent, per annum.

Base case demand projections are adjusted downward for emission reduction scenarios to take into account:

- Lower economic growth as a result of internalising costs of CO_2 emissions into final goods and services consumed

- Lower energy required per unit of GDP due to structural change in the economy (energy intensive industries decline at the expense of less energy intensive industries) and greater uptake of energy saving technologies and processes. Counter to this is the possible protection of carbon intensive export exposed industries which will reduce the amount of restructuring that might have taken place (Prime Ministerial Task Group on Emissions Trading, 2007)

- The degree of change in GDP and energy efficiency is not calculated by the model but is adapted from the literature such as Energy Futures Forum (2006). The imposition of CO_2 prices generally reduces electricity demand growth to around 1.5 per cent to 2030

- Demand growth is not entirely fixed because ESM assumes that consumers will respond negatively to electricity price rises and positively to electricity price decreases. As reported in Graham et al. (2005), price elasticities of demand for electricity in the literature generally range from -0.2 to -0.5. This means a 10 per cent increase in prices would lead to a 2 to 5 per cent decrease in electricity demand

- The price elasticity of demand for electricity can be expected to change over time. A useful way to consider this is to think of a household budget. For a person earning an after tax income of $25,000 and an annual electricity bill of $1,000, electricity represents 4 per cent of their annual budget. By 2050, assuming a 2 per cent per annum real increase in wages, their after tax real income will be approximately $60,000. On a constant price basis electricity now represents just 1.6 per cent of the annual budget. As a result, the household’s response to a given percentage change in this budget item is likely to be smaller than at present. If we also consider that price elasticity of demand estimates are based on data from the previous two decades then it is possible that present price elasticity estimates are already out of date in terms of reflecting household and other group’s responses to price changes.

For this reason, in ESM it is assumed the price elasticity of demand is at the very bottom of the range in the literature at -0.2. Furthermore, this price elasticity only applies for large price changes (above 25 per cent). For small price changes, the price elasticity of demand is assumed to be -0.1. These are applied uniformly across all customers, except for industrial end-users.

7.4 Electricity generation technology cost and performance

Table 20 shows key technology cost and performance assumptions for centralised generation (CG) plant that have been applied in modelling the base case scenario. Capital costs refer to the sent-out plant cost including the capital charges during construction period, royalty allowances, cost of land and site improvement or mine development and other owner’s costs.

The volatility of generation markets can have a positive or negative effect on generation plant costs. For example, in the years during and following the Asian Economic Crisis, the costs of power plant, particularly gas-fired units, fell significantly as many potential buyers in Asia were forced out of the generation plant market. Currently it appears the market has moved in the opposite direction. A surge in demand for new power plants has occurred together with a period of strong demand growth for metals and other plant input materials (EIA, 2006).

Operating and maintenance (O&M) costs include labour charges for regular operation and maintenance of plant equipment, cost of maintenance material, and labour charges associated with administration and support functions for plant operations.

The capital cost, O&M cost and thermal efficiency data for CG technologies are recent CSIRO estimates. Fuel costs are derived from the primary cost of fuel that prevailed in the base-year, 2006. On average, across the States these are estimated to be: black coal ($1/GJ); brown coal ($0.5/GJ); natural gas ($4/GJ); biomass ($1.5/GJ); diesel ($15/GJ) and uranium ($0.75/GJ).

Technology cost and performance assumptions for DG technologies are shown in Table 21.

Table 20: Technology cost and performance assumptions, 2010: centralised generation

	Capital plant cost (AUD/kW sent-out)	Capacity factor	Thermal efficiency	O&M Fixed cost (AUD/MWh)	O&M Variable cost (AUD/MWh)	Fuel cost (AUD per MWh)	Economic life (years)
Brown coal pf	2840	0.87	28.0	3.2	1.5	5.8	50
Black coal pf	2420	0.80	35.1	3.2	1.6	9.0	50
Black coal IGCC	3095	0.80	41.0	3.2	1.6	8.8	50
Natural gas CCGT	920	0.80	49.0	2.9	4.9	22.0	25
Solar thermal	5550	0.25	N/A	22.3	1.5	N/A	25
Wind	2235	0.29	N/A	13.5	1.6	N/A	25
Large hydro	3120	0.20	N/A	20.0	2.0	N/A	100
Biomass	3160	0.55	26.0	12.0	3.0	20.8	30
Brown coal IGCC	3420	0.80	41.0	3.2	1.5	4.4	50
Brown coal CCS	5600	0.80	25.0	4.3	19.4	5.6	50
Black coal CCS	4840	0.80	27.2	4.3	19.4	10.8	50
Wave	9640	0.50	N/A	15.1	17.0	N/A	25
Ocean current	6280	0.35	N/A	21.5	17.0	N/A	25
Gas peak	440	0.20	20.0	12.1	7.5	54.0	25
Gas CCS	3295	0.80	40.0	10.7	15.0	25.1	25
Nuclear	4150	0.80	34.0	5.0	2.0	7.9	50
Hot fractured rocks	5200	0.80	N/A	10.0	2.0	N/A	25

Notes:
pf: pulverised fuel; IGCC: Integrated Gasification Combined Cycle; CCGT: Combined Cycle Gas Turbine.
Capture rate of 90% is assumed for CCS technologies.
The capital cost of nuclear power includes the cost of decommissioning the plant (it adds approximately $500/kW). This approach is mathematically equivalent to adding the decommissioning cost to the annual operating cost of the plant and so does not pre-empt any potential arrangements in Australia with regard to paying upfront versus making annual payment over the life of the plant.
Thermal efficiency refers to the percentage of useful energy output to non-renewable energy input based on gross calorific value (higher heating value). These ratios are only recorded if they use a fuel.
Capacity factors for renewable are indicative and represent an average of the best available currently undeveloped sites across Australia.
Fuel costs assume current costs of fuel. Increases over time are taken into account in the modelling.

Source: Graham et al. (2009)

Table 21: Technology cost and performance assumptions, 2010: distributed generation

Technology name	End-user	Fuel	Indicative size	O&M cost ($/MWh)	Capital Cost ($/kW)	Electrical Efficiency (% HHV)	Maximum Total Efficiency (% HHV)	Fuel transport cost ($/GJ)	Ec. life (years)	Capacity factor (%)
Combined cycle CHP	Ind	Gas	30 MW	35	1935	45	81	1.35	20	65
Fuel cell CHP	Res	Gas	2 kW	70	3476	58	79	11.20	15	80
Microturbine CCHP	Com	Gas	60 kW	15	4268	28	78	5.85	15	43
Microturbine CHP	Com	Gas	60 kW	10	3734	28	78	5.85	15	18
Rankine CHP	Rur	Biomass	30 MW	30	3169	28	56	24.60	25	65
Rec. engine	Ind	Gas	5 MW	5	1265	40	N/A	1.35	20	1
Rec. engine	Com	Gas	500 kW	2.5	1265	38	N/A	5.85	20	3
Rec. engine	Res	Gas	5 kW	2	919	36	N/A	11.20	20	1
Rec. engine	Com	Diesel	500 kW	5	460	45	N/A	1.55	15	3
Rec. engine	Com	Biogas	500 kW	0.5	2068	38	N/A	0.50	20	80
Rec. engine CCHP	Res	Gas	5 MW	15	4439	40	84	1.35	20	80
Rec. engine CCHP	Com	Gas	500 kW	10	2497	38	80	5.85	20	43
Rec. engine CCHP	Res	Biogas	5 MW	15	4439	40	84	0.50	20	80
Rec. engine CCHP	Com	Biogas	500 kW	10	2497	38	80	0.50	20	43
Rec. engine CHP	Ind	Gas	1 MW	7.5	1776	40	84	1.35	20	65
Rec. engine CHP	Com	Gas	500 kW	5	1998	38	80	5.85	20	18
Solar PV	Com	Solar	40 kW	0.5	7027	N/A	N/A	N/A	25	variable
Solar PV	Res	Solar	1 kW	0.5	8384	N/A	N/A	N/A	25	variable
Solar PV	Rur	Solar	1 kW	0.5	9384	N/A	N/A	N/A	25	variable
Wind turbine	Com	Wind	10 kW	0.5	6090	N/A	N/A	N/A	15	variable
Wind turbine	Res	Wind	1 kW	0.5	4964	N/A	N/A	N/A	10	variable
Wind turbine	Rur	Wind	1 kW	0.5	4964	N/A	N/A	N/A	10	variable

Source: CSIRO (2009)

7.4.1 Capacity factors for distributed generation

Capacity factors for DG technologies can vary depending on end-user requirements. Table 22 lists the capacity factors that have been assumed in the modelling.

Table 22: Capacity factors by DG technology and end-user

Technology/end-user	Industrial	Commercial	Residential	Rural
Diesel engines	3%	1%	1%	30%
Gas engines	30%	30%	N/A	N/A
Gas turbines	30%	N/A	N/A	N/A
Gas Cogeneration	65%	30%	30-80%	N/A
Gas Trigeneration	N/A	43%	80%	N/A
Biomass Cogen	N/A	N/A	N/A	45-80%
Biomass	N/A	N/A	N/A	80%
Biogas Trigeneration	N/A	43%	80%	N/A
Landfill gas engines	N/A	80%	N/A	N/A
Solar PV	17%	17%	17%	25%
Wind	10%	10%	10%	15%

The following are general comments on Table 22:

- N/A means technology and end-user combinations are generally not applicable
- 30% capacity factor used where specific information not available
- A capacity factor of 80% usually reflects technology operating as base-load, and
- Capacity factors vary by State. Values in table are for NSW.

Some specific comments are also in order for Table 22. These include:

- Diesel engines in industrial category mainly used for network support by distribution network service providers (DNSPs). Financial analysis typically conducted on 300 hours of operation per year (approximate 3% capacity factor). Employed in commercial and residential sectors as stand-by capacity in case of a power outage. Principally used in rural areas for off-grid power supply. Due to the lack of specific information a 30% capacity factor is assumed in rural areas
- Gas cogeneration installed in an industrial setting reflects a derived demand for process heat. It is assumed that the cogen unit meets the base-load heat demand (steam or hot water) with boilers used to meet peaks. Industrial processes are assumed to be operating during weekdays at a unit availability of 95%, gives a capacity factor of approximately 65%. This may understate usage in firms running processes on a twenty-four hour basis
- Gas cogeneration in a commercial setting is usually sited in buildings to provide hot water and space heating during cooler months. This gives an approximate capacity factor of 14-30% depending on State

- Gas cogeneration in a residential setting reflects two alternative models. One is a high-density model where the provision of space heating and hot water is provided to an apartment building during cooler months. The second model is the provision of space heating and hot water to a single household via a micro CHP unit. The high capacity factor applies to the latter because of the large heat to electricity output of micro CHP units (e.g. fuel cells)

- Gas trigeneration in a commercial setting is usually sited in buildings to provide hot water and space heating and cooling during week day office hours (7:00 – 22:00). This implies a 43% capacity factor. Note, this may understate usage in other commercial settings (e.g. shopping centres, airport terminals) where capacity factors could be higher

- Gas trigeneration in a residential setting reflects a high-density model similar to cogeneration. It can also reflect a low-density model such as a district heating and cooling system in a housing sub-division (e.g. GridX). The distribution of loads between a large number of households implies a base-load operation

- Biomass Cogen and biomass plants usually operate where the fuel is a by-product of another process (e.g. bagasse from sugar cane harvesting or wood waste from timber mills). The lower capacity factor reflects seasonal processes where fuel is only available during the harvesting season with the higher capacity factor applicable to non-seasonal processes

- Biogas trigeneration: see Gas cogeneration

- Landfill gas engines are generally assumed to be operating as base-load plant

- Solar PV capacity factors for metro areas are lower than that for rural areas reflecting the influence of cloud cover in coastal metropolitan areas. The 17% capacity factor is estimated data for Sydney for residential PV (Rae et al., 2009)

- Lower capacity factors for wind in non-rural areas reflect the influence of turbulence from the built environment on useful power production from small wind turbines. Higher capacity factors in rural areas reflect use of larger turbines and less impact of turbulence.

7.5 Treatment of technological change in electricity sector

7.5.1 Centralised plant

CSIRO use an equilibrium modelling framework that features endogenous experience curves for electricity generation technology capital costs. The model has three regions: the developed world, developing world and Australia which exist in a global framework.

The model of the electricity market is solved as a mixed integer linear program. We call this tool the Global and Local Learning Model (GALLM). There are many inputs to this model such as the carbon price and the prices and physical limits of energy resources used by the different power plants.

GALLM optimally selects the technology mix which meets electricity demand at lowest cost, simultaneously determining the uptake and change in costs of the set of electricity generation technologies included in the model for each region.

Whilst this learning curve approach is less arbitrary than, for example, applying a cost de-escalation factor per year (since the price reduction is determined endogenously by cumulative production rather than time alone), it remains a simplification of the many factors impacting upon the rate of change in costs of technologies. The additional factors may be quite complex and can vary between technologies and even producers of the same product within the same factory (Alberth, 2008; Dutton and Thomas, 1984). Nevertheless, four broad factors have been identified that influence the slope of experience curves that may not be the result of learning about the technology (IEA, 2000); market forces; technology structural change; government policy and R&D spending; and local/global technological change and compound learning.

Owing to the existence of these other drivers of technological change we have included some additional features in GALLM to address a limited set of them. As for the remainder, we are undertaking research to incorporate them in the future versions of the model.

Local versus global technological change

Whilst we are primarily interested in the local (Australian) cost of electricity generating technologies, international estimates of learning rates are more commonly available and may not be applicable within a local setting. International learning rates are based on international cumulative capacity and, since Australia's cumulative capacity is much lower, Australia's incremental additions to global capacity can only generate small changes in costs. Alternatively, estimating experience curves specifically for Australian cumulative capacity and costs would not be appropriate either since most technological components are imported and are thus better explained by global developments. Applying changes in Australian cumulative capacity alone would lead to the erroneous conclusion that much faster learning is possible in Australia than internationally (Junginger et al., 2005).

To avoid these methodological pitfalls, GALLM only applies global learning curves parameters to Australia for those technologies for which Australia is assumed to benefit from the technology spillovers by way of lower cost local technologies. The exceptions to this rule are wind power. For wind power GALLM calculates two types of experience curves (international and local). Local learning is based around the know-how for installing imported wind turbines. At this stage, this feature only applies to this technology. It is intended that this approach will be extended to all technologies when further technology-specific information is obtained.

Technology price bubbles

If current price increases are part of a temporary bubble then the true technology cost curve lies at a lower level than current prices suggest. This is the assumption made in GALLM[2]. Accordingly, the recent price increases are not factored into the experience curves provided to

[2] The assumption is made on the basis that the bubble most likely represents increased profits to either raw material suppliers or power plant manufactures for tight market conditions. Unless a market has strong barriers to entry then economic theory predicts that above normal profits cannot be sustained indefinitely. In practical terms, this means that the price must return to closer to the true cost curve.

the model. The price increase has been reproduced via another mechanism which we have called a ‘penalty’ constraint. This penalty has been represented in GALLM as an additional payment to technology suppliers when investment in wind and other technologies is high relative to the total size of the power plant market, exceeding the capacity of manufacturers to supply the market.

When this approach to modelling technology price bubbles is applied, GALLM calculates both the beginning and the end of the assumed price bubble by determining when the demand for wind and coal fired power stations no longer dominates new power station investment. In the context of a carbon price this tends to mean that the price bubble ends during the next decade as coal with CCS tends to be favoured over normal coal fired power and alternative renewable technologies other than wind become more cost competitive.

Besides replicating the current price bubble, projections from GALLM also predict some future smaller price bubbles when certain technologies become popular. Consequently, CSIRO’s cost projections can at times appear to be more volatile compared to other projections. CSIRO’s projections of long term costs for some technologies, such as wind, are generally lower since we assume that wind plant prices are currently inflated by a price bubble.

Emerging technologies

Emerging technologies present a number of significant challenges for projecting costs. The first is that it is usually appropriate to assign emerging technologies a high learning rate (the approach undertaken by the US DOE) given that new technologies typically display rapid improvements perhaps reflecting the process of discovery or that economies of scale in production can be reasonably anticipated in most manufactured products. The consequence of a high learning rate and low or near zero plant deployment is that the learning algorithm will tend to overestimate the rapidity with which the technology’s costs are reduced.

To prevent this occurrence in the model, without unnecessarily penalising emerging technologies, we introduce a time based constraint on how quickly the new technology can be deployed. The constraint is specifically related to how quickly the technology can double its capacity. For example we might assume that a technology cannot more than double its capacity in a single year. As the technology reaches significant volumes the constraint becomes less relevant because other market forces prevent further rapid deployment.

The second challenge for emerging technologies is that there is often a degree of under-estimation of full scale commercial plant costs whilst the technology is in the concept stage. During development of investment plans and finer scale engineering analysis that occurs as it moves beyond the concept stage, additional costs are found which were overlooked when only higher level information was required. To account for this we add 10 per cent to cost estimates we find in the literature for emerging technologies (over and above any normal engineering contingency factor), as done by the US DOE (the optimism factor).

Based on this approach, the estimated time path of capital costs for our CG technology set is shown in Figure 34 through Figure 39.

Figure 34: Capital cost, non-renewable CG technology, 2020

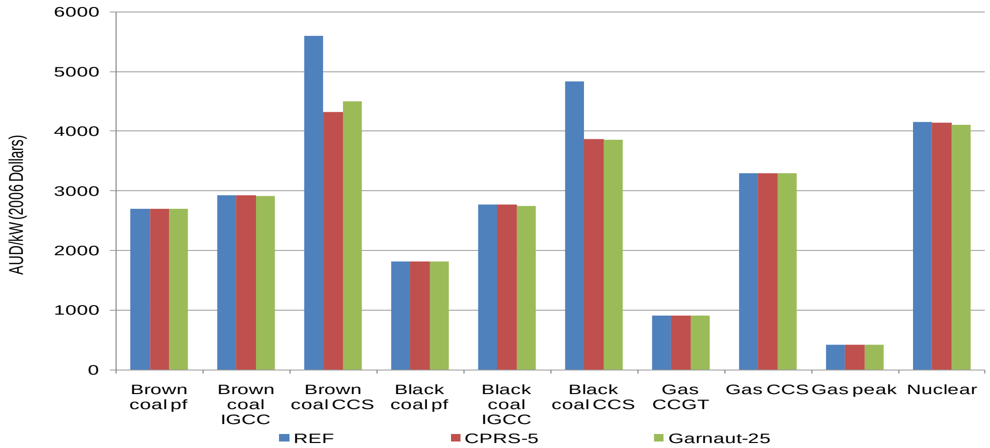


Figure 35: Capital cost, non-renewable CG technology, 2030

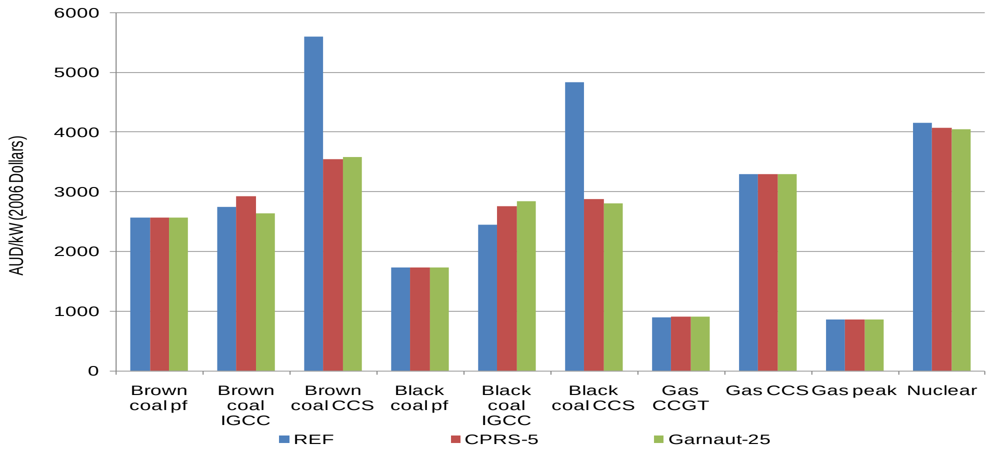


Figure 36: Capital cost, non-renewable CG technology, 2050

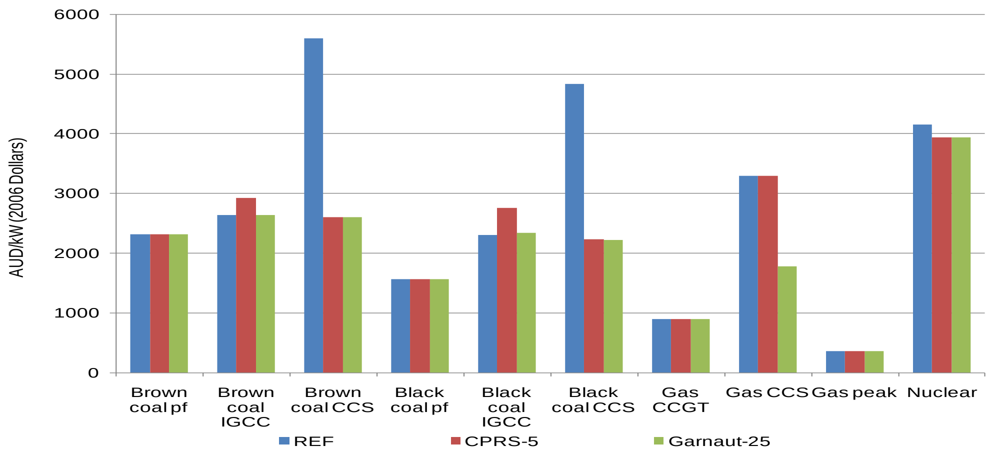


Figure 37: Capital cost, renewable CG technology, 2020

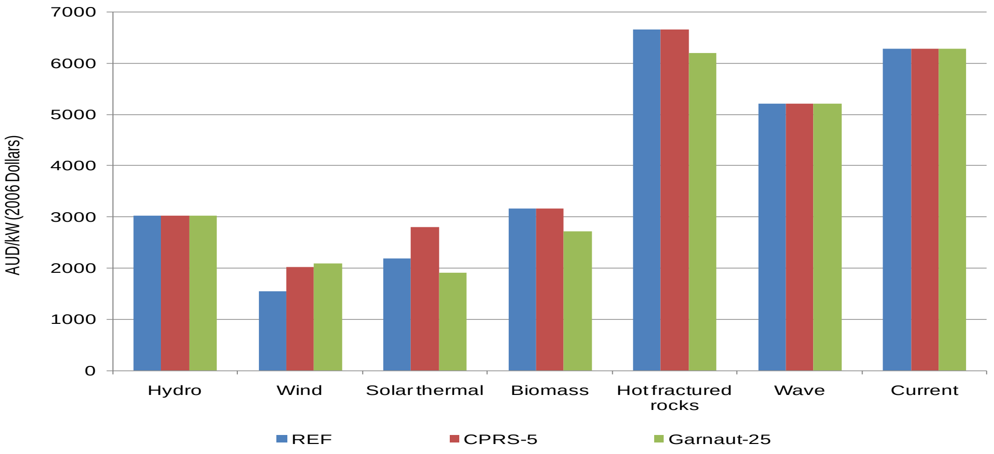


Figure 38: Capital cost, renewable CG technology, 2030

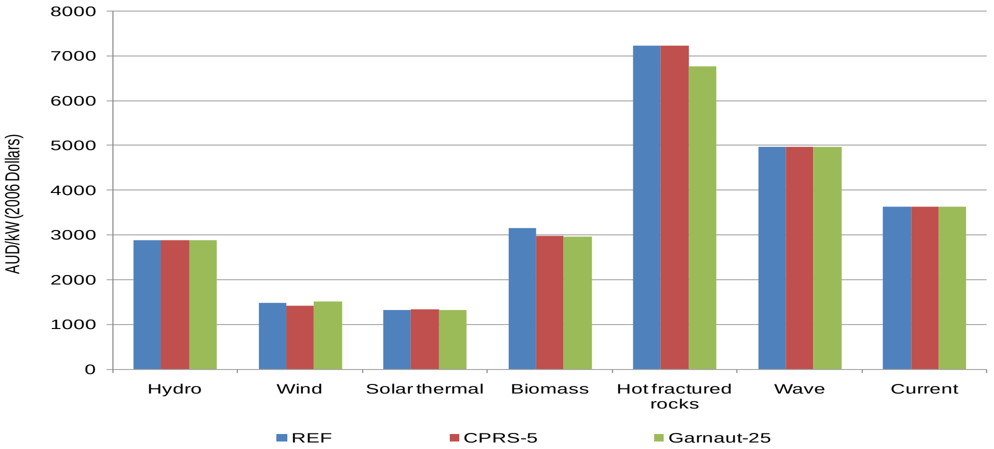
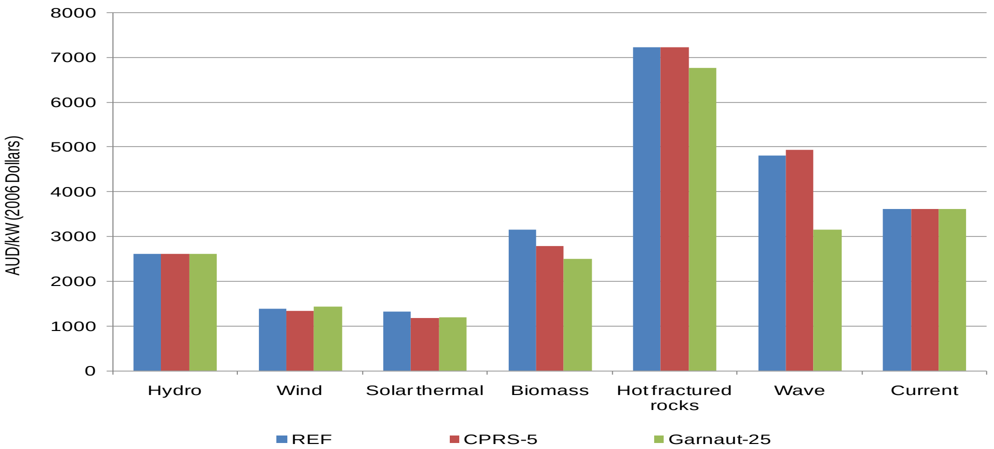
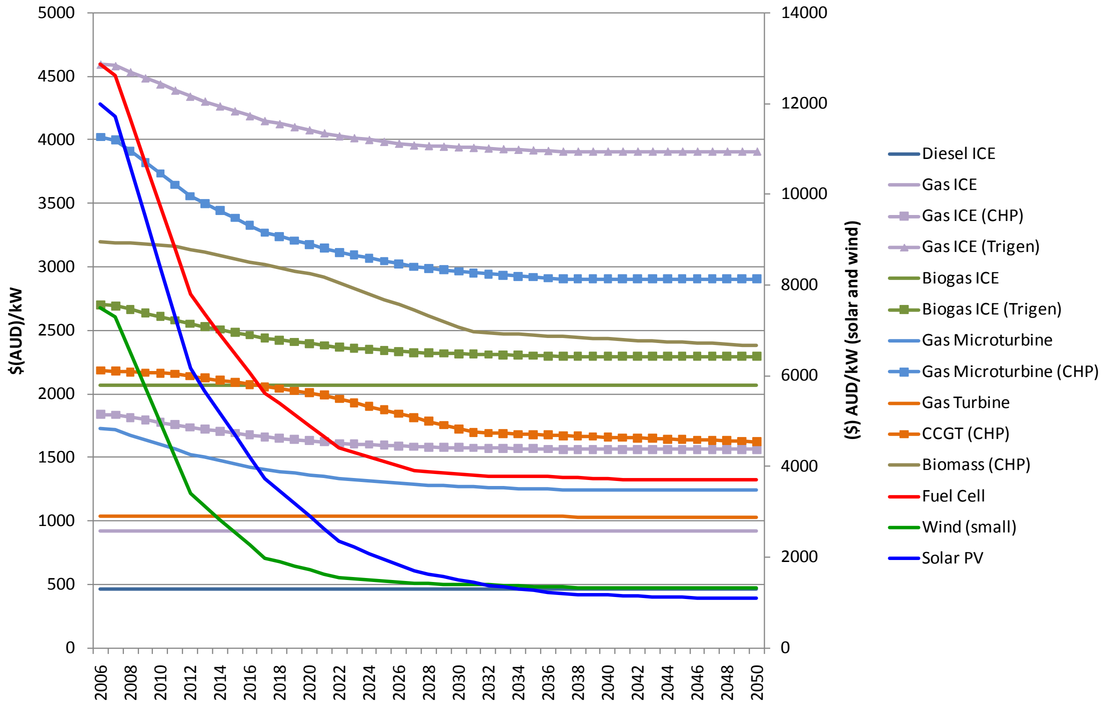


Figure 39: Capital cost, renewable CG technology, 2050



With regard to DG technologies, we employed estimates from a report commissioned by the UK Department of Industry (Energy Savings Trust, 2005). It uses a similar methodology to that described for CG technologies, but does not place limits on the maximum rate of change over a time period or impose lower bounds. The estimated time path of capital costs for our DG technology set is shown in Figure 40.

Figure 40: Estimated time path of installed capital costs for DG technologies



The abbreviations are as follows. ICE: internal combustion engine; CHP: combined heat and power; CCGT: combined cycle gas turbine; PV: photovoltaic.

7.6 Air (dry) cooling

While now past, the occurrence of the worst drought conditions in eastern Australia since Federation heightened debate about the efficient allocation of scarce water resources among competing end-users. This manifested in the widespread use of water restrictions, debate over desalination and stormwater harvesting in major cities, and greater discussions between the States and Commonwealth over administration of the Murray-Darling Basin.

The situation in south-east Queensland forced the State Government to cut the water usage of Tarong North and Swanbank coal-fired power stations by 40 and 20 per cent, respectively. Given that electricity supply in Australia is currently dominated by coal-fired generation (approximately 81 per cent) this has raised the possibility of reduced water supply to power stations in other jurisdictions in the future.

The default is to assume that new base load fossil fuel power stations installed after 2007 will be dry-cooled. We do not assume that existing water-cooled base load fossil fuel power stations will be converted to air-cooled plant.

The effect of air cooling is a subtraction of approximately 2 per cent in thermal efficiency relative to a water cooled plant and an additional $100/kW in installed capital cost.

7.7 Intermittency

Under the National Electricity Code (NEC), an intermittent generator is classified as: “a generating unit whose output is not readily predictable, including, without limitation, solar generators, wave turbine generators, wind turbine generators and hydro-generators without any material storage capability” (NECA, 2002: Chapter 10, p 27A).

An increased penetration of intermittent supply raises several issues in the Australian context. First, it may impair the accuracy of “demand” (scheduled generation) forecasts within the NEM. Second, it has implications for electrical system stability in maintaining power system frequency within defined limits through the dispatch of frequency control ancillary services (NEMMCO, 2003). Related to the above issues, is the increased need for spinning reserve to meet unexpected shortfalls in scheduled generation or increased fluctuations in frequency. To be reliable, such reserve would need to be provided by base-load fossil fuels (most likely gas), or non-intermittent renewable sources (e.g., biomass or hot fractured rocks).

A number of measures are being considered to overcome the problems posed by an increased proportion of intermittent generation in the NEM. The first measure is an improved spatial positioning of the intermittent technologies to reduce the volatility of their combined output. This measure relates to the observation that wind regimes experienced across a large power system are unlikely to be highly correlated (Archer and Jacobsen, 2003). Ideally, wind farms should be spread over different regions and not be permitted to bank up in single regions. Another measure is improvements in weather forecasting to reduce the uncertainty in the dispatch interval. Reliable wind power forecasting has the potential to considerably improve the cost-effectiveness of wind farms connected to the grid by reducing dispatch and commitment errors, reducing the need for spinning reserve (Outhred, 2003). Wind forecasting has now been implemented together with classification of wind power as ‘semi-dispatchable’ so that it can be shutdown remotely if required for system stability.

Recognising the ongoing difficulty in managing intermittency associated with wind and solar energy, the contribution of large intermittent technologies was constrained to not exceed 20 per cent of total system generation capacity by 2020 and then linearly increased to a limit of 30 per cent by 2030 to recognise some improvement in cost effective storage availability. There is some uncertainty about whether this constraint is at the right level. Wind is already at a high penetration in overseas countries (e.g. Denmark and Germany) and South Australia, suggesting the constraint may be too low. The highly probable future development of cost-effective electricity or energy storage could push shares above 30 per cent if is progresses faster than expected.

Within ESM it is assumed that the intermittent constraint applies to centralised and not DG on the presumption that DG will be sufficiently geographically dispersed and at smaller scale than large intermittent power stations.

8. APPENDIX D: DEFAULT POLICY SETTINGS

This section briefly discusses default policy settings that are applied in the reference scenario, and will remain active in the comparative scenarios unless otherwise dictated by the scenario definition.

8.1 Transport

While the comparative scenarios will explore policy development in various areas, the default settings will include policy that have been announced or are currently in place.

City planning and infrastructure investment are implied by the assumptions in the section on transport services demand and fuel efficiency. This section outlines three additional polices being the cost of vehicle registration, excise rates, the New South Wales ethanol mandate and current vehicle emission standards.

8.1.1 Vehicle registration

Most states provide vehicle registration fees on stepped scale with lower fees being for smaller vehicles. Victoria is an exception (based on postcode). Pensioners and other groups also receive rebates. Victoria provides a $50 rebate for hybrid electric vehicles. It is assumed these policy settings remain in place and the cost of registration is maintained in real terms. Trucks and buses registration costs are set nationally and also increase with size.

8.1.2 Excise rates and levies

The aviation excise rate is a levy to cover the costs of air traffic and safety services and is 3.5 cents per litre.

Future excise rates changed twice during the course of this study. The first change which involved extending the rate at which ethanol excise is phased in was included. However, a further change which was announced in the May Federal budget could not be incorporated due to time constraints. The most relevant change for this study is that the planned phase in of excise rates for road biofuels were delayed indefinitely. The effect of this change on the modelling has not been examined. However, in theory it will marginally extend the period under which the road sector is an attractive market for biofuels, all else constant.

Notwithstanding this change the excise system will gradually phase in a system of rates based on groupings of similar levels of energy content across the full range of conventional and alternative fuels. Alternative fuels will be more costly as a result but still discounted relative to conventional fuels. The phase-in period is to 2015. Table 23 and 24 show the effective excise rates for alternative fuels.

It is assumed that the level of excise in 2015 remains constant in nominal terms. As a result, excise rates are declining in real terms.

Table 23: Effective road excise rates for alternative fuels other than ethanol, 2010-2015

Fuel type	Energy content band	1 July 2010	1 July 2011	1 July 2012	1 July 2013	1 July 2014	1 July 2015
Biofuels							
Biodiesel (c/L)	High	0	3.8	7.6	11.4	15.3	19.1
Domestic Ethanol (c/L)	Mid	0	2.5	5.0	7.5	10.0	12.5
Imported Ethanol (c/L)	Mid	38.1	25	21.9	18.8	15.6	12.5
Other alternative fuels							
LPG (c/L)	Mid	Nil	2.5	5.0	7.5	10.0	12.5
LNG (c/L)	Mid	Nil	2.5	5.0	7.5	10.0	12.5
CNG (c/m^3)	Other	Nil	3.8	7.6	11.4	15.2	19.0

Table 24: Effective road excise rates for ethanol, 2010-2020

Rate and grant	From 1 July 2010	From 1 July 2011	From 1 July 2012	From 1 July 2013	From 1 July 2014	From 1 July 2015	From 1 July 2016	From 1 July 2017	From 1 July 2018	From 1 July 2019	From 1 July 2020
Legislated rate for ethanol (and final rate applying to exports)											
Legislated rate	38.143	25	21.9	18.8	15.6	12.5	12.5	12.5	12.5	12.5	12.5
Domestic ethanol – production grant											
Production Grant for Ethanol	38.143	23.75	19.4	15.05	10.6	6.25	5	3.75	2.5	1.25	0
Domestic ethanol – legislative rate less grant											
Legislated rate less grant	0	1.25	2.5	3.75	5	6.25	7.5	8.75	10	11.25	12.5

8.1.3 New South Wales biofuel mandate

Under the *Biofuel (Ethanol Content) Act 2007* which came into effect on 1 October 2007, primary petrol wholesalers will need to ensure that ethanol makes up a minimum of 2 per cent of the total volume of NSW sales. Not all fuels sold will contain ethanol but the consumer has the choice of filling up with E10 petrol (contains a blend of 10 per cent ethanol).

Under the *Biofuel (Ethanol Content) Amendment Act 2009* which came into effect on 1 October 2009, the Amendment Act:

- Renames the original Act to become the *Biofuels Act 2007*
- Increases the volumetric ethanol mandate to 4% from 1 January 2010
- Further increases the ethanol mandate to 6% from 1 July 2011
- Requires all regular grade unleaded petrol to be E10 from 1 July 2012
- Establishes a volumetric biodiesel mandate of 2% (this requirement has been suspended until 1 January 2010)
- Increases the biodiesel mandate to 5% from 1 January 2012
- Amends the definition of primary wholesaler to include diesel as well as petrol
- Applies the volumetric mandates to major retailers (control more than 20 service stations) as well as primary wholesalers
- Provides for sustainability standards for biofuels, and
- Provides for exemptions from the requirement for all unleaded petrol (ULP) to be E10 for marinas and small businesses suffering hardship.

The Amendment Act provides that the implementation dates may be delayed or measures may be wholly or partly suspended under certain circumstances, for example if sufficient feedstock or production of biofuels is not available.

The New South Wales biofuels mandate will be directly applied in the model as a constraint on the minimum use of biofuels in fuel consumed by vehicles in NSW.

8.2 Electricity

8.2.1 Nuclear power

Nuclear power is not supported by the current federal government and is also legislatively prevented from being taken up in most States. The default assumption is to disallow nuclear power as an available technology.

8.2.2 Australian Renewable Energy Target (RET)

The Australian *Renewable Energy (Electricity) Act 2000* introduced the Mandatory Renewable Energy Target (MRET) to achieve 9,500 GWh of renewable energy by 2010 and to maintain that level to 2020.

Amendments to the *Renewable Energy (Electricity) Act 2000* legislated in September 2009 included:

- Increase in and extension of the renewable energy target
  - The target increases from 9,500 GWh to 45,000 GWh by 2020
  - The target is extended from 2020 to 2030.
- Solar Credits (REC Multiplier) – eligible small generation units (small-scale solar PV, wind and hydro electricity systems) can receive Solar Credits
  - Solar credits is a mechanism under the expanded RET scheme which multiplies the number of RECs able to be created for the system
  - Solar Credits applies to eligible systems installed on or after 9 June 2009.

Table 25: Solar credits (REC Multiplier) for eligible small generation units

Installation period	Multiplier
9 June 2009 – 30 June 2010	5x
1 July 2010 – 30 June 2011	5x
1 July 2011 – 30 June 2012	5x
1 July 2012 – 30 June 2013	4x
1 July 2013 – 30 June 2014	3x
1 July 2014 – 30 June 2015	2x

The Commonwealth Parliament passed, on 24 June 2010, legislation to implement the enhanced RET scheme. From 1 January 2011, the existing scheme will be separated into two parts - the Small-scale Renewable Energy Scheme (SRES) and the Large-scale Renewable Energy Target (LRET).

Under the SRES small-scale technologies will receive a fixed price for Renewable Energy Certificates (RECs) set at $40. Eligible small generation units will still receive solar credits under SRES.

Under the LRET, a 41,000 GWh target for 2020 has been set to achieve a level of large-scale renewable electricity generation above what was expected under the existing RET. Table 26 lists the new LRET annual targets (to commence in 2011) for large-scale renewable electricity generation.

Table 26: Large-scale renewable energy target, 2011-2030

Year	Revised targets (GWh)
2011	10,400
2012	12,300
2013	14,200
2014	16,100
2015	18,000
2016	22,600
2017	27,200
2018	31,800
2019	36,400
2020-2030	41,000

Within ESM, we model LRET as a constraint on sent out electricity by ensuring that the amount of centralised renewable generation is not less than the minimum amounts set out in the proposed legislation for each year to 2030. The SRES is modelled as a subsidy available to renewable distributed generation technologies.

8.2.3 Queensland 18 per cent gas target

On 24 May 2000, the Queensland Government announced the *Queensland Energy Policy – A Cleaner Energy Strategy*, with the key objectives of the policy being to diversify its energy mix, facilitate the supply and use of natural gas in Queensland, especially in electricity generation, and reduce growth in greenhouse gas emissions. A key component of the energy policy is the State’s 13 per cent gas scheme, which requires electricity retailers and other liable parties to source at least 13 per cent of their electricity from natural gas-fired generation. The scheme commenced on 1 January 2005 and will remain in place until 31 December 2019.

It should be noted that the Queensland Government recently expanded its gas target, requiring the share of natural gas-fired electricity consumed in Queensland to increase to 18 per cent by 2020. This policy change was included in the modelling in this report.

This scheme is implemented in the model in an approximate manner, requiring the share of natural gas-fired electricity consumed in Queensland to increase to 18 per cent by 2020. This modification reflects evidence that the amount of gas-fired generation was below target in 2005.

8.2.4 NSW Greenhouse Gas Abatement Scheme (GGAS)

In January 2002, the NSW Government released a Benchmarks Position Paper that set the aims and methodology for the Greenhouse Gas Abatement Scheme (GGAS). The scheme came into effect from 1 January 2003. From that time, NSW electricity retailers and some other parties ("benchmark participants") must meet mandatory targets for abating the emission of greenhouse gases from electricity production and use, up until 2012.

The State-wide benchmark is to reduce greenhouse gas emissions to 7.27 tonnes of carbon dioxide equivalent per capita by 2007, which is 5 per cent below the baseline year of 1989-90. The targets for abatement are higher each year from 2003 to 2007, and then the benchmark level must be maintained until 2012.

To reduce the average emissions of greenhouse gases, participants will purchase and surrender abatement certificates to the Independent Pricing and Regulatory Tribunal (IPART). Abatement certificates can be created from the following activities:

- Reduction in the greenhouse intensity of electricity generation
- Activities that result in reduced consumption of electricity ("demand side abatement")
- The capture of carbon from the atmosphere in forests, referred to as CO_2 sequestration, and
- Activities carried out by elective participants that reduce on-site emissions not directly related to electricity consumption.

Similar to RET, GGAS is modelled as a constraint that requires total emissions from NSW electricity generation to be less than or equal to the product of per person emissions and state population.

As mentioned above, currently the benchmark scheme ends in 2012. Rather than extending the scheme beyond 2012, the NSW Government has stated the preference for the introduction of a single national trading scheme. In the modelling of emission reduction scenarios, GGAS is not extended beyond 2012 due to the commencement of emissions trading in 2013.

8.2.5 State Renewable Energy Targets

It is assumed that the state renewable energy targets are replaced by the expanded RET.

8.2.6 Feed-in tariffs

A range of State based feed-in tariffs apply across Australia. Within ESM, the feed-in tariffs are implemented according to the schedules shown in Table 27.

Table 27: Australian State and Territory feed-in tariffs

State/Territory	Start date	Size limits	Rate (c/kWh)	Duration (years)	Type	Cap
VIC	2009	5 kW	60	15	Net	
SA	2008	10 kW	44	20	Net	
ACT	2009	< 10 kW	50.05	20	Gross	
		10-30 kW	40.04			
QLD	2008	10 kW	44	20	Net	
NSW	2010	10 kW	60	7	Gross	Review at 50 MW
WA	2010	5 kW (SWIS) 30 kW (NWIS)	40	10	Net	Review at 10 MW or every 3 years

9. APPENDIX E: MODELLING FRAMEWORK

9.1 Goals of the modelling framework

Prior to commencement of the Sustainable Aviation Fuels Road Map (SAFRM) study CSIRO discussed with the aviation industry the key drivers and issues that would need to be modelled in order to establish the modelling requirements.

The standard outputs required by the study are GHG emissions, aviation demand, and fuel consumption by fuel and original feedstock.

These outputs should ideally be supplied for both Australia and New Zealand on an annual basis. An important consideration is whether it is necessary to model the world aviation market in total. From a fuel supply perspective it was judged that most sustainable biofuel would likely have to be sourced locally. However, countries in Europe may source material from Africa. Some taxes may be imposed by the destination country which affect fuel choice. Overall, it was assumed that the international aviation market did not need to be modelled in detail.

Additional features required are the ability to calculate macroeconomic impacts via measures such as Gross Domestic Product (GDP) and industry output. With these features the model would be able to provide some indication of social impacts in so far as they are related to economic well being.

There is also a need to understand bio-refinery product pathways since each biomass type will be suited to a particular type of refining process and each process will have different costs.

The modelling also needs to be able to measure any energy security benefits such as reduced import dependency of fuel supplies.

Competition for biofuels was also expected to be an issue so the modelling framework needs to be capable of indicating whether biomass energy sources are best utilised in aviation or in other sectors.

9.2 Integrated economic and energy system modelling

An economic framework underpinned by detailed technological representation of alternative fuels and their uses would be capable of addressing all of the issue above. However, there are limits to how much a single model can contain. Tracking the stock of capital and goods and service usage patterns for all relevant industry sectors (e.g. transport, agriculture, forestry) across Australia and New Zealand would make the model too computationally and structurally large to be practical. The solution is to integrate two or more models and solve them iteratively.

In this study we interface a partial equilibrium model of the electricity and transport sectors of Australia and New Zealand with a general equilibrium model of the national economy. A partial equilibrium model is a type of economic model which represents a single market or sector. It seeks to determine the market equilibrium conditions for one sector of the economy (in this case the energy and transport sector) holding all else constant. The main strength of a partial equilibrium model is that because it draws a narrower boundary on linkages with the rest of the economy it can provide a much more detailed representation of real world aspects of the industry such as, the fuels and technology it uses or could use in the future, the stocks of equipment including their age, the types of end users and their various attributes.

The main limitation, as the name suggests, is that partial equilibrium models provide only a partial picture of the total impact of the scenario being explored on the national economy. The alternative is to use a general equilibrium model which models every sector in the economy simultaneously.

The partial equilibrium model that is applied in this study is CSIRO’s Energy Sector Model (ESM) which was designed for analysing transport and electricity technology scenarios in Australia. However, New Zealand was added as an additional region in the model for this study. The general equilibrium model used in this study is MMRF which is a model supplied by Monash University’s Centre of Policy Studies (CoPS). Modelling of the New Zealand economy was outside the scope of this study.

9.3 Energy Sector Model (ESM)

Energy Sector Model (ESM) was co-developed by the Commonwealth Scientific and Industrial Research Organisation (CSIRO) and the Australian Bureau of Agricultural and Resource Economics (ABARE) in 2006. Since that time CSIRO has significantly modified and expanded ESM.

As discussed ESM is a partial equilibrium (bottom-up) model of the electricity and transport sectors. The model has a robust economic decision making framework around the cost of alternative fuels and vehicles as well as detailed fuel and vehicle technical performance characterisation such as fuel efficiencies and emission factors by transport mode, vehicle type, engine type and age. It also has a detailed representation of the electricity generation sector. Competition for resources between the two sectors and relative costs of abatement are resolved simultaneously within the model.

ESM has been applied in scenario analysis of transport energy futures including: alternative emission targets (e.g., CSIRO, 2008; Graham et al., 2008; Reedman and Graham, 2009), alternative carbon price regimes (e.g., CSIRO and ABARE, 2006; Garnaut, 2008; Commonwealth of Australia, 2008) and peak oil scenarios (Graham and Reedman, 2010).

9.3.1 ESM model equations and structure

ESM is solved as a linear program where the objective function is to maximise welfare which is the discounted sum of consumer and producer surplus over time. The sum of consumer and producer surplus is calculated as the integral of the demand functions minus the integral of the supply functions which are both disaggregated into many components across the electricity and transport markets. The objective function is maximised subject to constraints that control for the physical limitations of fuel resources, the stock of electricity plant and vehicles, greenhouse gas emissions as prescribed by legislation, and various market and technology specific constraints such as the need to maintain a minimum number of peaking plants to meet rapid changes in the electricity load. The main components of ESM include:

- Coverage of all States and the Northern Territory (Australian Capital Territory is modelled as part of NSW) and New Zealand

- Nine road transport modes: light, medium and heavy passenger cars; light, medium and heavy commercial vehicles; rigid trucks; articulated trucks and buses

- Five engine types: internal combustion; hybrid electric/internal combustion; hybrid plug-in electric/internal combustion; fully electric and fuel cell

- Thirteen road transport fuels: petrol; diesel; liquefied petroleum gas (LPG); natural gas (compressed (CNG) or liquefied (LNG)); petrol with 10 per cent ethanol blend; diesel with 20 per cent biodiesel blend; ethanol and biodiesel at high concentrations; biomass to liquids diesel; gas to liquids diesel; coal to liquids diesel with upstream CO_2 capture; hydrogen (from renewables) and electricity

- Seventeen centralised generation (CG) electricity plant types: black coal pulverised fuel; black coal integrated gasification combined cycle (IGCC); black coal with CO_2 capture and sequestration (CCS) (90 per cent capture rate); brown coal pulverised fuel; brown coal IGCC; brown coal with CCS (90 per cent capture rate); natural gas combined cycle; natural gas peaking plant; natural gas with CCS (90 per cent capture rate); biomass; hydro; wind; solar thermal; hot fractured rocks (geothermal), wave, ocean current and nuclear

- Seventeen distributed generation (DG) electricity plant types: internal combustion diesel; internal combustion gas; gas turbine; gas micro turbine; gas combined heat and power (CHP); gas micro turbine CHP; gas micro turbine with combined cooling, heat and power (CCHP); gas reciprocating engine CCHP; gas reciprocating engine CHP; solar photovoltaic; biomass CHP; biomass steam; biogas reciprocating engine; wind; natural gas fuel cell and hydrogen fuel cell

- Trade in electricity between National Electricity Market (NEM) regions

- All vehicles and centralised electricity generation plants are assigned a vintage based on when they were first purchased or installed in annual increments

- Four electricity end use sectors: industrial; commercial & services; rural and residential

- Time is represented in annual frequency (2006, 2007, …, 2050).

All technologies are assessed on the basis of their relative costs subject to constraints such as the turnover of capital stock, existing or new policies such as subsidies and taxes. The model aims to mirror real world investment decisions by simultaneously taking into account:

- The requirement to earn a reasonable return on investment over the life of a plant or vehicle

- That the actions of one investor or user affects the financial viability of all other investors or users simultaneously and dynamically

- That consumers react to price signals (price elastic demand)
- That the consumption of energy resources by one user affects the price and availability of that resource for other users, and the overall cost of energy and transport services, and
- Energy and transport market policies and regulations.

The model evaluates uptake on the basis of cost competitiveness but at the same time takes into account the key constraints with regard to the operation of energy and transport markets, current excise and mandated fuel mix legislation, GHG emission limits, existing plant and vehicle stock in each State, and lead times in the availability of new vehicles or plant. It does not take into account issues such as community acceptance of technologies but these can be controlled by imposing various scenario assumptions which constrain the solution to user provided limits.

9.3.2 ESM model outputs

For given time paths of the exogenous (or input) variables that define the economic environment, ESM determines the time paths of the endogenous (output) variables. Key output variables include:

- Fuel, engine, and electricity generation technology uptake
- Fuel consumption
- Cost of transport services (for example, cents per kilometre)
- Price of fuels
- GHG and criteria air pollutant emissions
- Wholesale and retail electricity prices
- Demand for transport and electricity services.

Some of these outputs can also be defined as fixed inputs depending upon the design of the scenario.

The endogenous variables are determined using demand and production relationships, commodity balance definitions and assumptions of competitive markets at each time step for fuels, electricity and transport services, and over time for assets such as vehicles and plant capacities. With respect to asset markets, the assumption is used that market participants know future outcomes of their joint actions over the entire time horizon of the model.

9.3.3 Limitations of ESM

The suggested modelling approach suffers from two major limitations which are discussed.

The first is that it includes many assumptions for parameters that are in reality uncertain and in some cases evolving rapidly. Parameters of most concern include for example possible breakthroughs in so called “second generation” biofuel production technologies and the unknown quality and cost of future offerings of fully and partially electrified vehicles. These limitations are only partially addressed by scenario or sensitivity analysis.

A second major limitation is that ESM only takes account of cost as the major determining factor in technology and fuel uptake. Therefore, it cannot capture the behaviour of so-called “fast adopters” who take up new technology before it has reached a competitive price point. For example, most consumers of hybrid electric vehicles today could be considered “fast adopters”. Their purchase cannot be justified on economic grounds since the additional cost of such vehicles is not offset by fuel savings in any reasonable period of time (relative to the cost of borrowing). Nevertheless, hybrid electric vehicles are purchased and such purchasers may be motivated by a variety of factors including a strong interest in new technology, the desire to reduce emissions or status. As a result of this limitation, ESM’s projections of the initial technology uptake for new technologies could be considered conservative.

However, another factor which ESM overlooks is community acceptance and this limitation might lead ESM to overestimate the rate of uptake of some fuels and technologies. For example, greater use of gaseous fuels such as LPG and the introduction of electricity as a transport fuel might be resisted by the Australian community which has predominantly used liquid fuels for transport over the past century. By design, ESM only considers whether the choice is economically viable.

As a result of these limitations, the technology and fuel uptake projections that will be estimated need to be interpreted with caution. In reality, consumers will consider a variety factors in fuel and vehicle purchasing decisions. However, it is the view of the authors that the projections are nonetheless instructive in that they indicate the point at which the various technology or fuel options should become widely attractive to all consumers.

9.4 MMRF

MMRF is a detailed, dynamic, multi-sectoral, multi-regional model of Australia. The current version of the model distinguishes 58 industries, 63 products, 8 states/territories and 56 sub-state regions. There are five types of agents in the model: industries, capital creators, households, governments, and foreigners. For each sector in each region there is an associated capital creator. The sectors each produce a single commodity and the capital creators each produce units of capital that are specific to the associated sector. Each region in MMRF has a single household and a regional government. There is also a federal government. Finally, there are foreigners, whose behaviour is summarised by export demand curves for the products of each region and by supply curves for international imports to each region.

MMRF determines regional supplies and demands of commodities through optimising behaviour of agents in competitive markets. Optimising behaviour also determines industry demands for labour and capital. Labour supply at the national level in the long run is determined by demographic factors, while national capital supply responds to rates of return. Labour and capital can cross regional borders so that each region's endowment of productive resources reflects regional employment opportunities and relative rates of return.

The specifications of supply and demand behaviour co-ordinated through market clearing equations comprise the general equilibrium (GE) core of the model. There are four blocks of equations in addition to the core. The first two describe regional and federal government finances, and the operation of regional labour markets. The third block contains dynamic equations that describe physical capital accumulation and lagged adjustment processes in the national labour market. The fourth block, which is of direct relevance to this study, contains enhancements for the study of greenhouse gas issues.

9.4.1 Linking ESM and MMRF outputs

MMRF projects future demand for transport services based on the reference case that has been developed and any policies or scenarios imposed. ESM fixes the level of aviation and other transport sector demand based on these MMRF projections.

ESM provides data for changes in fuel and emissions by region consistent with MMRF demand projections. The transitions to bio-derived diesel, jet fuel and ethanol blended petrol are modelled in MMRF as changes to the emission intensity of these fuels. In modelling terms this means emissions from road and aviation transport are made exogenous and shocked to ESM settings via endogenous shifts in technological change variables for emissions per unit of fuel used. In the road sector, changes in the mix of gasoline, diesel and LPG, are modelled via demand-shift (technological change) variables in industry usage of each fuel type which are made endogenous.

These fuel and emission inputs to MMRF lead to changes in costs and consequently changes in transport services demand. Typically another iteration of the linking process is completed to take account of this. Multiple iterations are avoided as they can be cumbersome since converting data from one model to the other is not straight forward due to differences in aggregation and format of variables.

9.5 Approach to modelling the scenarios with ESM-MMRF

Given the difficulty in linking the two models only the reference case and CPRS-5 carbon price scenario were modelled using both the ESM and MMRF models. The reference case establishes demand under current trends and policy settings. The CPRS-5 carbon price scenario significantly impacts upon the whole economy and therefore warrants additional macroeconomic modelling to take account of the carbon price impacts across all industries. The remaining scenarios were only modelled using ESM as the macroeconomic impacts were judged to be less significant and more confined to the aviation and transport sector (Table 28). As such, the reference case aviation demand and economic conditions as projected via MMRF were assumed to apply in those scenarios.

Table 28: Approaches used to model the reference case and scenarios

	Models applied	
Reference case	ESM	MMRF
CPRS-5 carbon price	ESM	MMRF
Low cost scenario	ESM	✕
Level playing field scenario	ESM	✕
Road map scenario	ESM	✕

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