9. Decarbonising energy supply

9.1. Introduction

In Chapter 6 we describe a Medium Efficiency pattern of demand for energy in 2040 in which total demand for stationary energy is 25% higher than it was in 2001. As population is projected by the Australian Bureau of Statistics to grow by over 29% to 25 million, this represents a slight reduction in per capita energy demand. To achieve this result, we have modelled an extensive, but quite achievable uptake of energy efficiency technologies and practices across all sectors of the economy. In the absence of policies to support the wide adoption of cost effective energy efficiency, we project an increase in energy demand from 2001 of 57%. Our modelling of demand by itself assumes no change in the mix of fuels within each individual economic sector modelled; the only source of fuel mix change is the shift in relative sizes of the various economic sectors. The consequence is that the fuel mix does not differ greatly from that in 2001; coal and natural gas take slightly smaller shares of the total and petroleum products a slightly larger share. The analysis of demand makes no assumptions about the mix of generation technologies and fuels used to supply electricity.

The overall effect is that an increase in demand for energy of 25%, with no change in fuel mix in electricity generation, will cause greenhouse gas emissions also to increase by about 25%. As discussed in Chapter 2, at the assumed level of fossil fuel prices in 2040, we estimate, on the basis of marginal abatement costs, that it is more cost effective to achieve further emission reductions by adopting alternative low emission sources of energy supply, than by further reducing demand through increased energy efficiency.

Four distinct measures have been modelled and are discussed in the remaining sections of this Chapter:

1) introduction of solar thermal pre-heating into the supply of steam and hot water in industrial and commercial applications (widespread use of solar thermal technology is already factored into the Residential sector);
2) substitution of natural gas for coal in almost all non-metallurgical applications;
3) widespread adoption of cogeneration, as described in Section 7.6; and
4) a change in the mix of electricity generation technologies, away from coal and towards natural gas and renewable energy.

Changing the electricity generation mix is by far the most important of these and is discussed at greatest length. Consideration was given to using biomass as an additional substitute energy source in Steps (1) and (2) above, but it was judged that it would be more cost effective to use limited biomass resources for electricity generation and, if further resources were available, for the production of transport fuels.

It is important to appreciate that all the technologies deployed in Steps (1) to (4) are already commercially well established and in most cases are widely used throughout the energy system today. In most cases, their current market share is limited by relative costs and prices, as ultimately determined by the current underlying prices of coal and natural gas. It can be expected that, with no change in policy settings, all will continue to gain market share, as fossil fuel prices move gradually upward. Hence the full

Baseline scenario, where demand for energy is at the Baseline level described in Chapter 5, will also include a higher penetration than in 2001 of all the technologies considered in this Chapter.

We have therefore modelled two different levels of energy demand and associated levels of uptake of fuel substitution Steps (1), (2) and (3): one based on the Baseline energy demand of Chapter 5 and one based on the Medium Efficiency demand of Chapter 6. In addition, four different electricity supply system technology mixes were modelled, two for each energy demand/direct fuel substitution set. A complete definition of the four scenarios and of their associated energy use and emissions are given in the next Chapter. In this Chapter we describe the modelling assumptions lying behind each combination.

9.2. Solar thermal pre-heating

Solar thermal devices available today are capable of delivering energy, carried in the form of steam or other working fluids, at temperatures well in excess of 100^oC. Technically, they would be able to meet much of the industrial and commercial demand for steam and hot water. However, to achieve the higher temperatures more sophisticated equipment, such as evacuated tube collectors, is needed. The technology is most cost effective when used as a pre-heater, to raise the temperature of water from the environmental ambient to a temperature somewhat below 100^oC, as commercial solar water heaters do. Moreover, as explained in Chapter 8, establishments with a substantial demand for steam and hot water are ideally suited to host cogeneration plants, but this requires the use of combustion fuels, such as natural gas, which can achieve much higher temperatures than even the most sophisticated solar collector. Hence there is a partial trade-off between use of solar thermal heat and use of cogeneration.

With detailed information about an individual industrial site, it would be possible to determine a mix of solar thermal and cogeneration which minimizes total greenhouse gas emissions. Such optimisation is of course impossible in a high level national study. We have therefore used our professional judgment to estimate the substitution of solar thermal energy, in the form of pre-heaters in boiler systems in all end use sectors of the economy except Iron and Steel, where excess quantities of coal by-product gases are used to produce steam and generate electricity at integrated steel works, and sugar, where there is an excess of biomass fuel. We assume greater use of solar thermal in the Food, Beverages and Tobacco, and All Other Manufacturing sectors, because it is better suited to the smaller scale and lower steam temperature requirements that typify these sectors. A modest substitution of solar water heating for natural gas in the Commercial/Services sector is also assumed.

In the Medium Efficiency demand case a total of 51 PJ of boiler fuel is displaced in manufacturing and mining and a further 3 PJ in the Commercial/Services sector. In the Baseline demand case the quantity of boiler fuel displaced is 27 PJ in total.

Not included here is the extensive adoption of solar water heating in the Residential sector, which, for reasons of methodological simplicity, was modelled jointly with energy efficiency in the Residential sector, as described in Chapter 6. In the Medium Efficiency case residential solar hot water displaces 35 PJ of electricity, 32 PJ of natural gas and 3 PJ of LPG, a total of 70 PJ, while in the Baseline case 35 PJ are displaced.

9.3. Substitution of gas for coal and petroleum

Most sectors of the economy currently use limited quantities of coal as a boiler and kiln fuel. Ever since natural gas first became available in Australia, nearly thirty five years ago in some States, it has steadily been replacing both coal and petroleum products as the direct combustion fuel of choice in all areas of stationary energy use. It could readily substitute for all remaining non-metallurgical uses of coal, except the few without access to gas supplies. Gas is generally a technically superior alternative, but costs more. We expect that this substitution trend will continue, even in the absence of new policies to encourage reduced greenhouse gas emissions.

In the Medium Efficiency demand case, coal is almost completely displaced by natural gas in these applications. The greatest effect is in the Non-ferrous Metals sector, where currently two alumina plants and one nickel plant, among others, use very large quantities of coal as boiler fuel, and cement, where three of the four major plants currently use coal. We assume that where coal is used, in the form of coke, in metallurgical applications, there will be no fuel substitution. Coal by-products continuer to be used as boiler fuel in the Iron and Steel sector, for the reason given above.[1]

In total, 130 PJ of coal demand in the Medium Efficiency demand case are displaced. The use of natural gas instead of coal will lead to increased energy efficiency, because of the superior technical characteristics of gas. However, we have made no explicit allowance for this effect, which is a conservative element in our assumptions.

Petroleum products, mainly in the form of LPG and fuel oil, are also used in boilers, kilns and space heating installations. By far the largest user is the alumina plant at Gove, which will almost certainly switch from fuel oil to natural gas within the next few years. We assume some modest additional substitution in other sectors. However, much current use of LPG occurs where a gaseous fuel is required for technical reasons and natural gas is not available. While it is certain that by 2040 the natural gas distribution network will be more extensive than it is today, it is also certain that some locations will remain without a piped gas supply, and will continue to rely on LPG. We also assume continued use in the Basic Chemicals sector of petroleum in the form of “waste” by-products from the various chemical processes that use petroleum product feedstocks. Petroleum products continue to be the main source of energy in the Mining, Construction and Agriculture, Forestry and Fishing sectors. Outside these sectors, the assumed substitutions reduce demand for petroleum products by 48 PJ, from 115 to 67 PJ (of which 24 PJ are in Chemicals).

In the Baseline case there is also significant displacement of coal and petroleum by natural gas, totalling 96 PJ of coal and 32 PJ of petroleum products, but this is from a somewhat higher base consumption of coal and petroleum, since all fuels are used less efficiently in this case than in the Medium Efficiency case. In total, 61 PJ more coal and 36 PJ more petroleum are used in boiler and kiln processes in the Baseline case than in the Medium Efficiency demand case.

[1] However, there is potential to use charcoal from biomass as an alternative to coke (see Section 11.2).

9.4. Greater use of cogeneration

ABARE reports that cogeneration plants supplied a total of 25 PJ (about 7 TWh) of electricity in 2001. This represents nearly 4% of total final demand for electricity. It excludes electricity generated at several new, large CCGT based cogeneration plants located at alumina, chemical and paper plants in several States, which both ABARE and the ESAA report as part of the electricity generation sector.

As explained in Section 2.1, in our model we subtract an estimate of the additional energy consumption associated with the 25 PJ of cogenerated electricity and re-allocate it to the electricity sector. This means that projected demand for thermal energy in the various host sectors represents the demand directly associated with the industrial process, and does not include any forward projection of demand from existing cogeneration plants.

In very broad terms, the capacity to support cogeneration at a site is proportional to the host steam load at the site. Consequently, reducing steam loads by increasing energy efficiency reduces potential cogeneration capacity. Substituting use of natural gas or other fuel with solar thermal collectors has a similar effect, as explained above. The logic of our energy system model therefore calls for cogeneration to be introduced into the supply mix following these fuel substitution steps.

In the Medium Efficiency case we introduce cogeneration into all sectors where there is a significant demand for energy in boiler systems. We assume that the following proportions of boiler fuel demand in each sector are suitable to host cogeneration:

Sugar	100%
Iron and Steel, Non-ferrous Metals	90%
Pulp and Paper	80%
All other industry sectors	50%

There is also significant potential for cogeneration in the Commercial/Services sector, in association with both heating and cooling loads in buildings. With heating, a gas engine or small gas turbine is used to generate electricity and the waste heat supplies the space heating demand. With cooling, the waste heat is instead used to drive an absorption chiller, which would replace an electric motor driven compressor chiller, with associated savings in electricity demand. Both types of installation were modelled, assuming that cogeneration installations could supply 50% of the heating and 50% of the cooling demand from the sector.

The results showed that while cogeneration supplying space heating reduced total greenhouse gas emissions, cogeneration with absorption chillers supplying cooling increased emissions. This is because, on the assumptions in our model, the additional gas consumption required for the absorption chillers exceeds the quantity of gas needed to generate the displaced electricity (previously driving a compressor chiller) in a stand-alone gas fired power station. Accordingly, we have not included gas cogeneration with space cooling in our Clean Energy scenario[2].

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[2] However, other gas-based solutions show potential for lower emissions. For example, Hornsby Library is a site for CSIRO's trial micro-cogeneration system with its waste heat being used to regenerate a desiccant wheel which is then used for cooling.

The result of the analysis is that total cogenerated electricity in 2040 is 132 PJ (37 TWh), as shown, by fuel source, in Table 9.1 below.

In the Baseline case we make the simplifying assumption that uptake of cogeneration in the energy intensive manufacturing sectors (including sugar milling) where the economics are most favourable, is the same as in the Medium Efficiency case, but there is no additional cogeneration in other economic sectors. However, with a lower level of energy efficiency, host thermal loads are larger than in the Medium Efficiency case, so that for a given level of uptake of cogeneration, in terms of share of potential host thermal loads, there is actually more cogeneration capacity and more cogenerated electricity. Hence total cogeneration in the Baseline is only 19% less than in the Medium Efficiency case.

Table 9.1: Quantities of cogenerated electricity under the two demand scenarios

Fuel source	**Cogenerated electricity (PJ)**	
	Medium Efficiency	**Baseline**
Coal (including blast furnace gas)	2	19
Biomass	21	22
Petroleum (including petrochemical “waste” gases)	3	7
Natural gas	106	61
Totals	133	108

The final step in the analysis is to introduce cogenerated electricity into the total electricity system supply mix, that is described below. This we do by assuming that biomass cogeneration displaces electricity that would otherwise be generated at stand alone biomass power plants, on the basis of our modelled supply mix, while natural gas, coal and petroleum fuelled cogeneration displaces electricity from gas power plants.

9.5. Decarbonising the electricity supply mix

In 2001 energy which users obtained by direct combustion of fuels and collection of solar heat provided 69% of the energy supplied to users (including use in the production and processing of fuels other than electricity), but accounted for only 31% of greenhouse gas emissions from stationary energy. Electricity generation accounted for the other 69% of emissions.

In our Baseline demand case for 2040, the requirement for energy supplied by combustion and solar heat rises 42% to 2,069 PJ, while emissions increase by 37%. In the Medium Efficiency case, with additional substitution of low emission fuels as described above, the increase in energy supplied is limited to 22%, relative to 2001, and the increase in emissions to 12%.

Electricity requirements increase faster than requirements for other fuels in the Baseline case, but not in the Medium Efficiency case. In 2040 they are 69% higher than in 2001 in the Baseline case and 24% higher in the Medium Efficiency case. In Chapters 7 and 8 we described and reviewed the different technologies which might be used to meet these requirements. In this Section we describe how the electricity supply system has been modelled in the different scenarios constructed for this study.

In each case the system consists of a mix of different types of generating plant. The types of generation fuel and technology included are shown in Table 9.2, which also shows the key technical characteristics of each type.

For the coal and biomass technologies, thermal efficiency has been assumed to improve significantly, relative to current generating plant using those fuels. The effect will be an appreciable reduction in fuel use and, in the case of coal, greenhouse gas emissions, to generate a given quantity of electricity. For combined cycle gas turbine (CCGT) natural gas plant, a lesser improvement has been assumed, for two reasons: firstly, in order to err on the side of conservatism, so far as the characteristics of "cleaner" technologies are concerned and, secondly, because much of the CCGT plant will be required to operate in load following mode (or be substituted by less efficient open cycle plant), with consequently reduced thermal efficiency.

Table 9.2: Characteristics of different types of electricity generation

Generation fuel/technology	Generation efficiency (fuel to electricity)[a]	Own use of electricity (% of generated)	Transmission and distribution losses (% of sent out)
Black coal (conventional)	45%	5%	8%
Brown coal (conventional)	35%	8%	8%
Biomass	40%	5%	8%
Petroleum	45%	1%	8%
Natural gas (CCGT)	50%	1%	8%
Photovoltaics	*na*	*na*	2%
Hydro	*na*	*na*	8%
Wind	*na*	*na*	8%
Cogeneration	77%[b]	*na*	2%

Notes:
a. Thermal efficiency calculated according to Gross Calorific Value (see Glossary).
b. Except sugar, 140%, because of assumed concurrent improvements in overall efficiency of bagasse utilisation.

Own use of electricity is much the same as in current plant of the same technology type.

Transmission and distribution losses for the centralised generation technologies, including wind and biomass, are much the same as in the present transmission and distribution systems. Only cogeneration and photovoltaics are assumed to be distributed generation technologies in this sense, and allocated much lower losses. It may be argued that biomass and wind should also be treated as distributed technologies, with lower transmission and distribution losses. This would be true with low rates of penetration of these technologies, but, at higher rates of penetration, the electricity supplied by these technologies would exceed demand in the immediate locality. Much of it would require transmission to major urban centres of demand, thus taking on the characteristics of centralised generation.

It will be noted that the list of technologies includes neither coal with CO_2 capture and geosequestration, nor coal based IGCC; the coal technologies included are conventional thermal generation, with improved efficiency performance. These "low emission" coal technologies do not form part of our various low emission electricity supply system scenarios because, as described in Chapters 7 and 8, both are more costly incremental sources of electricity supply system greenhouse abatement than wind or biomass, up to the level that the latter are included in the various electricity supply system plant mixes modelled for this study (see below). (Incremental abatement is measured in terms of marginal dollars per tonne of marginal abatement relative to conventional coal, the lowest cost source of electricity.)

Baseline scenario (Scenario 1)

Our Baseline scenario consists of energy demand at the Baseline level, which includes 1,129 PJ (314 TWh) of electricity, direct fuel substitution at the level described earlier in this Chapter, and 108 PJ of electricity supplied by cogeneration. The mix of generating plant that supplies the remainder of the electricity demand is our estimate of that which will occur in the absence of further policy measures to limit greenhouse gas emissions from stationary energy.

The last few years have seen the beginning of a shift away from coal and towards natural gas for electricity generation. In common with most other observers, we expect this trend to continue, with current policy settings (including anticipated further changes to energy markets). For example, ABARE's projection for 2019-20 has coal's share of electricity generation falling from the current level of over 80% to about 71%. Natural gas makes up most of the difference, but there are also increases in biomass, hydro and wind. Our 2040 Baseline scenario is very similar, with coal having a share of 67%, natural gas (including cogeneration) 16%, and biomass 8%.

Table 9.3 shows the energy generation and corresponding approximate capacity for Scenario 1, and also Scenario 2 (see below) and compares them with actual figures for 2001. All these figures are in terms of electricity generated, rather than electricity supplied, and include electricity lost in transmission and distribution and electricity used at power stations. Note that the available data do not allow capacity corresponding to the 25 PJ of cogenerated electricity reported by ABARE for 2001 to be estimated. For 2040, cogeneration is calculated in relation to host thermal loads, without any assumptions about hours of operation, so calculating capacity has little meaning.

Clean Energy scenario (Scenario 2)

Our principal Clean Energy scenario is one in which greenhouse emissions from stationary energy in 2040 are 50% of their level in 2001. Significant reductions in emissions below the level of Scenario 1 are achieved by increased energy use efficiency, as specified by the Medium Efficiency demand case, and associated adoption of solar thermal pre-heating, increased substitution of natural gas for coal in direct combustion, and widespread uptake of cogeneration, as described in Sections 9.2, 9.3 and 9.4. In our model of the Australian energy system, further reductions in emissions are achieved by replacing coal as a fuel for electricity generation, using what we have termed a qualitative optimisation approach. The electricity supply system includes 133 PJ (37 TWh) from cogeneration. To construct the remainder of the supply mix, the following steps were taken.

Firstly, wind energy, a relatively low cost, zero emission technology, was adopted up to the point where it starts to require significant back-up generation (from gas turbine plant) in order to achieve acceptable levels of availability, having regards to the diversity available through differences in prevailing wind conditions at any given time across the extensive areas covered by the two major Australian grids (eastern and south west). As described in Chapter 7, we estimate this level to be 20% of total generation and we assess that there are sufficient suitable sites in Australia to be able to supply this level of wind generation (182 PJ or 51 TWh per year) at the costs given in Chapter 7.

Secondly, hydro generation was increased to about 10% above its current level (all four scenarios have the same level of hydro) and a small quantity of petroleum fuelled generation was retained (again, as in all four scenarios), for use in remote and off-grid locations.

Thirdly, photovoltaic generation was adopted to a level of 4.5% of grid generation (38 PJ or 11 TWh per year). Although more expensive on a purely energy basis than the other generation technologies, photovoltaic generation has the great advantage of producing all its electricity during the day and producing maximum output on bright sunny days. Consequently, almost all the output from photovoltaic installation occurs at times of intermediate and peak load, when wholesale electricity prices are considerably above their average level. Added to the fact that most of the output of building integrated photovoltaics can be used in the immediate vicinity of the installations, with consequent large savings in transmission and distribution costs, these conditions make a modest level of photovoltaic generation cost competitive with the other low emission generation technologies.

Finally, the remaining demand for electricity was supplied by a mix of biomass, natural gas and coal. The mix was adjusted to achieve the overall result of a 50% emission reduction. A significant proportion of gas fired generation was required because of its superior technical ability to follow variations in load so as to supply intermediate and peak demand. It was found that this requirement had the effect of constraining coal fired capacity to a relatively small proportion of total generation. Increasing coal (high emission) would have meant increasing biomass (zero emission) also, leaving insufficient capacity of medium emission natural gas generation.

The supply mix adopted for Scenario 2, shown in Figure 9.1, has 73 PJ (20 TWh) supplied by coal fired power stations, which is equivalent to retiring the vast majority of coal-fired power stations, retaining in 2040 only the three Queensland coal-fired power stations that were commissioned in 2000-2003, and adding no new stations from now on.

More details of this Scenario are shown in Table 9.3 and also Figure 9.1.

Other low emission scenarios

For illustrative purposes, two other low emission scenarios were also constructed.

Scenario 3 is identical with Scenario 2, except that coal fired generation is reduced to zero, with the extra generation coming from natural gas and biomass. This results in a further reduction in emissions. Scenario 4 is a low emission scenario with the higher, Baseline level of energy demand, as in Scenario 1. Meeting the higher demand for electricity requires significantly more generating capacity, and is much harder to achieve, in terms of both available energy resources, such as natural gas, biomass and wind, and in terms of cost.

Figure 9.2 compares all four Scenarios with each other and with 2001.

Table 9.3: Electricity generation[g] and approximate capacity by fuel source, 2001 and 2040 Scenarios 1 and 2

Generation technology/fuel	Generation (PJ[c])			Approximate capacity (GW)		
	2001	2040		2001[a]	2040 [b]	
		Scenario 1	Scenario 2		Scenario 1	Scenario 2
Black coal	414.9	625	84	22.0[e]	25	3.3
Brown coal	190.6	220	0	7.2	0	0
Natural gas (excl. cogeneration)	76.0[f]	124	154	6.6[d, f]	8	10
Petroleum	6.4	12	9	1.1	1.3	1
Hydro	60.4	68	68	7.7	9	9
Biomass (excl. cogeneration)	2.5	78	245	0.55	5.4	17
Wind	1	25	182	<0.1	2.6	19
Direct solar	<0.1	6	38	<0.01	1.2	7.5
Cogeneration (gas + biomass)	24.6 [f]	110	135	*na*	*na*	*na*
TOTAL	776.4	1,267	916	*na*	*na*	*na*

Notes:

a. Approximate capacities for 2001 based mainly on ESAA (2003), Tables 2.1, 2.3 and 2.4.
b. Approximate capacities for 2040 calculated by assuming the following average capacity factors. black coal 0.8; natural gas combined cycle 0.75, natural gas peak-load turbines 0.1; biomass 0.7, wind 0.3, direct solar 0.6. Excludes additional peak-load backup for wind.
c. 1 TWh = 3.6 PJ
d. Natural gas capacity in 2001 was about 2 GW steam, 1.5 GW combined cycle, 2.5 GW gas turbines (gas fuel) and 0.6 GW gas turbines (dual fuel, gas & oil).
e. Includes 1.9 GW dual fuel (black coal + gas).
f. Large CCGT cogeneration plants are included under gas fired generation, not under cogeneration, in 2001 data.
g. This table gives the final energy actually generated as electricity, not the primary energy input to electricity generation.

Fig. 9.1: Electricity generated by fuel/source, 2040, Clean Energy – Scenario 2

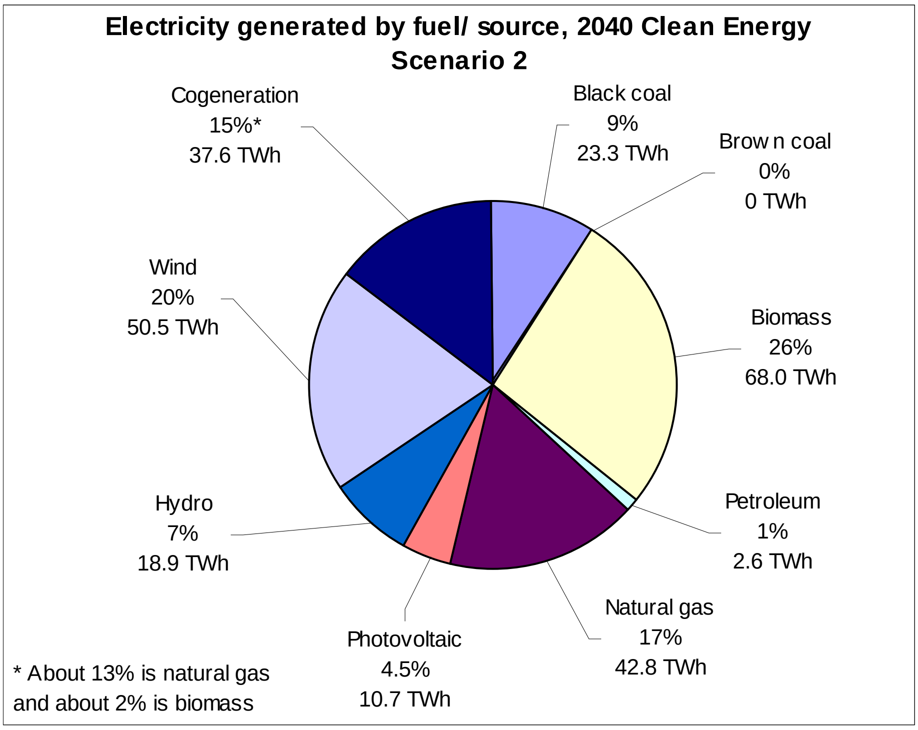
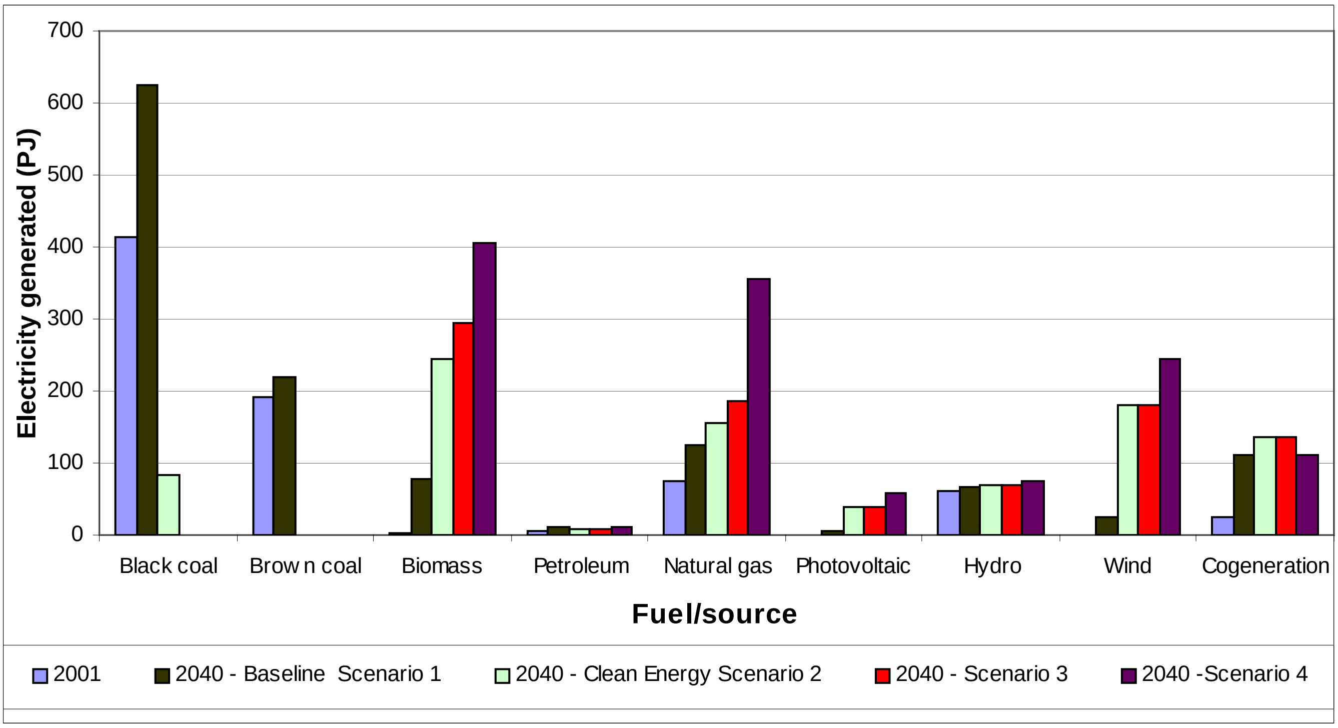


Fig. 9.2: Electricity generated by fuel/source, 2001 and all 2040 Scenarios



9.6. Decarbonising transport

Although the subject of the present report is stationary energy, we cannot ignore transport entirely because it is an input to stationary energy use. In Section 6.6 we considered a somewhat more efficient transport system based on the 2001 fuel mix. These efficiencies could be achieved by improving urban public transport and facilities for walking and cycling, combined with a comprehensive mix of transport and planning policies to make these modes more attractive, a small shift from road to rail freight (based on improved rail infrastructure), and improved fuel efficiency of road and air transport. This results in an increase of 45% in energy demand by transport between 2001 and 2040[3].

On the supply side we now investigate simple measures for reducing the greenhouse intensity of this demand. In the spirit of this report we keep with small improvements to existing technologies and assume that almost all road vehicles in 2040 are highly efficient hybrid petrol-electric or diesel-electric vehicles with half the greenhouse gas emissions per km travelled of the present road fleet. This is consistent with current fuel efficiency achievements of hybrid vehicles. These vehicles do not require an external source of electricity – rather the batteries are charged from the petrol or diesel engine, supplemented by regenerative braking. In addition it is assumed that the small minority of vehicles that are unsuitable for hybrid propulsion (e.g. because of size or type of use) have diesel engines fuelled by a 100% bio-oil from crops. It is further assumed as a rough approximation that the 45% increase in transport energy demand applies to each of cars, trucks and aircraft.

Thus, in this scenario, CO_2 emissions from road transport in 2040 decrease to 27.5% below those in 2001, while emissions from civil air transport increase to 45% above the 2001 value. But in 2001, road transport accounted for 90% of Australia's Transport emissions and civil air transport only 6%. Therefore, assuming to first approximation a similar pattern in 2040, the net effect is that transport emissions in this scenario in 2040 will be 25% below those of 2001. An effect of this will be to reduce slightly CO_2 emissions from stationary energy in 2040. However, since this is a small effect, we have not included it in our 2040 scenarios for stationary energy.

By 2040 it is probable that petrol and diesel will be scarce and priced considerably above current levels (Hall et al., 2003). So we assume that, in the absence of major technical breakthroughs, hybrid vehicles will be the standard kind of vehicle in large-scale mass production and so will be only a little more expensive than ordinary vehicles. Therefore it is plausible to assume that this supply-side transport scenario will have no additional net costs in 2040.

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[3] Without these efficiency improvements, transport energy demand could have increased by about 100%. Nevertheless, we consider that strong demand-side measures could potentially limit the growth in vehicle-km travelled to much less than the 45% increase used here.