Emission Cuts Realities – Electricity Generation

Cost and CO_2 emissions projections for different electricity generation options for Australia to 2050

By
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Abstract

Five options for cutting CO_2 emissions from electricity generation in Australia are compared with a 'Business as Usual' option over the period 2010 to 2050. The six options comprise combinations of coal, gas, nuclear, wind and solar thermal technologies.

The conclusions: The nuclear option reduces CO_2 emissions the most, is the only option that can be built quickly enough to make the deep emissions cuts required, and is the least cost of the options that can cut emissions sustainably. Solar thermal and wind power are the highest cost of the options considered. The cost of avoiding emissions is lowest with nuclear and highest with solar and wind power.

Contents

Introduction

This paper presents a simple analysis of CO_2 emissions, capital expenditure, electricity generation costs and the emissions avoidance cost for six options for supplying Australia's electricity. The results are presented at five year intervals for the period 2010 to 2050.

The purpose of this paper is to address two questions that were raised in discussion of three earlier papers (Lang 2009a, Lang 2009b, Lang 2009c). The papers 'Solar Power Realities' (Lang 2009b), and the Addendum (2009c), looked at the cost of reducing CO2 emissions using solar power. They did this by looking at the limit situation; that is, we replace all our fossil fuel electricity generation 'overnight' with either solar power and energy storage or with nuclear power. The papers concluded that solar power would cost at least 40 times more than nuclear to supply the National Electricity Market (NEM). The estimates were based on current prices for currently available technologies and for the NEM demand in 2007.

The first paper, "Cost and Quantity of Greenhouse Gas Emissions Avoided by Wind Generation" (Lang 2009a), concluded that wind power with back-up by gas generators saves little greenhouse gas emissions and the avoidance cost is high compared with other alternatives.

Discussion of these analyses raised two main questions:

1. The limit situation does not take into account what happens during the transition period. The earliest we could begin commissioning nuclear is about 2020. So, what should we do until then? Does it make sense to build wind power as fast as possible until 2020, at least, so we can cut greenhouse gas emissions as quickly as possible and start as early as possible?

2. The previous papers consider replacement of fossil fuel generators with one technology only rather than with a mix of technologies. This raises the question: would a mix of technologies be better able to meet the demand and at lower cost. Would a mix of solar and wind be lower cost than either alone, and lower cost than nuclear?

To attempt to answer these questions, in a 'ball park' way, I conducted a simple analysis of the cost, and CO2 emissions from six options (six technology mixes) for the period 2010 to 2050. The six options are:

1. Business as Usual (BAU).

2. Combined Cycle Gas Turbine (CCGT).

3. Nuclear and CCGT.

4. Wind and Gas[1].

5. Solar Thermal and CCGT

6. Solar Thermal, Wind and Gas.

Throughout the paper ‘emissions’ refers to ‘CO2-e emissions’. More specifically, it refers to CO2-e emissions from electricity sent out from the power station. The figures are not life cycle emissions (see assumption 10, below).

Assumptions

Assumptions that apply to all options are described in this section. Assumptions that are specific to an option or to a technology are described under the relevant option in the Methodology section.

1. The total energy supplied is as per the ABARE (2007) projections of electricity supply to 2030, extended linearly to 2050. All options must supply this total energy for each period and all must provide the same quality of power as the Business as Usual case. To achieve this, intermittent renewable energy generators must be backed up by a responsive generator technology.

2. For all except the Business as Usual case, it is assumed that coal fired power stations can be and will be decommissioned at the rate of 1 GW per year for black coal generators and 0.4 GW per year for brown coal generators.

3. The energy deficit caused by decommissioning the coal fired power stations is supplied by replacement generating capacity. Five options for replacement generating capacity are considered. Each option comprises a mix of a few technologies that in combination are capable, theoretically, of providing the energy and the power that would have been provided by the coal power stations. That is, the mixes of replacement technologies must be capable of providing the same power quality, and of supplying it on demand, at all times.

4. The ABARE (2007) projections provide the breakdown of energy supply by nine generation types; four fossil fuel and five renewable energy. The energy supplied by the seven non-coal technologies is the same in all six options[2]. The Business as Usual case is as per the ABARE (2007) projections for all nine technologies.

5. The main constraint in the analyses is the assumed decommissioning rate for coal fired power stations and the assumed build rate achievable for the replacement technologies. The build rate assumptions are arguably optimistic. The achievability of the assumed build rates is discussed in a later section.

[1] Gas means a mix of Open Cycle Gas Turbine (OCGT) and Combined Cycle Gas Turbine (CCGT)
[2] There is one exception to this statement – see Option 3 – Nuclear and CCGT.

6. The capital expenditures do not include the cost of replacement of the reserve capacity margin that is needed to cover for scheduled and unscheduled outages because the reserve capacity margin is assumed to be the same for all options.

7. The analyses are intentionally simple so that non-specialists can follow the assumptions and analyses. A more thorough analysis would use sophisticated modelling to optimise the mix of technologies and to calculate the long run marginal cost of electricity sent out. All available technologies would be included in the analyses rather then the simple mixes used in these analyses. Such analyses are complicated and need sophisticated modelling capability. For examples see EPRI (2009a), MIT (2007), MIT (2009), ACIL-Tasman (2009), Frontier Economics (2009), ATSE (2008).

8. Transmission costs are similar for the Business as Usual, CCGT and Nuclear options. So no additional cost is included for transmission for the CCGT and Nuclear options. Extra costs for transmission are included for the Wind and Solar Thermal options.

9. No allowance is made for the lower energy growth rate that energy efficiency improvements will bring. This omission is offset because no allowance is made for the higher growth rate as cleaner electricity replaces gas for heating and replaces oil for land transport (either in electric vehicles or through synthetic fuels such as methanol or hydrogen that use electricity for their production).

10. CO_2 emissions from nuclear and the renewable energy technologies are assumed to be zero in operation, consistent with DCC (2009), EPRI (2009b) and Frontier (2009). On a Life Cycle Analysis (LCA) basis the emissions from these technologies are small compared with fossil fuel generation. These are ignored in this simple analysis. [Lightbucket (2009) lists the results from authoritative studies of LCA emissions from electricity generation].

11. No attempt has been made to reconcile CO_2 emissions calculated for the Business as Usual option with the emissions projections published by the Department of Climate Change (2009).

12. The ABARE (2007) energy projections are for all Australia's electricity supply, both off-grid and on-grid. However, the analyses here apply the ABARE (2007) figures as if they were for grid connected electricity. This simplification means the potential for emissions reductions and the cost of the options is overstated (perhaps by 10% in early years decreasing over time).

Table 1 lists the CO2-e emissions intensities for sent out electricity in 2010 for the Business as Usual technologies.

Table 2 summarises the assumptions and inputs for the coal and replacement technologies.

Table 1. CO2-e emissions intensities for Business as Usual technologies for sent-out electricity in 2010

Technology	t CO2-e/MWh
Black coal	0.84
Brown coal	1.20
Oil	0.78
Natural gas	0.49
Biomass	0
Biogas	0
Hydroelectricity	0
Solar energy	0
Wind energy	0

Source: see Appendix 1: CO_2 Emissions Intensity

Table 2: Assumed input values for the existing black coal and brown coal and for the new replacement technologies; in 2010

		Existing technologies		Replacement technologies				
Variable	Units	Black Coal	Brown Coal	CCGT[3]	OCGT[4]	Nuclear	Wind	Solar Thermal
Emissions Intensity[5]	t CO2-e /MWh	0.84	1.20	0.45	0.70	0.00	0.00	0.00
Emissions Intensity (back-up mode)[6]	t CO2-e /MWh			0.53	0.94			
Economic life[7]	years	40	40	30	30	50	25	25
Availability[8]	%			92%	97%	90%	N/A	N/A
Capacity Factor assumed for converting capacity and energy	%	90%	90%	90%	90%	90%	30%	90%
Capital Cost (2010)[9]	$/MW			$1,368	$985	$5,207	$2,591	$11,046
LRMC[10]	$/MWh	$40	$40	$60	$97	$101	$110	$233
Electricity cost (back-up mode)[11]	$/MWh			$66	$111			
Prescribed rate for decommissioning or commissioning	GW/year	-1.0	-0.4	fill energy deficit	fill energy deficit	1 to 2	1.4	0.5 to 1

[3] CCGT = Combined Cycle Gas Turbine
[4] OCGT = Open Cycle Gas Turbine
[5] Source: Appendix 1 for black coal and brown coal. ACIL-Tasman (2009), Table 41 for CCGT and OCGT, EPRI (2009b), Table 1-6 for Nuclear, Wind and Solar Thermal.
[6] CO2 emissions intensity increased by 17% for CCGT and by 34% for OCGT when backing up for wind power (Hawkins, 2009).
[7] Source: ACIL-Tasman (2009), Table 33 for new coal, CCGT, OCGT and nuclear.
[8] Source: ACIL-Tasman (2009), Table 32
[9] Source: ACIL-Tasman (2009), Table 35 CCGT, OCGT and nuclear; EPRI (2009b), Table 1-10 for wind; NEEDS (2008), Figure 3.7, p 38, for solar thermal in 2010, pus 25% for construction in remote desert locations.
[10] LRMC = Long Run Marginal Cost. Data sources. Refer to Appendix 2.
[11] LRMC increased by 17% for CCGT and by 34% for OCGT when backing up for wind power (Hawkins, 2009).

Methodology

This section explains how the analyses were done.

Option 1 – Business as Usual (BAU)

The ABARE (2007) projections for electricity supply for the years 2005-06 to 2029-30 were extended to 2050 and converted from petajoules (PJ) to terawatt-hours (TWh). Figure 1 shows the energy projections for the Business as Usual option.

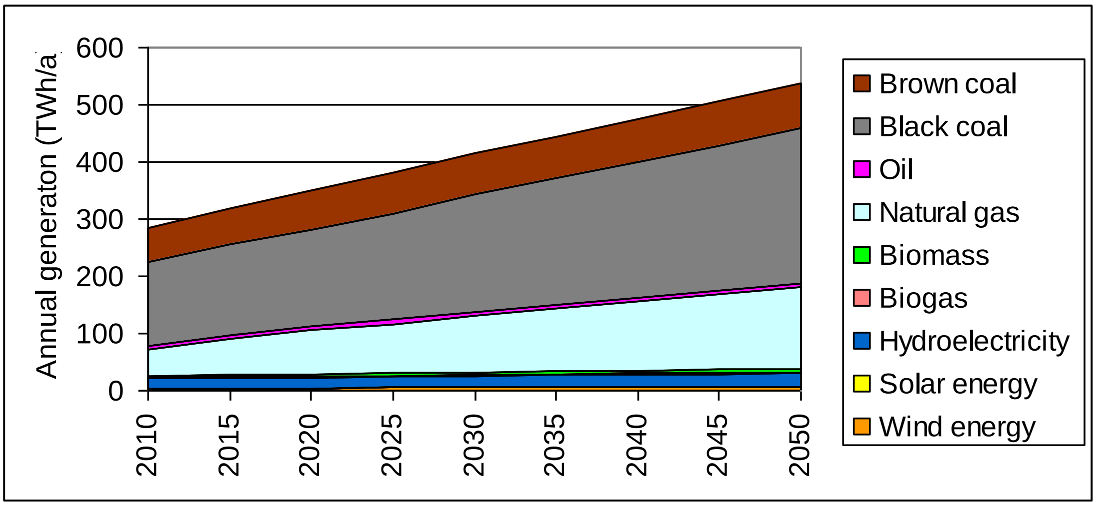

Figure 1: Option 1 – Business as Usual, annual electricity generation (TWh/a). Projections to 2030 from ABARE (2007). The trends from 2020 to 2030 were extended to 2050. The technologies in this chart are the technologies in the ABARE projections. In the charts in the following sections the bottom seven technologies in the chart legend, and the energy they supply, are identical for all options.

The CO_2 emissions were calculated for the Business as Usual case by multiplying the energy by the CO_2 emissions factors. The assumed emissions factors for 2010 are listed in Table 1. Emissions factors for the periods after 2010 were reduced at the rate of 1% per 5 years to account for average efficiency improvements for the existing generators and new generators. The renewable and nuclear technologies are assumed to produce zero emissions (Table 1).

To compare the cost difference between the options we need only compare the cost of the coal with the replacement technologies. All the other technologies are the same for all options.

The capital expenditure for coal in the Business as Usual case comprises two components:

a) the capital expenditure of new coal capacity added to meet the rising demand for electricity; and
b) the capital expenditure of new coal to replace old coal that has reached the end of its economic life. To work with capital expenditure, we must convert the energy figures in the ABARE projections to average power.

The energy (TWh) was converted to average power (GW) using a capacity factor of 90% (refer Table 2). As mentioned previously, this simple analysis ignores the reserve capacity margin needed in the generation system.

The amount of new coal capacity required each year for the Business as Usual case was calculated from the ABARE (2007) projections. The amount of new coal to replace existing coal at the end of its economic life was calculated as 2% of existing capacity per year[12].

The capital cost of new coal capacity for the Business as Usual option was calculated by multiplying the amount of new coal capacity by the unit rate for Ultra Super Critical Black Coal (air cooled) and Ultra Super Critical Brown Coal (air cooled) (refer Table 35, ACIL-Tasman 2009).

All non-BAU options

For all options other than Business as Usual, black coal capacity is decommissioned at the rate of 1 GW per year, and brown coal at the rate of 0.4 GW per year. Decommissioning starts in 2010. All black coal is decommissioned by 2040 and all brown coal by 2035.

The amount of energy these power stations would have generated if not decommissioned is calculated. This is the energy deficit that must be supplied by the replacement generators in all the non Business as Usual options.

The CO2 emissions from the remaining coal capacity are calculated by multiplying the energy generated from black coal and brown coal by the emissions factor for that technology for that year.

The Business as Usual Option comprises projections for nine technologies, - Black Coal, Brown Coal and seven others. The emissions from all the seven non-coal technologies are the same for all options.

The following sections describe the five options considered here for replacing the energy from the decommissioned coal power stations.

Option 2 – Combined Cycle Gas Turbine (CCGT)

CCGT is built to replace the energy deficit resulting from the decommissioning of the coal fired plants. The amount of CCGT capacity required is calculated by

[12] Assuming a 40 year economic life, the plants would be replaced at the rate of 2.5% per year if the capacity was constant from year to year. However, the capacity is increasing over time. In any one year we need to replace only the plants that are 40 years old. If the capacity doubles in 40 years, then we need to replace 1.25% of the total existing capacity in each year. I have assumed 2% as a round figure in between 1.25% and 2.5%.

multiplying the energy deficit by 90% capacity factor. Figure 2 shows the energy supplied by each technology.

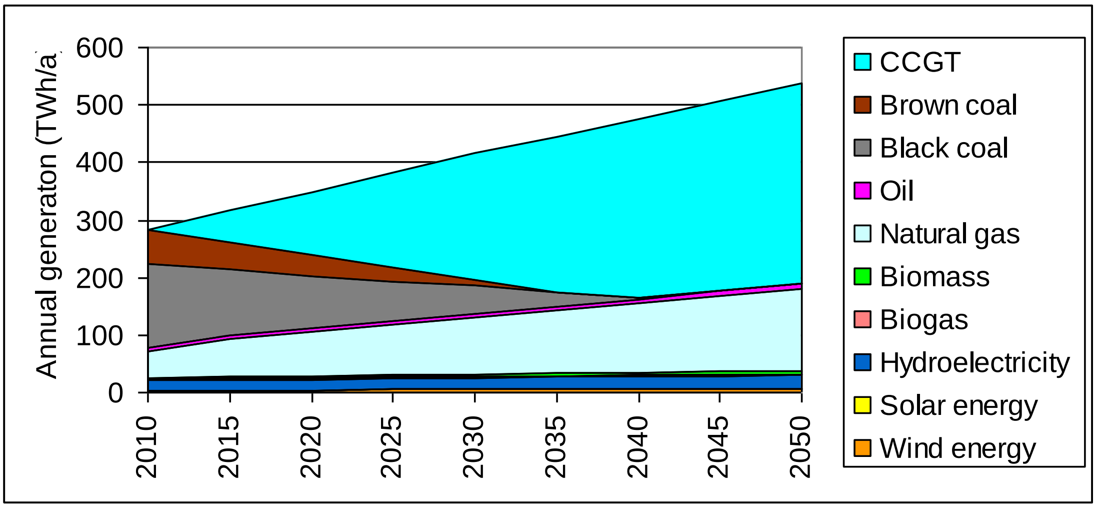

Figure 2: Option 2 – CCGT, annual electricity generation (TWh/a). The seven technologies listed at the bottom of the legend supply the same amount of energy in all options[13]. Black coal and brown coal supply the same energy in all options other than the Business as Usual option. The technologies listed above Brown Coal in the legend are the replacements for the decommissioned coal generators.

The CO_2 emissions for CCGT are calculated using a CO_2 emissions factor of 0.45 t CO_2/MWh, decreasing at 1% per five year to reflect increasing generation efficiency.

The CO_2 emissions from the remaining coal generators and from the other seven technologies are included in the total for this option.

The capital cost for this option is calculated using the unit rate for new build CCGT (air cooled) given in Table 35, ACIL Tasman (2009), and decreasing at -0.4% pa from 2030 to 2050.

Option 3 – Nuclear and CCGT

For this option, nuclear power is commissioned at the rate of 1 GW per year from 2020 to 2025, then at 1.5 GW per year to 2030, then at 2 GW per year to 2050. The reason for selecting these rates is discussed below in "How achievable are the build rates"

CCGT is commissioned at the rate needed to make up the difference between the energy that the nuclear power can supply and the energy deficit caused by decommissioning the coal power stations. Figure 3 shows how much energy is produced by each technology.

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[13] "Natural Gas' is the item shown sixth from the bottom in the figure legends. It is the natural gas generation that is in the ABARE (2009a) projections. It is a mix of OCGT and CCGT. It is distinct from the new CCGT added in Options 2 to 6, and the new CCGT and OCGT added in Options 4 and 6.

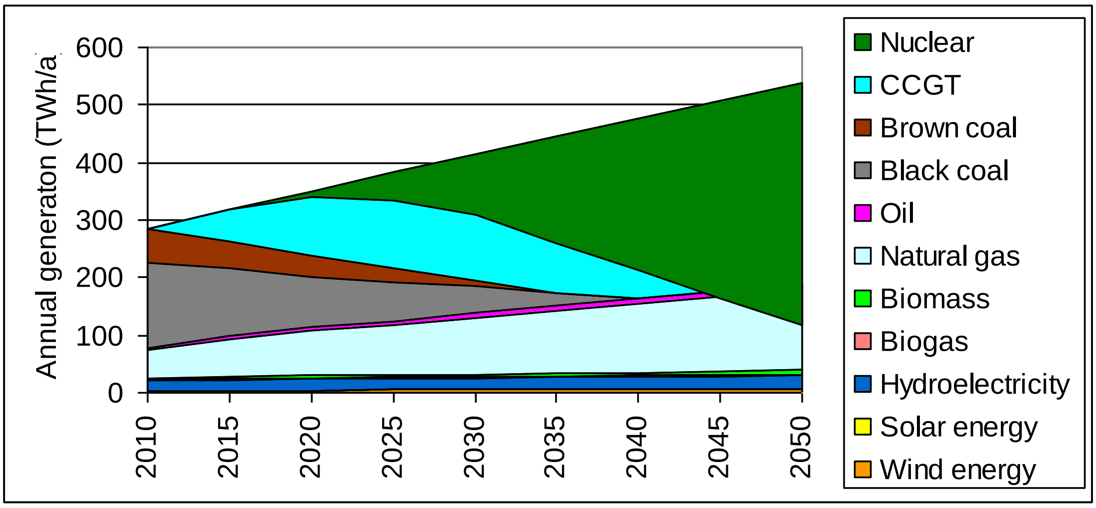

Figure 3: Option 3 – Nuclear and CCGT, annual electricity generation (TWh/a). The seven technologies listed at the bottom of the legend supply the same amount of energy in all six options. Black coal and brown coal supply the same energy in all options except the Business as Usual option. The technologies listed above Brown coal in the legend are the replacement for the decommissioned coal generators.

From 2010 to 2019, no nuclear capacity is commissioned so the CCGT capacity is the same as in Option 2 – CCGT. From 2020 to 2025, nuclear is not built fast enough to replace the coal capacity being decommissioned, so CCGT is added to supply the energy deficit. After 2025, nuclear is being built faster than coal is being decommissioned. So, progressively less energy is being required from CCGT. This shows up (in this simple analysis) as a reduction in CCGT capacity. The practical interpretation of this is that the Natural Gas[14] generation capacity would be reduced at this rate. This means that Natural Gas generation capacity would not be replaced at the end of its 30 year economic life. This begins from about 2025.

CO_2 emissions for nuclear are assumed to be zero (see Assumption 10). CO_2 emissions for Coal, CCGT and the other technologies are calculated in the same way as for Option 2 – CCGT. As for capacity, the negative emissions shown against CCGT should actually be a reduction in emissions from ‘Natural Gas’ but for simplicity of calculation they are shown as negative for CCGT.

The capital cost calculations for this option are similar to those for Option 2 - CCGT. The cost of the nuclear capacity is at the unit rate in ACIL-Tasman (2009), Table 35, and decreasing at -0.9% pa from 2030 to 2035 then at -0.6% pa to 2050.

Option 4 – Wind and Gas

For this option, wind power capacity is commissioned at the same rate as the coal fired plants are decommissioned. So when all wind farms are producing full power (a rare event), the wind farms will supply all the energy that the decommissioned coal

[14] “Natural Gas’ is the item shown sixth from the bottom in the figure legends. It is the natural gas generation that is in the ABARE (2009a) projections. It is a mix of OCGT and CCGT. It is distinct from the new CCGT added in Options 2 to 6, and the new CCGT and OCGT added in Option 4.

fired power plants would have supplied. When the wind farms are not producing full power, back-up generation is required to make up for the energy deficit.

Back-up capacity is provided by a combination of Combined Cycle Gas Turbines (CCGT) and Open Cycle Gas Turbines (OCGT). Equal proportions are assumed. A Capacity Credit of 8% is assumed (AER, 2009), so 1 GW of wind power capacity is assumed to be backed up by 0.46 GW of OCGT and 0.46 GW of CCGT[15]. The proportions, on the basis of capacity, are 1.0:0.46:0.46.

The energy is calculated assuming a capacity factor of 30% for Wind and availability of 90% for OCGT and CCGT. So, on average, 3 GWh of energy is supplied by a combination of Wind, OCGT and CCGT in the proportions 1:1:1. Figure 4 shows how much energy is produced by each technology.

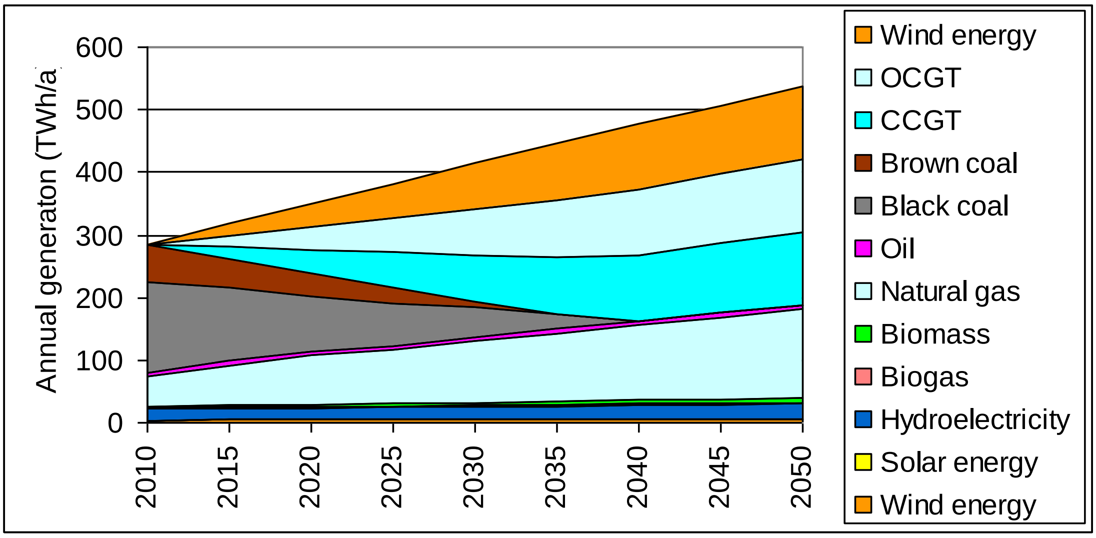

Figure 4: Option 4 – Wind and gas; annual electricity generation (TWh/a). The seven technologies listed at the bottom of the legend supply the same amount of energy in all six options. Black coal and brown coal supply the same energy in all options except the Business as Usual option. The technologies listed above Brown coal in the legend are the replacement for the decommissioned coal generators.

CO_2 emissions for wind generation are assumed to be zero (refer to 'Assumptions' and Table 1). The CO_2 emissions for OCGT are calculated using a CO_2 emissions intensity of 0.7 t CO2/MWh, decreasing at 1% per five years to reflect increasing generation efficiency. CO_2 emissions for CCGT, Coal and the other technologies are calculated in the same way as for Option 2 – CCGT. The lower efficiency and higher emissions from the gas turbines when operating in back up mode (Lang, 2009a; Hawkins, 2009) are included in this analysis. The CO2 emissions are increased by 34% for OCGT and 17% for CCGT (Hawkins, 2009) when these technologies are operating in back-up mode. The higher emissions rate is applied to the proportion of the energy that is generated when they are assumed to be operating in 'back-up' mode. For simplicity this is assumed to be equal to the proportion of the replacement

[15] In practice more gas capacity will be built than this calculation indicates. OCGT and CCGT run at lower capacity factors in practice than the 90% used in this analysis for calculating the amount of capacity required.

energy that is generated by Wind. In effect, the increased emissions factor is applied to half the energy generated by the CCGT and OCGT replacement generators.

The capital cost calculations for this option are similar to those for Option 2 - CCGT and Option 3 – Nuclear and CCGT. The capital cost of the wind capacity is $2591/kW[16] (ABARE 2009) in 2010 and decreasing in future periods at -0.6% pa (Frontier, 2009). The cost of OCGT and CCGT capacity is at the unit rate in ACIL-Tasman (2009), Table 35, increasing at +0.4% pa and +0.5% pa from 2030 to 2050.

As mentioned above, the OCGT and CCGT generators are less efficient when operating in back up mode for wind. These analyses assume that the electricity generation costs are 17% higher for CCGT and 34% higher for OCGT (Hawkins, 2009). However, only half the energy generated by these technologies is considered to be in back-up mode, so electricity cost is increased by 8.5% for CCGT and 17% for OCGT when operating in back-up mode.

Wind power is assumed to have an economic life of 25 years and gas 30 years. Wind and gas capacity installed in 2010 must be replaced in 2035 and 2040 respectively. The capital costs of replacing wind and gas at the end of their economic lives are calculated at the capital cost rate applicable for the year in which the replacement is commissioned.

Wind power requires significant additional capital expenditure for transmission and network management capability. Based on estimated costs for extra transmission capacity incurred because of wind generation in the USA, $1,000/kW of installed wind capacity is included (Gene Preston, pers. comm., 3 Nov 2009). The transmission cost for wind power raises the cost of electricity by an assumed $15/MWh on average (Gene Preston, Dec 2009, pers. comm. and EPRI, 2009a).

Option 5 – Solar Thermal and CCGT

This option is similar to Option 3 – Nuclear & CCGT but with solar thermal instead of nuclear.

The differences are:

1. The build rate of solar thermal capacity in this option (Option 5) is half the build rate of nuclear in Option 3 – Nuclear & CCGT

2. Therefore, the build rate of CCGT is higher in this option than in the Nuclear & CCGT option (to make up the energy difference). This means emissions are higher in the Solar & CCGT option than in the Nuclear & CCGT option.

3. Solar thermal capacity has an assumed life expectancy of 25 years so replacement of solar thermal capacity begins 25 years after the first installation; so replacement begins in 2045.

[16] Average of seven wind farms listed as 'under construction' in ABARE (2009). This Australian cost is close to the US cost in EPRI (2009b), Table 7.1, p 7-5, which is US$2350/kW = A$2611/kW.

4. Whereas nuclear would be built near population centres, where work force, infrastructure, suppliers and services are available, this is not the case for solar thermal[17]. Solar thermal needs to be built in areas of high insolation (deserts) and the power stations must be widely distributed to minimise the impacts of widespread cloud cover.

5. Transmission costs are included at the rate of $1,200/kW (derived from estimates in AEMO, 2009).

Solar thermal capacity is commissioned at the rate of 0.5 GW per year from 2020 to 2025, then at 0.75 GW per year to 2030, then at 1 GW per year to 2050. However, from 2040, some of the new build is for replacing existing old capacity. Solar thermal capacity is assumed to have the same capacity factor as nuclear, i.e. 90%. This is based on NEEDS (2008) which forecasts that solar thermal will have this capability by 2020.[18]

CCGT is commissioned at the rate needed to make up the difference between the energy that the solar thermal capacity can provide and the energy deficit caused by decommissioning the coal fired power stations.

From 2010 to 2019, negligible solar thermal is commissioned so CCGT is built at the same rate as in Option 2 - CCGT and Option 3 – Nuclear & CCGT. From 2020 to 2040 CCGT is being added because solar thermal is not being built fast enough to replace the coal capacity being decommissioned. By 2040 all coal capacity has been decommissioned. So, from 2040 less energy is being required from CCGT. This shows up, in this simple analysis, as reduction in CCGT capacity. The practical interpretation of the reduction of CCGT capacity is that the Natural Gas[19] generation capacity would be reduced at this rate. What this means is that the Natural Gas generation would not be replaced at the end of its 30 year economic life. This begins from about 2040. Figure 5 shows how much energy is produced by each technology.

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[17] The NEEDS (2009) costs are based on constructing the Andasol 1 solar thermal power station in Spain. The cost of constructing widely distributed solar thermal power stations over an area of some 3000 km by 1000 km in Australia's deserts will be higher than the cost of constructing in Spain - where there is well developed infrastructure and larger work force nearer to the sites. To construct the solar thermal power stations in areas throughout central Australia will require large mobile construction camps, fly-in fly-out work force, large concrete batch plants, large supply of water, energy and good roads to each power station. Air fields suitable for fly-in fly-out will be required at say one per 250 MW power station. That means we need to build such air fields at the rate of about two, then three, then four per year.

[18] There is an alternative to solar thermal with sufficient energy storage for 90% capacity factor. The alternative is solar thermal hybrid. Gas generates power when the sun isn't shining and there is insufficient energy storage. The hybrid options emits much more CO2 than CST alone and the electricity costs are higher (EPRI, 2009a, page 10-20), although this comparison is made at a capacity factor of 34% not 90%. NEEDS argues that the solar thermal with 8000 full load hours energy storage will be available and electricity costs will be less than the hybrid option by 2020. The hybrid option is not included in the options considered here.

[19] 'Natural Gas' means the natural gas item in the ABARE projections. Refer Figure 5 legend.

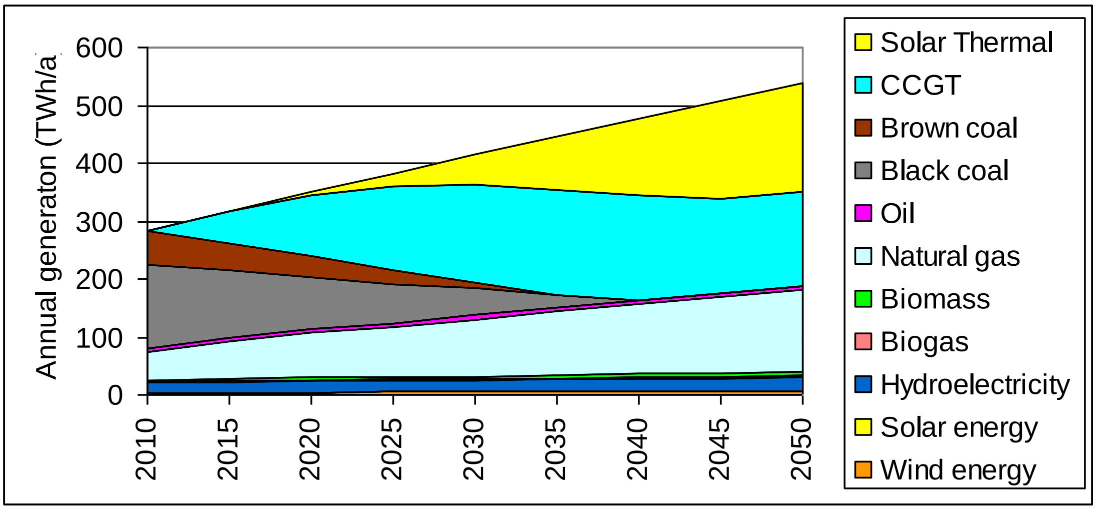

Figure 5: Option 5 – Solar thermal and CCGT annual electricity generation (TWh/a). The seven technologies listed at the bottom of the legend supply the same amount of energy in all six options. Black coal and brown coal supply the same energy in all options except the Business as Usual option. The technologies listed above Brown coal in the legend are the replacement for the decommissioned coal generators.

CO_2 emissions for solar thermal are assumed to be zero (refer Table 1). CO_2 emissions for coal, CCGT and the other technologies are calculated in the same way as for Option 3 – Nuclear and CCGT. The negative emissions shown against CCGT should actually be a reduction in emissions from 'Natural Gas' but for simplicity they are shown as negative against CCGT.

The capital cost calculations for this option are similar to those for Option 3 – Nuclear and CCGT, except that the capital cost of transmission is added and the capital cost of replacing retiring solar thermal capacity is included from 2045. The capital cost of the solar thermal capacity is based on adjusted unit rates from NEEDS (2008), Figure 3.11, Case B[20]. The rates are adjusted to attempt to make them more consistent with the way the ACIL-Tasman (2009) rates were derived. Two adjustments were made. Firstly, the initial capital cost unit rate is adjusted up by 25% to allow for the greater cost of constructing widely distributed power stations across an area roughly 1000 km by 3000 km of Australia's deserts. Secondly, the learning rate in NEEDS (2008) is replaced with the same rate of cost reduction as for nuclear in Option 3- Nuclear and CCGT.

The capacity factor assumed for solar thermal is the same as for nuclear, coal and gas. This requires that the solar thermal power stations have sufficient energy storage for 24 hour operation and can provide for 8,000 full-load hours per year. Needs (2008) forecast that this capability could be available by 2020. The additional capacity needed to ensure full power generation throughout winter and throughout periods of overcast weather (Lang, 2009b), is not allowed for in this analysis.

As for wind, transmission is a significant cost item for solar thermal. The capital expenditure for transmission for solar thermal is calculated at $1200/kW (based on estimates in AEMO, 2009). Electricity cost includes $15/MWh for transmission.

[20] The 'learning rates', and hence the costs, in the NEEDS report seem optimistic (see Appendix 2)

Option 6 – Solar Thermal, Wind and Gas

For this option, it is assumed that solar thermal is commissioned at the same rate as in Option 5 – Solar Thermal & CCGT. Wind, CCGT and OCGT are commissioned at the same rate as in Option 4 – Wind & Gas. The solar capacity does not reduce the amount of gas capacity needed to back-up for the wind capacity. Gas capacity required to back up for wind does not change but the amount of energy the gas generates does change, with the gas generators working at lower capacity factors

The energy generated by solar thermal is the same as in Option 5 – Solar Thermal and CCGT. The energy generated by wind is the same as in Option 4 – Wind & Gas. The energy generated by OCGT and CCGT makes up the energy deficit. Figure 6 shows how much energy is produced by each technology.

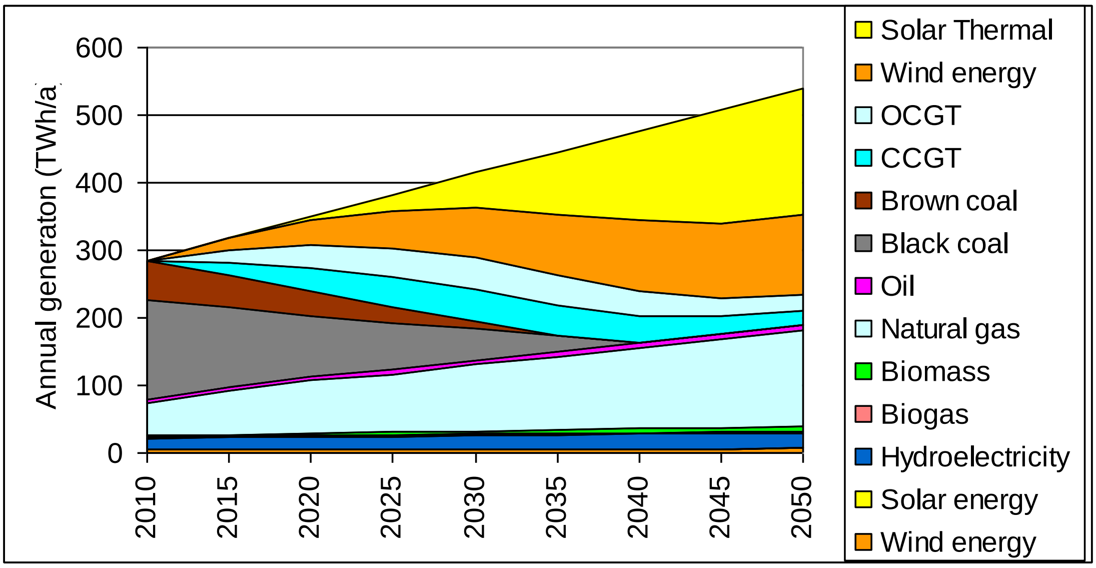

Figure 6: Option 6 – Solar thermal, wind and gas; annual electricity generation (TWh/a). The seven technologies listed at the bottom of the legend supply the same amount of energy in all options. Black coal and brown coal supply the same energy in all options other than the Business as Usual option. The technologies listed above Brown Coal are the replacements for the decommissioned coal generators.

CO_2 emissions for wind and solar are assumed to be zero in this analysis (see Table 1). CO_2 emissions for OCGT, CCGT, coal and the other seven technologies are calculated in the same way as for Option 4 – Wind and Gas.

The capital cost calculations for this option are similar to those for Option 4 – Wind & Gas and Option 5 – Solar Thermal & CCGT. The capital cost of the solar capacity in this option is the same as for Option 5 – Solar Thermal & CCGT. The capital cost of the wind capacity is the same as for Option 4 – Wind & Gas. The capital cost of the gas capacity is less than Option 4 – Wind & Gas because of the contribution from solar thermal; solar thermal provides its share of energy and the gas makes up the deficit. Transmission cost is included at $15/MWh for solar thermal and for wind.

Build rates

The rate of decommissioning coal and commissioning the replacement generating capacity, for each option, is summarised in Table 3. The figures in the shaded cells are prescribed inputs and the unshaded cells are calculated values.

Table 3: Rate of decommissioning and commissioning capacity (GW per 5 years)

	2010	2015	2020	2025	2030	2035	2040	2045	2050
Option 1- Business as Usual									
Black Coal	2.7	2.8	3.5	4.8	5.0	4.7	5.1	5.3	5.5
Brown Coal	1.2	1.1	1.7	1.4	0.9	1.2	1.2	1.2	1.2
Decommissioning									
Black Coal	0.0	-5.0	-5.0	-5.0	-5.0	-5.0	-5.0	0.0	0.0
Brown Coal	0.0	-2.0	-2.0	-2.0	-2.0	-1.5	0.0	0.0	0.0
Option 2 - CCGT									
CCGT	0.0	7.0	7.0	7.0	7.0	6.5	5.2	9.3	9.3
Option 3 - Nuclear & CCGT									
Nuclear	0.0	0.0	1.0	5.0	7.5	10.0	10.0	10.0	10.0
CCGT	0.0	7.0	6.0	2.0	-0.5	-3.5	-4.8	-7.7	-7.7
Option 4 - Wind & Gas									
Wind	0.0	7.0	7.0	7.0	7.0	6.5	12.2	9.3	9.3
CCGT	0.0	3.2	3.2	3.2	3.2	3.0	2.4	4.3	4.3
OCGT	0.0	3.2	3.2	3.2	3.2	3.0	2.4	4.3	4.3
Option 5 - Solar & CCGT									
Solar Thermal	0.0	0.0	0.5	2.5	3.8	5.0	5.0	5.0	5.0
CCGT	0.0	7.0	6.5	4.5	3.3	1.5	0.2	-2.2	-0.2
Option 6 - Solar & Wind & Gas									
Wind	0.0	7.0	7.0	7.0	7.0	6.5	12.2	9.3	9.3
Solar thermal	0.0	0.0	0.5	2.5	3.8	5.0	5.0	5.0	5.0
CCGT	0.0	3.2	3.2	3.2	3.2	3.0	2.4	4.3	4.3
OCGT	0.0	3.2	3.2	3.2	3.2	3.0	2.4	4.3	4.3

Electricity Costs

The cost of electricity, for coal and the replacement technologies, was calculated for each option. The electricity costs were calculated by applying the electricity cost unit rate (see Table 4 and Appendix 2) to the proportion of energy generated by each technology. Appendix 2 explains the sources and derivation of the electricity cost unit rates for use in this analysis.

Table 4: Electricity cost unit rates for the replacement technologies ($/MWh, 2009 $)

	2010	2015	2020	2025	2030	2035	2040	2045	2050
Black Coal (existing)	40	40	40	40	40	40	40	40	40
Brown Coal (existing)	40	40	40	40	40	40	40	40	40
Black Coal (new)	55	51	50	49	48	48	47	47	46
Brown Coal (new)	53	50	50	49	48	48	48	47	47
CCGT	60	57	59	60	62	64	65	67	69
OCGT	97	92	96	97	100	102	104	106	108
Nuclear	101	99	98	96	86	82	80	77	75
Wind	110	107	104	101	98	95	92	89	86
Solar Thermal	233	229	225	220	197	189	184	178	173

CO_2 Avoidance Cost

The CO_2 avoidance cost (the cost to avoid a tonne of CO_2 emissions) was calculated for each option. It is the difference in electricity cost between Business as Usual and the respective option divided by the difference in CO2 emission between the Business as Usual and the respective option.

Results

The results of the analyses are summarised in Figures 7 to 12.

Figure 7 compares the total CO_2 emissions per year from the six options.

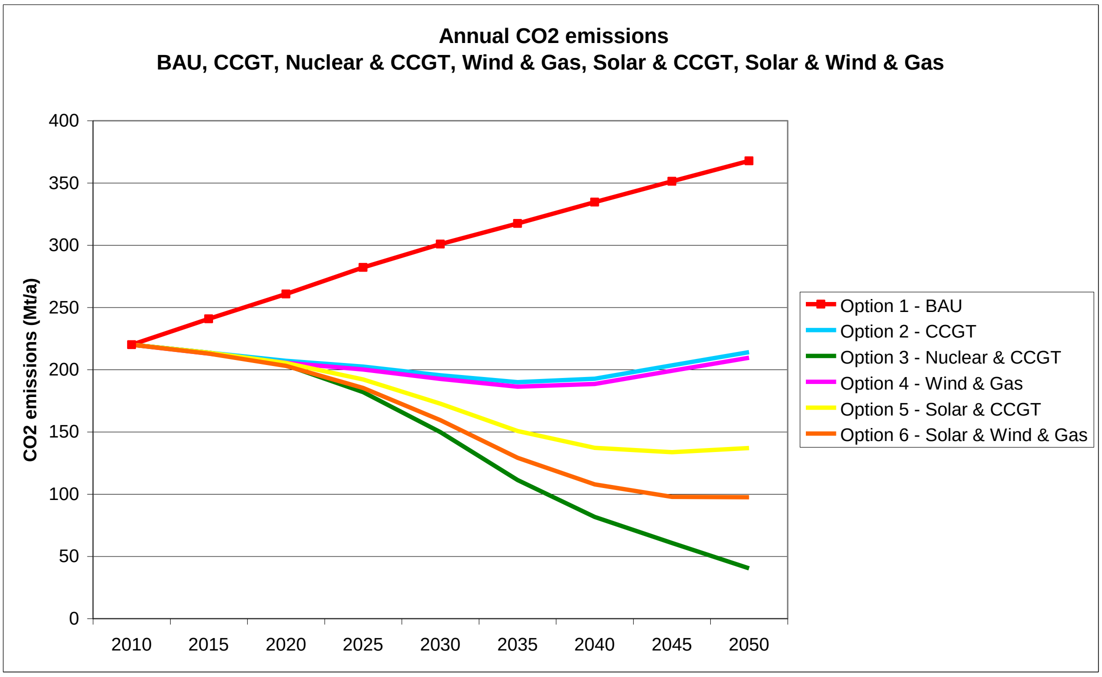

Figure 7: CO_2 emissions per year for the six options

Figure 8 compares the capital expenditure per 5 years for the six options. The capital expenditure is for coal and the replacement technologies only. The capital expenditure for the other seven technologies is the same for all options; these costs are not included in the total capital expenditure figures shown here.

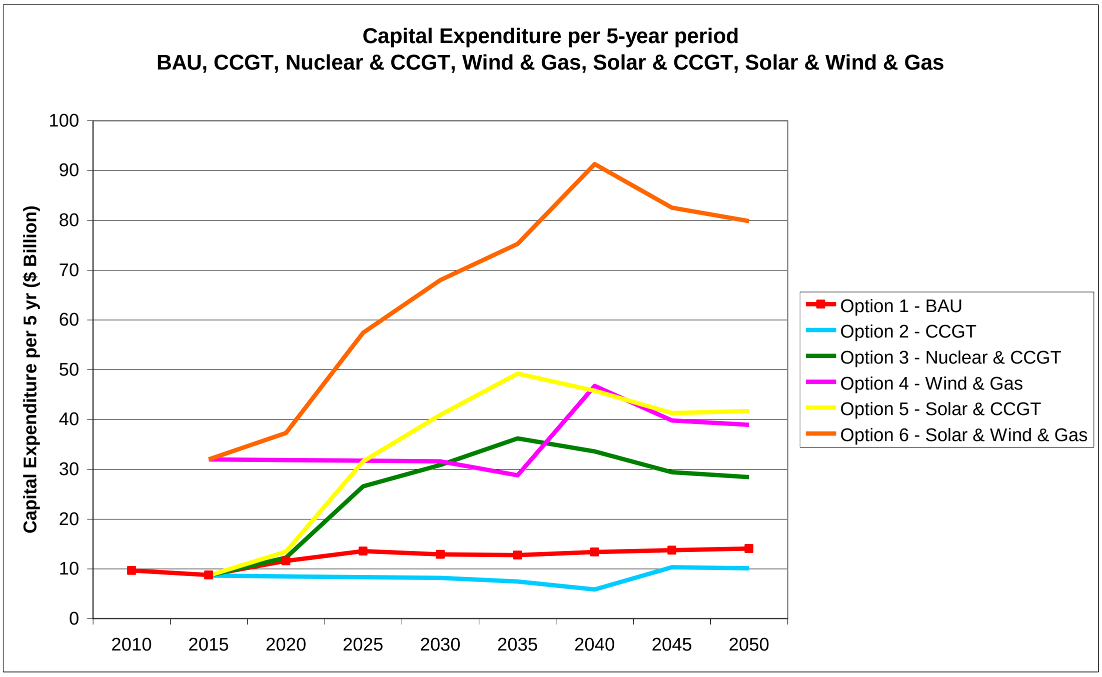

Figure 8: Capital expenditure per 5-years for the six options (Constant 2009 $).

Figure 9 compares the cumulative capital expenditure of the six options.

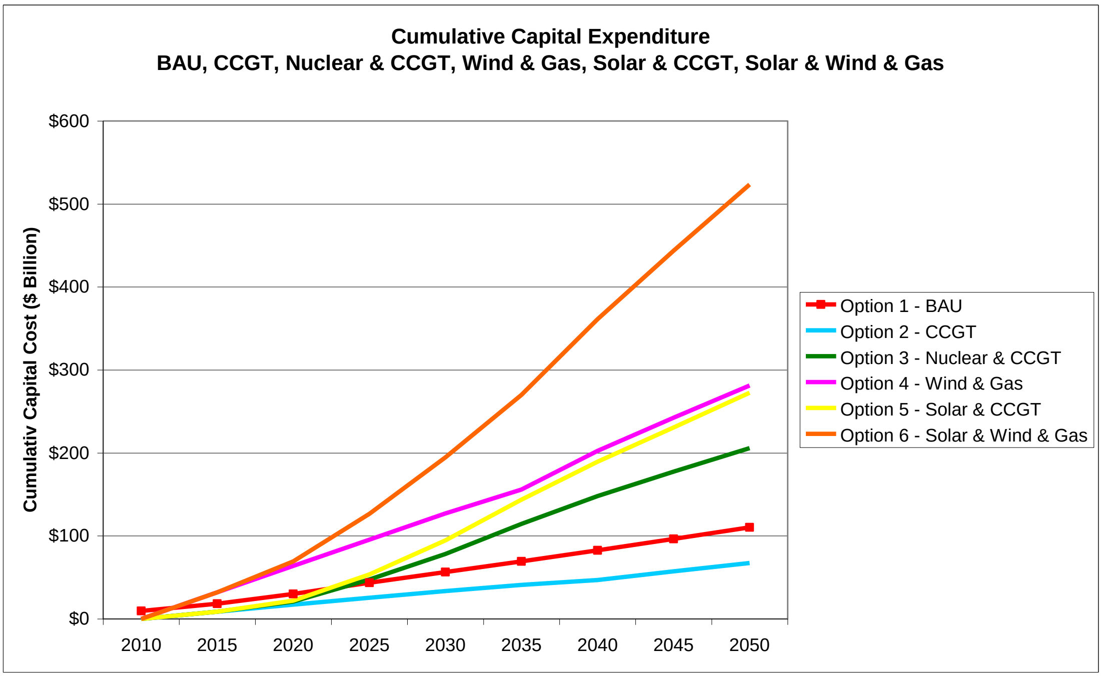

Figure 9: Cumulative capital expenditure for the six options. (Constant 2009 $)

Figure 10 shows the long run marginal cost of electricity for coal and the replacement technologies only. These costs do not include the cost for the seven technologies that are the same in all options.

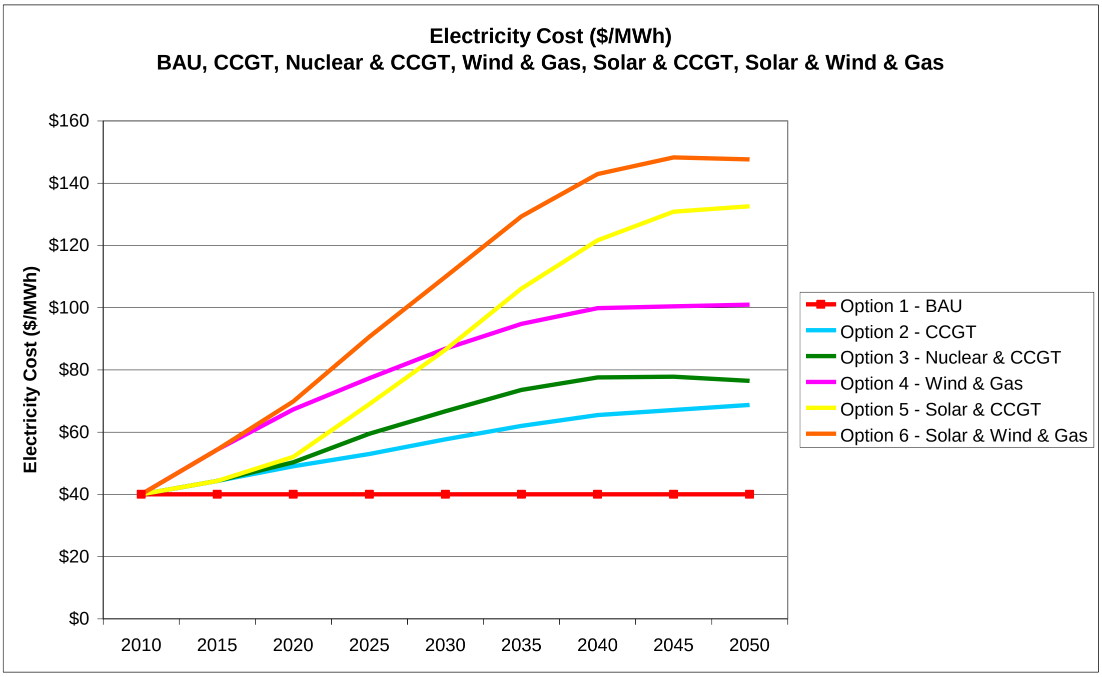

Figure 10: Electricity cost for the six options. ($/MWh sent out, Constant 2009 $)

Figure 11 compares the options on the basis of the CO2 avoidance cost; i.e. the cost to avoid a tonne of CO_2.

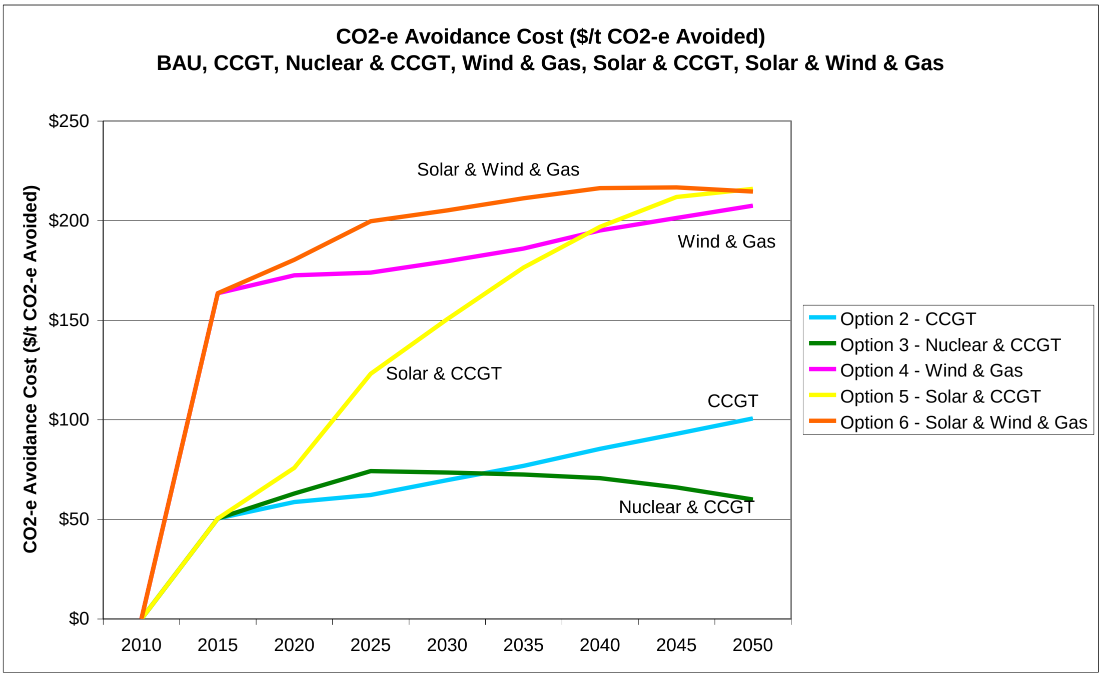

Figure 11: Cost per tonne of CO_2-e avoided (compared with Business as Usual) ($/t CO_2-e Avoided)

Discussion

The following can be interpreted from Figures 7 and 8:

Option 1 – Business as Usual produces the highest CO_2 emissions by a large margin. Capital expenditure is fairly consistent at about $10 to $15 billion per 5 years, or about $2 to $3 billion per year.

Option 2 - CCGT has the highest emissions of the replacement options. It has the lowest capital cost of all options (although it has the highest operating cost). The CO_2 emissions with this option are only slightly less in 2050 than in 2010. The reason the curve turns up from 2040 is that all coal fired power stations have been decommissioned. Therefore, CCGT is being added but no coal is being removed. So we are adding emissions from the CCGT without cutting any from coal generation.

Option 3 – Nuclear and CCGT has the lowest CO_2 emissions from 2020. It has the lowest capital expenditure, except Business as Usual and CCGT, for most of the period from 2010 to 2050. From 2035 the capital expenditure rate decreases.

Option 4 – Wind, with CCGT and OCGT for back-up, produces slightly lower CO_2 emissions than the CCGT. However, this is achieved at high cost - about $4 billion to $6 billion per year more than CCGT. The step up in expenditure in 2040 is for replacement of the wind capacity installed in 2015. The emissions increase from 2040 as electricity demand increases and once the coal generators have been decommissioned.

Option 5 – Solar Thermal and CCGT. Solar thermal capacity is built at half the rate of nuclear, and provides half the energy. CCGT must be built faster in the solar option than in the nuclear option to make up the energy deficit. The CO_2 emissions from 2010 to 2019 are the same for the three options CCGT, Nuclear & CCGT and Wind & CCGT. From 2020, the CO_2 emissions from the solar thermal option are higher than from the nuclear option. By 2050, the CO_2 emissions from the solar thermal option are over three times those from the nuclear option, and increasing as electricity demand increases. The capital expenditure for the solar option is substantially higher than for nuclear throughout.

Option 6 – Solar, Wind and Gas is a combination of Options 4 and 5. CO_2 emissions are the second lowest from 2020 to 2050. Importantly, this option requires around $5 billion to $6 billion per year higher capital expenditure than nuclear to 2030. From 2030 to 2050 the difference in capital expenditure blows out to over $10 billion per year higher rate of expenditure for this option.

Figure 9 shows the cumulative capital cost and Figure 10 shows the long run marginal cost of electricity (LRMC). The following can be interpreted from these two charts:

CCGT is the lowest cost option throughout the period from 2010 to 2050.

Nuclear & CCGT has the lowest total cost (cumulative capital expenditure) of all options except Business as Usual and CCGT. The electricity cost for the Nuclear & CCGT option peaks in 2045 then starts to decrease as Natural Gas is decommissioned.

The steep rise in capital expenditure and electricity cost for the Wind option and the Solar Thermal and Wind option is because of the high cost of Wind and because Wind is being added at the rate of 1.4 GW per year from 2011, which is three times the rate Wind was commissioned in 2008.

The options with wind and solar thermal produce the highest cost electricity throughout.

The cumulative capital expenditure for the Solar Thermal option is about 30% higher than for nuclear. This is despite the fact that the solar thermal capacity is being built at half the rate of nuclear.

Important to note: The electricity cost for the Solar Thermal, Wind and Gas option is higher than the Solar Thermal and CCGT option. This indicates that combining renewable energy generators does not reduce the cost.

Figure 11 compares the options on the basis of the cost of avoiding a tonne of CO2 emissions. The CCGT option has the lowest avoidance cost to 2035 and then the Nuclear & CCGT option is lowest thereafter. The difference, in 2015, between the options that have Wind in their mix ($163/t CO2-e) and those that do not (50/t CO2-e) is because wind with gas back up is far more expensive but avoids insignificant extra emissions (see Figure 7). In the long run, Nuclear & CCGT is the least cost way to reduce emissions from electricity generation. The options with Wind and Solar are the highest cost way to avoid emissions.

How achievable are the assumed build rates?

The build rate for Business as Usual has been achieved consistently to date, so there can be no doubt that it is achievable.

The build rate for CCGT is about twice the build rate for coal in the Business as Usual case and about 15 times the current build rate for Natural Gas generation plant.

The build rate for wind capacity (1.4 GW per year) is about 3 times the build rate achieved in 2008 (0.48 GW) (GWEC, 2008). For comparison, in 2008 USA installed 8.4 GW and China 6.3 GW (GWEC, 2009). Interestingly, developed countries with larger economies than Australia, installed not much more than Australia, e.g. Canada (0.5 GW). AER (2009), Table 1.4 shows a peak for proposed commissioning of 2.8 GW in 2011. In practice, the build rate for wind will be limited by transmission capacity and the amount of wind power that can be accepted by the grid. The assumed build rate of 1.4 GW per year (500-700 turbines a year based on current turbine sizes) seems achievable in the future.

The rate of commissioning nuclear from 2020 to 2025 is 1 GW per year. That is equivalent to one new reactor per mainland state every 5 years. To put this in perspective, France commissioned its Gen II nuclear power plants at the rate of 3 GW per year for two decades (WNA, 2009). And Japan, China and Korea have been building the new Gen III nuclear power plants in about 4 years. So, it would seem the build rate for nuclear assumed here could be achieved from 2020, if necessary.

The assumed rate of commissioning solar thermal in these analyses, seems highly optimistic. The quantity of steel and concrete required is an indication of the amount of construction effort required. Solar thermal requires about 8 times more concrete and 15 times more steel than nuclear per MW of capacity (Table 5). The build rate for solar thermal, assumed in these analyses, is half the rate of nuclear, so each year we would need to construct solar thermal plants comprising 4 times more concrete and seven times more steel than the nuclear plants. But that's not all. Nuclear would be built relatively close to the population centres, where services, infrastructure and work force is more readily available. Conversely, the solar plants need to be built in the desert regions. They will require four times as much water (for concrete) as nuclear. Water pipe lines will need to be built across the desert to supply the water. Dams will need to be built in the tropical north to store water and desalination plants along the coast elsewhere. To develop and retain a skilled work force to work in such regions will be costly. Work will be for about 9 months of the year to avoid the hottest periods. Based on the quantities of steel and concrete, towns will be required in the desert that accommodate about four times the work force required for constructing a nuclear power station. Fly-in-fly-out airports will need to be built for each town with a capability to move much larger numbers of people than the largest mining operations. Two such towns and airfields must be built per year to achieve the solar thermal build rate. It is hard to imagine how a build rate for solar thermal could be even $1/10^{th}$ the build rate that could be achieved with nuclear.

The build rate for nuclear would be difficult to achieve. But the build rates for solar thermal would be much more difficult to achieve.

Table 5: Concrete and steel per rated MW

	Concrete	Steel	Source:
Wind Onshore	433	116	ISA (2007), p145
Solar Thermal (7.5 h storage)	1303	415	NEEDS (2008) - Andasol 1, p88
Solar Thermal (18 h storage)	2606	830	rough calculation (x 2)
Nuclear	323	57	ISA (2007), p46

	Ratio to nuclear	
	Concrete	Steel
Wind Onshore (Note 1)	1.3	2.0
Solar Thermal (18 h storage)	8.1	14.6
Nuclear	1.0	1.0

Adapted from Martin Nicholson, pers. comm., (2009)
Note 1: The wind figures must be increased by a factor of 6 to be equivalent to nuclear power per unit of energy. (Capacity factor and economic life: wind: 30%, 25 yr; nuclear: 90%, 50 yr).

Sensitivity to assumptions and inputs

The results are highly sensitive to some of the assumptions and inputs. The most sensitive inputs are the projections of future capital cost, electricity cost, and the development rates for solar thermal. However, the ranking of the options under different inputs, and therefore the conclusions are robust over the ranges tested.

Answers to the questions

This paper set out to address the two questions stated in the Introduction, viz.:

1. Does it make sense to build wind power as fast as possible until 2020, at least, so we can cut greenhouse gas emissions as quickly as possible and start cutting as early as possible?

2. Would a mix of technologies be better able to meet the demand and do so at lower cost? For example, would a mix of solar and wind be lower cost than either alone, and lower cost than nuclear?

Figure 11 provides the answers.

The answer to Question 1 is 'No'. Figure 11 shows the emissions avoidance cost for the options without wind is \$50/t CO2-e and for the options with wind is \$163/tCO2-e in 2015. In 2020, the ranking is the same but the costs are higher (see Figure 11).

The answer to Question 2 is 'No'. The option with the mix of Solar Thermal and Wind has the highest avoidance cost of all options. It has the highest capital expenditure by far (Figures 8 and 9), and the highest electricity cost (figure 10). Its CO2 emissions are greater than the nuclear option. It has no advantages.

Figure 12 summarises the position in 2050. The figure compares the six options on the basis of the electricity cost of the coal and replacement technologies and the total CO2 emissions per year for each option. Clearly, the Nuclear and CCGT option produces the lowest emissions and the cost penalty is marginally higher than CCGT.

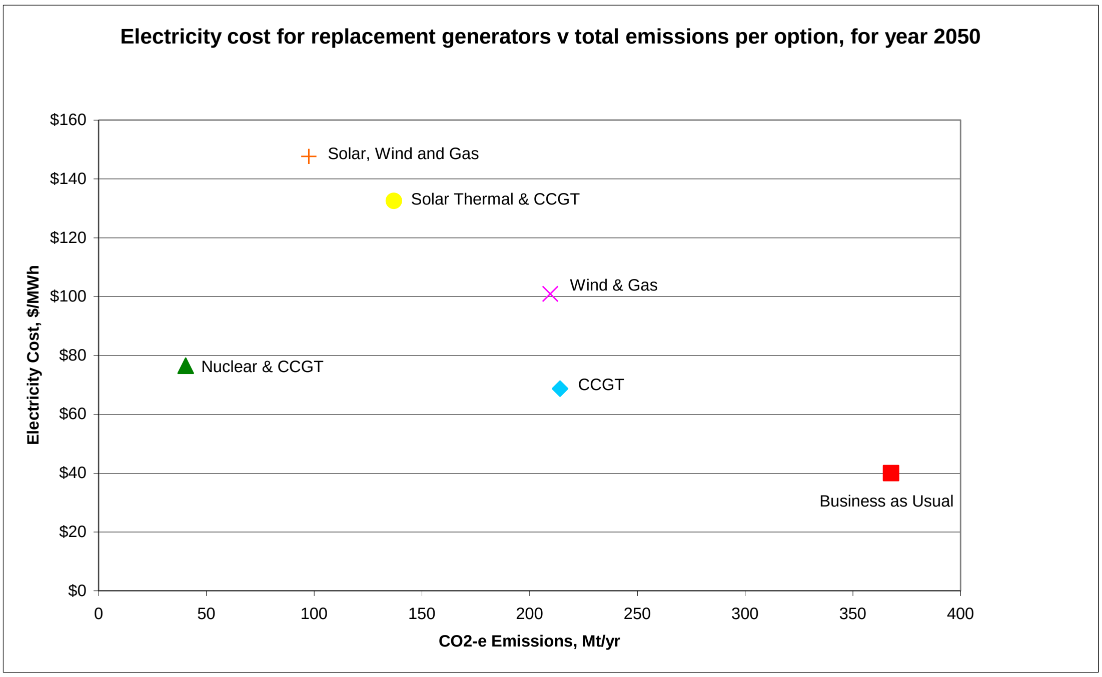

Figure 12: Long run marginal cost of electricity (\$/MWh) in 2050 (for the coal and replacement technologies only) versus total emissions (t CO2-e/MWh) from all the technologies in each option.

Conclusions

Business as Usual (mostly coal) is the least cost option but has the highest CO2 emissions.

The Nuclear power option will enable the largest cut in CO2-e emissions from electricity generation.

The Nuclear option is the only option that can be built quickly enough to make the deep cuts required by 2050.

The Nuclear option is the least cost of the options that can cut emissions sustainably.

Wind and solar are the highest cost ways to cut emissions.

A mixture of solar thermal and wind power is the highest cost and has the highest avoidance cost of the options considered. Mixing these technologies does not reduce the cost, it increases the cost.

The results are sensitive to the input assumptions and input data, but the ranking of the options, and therefore the conclusions, are robust to the changes of inputs tested.

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Appendices

Appendix 1 - CO_2 Emissions Intensity

I have not been able to obtain Australian average CO_2 emissions factors for the generation technologies cited in the ABARE (2007) projections of electricity supply. So I have attempted to calculate them for the purpose of this simple comparison.

ABARE + DCC

http://www.abareconomics.com/interactive/energy_dec07/excel/I1.xls
http://www.climatechange.gov.au/~/media/publications/greenhouse-gas/national-greenhouse-factors-june-2009-pdf.ashx

Below is an example calculation of sent-out CO_2 emissions intensity for electricity generated from Black Coal.

From ABARE (2007), Table I (for 2007-08):

Electricity sent out = 518.3 PJ
Black Coal consumed = 1,374.6 PJ

From DCC NGA Factors (2009), Table 1 and Example 1:

Emissions factor for burning black coal = 88.4 kg CO_2-e/GJ = 88,400 t CO_2-e/PJ

Emissions intensity for electricity (from black coal) = 1374.6 x 88,400 / 518.3 = 234,448.5 t CO_2-e/PJ

Convert to t CO_2-e/MWh:

234,448.5 x 3600 / 1,000,000,000 = 0.844 t CO_2-e/MWh

The calculations for the four fossil fuel technologies yield the following emissions intensity (in t CO_2-e/MWh sent out):

Technology	Emissions intensity (t CO_2-e/MWh sent out)
Black coal	0.84
Brown coal	1.20
Oil	0.78
Natural gas	0.49

These figures, especially natural gas, seem low compared with ACIL-Tasman and NSW GGas figures (see below).

NSW GGAS Fact Sheet, Nov 09

http://www.greenhousegas.nsw.gov.au/Documents/FS-Comp-PoolCoeff-Nov09.pdf

The CO_2 emissions intensity for NSW electricity (sent out) in 2008 was 0.983 t CO_2-e/MWh. This includes electricity generated by black coal, hydro and natural gas. Because the emissions from hydro are zero and the emissions from natural gas generation are about 0.7, it follows that the emissions from coal must be greater than 0.983. Since about 6% is generated by hydro and 10% by natural gas, a rough estimate would put the emissions from black coal generation at about 1.05 t CO_2-e/MWh.

ACIL-Tasman

ACIL-Tasman, 2009, "Fuel resource, new entry and generation costs in the NEM" Table 18 to 22 Emission factors and intensity for existing and committed
http://www.aciltasman.com.au/images/pdf/419_0035.pdf

The unweighted-average emission factors for the existing power stations in NSW, Qld, SA, Tas and Vic are as follows (t CO_2-e/MWh, sent out):

Brown Coal	1.32
Black Coal	1.00
Oil	0.99
Natural Gas	0.67

A weighted average would provide more accurate emissions intensities.

Summary

Emissions intensity (t CO_2-e/MWh sent out):

Technology	ABARE + DCC	ACIL-Tasman	New entrant technologies (ACIL-Tasman, Table 41)
Black coal	0.84	1.00	SC (WC) = 0.84
Brown coal	1.20	1.32	SC (WC) = 0.99
Oil	0.78	0.99	
Natural gas	0.49	0.67	OCGT = 0.76; CCGT = 0.47

The emissions intensities calculated by applying the DCC emissions factors to the ABARE primary fuels consumption are lower than the unweighted-average of the ACIL-Tasman emissions intensities. Furthermore, the emissions intensities calculated from ABARE and DCC are close to or even lower, in the case of natural gas, than the new and more efficient technologies that are not yet implemented (last column in table above). The ACIL-Tasman figures appear to be the most detailed analysis of the CO_2 emissions intensities and the best documented. However, the ABARE + DCC total emissions calculated using the ABARE+DCC figures are closer to the official total emissions from electricity for Australia, so I shall use these until I find a better source.

Appendix 2 – Electricity Cost for the coal and replacement technologies

Table 2-1: Electricity cost for coal and the replacement technologies (Long Run Marginal Cost, $/MWh sent out, in constant 2009 $).

Technology	2010	2015	2020	2025	2030	2035	2040	2045	2050
Black Coal	40	40	40	40	40	40	40	40	40
Brown Coal	40	40	40	40	40	40	40	40	40
USC Black	55	51	50	49	48	48	47	47	46
USC Brown	53	50	50	49	48	48	48	47	47
CCGT	60	57	59	60	62	64	65	67	69
OCGT	97	92	96	97	100	102	104	106	108
Nuclear	101	99	98	96	86	82	80	77	75
Wind	110	107	104	101	98	95	92	89	86
Solar Thermal	233	229	225	220	197	189	184	178	173

The colours in Table 2-1 show the source of the data. The legend is below:

Legend	Source and Comments
	Information sourced from references
	IES (2004), Exhibit 1-2. $38 at CF=90% in 2004. Assumed: $40 for 2010.
	ACIL-Tasman (2009), Table 52. Projections are for the period 2010 to 2029.
	EPRI (2009b), Table 7.1 p7-5 and p10-19. US$99/MWh = A$110/MWh @ conversion rate A$1 = US$0.90
	NEEDS (2008), p34, Fig 3.11: Solar only, Case B, Pessimistic, 2008, = 14 Eur cents/kWh. At exchange rate $1 = EUR 0.60, the electricity cost = A$233/MWh. This is the value used in this analysis. For comparison, EPRI (2009b), Table 8-2 and p10-20 gives cost as US$225/MWh (= A$250/MWh) for case with 6 h energy storage (2008 constant $). It is worth noting that the cost has increased 30% in 1 year; the cost in the 2008 version of this same report was US$175/MWh.
	Author's projections
	$40 continued throughout the period.
	Cost reduction rate of -0.2% pa applied from the 2030 to 2050. This is a continuation of the rate ACIL-Tasman used for the last three years of their projections.
	Linear trend line fitted to the LRMC for the period 2013 to 2029 and applied from 2030 to 2050.
	ACIL-Tasman applied a learning curve, applicable for FOAK in Australia, for the years 2024 to 2029. My projection is at -0.9%pa from 2030 to 2035, then at -0.6% pa to 2050. The -0.6% pa is the same as Frontier (2009), Table 15 for the capital cost reduction rate for Wind, IGCC and USC CCS.
	Extended at the cost reduction rate of -0.6% pa based on the capital cost learning curve for Wind in Frontier (2009), Table 15
	Applied same cost reduction rates as nuclear; because this analysis assumes both technologies start being commissioned in 2020.

How were the costs, and rates of change, selected?

IES (2004) is the most recent, authoritative reference for the long run marginal cost (LMRC) of the existing Australian coal fired power stations that I am aware of. So I used their LRMC of $38 for 90% capacity factor and rounded to $40 because the IES figures are now about 6 years out of date.

ACIL-Tasman (2009) provides the most complete and detailed set of consistent data for the period 2010 to 2029. It is in constant 2009 dollars. However, it does not have data for Wind or Solar Thermal. It also does not cover the period 2030 to 2050. So other sources are needed. ACIL-Tasman data is used where ever it is available.

EPRI (2009b) provides consistent costs for all technologies in 2009 constant dollars. It does not provide yearly projections but does give projected costs at both 2015 and 2025. The EPRI cost is used for Wind in 2010 and as is also used as a check on the solar thermal cost.

NEEDS (2008) provides detailed cost projections to 2050. However, the cost reduction rates appear to be extremely optimistic for a technology development rate. NEEDS uses a cost reduction rate of about 10% per year from 2007. Comparing the (EPRI 2009b) with the equivalent previous EPRI report (November 2008) shows the LRMC has actually increased 30% in one year. The cost reduction rates applied in the NEEDS (2008) report are not used in the analysis.

Frontier (2009), Table 15 provides cost reduction rates for all technologies except nuclear and solar thermal.

Where I could deduce reasonable rates of change of the costs from the ACIL-Tasman LRMC data for the period 2010 to 2029, I used it and extended it from 2030 to 2050. This was the case for CCGT and OCGT. However, I excluded the years 2010 and 2011 because of a sudden drop in LRMC which does not seem to be applicable to the remainder of their projected trend. The future coal technologies, Ultra Super Critical (USC) coal, are used in the Business as Usual Option. The learning rate applied to USC coal is the rate that ACIL-Tasman used for the last three years of their projections.

Nuclear is more difficult. ACIL-Tasman applied a cost reduction rate of -0.5% pa from 2010 to 2024. This represents the assumed cost reduction rate internationally for this period. ACIL-Tasman then applies a much steeper cost reduction rate for the period 2025 to 2029. This represents the cost reduction as Australia gains experience building its second to fourth nuclear power plants. This cost reduction rate would continue but at a reducing rate. A fitted curve to the initial data is too steep. So I have selected a rate of -0.9% pa for 5 years (2030 to 2035) then -0.6% pa to 2050. This is the same rate as Frontier gives for Wind, IGCC and Ultra Super Critical coal.

For Wind I used a cost reduction rate of -0.6% pa for the full period from 2010 to 2050. This is the cost reduction rate for Wind in Frontier (2009).

For Solar Thermal I have applied the same cost reduction rate as for nuclear for the complete period from 2010 to 2050. The reason is that both technologies are assumed, in this analysis, to begin being commissioned in 2020. As mentioned above, the cost reduction rates in the NEEDS (2009), which they called “learning rates”, are considered to be far too optimistic for this analysis, and completely inconsistent with the cost reduction rates for the other technologies. There is also no actual experience, that I am aware of, that would support this rate. In fact the reverse is the case. For example, EPRI’s estimate of the cost of electricity from solar thermal has increased by 30% in one year which also indicates that the cost reduction rates assumed by NEEDS are overly optimistic.

Transmission Costs

Transmissions costs for wind and solar power are calculated at the rate of $15/MWh (Gene Preston, Dec 2009, pers. comm. and EPRI, 2009a, pB-9).

Appendix 3 – Calculated 'Capacity' (MW)

The calculated 'capacity' is actually the average power. It is calculated by converting energy sent-out by the capacity factor assumed for conversion. The capacity factor assumed for conversion is shown in the far right column. These calculations do not align with the actual installed capacities. They do not include the capacity need to meet peak demand nor the reserve margin needed to cover for scheduled and unscheduled outages.

The first section of the table shows the calculated 'capacity' for all the Business as Usual technologies. The second section shows the calculated 'capacity' of coal generators remaining after decommissioning. The remaining sections show the calculated 'capacity' of the replacement technologies.

Option 1 - BAU	2010	2015	2020	2025	2030	2035	2040	2045	2050	CF
Black coal	18.6	19.9	21.2	23.6	26.1	27.9	30.0	32.1	34.2	90%
Brown coal	7.3	7.9	8.7	9.2	9.2	9.5	9.7	9.9	10.1	90%
Oil	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	90%
Natural gas	6.0	8.3	9.8	11.0	12.5	13.9	15.3	16.6	18.0	90%
Biomass	0.3	0.3	0.5	0.5	0.5	0.6	0.7	0.8	0.8	90%
Biogas	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	90%
Hydroelectricity	13.3	13.8	14.3	14.9	15.5	16.0	16.6	17.2	17.7	15%
Solar energy	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	15%
Wind energy	1.6	1.6	1.7	1.8	2.1	2.1	2.3	2.4	2.5	30%
Total	**48.1**	**52.9**	**57.4**	**62.2**	**67.0**	**71.3**	**75.8**	**80.3**	**84.8**	
Coal remaining after decommissioning										
Black coal	18.6	14.9	11.2	8.6	6.1	2.9	0.0	0.0	0.0	90%
Brown coal	7.3	5.9	4.7	3.2	1.2	0.0	0.0	0.0	0.0	90%
Option 2 - CCGT										
CCGT	0.0	7.0	14.0	21.0	28.0	34.5	39.7	42.0	44.4	90%
Option 3 - Nuclear & CCGT										
Nuclear	0.0	0.0	1.0	6.0	13.5	23.5	33.5	43.5	53.5	90%
CCGT	0.0	7.0	13.0	15.0	14.5	11.0	6.2	-1.5	-9.1	90%
Option 4 - Wind & Gas										
Wind	0.0	7.0	14.0	21.0	28.0	34.5	39.7	42.0	44.4	30%
CCGT	0.0	3.2	6.4	9.7	12.9	15.9	18.3	19.3	20.4	90%
OCGT	0.0	3.2	6.4	9.7	12.9	15.9	18.3	19.3	20.4	90%
Option 5 - Solar & CCGT										
Solar Thermal	0.0	0.0	0.5	3.0	6.8	11.8	16.8	21.3	23.8	90%
CCGT	0.0	7.0	13.5	18.0	21.3	22.8	22.9	20.8	20.6	90%
Option 6 - Solar & Wind & Gas										
Wind	0.0	7.0	14.0	21.0	28.0	34.5	39.7	42.0	44.4	30%
Solar thermal	0.0	0.0	0.5	3.0	6.8	11.8	16.8	21.3	23.8	90%
CCGT	0.0	3.2	6.4	9.7	12.9	15.9	18.3	19.3	20.4	90%
OCGT	0.0	3.2	6.4	9.7	12.9	15.9	18.3	19.3	20.4	90%

About the author

Peter Lang is a retired geologist and engineer with 40 years experience on a wide range of energy projects throughout the world, including managing energy R&D and providing policy advice for government and opposition. His experience includes: coal, oil, gas, hydro, geothermal, nuclear power plants, nuclear waste disposal, and a wide range of energy end use management projects.