Renewable electricity for Australia – the cost

Critique of
"Simulations of Scenarios with 100% Renewable Electricity in the Australian National Electricity Market"

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Summary

Here I review the paper "*Simulations of Scenarios with 100% Renewable Electricity in the Australian National Electricity Market*" by Elliston *et al.* (2011a) (henceforth EDM-2011). That paper does not analyse costs, so I have also made a crude estimate of the cost of the scenario simulated and three variants of it.

For the EDM-2011 baseline simulation, and using costs derived for the Federal Department of Resources, Energy and Tourism (DRET, 2011b), the costs are estimated to be: $568 billion capital cost, $336/MWh cost of electricity and $290/tonne CO2 abatement cost.

That is, the wholesale cost of electricity for the simulated system would be seven times more than now, with an abatement cost that is 13 times the starting price of the Australian carbon tax and 30 times the European carbon price. (This cost of electricity does not include costs for the existing electricity network).

Although it ignores costings, the EDM-2011 study is a useful contribution. It demonstrates that, even with highly optimistic assumptions, renewable energy cannot realistically provide 100% of Australia's electricity generation. Their scenario does not have sufficient capacity to meet peak winter demand, has no capacity reserve and is dependent on a technology – 'gas turbines running on biofuels' - that exist only at small scale and at high cost.

Introduction

I have reviewed and critiqued the paper "*Simulations of Scenarios with 100% Renewable Electricity in the Australian National Electricity Market*" by Elliston *et al.* (2011a) (henceforth EDM-2011).

This paper comments on the key assumptions in the EDM-2011 study. It then goes beyond that work to estimate the cost for the baseline scenario and three variants of it and compares these four scenarios on the basis of CO2 emissions intensity, capital cost, cost of electricity and CO2 abatement cost.

Comments on the EDM-2011 study

The objective of the desktop study by EDM-2011 was to investigate whether renewable energy generation alone could meet the year 2010 electricity demand of the National Electricity Market (NEM). Costs were not considered. The study used computer simulation to match estimated energy generation by various renewable sources to the known hourly average demand in 2010. This simulation, referred to here as the "baseline simulation" proposed a system comprising:

- 15.6 GW (nameplate generation capacity) of parabolic trough concentrating solar thermal (CST) plants with 15 hours thermal storage, located at six remote sites far from the major demand centres;

- 23.2 GW of wind farms at the existing NEM wind farm locations - scaled up in capacity from 1.5 GW existing in 2010;

- 14.6 GW of roof-top solar photovoltaic (PV) in Brisbane, Sydney, Canberra, Melbourne and Adelaide;
- 7.1 GW of existing hydro and pumped hydro;
- 24 GW of gas turbines running on biofuels;
- A transmission system where "*power can flow unconstrained from any generation site to any demand site*" – this theoretical construct is termed a "copperplate" transmission system.

The accompanying slide presentation by Elliston *et al.* (2011b), particularly slides 5 to 12, provides a succinct summary of the objective, scope for their simulation study, the exclusions from the scope, the assumptions and the results.

The results of the baseline simulation show that there are six hours during the year 2010 when demand is not met, with a maximum power supply shortfall of 1.33 GW. It should be noted that the supply shortfall would be significantly greater with higher time resolutions, e.g. 5 minute data rather than the 1 hour increments used, but this limitation is not addressed by EDM-2011.

The EDM-2011 approach is more realistic than Beyond Zero Emissions (2010) "*Zero Carbon Australia – Stationary Energy Plan*" (critiqued by Nicholson and Lang (2010), Diesendorf (2010), Trainer (2010) and others), especially because EDM-2011's approach, as they say, *"is limited to the electricity sector in a recent year, providing a more straight forward basis for exploring this question of matching variable renewable energy sources to demand.*" As the authors say, "*this approach minimises the number of working assumptions*".

Despite the lack of costings, the EDM-2011 study is a useful contribution. It demonstrates that, even with highly optimistic assumptions, renewable energy cannot realistically provide 100% of our electricity generation. The baseline simulation does not have sufficient capacity to meet peak winter demand, has no capacity reserve, and is dependent on a technology - gas turbines running on biofuels - that currently exist only at small scale and at high cost.

The study is based on a number of assumptions that I argue are unacceptable:

1. a system with insufficient capacity to meet the winter peak demand and no capacity reserve margin would violate Australian Energy Regulator (AER) requirements;
2. the assumed capacity factors for the renewable energy generators are too high to be credible for the average plant life in a 100% renewable energy system;
3. the assumptions about the way the existing hydro and pumped hydro facilities can be used are not practical;
4. the assumptions about pumping and generating capacity of the pumped hydro plants are unjustified;

5. the practicable capacity of gas generators running on biofuels (and the capability of the biofuel system to provide the fuel and store it until needed) has not been demonstrated and critical details are glossed over;

6. the assumptions about a 'copper-plate' transmission system is unrealistic;

7. the assumptions about reducing winter peak demand is highly optimistic and not borne out by recent experience.

These assumptions, and the cost of the system simulated are discussed in the following sections.

Comments on the technologies and assumptions

Gas turbines running on biofuels

Gas turbines running on biofuels are not a proven, commercially viable electricity generation technology at the scale required (IEA, 2007).

Although some countries, e.g. those quoted by EDM-2011, do have some electricity generated by biomass, there are a wide variety of technologies used, and very little of it is gas turbines running on biofuels. Much of it is in small plants, such as combined heat and power (CHP) fuelled by wood waste, chicken litter and other waste products. Most of it is in thermal plants, not gas turbines. IEA/OECD (2010), Table 3.7 lists four countries with some biogas capacity but this is mostly as reciprocating engine generators on waste dumps, sewage plants and the like. According to *Energy in Australia 2011* (DRET, 2011a), Australia has 231 MW of biogas generating capacity.

The land area that would be required for the required biofuel production would be unacceptable (1.6 million hectares of prime agricultural land in good years (Electropaedia); far more in droughts; this represents 74% of Australia's irrigated agricultural land and 4% of all arable land (ARNA, 2009)). The water requirements would also be unacceptable. As would the truck movements required to collect the biomass. A large commercial plant would need 100 to 200 truck movements per day and night collecting biomass from an area of 100 km radius (Simms *et al.*, 2009)

The existing biomass electricity generation plants tend to be baseload or intermediate load plants. Some of the European biogas systems, which use a biomass feed, take around 30 days to make the biogas from the biomass feed. Such plants cannot be used for just the few days a year in winter when the CST, PV and Wind plants are unable to supply enough power to meet the demand. The biogas plants listed in IEA (2010) *Projected cost of electricity generation*, Table 3.7 have assumed capacity factors of 80%, 85% and 90%. These types of plants are not suited to the peaking plant role envisaged by EDM-2011.

Grattan Institute (2012) gives cost estimates for biofuel electricity generation in Australia; however, the costs are based on a capacity factor of 70%. The report makes no mention of "gas turbines running on biofuels". The technologies mentioned are steam plants and reciprocating engines. Following are three quotes from the report (Section 8):

> *For Bioenergy to provide 10% or more of Australia's electricity needs it will have to use the large amounts of energy embodied within cereal crop residues*
>
> *Even at 20 to 30 megawatts such plants require large amounts of biomass fuel to realise good capacity factors that are essential to offsetting the high upfront capital costs.*
>
> *For a 30MW power plant at a 70% capacity factor the land area would be around 240,000 hectares and involve nearly 500 average sized wheat farms.*

Note, these plants have to be run with capacity factors of around 70% to be economically viable. They are certainly not the sort of 'peaker' plants envisaged by EDM-2011.

For the gas turbines running on biofuels to work as envisaged by EDM-2011, I envisage biogas would have to be produced throughout the year and stored for use during the few days in winter at the times when the remainder of the renewable energy generators cannot provide sufficient power. The amount of biogas required per year is estimated to be 290 PJ (equivalent to 116% of natural gas consumed in electricity generation and 37% of total gas consumption in the eastern states in 2009-10). But most of this is required over just a few short periods in winter.

The cost of electricity from the biogas plants is crudely estimated to be $563/MWh based on the 13% capacity factor assumed in the simulations. Unlike natural-gas-fired gas turbines, which utilise low capital cost generators with readily available fuel, the biofuel proposal also requires capital intensive biofuel plants, year-round feedstock harvesting, and large-scale biogas storage and distribution infrastructure.

Given that the biogas option is so expensive, a cost estimate below was done for an alternative using natural gas instead of biogas. All other assumptions are unchanged.

However, even this alternative would be much more expensive than a system that uses gas throughout the year. In the baseline simulation, most of the gas generation would occur over a few short time spans each year. That requires either the gas supply lines be sized to deliver the gas volumes needed over the short periods, or the gas must be stored at site for use when needed. Either option will have a significant impact on the price of the delivered fuel and, therefore, on the cost of electricity. The baseline simulation has 24 GW of gas generation capacity supplying 28.1 TWh of electricity per year. However, EDM-2011's Figure 3 shows that 26 GW is needed to provide a supply with no unserved energy and no unmet hours. This capacity in the EDM-2011 baseline simulation is about 4 times the capacity of the existing NEM gas generators.

We should expect the generators' fuel costs would increase by more than a factor of four. One reason is that there is a small total consumption of gas over the year, but high usage rate for just a few short periods. The gas supply system would have to provide the infrastructure to deliver the peak capacity demanded, but it would be paid for by a small quantity of gas sold per year. So the gas price during the winter peak demand would have to be increased significantly. A second reason the gas price would increase is that there would be a much higher demand for gas in winter at the same time as the gas demand peaks for winter heating.

Hydro

EDM-2011 assumes the water could be saved through most of the year and used on the few short periods in winter when the renewable energy generators cannot meet the demand. This is not how our hydro schemes are designed to operate, nor capable of operating. Here are some reasons why they cannot be operated in this way:

1. The generators would not be able to generate throughout the year to sell electricity at the time of peak demand. Therefore, their revenue would be much less over the year. So they would not be economically viable without a significant increase in the price they could charge for their electricity.

2. The hydro generation is needed throughout the year to balance the power surges in the system. That is one of the most valuable functions of the hydro system and it will almost certainly be required to continue to serve that role.

3. Hydro cannot be stored all year and released in a massive river flush over a few days in winter. To generate a great deal of energy over just a few days would mean large water releases which would compromise the management of storage and releases for irrigation and can cause flooding and unacceptable erosion to the river banks downstream.

4. If the management of storage and irrigation releases is compromised the water would be released in winter and not available for irrigation in summer.

Hydro generation is constrained by the average water inflows and the water storage capacity to level out the fluctuation in water inflows over the long term. Snowy Hydro's capacity factor is about 14%. Total generation by hydro in the NEM in 2009-10 was 12,522 GWh, and less in 2008-09 and 2007-08. This places an upper limit on the amount of hydro generation the simulation should generate.

It should be assumed the hydro generators will operate much as they do now.

Pumped hydro

The simulation assumes there will be no increase in the existing hydro and pumped hydro energy storage (PHES) capacity in the NEM. The existing pumped hydro plants have a maximum energy storage capacity of 20 GWh (Lang, 2010). There are also limits on the amount of energy that can be stored per hour and the time of day when pumping can occur.

The EDM-2011 simulation does not appear to limit the amount of energy that can be stored per day by the pumped hydro plants. I estimate the upper limit on the rate of storing recoverable energy with the pumped hydro plants is (MWh stored per hour):

Tumut 3	394
Wivenhoe	328
Kangaroo Valley & Bendeela	157

Furthermore, there is a minimum duration for which the pumps must be able to operate continuously once started (e.g. 4 hours). So days when the pumps will not be able to run continuously for the minimum duration will not be able to store energy.

There is also a limitation on the hours of the day when pumping and generating can occur. They cannot occur at the same time. Since most of the excess power that would otherwise be spilled occurs during daylight hours when the CST plants are able to generate excess energy, it would seem that, in the simulation, pumping must be reserved for daylight hours when there is excess solar generating capacity.

It is not clear from the EDM-2011 paper how the model handles the distinction between the energy generated by hydro versus pumped-hydro in the two Australian facilities that are both hydro and pumped-hydro (i.e. Tumut 3 and Kangaroo Creek & Bendeela). EDM-2011's Figure 2 shows pumped hydro generating at 2.2 GW for 40 hours on 9 and 10 January – a total of 88 GWh. This is not possible. There is only 20 GWh of storage and the pumps can store energy at about 4.5 GWh per day. The existing system would need to pump for about 7 hours with all pumps operating to be able to generate for 5 hours at 0.9 GW. So, the maximum daily generation, on consecutive days, would be about 4.5 GWh (excluding draw down from storage).

It would seem, with EDM-2011's assumption of pumped-hydro being dispatched first, the 20 GWh of available storage would not be recharged each day since only about 4.5 GWh could be recharged each day. In the simulation, pumped hydro contributes little during the critical winter days shown in Slide 12 (Elliston *et al*, 2011b) and generates nothing on some days, e.g. July 1, 2, 5 and 6.

Only Wivenhoe is a 'pure' pumped hydro facility. The other two facilities are mostly hydro, with a small pumped hydro capacity. Therefore, it is more realistic for the EDM-2011 simulation to assume the hydro capacity is 6.6 GW and the pumped hydro can generate about 4.5 GWh per day at up to 0.9 GW on consecutive days (more for a short time if drawing down from 20 GWh of stored energy).

Concentrating Solar Thermal (Parabolic Trough)

EDM-2011 assumes a 60% capacity factor for CST. The details underpinning this are sparse, thus a number of questions arise. Is the assumed capacity factor a realistic average for the life of the plant? What is the basis for the assumed capacity factor for CST? Does it take into account:

1. The system performance and reliability that is likely to be achieved over the full book life of the facilities?
2. Spilled energy?
3. Scheduled and unscheduled outages?
4. Outages in the long transmission lines (which are mostly in remote areas far from the major service centres, so repairs will take longer than for the existing system)? Inevitably, these transmission lines will have lower reliability than the NEM average. Therefore, the capacity factor of the wind and CST plants would be reduced because of transmission line outages.

PV

What would be the average capacity factor for a fleet of 14.6 GW of roof-top, fixed plate PV over a 30 year life?

- How much would have to be spilled because the distribution system cannot handle the peak power output and power surges?
- How much would the assumed 16% capacity factor be reduced over the 30 year assumed life of each installation as a result of, for example:
    - Performance deterioration of the solar panels
    - Performance deterioration due to collecting dirt and lack of cleaning
    - Some PV installations stop working or are disconnected, for whatever reason, and are never fixed or reconnected
    - Buildings are sold, new owners are not interested in maintaining the system; some don't keep it connected
    - Buildings are knocked down and rebuilt without reinstalling the original PV system (the cost analysis assumes an average 30 year life for the original installations).

Is 14.6 GW of roof top solar PV realistic? That would be the equivalent of 1 kW for every man woman and child, or average of over 2 kW per dwelling. The PV is assumed to be on residential dwellings many of which could be on apartment blocks with limited roof space. Many of the houses may have tree shading and many will not have sufficient north facing roof space for a 2 kW system.

While the inclusion of 14.6 GW of rooftop solar may be theoretically possible, the NEM could not accommodate such a concentrated non-dispatchable and variable energy supply without large-scale distributed storage and advanced 'smart-grid' management. All of which is expensive, but no attempt has been made to cost this

Wind

The assumed capacity factor of 30% for wind seems too high for a 100% renewable system. Although this is a valid figure for individual wind farms, much of the wind energy from a large-scale network of farms would have to be spilled. So the system wide average capacity factor for wind would be less than 30% in an all renewable energy system comprising primarily solar and wind generation.

Transmission

The EDM-2011 simulation assumes a 'copper-plate' transmission and distribution system ("*power can flow unconstrained from any generation site to any demand site*"). To achieve this assumption would require extensive additions to the existing transmission and distribution systems. The additions would need to have the capacity to carry the full peak power output from each generator plant.

The distribution systems would have to be upgraded to carry the peak power output of the PV systems in each area, or have smart grids to curtail the power output of the PV systems when they exceed the capacity of the distribution and transmission systems.

The additions to the transmission system would incur additional energy losses. Therefore, the 204.4 TWh of electricity generated in 2010 must be increased to account for the extra transmission and distribution losses. Appendix 2 contains more about the 'copperplate' transmission system assumptions, options and the basis for the cost estimates.

Winter peak demand reductions

EDM-2011 suggest methods to reduce the peak demand in winter so the renewable energy system can meet the demand. However, this approach is inconsistent with the stated objective which is to find a 100% renewable energy solution that can meet the 2010 NEM demand.

The relationship between energy efficiency and peak load is complex. As such, caution needs to be exercised in assuming that energy efficiency measures will invariably lead to commensurate reductions in peak demand. Indeed, electric vehicles and other unforeseeable new sources of demand may increase the peak.

Scenarios costed and compared

I have made a crude estimate of the capital cost, the Levelised Cost of Electricity (LCOE) and the CO2 Abatement Cost for the EDM-2011 baseline simulation. I have included an estimated cost for needed additions to the transmission and distribution systems to allow them to approach the 'copper-plate' assumption.

I have also analysed three additional scenarios with changes to some of the baseline assumptions. The changed assumptions include: sufficient generating capacity to meet all demand and maintain about 20% capacity reserve (which is less than a typical level for modern electricity networks, and much less than in the NEM); natural gas instead of biogas; reduced system-wide capacity factors for CST, PV and Wind, and less capacity for additions to the transmission system. The reduced capacity factors of CST, PV and Wind are compensated for by increasing the amount of generation by natural gas. Also included is additional generation to compensate for the increased energy loss in the additions to the transmission system.

The scenarios (detailed in Appendix 1) compared are:

1. Baseline EDM-2011 simulation (i.e. gas turbines running on biofuels)

2. Baseline with gas turbines running on natural gas

3. Less renewable energy + more gas to improve reliability - Scenario 2 with most pumped hydro capacity reassigned to hydro, reduced pumped hydro capacity factor, reduced capacity factor of CST, Wind and PV, increased natural gas capacity and capacity factor.

4. Reduced transmission capacity + more gas – Scenario 3 with half transmission capacity from wind farms, half transmission capacity of interstate interconnectors and reduced capacity factor of CST, PV, Wind and pumped hydro generation because of transmission constraints.

Capacity, capacity factor and generation assumptions

This section summarises the capacity, capacity factor, amount of generation contributed by each technology and each technology's share of the total generation. These data are presented for the baseline (Scenario 1) and the three varied scenarios identified above as Scenarios 2, 3 and 4.

1. Baseline (i.e. gas turbines running on biofuels)

Table 1 lists the capacity, capacity factor, annual generation and share of total generation for each technology in the baseline scenario.

Table 1:

	Units	Hydro	PHES	PV	Wind	CST	biogas	Total
Capacity	GW	4.9	2.2	14.6	23.2	15.6	24.0	**84.5**
Capacity factor		21%	20%	16%	30%	60%	13%	
Annual generation	GWh	9,014	3,854	20,463	60,970	81,994	28,099	**204,394**
Share		4%	2%	10%	30%	40%	14%	**100%**

The capacity factors for hydro and pumped hydro energy storage (PHES) are not explicitly stated in the EDM-2011 paper. I have estimated the capacity factors for the baseline case by subtracting the energy generated by the other technologies from the total 2010 NEM demand (stated by EDM-2011 to be 204.4 TWh).

2. Baseline with gas turbines running on natural gas

Scenario 2 is the same as Scenario 1 but with the gas turbines running on natural gas instead of on biofuels. Table 2 would be the same as Table 1 except the 'biogas' column would be renamed 'natural gas'.

3. Less renewable energy + more gas to improve reliability

The capacity, capacity factor, annual generation, and share for Scenario 3 are:

Table 3:

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Capacity (GW)	GW	6.6	0.9	14.6	23.2	15.6	33.0	**84.5**
Capacity factor		21%	10%	10%	23%	50%	25.6%	
Annual generation	GWh	12,141	770	12,790	46,743	68,328	73,860	**214,632**
Share		5%	0%	6%	21%	30%	34%	**100%**

The total capacity is not the sum of the individual capacities because all but 0.5 GW of the PHES capacity is included in 'Hydro'. The total generation is increased from 204.400 GWh to 214,600 GWh for an assumed 5% energy losses in the additions to the transmission system. The capacity of OCGT is increased from 24 to 33 GW to ensure 20% capacity reserve above peak winter demand. From Slide 12 (Elliston *et al*, 2011b), on July 1 peak demand is about 32.5 GW. At the time of peak demand there is little wind, no solar and no pumped hydro generation (because the pumped hydro was not recharged during the day). So, all the generation must be provided by hydro and gas. To maintain 20% reserve capacity (in case of unavailable generators) we need about 39.6 GW of gas and hydro capacity. We have 6.6 GW of hydro capacity, (excluding the 0.5 GW of 'pure' pumped hydro capacity because it may not have been recharged as was the case on July 1, 2, 5 and 6). So we need about 33 GW of gas capacity to give a 20% capacity reserve on 1 July 2010.

4. Reduced transmission capacity + more gas

The capacity, capacity factor, generation and share for Option 4 are:

Table 4:

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Capacity (GW)	GW	6.6	0.9	14.6	23.2	15.6	33.0	**86.5**
Capacity factor		21%	7%	10%	18%	40%	33.9%	
Annual generation	GWh	12,141	539	12,790	36,582	54,662	97,911	**214,626**
Share		6%	0.3%	6%	17%	25%	46%	**100%**

In this option the capacity of the transmission line from the wind farms is arbitrarily halved. The capacity factor and generation for wind is reduced because the transmissions line capacity is reduced. The capacity factor and generation for CST is reduced because the capacity of the intestate interconnector lines is halved, so less power can be transmitted from the solar plants, at times. The capacity factor and generation of PHES is reduced because the reduced capacity of the interstate interconnectors will reduce the amount of excess power that can be transmitted to and stored in the PHES facilities. The capacity factor and generation of OCGT is increased to compensate for the reduction in contribution from Wind and CST.

To clarify the differences between these assumptions for the four scenarios, the capacity of the technologies is compared in Figure 1, the capacity factor in Figure 2 and the annual generation in Figure 3.

Figure 1:

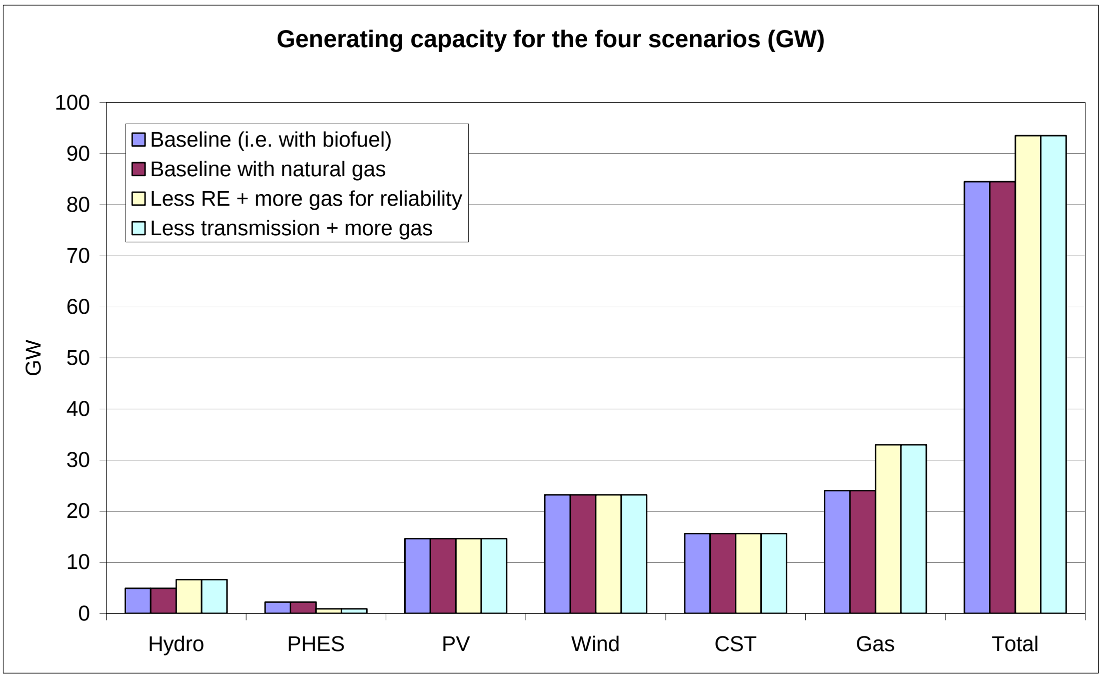


Figure 2:

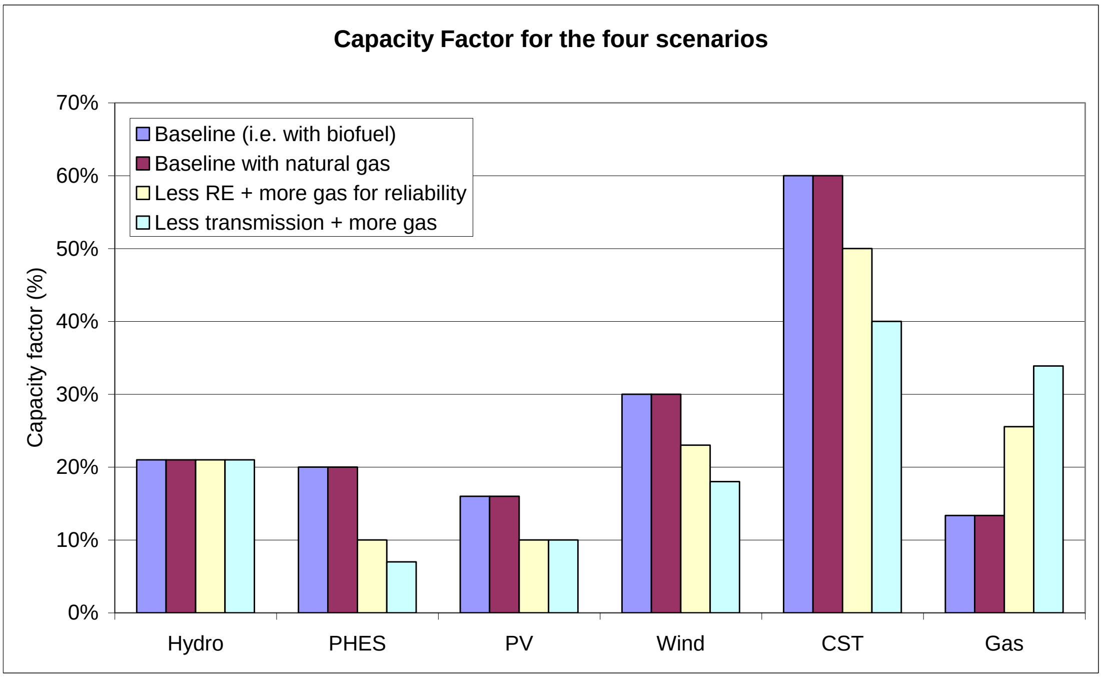
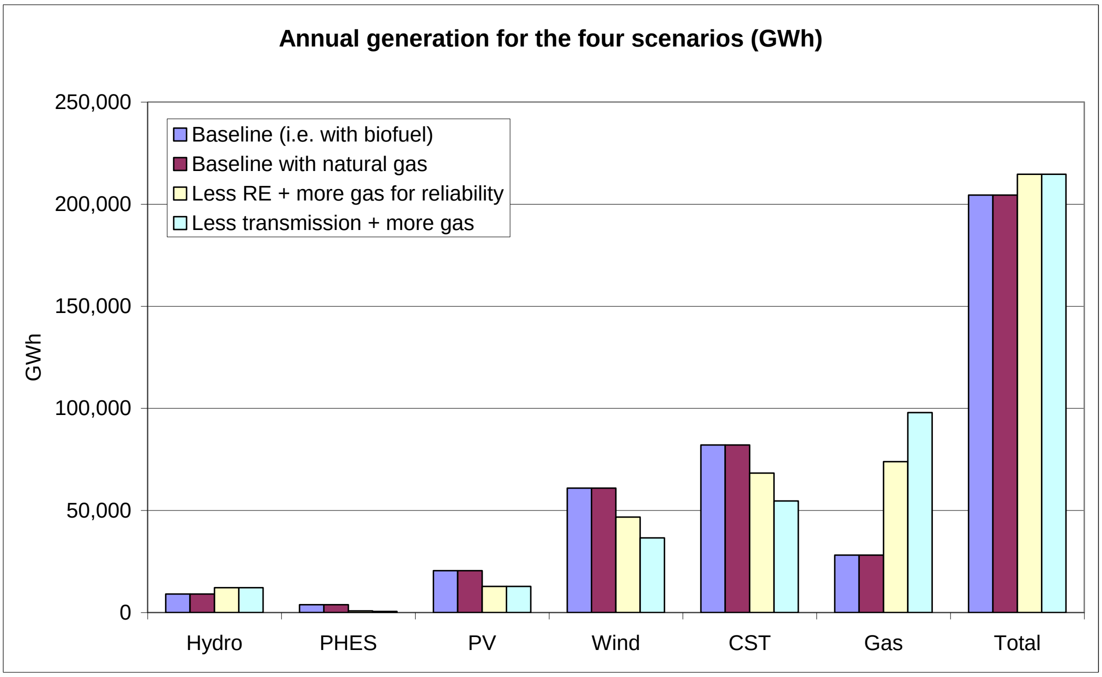


Figure 3



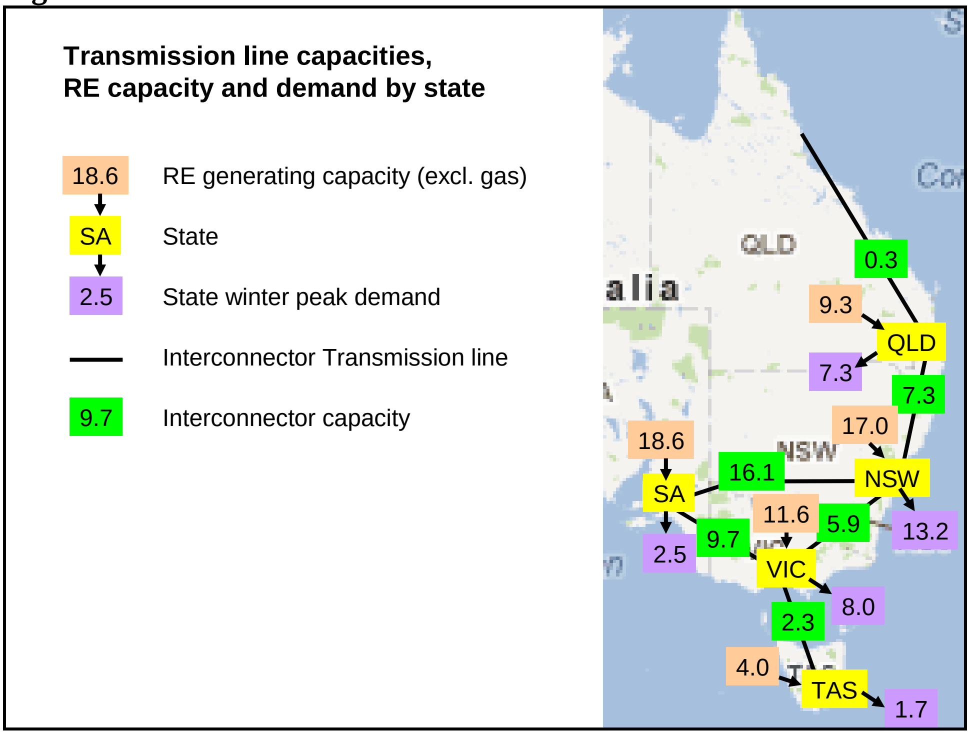
Transmission and Distribution assumptions

For estimating the cost of the transmission system additions needed to achieve the 'copper-plate' assumption (Scenarios 1, 2 and 3), I assumed the transmission lines from each CST plant and wind farm will be sized to carry the rated power output of each facility. The transmission lines are assumed to run from the plant to the closest capital city or to the nearest entry point to the interstate interconnector lines.

The capital cities would have to be linked with interconnector transmission lines. For this crude cost estimating exercise I assumed their capacity must be sufficient to transmit the lesser of the peak demand at the receiver end or generation capacity minus demand at the sender end.

Figure 4 provides a graphic summary of the estimated capacities for the interstate transmission lines, as well as the renewable energy generating capacity (excluding biofuelled gas turbines) and the winter peak demand for each state.

Figure 4:



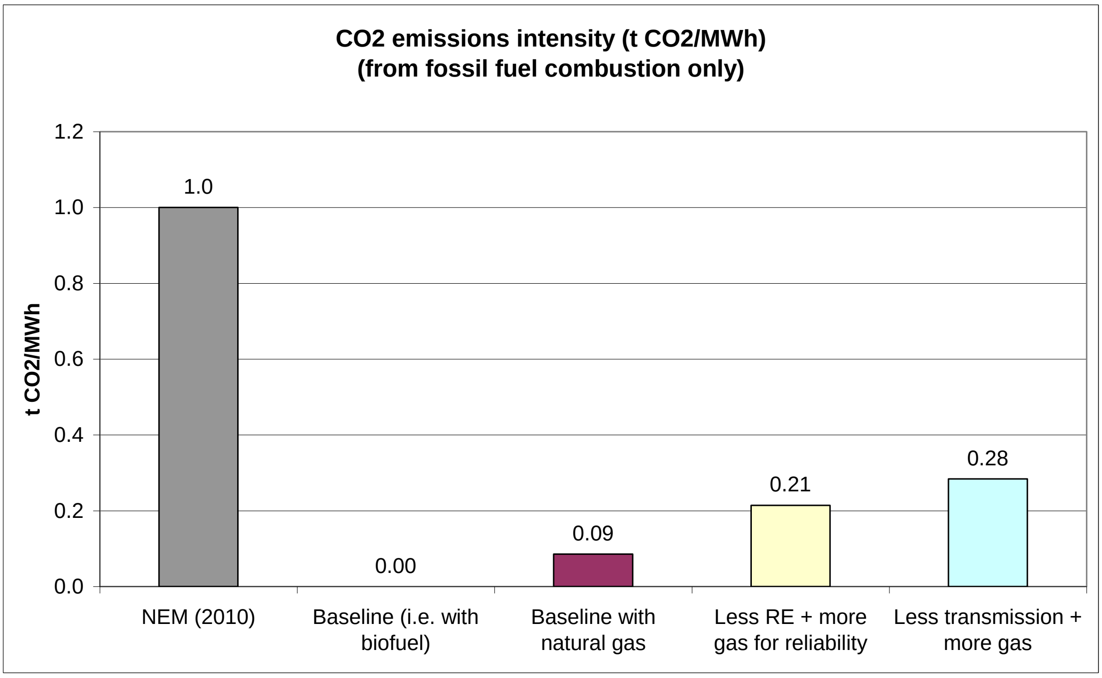
For Scenario 4, the capacity of the transmission lines from the wind farms is half the rated capacity of the wind farms. The capacity of the interstate interconnectors is half the capacity assumed for the 'Copper-plate' scenario (shown in Figure 4). The capacity factor of the PV, CST and wind farms is reduced because of the transmission capacity constraint. Increased generation from gas compensates for the reduced generation from the CST and Wind generators.

The distribution system must allow the 14.6 GW of roof top solar PV, which is located in the residential areas, to supply their peak output without curtailment. It is assumed the transmission network would need to be ungraded to achieve this.

CO2 emissions intensity

Figure 5 compares the CO2 emissions intensity of the four scenarios with the 2010 NEM emissions intensity (DCCEE, 2010). The emissions intensities for the scenarios are for fossil fuel combustion only. Importantly, they are for gas turbines running on natural gas and operating at optimum efficiency. They do not take into account the higher emissions produced when the gas turbines are operating at less than optimum efficiency, for example during start up, shut down, spinning reserve, part load and when their power is cycling up and down to respond to changes in demand and changes in the output of the PV panels and wind farms. If these were included the emissions intensity for the three scenarios that use natural gas would be higher. They would also be higher if fugitive emissions were included. The emissions intensity figure for the NEM includes fugitive emissions. None of the emissions intensities are life-cycle emissions so they do not include the emissions embodied in the plants. The emissions intensity used for the calculations is 0.622 t CO2/MWh 'sent out' (EPRI, 2010). See Appendix 1 for basis of estimates of CO2 emissions intensity.

Figure 5



Cost estimating methodology and assumptions

This section explains how the capital cost, Levelised Cost of Electricity (LCOE) and CO2 abatement cost for each scenario was estimated.

Except where otherwise stated, unit costs are derived from the Department of Resources Energy and Tourism (DRET, 2011b).

All costs are in 2009-10 Australian dollars.

Capital costs are '*Total Plant Cost*' and do not include '*Owner's Costs'* and '*Interest During Construction'* (IDC).

The inputs and intermediate calculation steps for each scenario are presented in Appendix 1.

Capital cost

Generation

The capital cost for each generator technology is the capacity times the unit cost ($/kW) for that technology. The capacity of each generator technology for each scenario is in Tables 1, 3 and 4. The unit cost for each technology, except gas turbines running on biofuels, CST and hydro, is the average of the high and low 'Total Plant Cost' in the DRET (2011c, 2011d) spreadsheets, converted to "sent out".

The central estimates are also presented in ACIL-Tasman (2010). The costs in the DRET spreadsheet are '$/kW installed', so they must be converted to '$/kW sent out':

$/kW 'sent out' = $/kW 'gross' / (100% - 'Auxiliary Load %')

DRET unit costs for CST are for 6 hours thermal storage. The EDM-2011 simulations assume 15 hours storage. The capital cost for CST is factored up by 1.53 to account for the increase of solar field and thermal storage size to increase energy storage from 6 hours to 15 hours. The factor of 1.53 was derived from the DRET (2011c) costs for CST without storage and CST with 6 hours storage, assuming a linear upscaling.

The DRET costs for PV are for 5 MW commercial installations. However, the simulations assume residential, roof-top, solar PV panels. These would normally be around 1 to 6 kW (say average 2 kW), not the 5 MW to which the DRET cost figures apply. The capital cost for PV should possibly be factored up by about 1.5 or 2. I have not done this in these analyses.

The DRET spreadsheets do not include 'gas turbines running on biofuels'. There is very little commercial experience or cost information available for this technology. The capital cost and LCOE for gas turbines running on biofuels are based on $5,051/kW. This was derived from (IEA, 2007), IEA (2010), Grattan Institute (2012) and considerations of what would be needed to provide a secure supply of biofuels in Australia. The cost estimate for gas generators running on biofuels has high uncertainty.

There is no capital cost for the hydro and pumped hydro plants because they already exist and there are no plans in the EDM-2011 baseline or the additional scenarios to build additional hydro plants.

Transmission additions and distribution enhancements

The capital cost estimate for the transmission system additions is the product of the transmission line length, the transmission line capacity and the unit cost ($/MW.km). The unit cost for additional transmission lines is estimated at $1,500/MW.km. This is derived from the AEMO (2011) cost estimates for the *South Australian Interconnector feasibility study* assuming a mix of AC and HVDC transmissions lines. The cost estimate assumptions and intermediate computation results are presented in Appendix 2. The largest uncertainty is in the transmission line capacity for the interstate connectors.

The capital cost for the distribution system enhancements to carry the PV generation is estimated at 20% of the asset value of the NEM distribution system.

Cost of electricity

The Levelised Cost of Electricity (LCOE) for the generator technologies was calculated using the NREL LCOE calculator. The capital cost and capacity factor for each technology and each scenario are in Tables 1, 3 and 4. The other input values are as per DRET (2011c, 2011d) spreadsheets for all except the gas turbines running on biofuels, hydro and pumped hydro. Table 5 lists the other inputs.

Table 5:

Discount rate (constant, before tax)	10.1%
Total Plant Cost (A$/kW 'sent out')	From Tables 1, 3 and 4
Capacity Factor (%)	From Tables 1, 3 and 4
Auxiliary Load (%)	As per DRET
Thermal Efficiency (%)	As per DRET
Fuel Cost (A$/GJ)	As per DRET
Fixed O&M (A$/kW-yr)	As per DRET
Variable O&M (A$/MWh)	As per DRET
Plant Life (yrs)	Fossil fuels = 40 Solar CST & PV = 30 Wind = 25

The estimates of LCOE for generation using gas turbines running on biofuel assumes capital costs of $5051/kW ('sent out') and fuel price of $10/GJ to account for the costs involved with production, storage and transport. All other inputs for calculating LCOE are the same as for natural gas fuelled OCGT.

The assumed LCOE for hydro is $50/MWh and for PHES is $300/MWh[1].

The LCOE for the additions to the transmission network were calculated using the NREL calculator. The inputs are the capital cost (estimated as described above and shown in Figure 7) and the O&M costs. The O&M costs were estimated from the 2010 NEM O&M cost for transmission factored in proportion of the line length of the new additions compared with the total length of existing NEM transmission lines (AER, 2011). Book life was assumed to be 40 years and discount rate as per Table 5.

The LCOE for the enhancements to the distribution system assumed the capital cost to be the equivalent to 20% of the 2010 value of the NEM's distribution system assets. The O&M costs are assumed to be 20% of the NEM's 2010 O&M costs (AER, 2011).

Costs not included in the cost estimates are:

1. owner's costs and interest during construction

2. biofuel generating costs may be understated

3. higher costs for natural gas to include the cost of building larger capacity gas pipes to supply 24 to 33 GW of peak gas generation (depending on the scenario), but with only 13% capacity factor to pay for the pipes (this means higher gas prices would have to be charged to pay for the high volume gas pipe system but with gas sales much less than the pipes could deliver).

[1] Crude estimate of LCOE: PHES plant would buy renewable energy when it would otherwise be spilled and would have to sell at about 4 times the buy price for PHES to be economically viable. If we assume electricity is bought at average $75/MWh, then LCOE for generation from PHES would be 4 x $75/MWh = $300/MWh.

4. Increased O&M costs for CST with 15 h storage instead of the 6 h for which the DRET O&M costs apply.

5. Costs for solar PV are probably too low (for kW sized, roof top, solar PV).

6. Cost of electricity for the *existing* NEM transmission and distribution network. (Only the cost of the transmission additions and distribution enhancements are included. If the LCOE for the existing NEM network was included it would increase the cost of electricity for all options and make no change to the capital cost or CO2 abatement cost.)

CO2 abatement cost

The CO2 abatement cost is the cost to reduce emissions intensity from the CO2 emissions intensity in the NEM in 2010 to the emissions intensity that would exist with the new scenario implemented; it is expressed as 'cost per tonne CO2 abated' ($/t CO2).

CO2 abatement cost = $(LCOE_2 – LCOE_1) / (EI_1 – EI_2)$
Where:
$LCOE_1$ = LCOE for the NEM in 2010
$LCOE_2$ = LCOE for the scenario
EI_1 = Emissions intensity for the NEM in 2010
EI_2 = Emissions intensity for the scenario

The LCOE and CO2 emissions intensity for the NEM in 2010 are taken as:
$LCOE_1$ = $45.40/MWh (AER, 2011; Chapter 1, Table 1.4)
EI_1 = 1.0 tonne/MWh (DCCEE, 2010, Table 5, weighted average for NEM)

The LCOE and CO2 emissions intensity for each scenario are in Appendix 1 (and charted in Figure 5 and Figure 6).

The inputs and intermediate calculation results for the CO2 abatement cost estimates are in Appendix 1.

Uncertainties in cost estimates

The greatest uncertainties in the cost estimates are in:

1. the fuel costs, capital costs and O&M costs for the gas turbines running on biofuels,

2. the cost of the solar thermal plants with 15 hours of thermal storage and their lifetime average capacity factor, and

3. the amount of additional transmission and distribution capacity needed.

Results

Capital cost, LCOE and CO2 abatement cost of the scenarios

Figure 6 compares the four scenarios on the basis of capital cost, cost of electricity and CO2 abatement cost.

Figure 6:

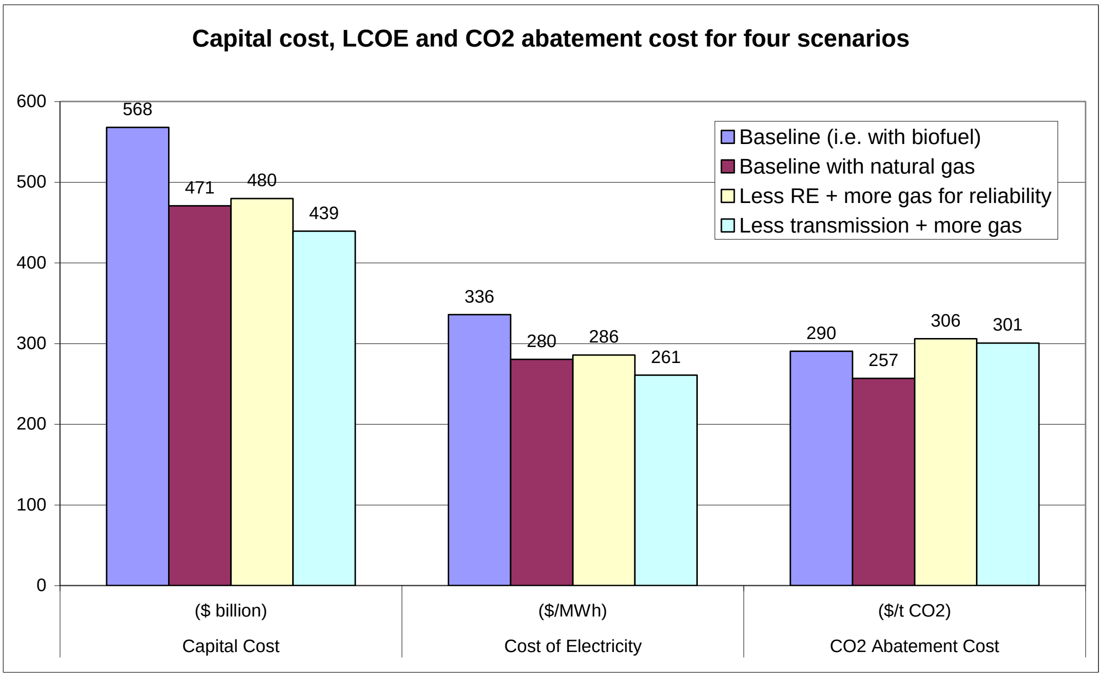
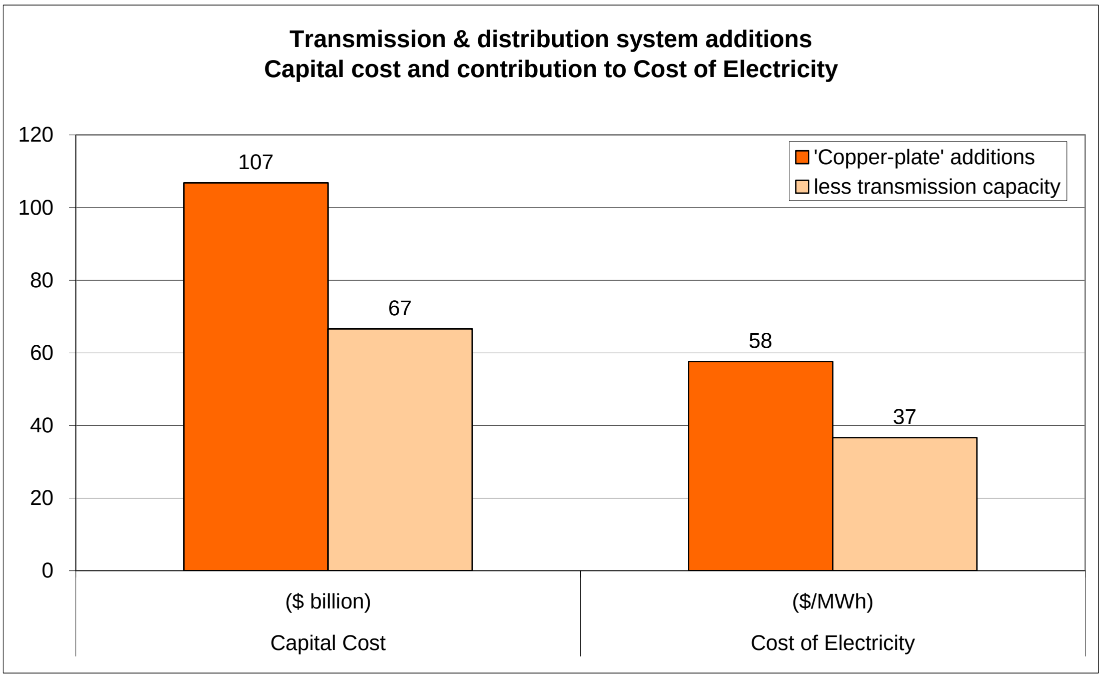


Figure 7 compares the capital cost and cost of electricity for the 'copper-plate' additions to the transmission system (Scenarios 1, 2 and 3) and the scenario with reduced additions to the transmission system (Scenario 4).

Figure 7:



Discussion

General

The EDM-2011 study reveals a great deal about the difficulty and cost of a largely renewable energy electricity system for Australia's NEM.

The study is more realistic than Beyond Zero Emissions' "*Zero Carbon Australia – Stationary Energy Plan*" (critiqued by Nicholson and Lang, 2010; Diesendorf, 2010; Trainer, 2010; and others), especially because their approach, as they say, *"is limited to the electricity sector in a recent year, providing a more straight forward basis for exploring this question of matching variable renewable energy sources to demand*." As the authors say, "*this approach minimises the number of working assumptions*".

Despite the lack of cost estimates – a deficiency rectified in this paper – the EDM-2011 study is a useful contribution. It demonstrates clearly that, even with highly optimistic assumptions, renewable energy cannot realistically provide 100% of our electricity generation with currently available technology. The baseline scenario does not have sufficient capacity to meet peak winter demand, has no capacity reserve and is dependent on a technology - gas turbines running on biofuels - that exist only at small scale and at high cost. Furthermore, Australia's hydro and pumped hydro facilities cannot be used in the way assumed in the simulations.

Reliability of supply

The system simulated by EDM-2011 would not provide a reliable electricity supply. The gas turbines running on biofuels and hydro-electricity provide nearly all the power, outside sun hours, on some winter days, e.g. July 1 to 6 for 2010 (Elliston *et al.*, 2011b, Slide 12). However, the gas turbines running on biofuels system does not currently exist at commercial scale. Furthermore, Australia's total hydro capacity cannot be run at full power for days and weeks at a time as is assumed in the simulation. As such, without the assumed generation from these two technologies, the system simulated has near zero generating capacity for many hours in winter. This would mean load shedding or rolling blackouts across the NEM, with no electricity for most consumers during those times.

If we substitute natural gas for biofuel for the gas turbines, we'd need capacity about equal to the winter peak demand (33 GW) to provide a reliable electricity supply with about 20% capacity reserve. That means, nearly all the generation would be by natural gas on some days in winter. The plants would be 'peaker' plants, not 'baseload', so they would be open cycle gas turbines (OCGT), which are the inefficient, high cost of electricity, high CO_2 emissions type of gas technology.

Cost

For the baseline scenario (Scenario 1) the electricity supply would be unreliable and the costs for a system built in the current decade are estimated to be around $568 billion capital cost, $336/MWh cost of electricity and $290/tonne CO_2 abatement cost (Figure 6).

That is, the wholesale cost of electricity for the simulated system would be seven times more than with the existing system, with an abatement cost that is 13 times the starting price of the Australian carbon tax (Energetix. 2011) and 30 times the European carbon price (European Energy Exchange, 2012). (The cost of electricity does not include the costs for the existing electricity grid).

For Scenario 2 (natural gas substituted for biofuel in the baseline scenario) the cost of electricity is estimated at $280/MWh (Figure 6), which is about six times the 2009-10 average cost of electricity generation in the NEM. The power supply would still be unreliable, but less so than with gas turbines running on biofuels.

For Scenario 3, where the assumptions are changed to provide a more reliable, mostly renewable electricity supply (although still not as reliable as we have now), more gas would be used and the cost of electricity is estimated at $286/MWh. CO2 abatement cost is estimated at $306/MWh (Figure 6).

Scenario 4 - If the transmission capacity is reduced the capital cost and cost of electricity are further reduced (Figure 6) but more gas is used and more CO2 emitted (Figure 5). This scenario has the lowest capital cost and lowest cost of electricity.

The assumed 'copper-plate' transmission system (Scenarios 1 to 3) adds $107 billion to the capital cost and $58/MWh to the LCOE (Figure 7). The reduced additions to the transmission system (Scenario 4) adds $67 billion to the capital cost and $37/MWh to the cost of electricity (see Figure 7). These costs are included in the capital costs, cost of electricity and CO2 abatements costs.

The transmission system additions are a high cost, especially when we consider there is no increase in demand driving these extra costs. These costly transmission upgrades are only required if the policy objective is to implement renewable energy, rather than to provide low emissions electricity at least cost..

Baseload

EDM-2011 conclude "*Achieving 100% renewable electricity also entails a radical 21st century re-conception of an electricity supply-demand system.*" They make their point succinctly in the last slide in their slide presentation where they state "*Baseload plant is an outmoded concept*" (Elliston *et al.* (2011b).

However, since the cost of electricity from the renewable energy option is some seven times the current cost of electricity, their study does not refute the fact that the "baseload plant" is still by far the least cost way to supply most of our electricity needs, and is far from being an "outmoded concept".

The least cost way to meet the demand and reliability requirements is with a mix of generators that are located close to the demand centres, connected by relatively short transmission lines to the main demand centres and capable of supplying the power to meet baseload at all times, intermediate load during day time on week days and peak demand whenever it occurs.

The least cost option to match generation to the demand profile in most countries where large hydro capacity is not available such as in Australia, is usually with coal, gas or nuclear for baseload, gas and hydro for intermediate load, and gas and hydro for peak load.

Bayless (2010) in "The case for baseload" provides *"an engineer's perspective on why not just any generation source will do when it comes to the system's capacity, stability and control*".   He says:

> *"The electric system is more than just the delivery of energy—it is the provision of reliability. First, the system must have capacity, that is, the capability to furnish energy instantaneously when needed. The system also must have frequency control, retain stability, remain running under varied conditions, and have access to voltage control. Each of those essential services for reliability must come from a component on the system. Those components are not free, and they don't just happen. They are the result of careful planning, engineering, good operating procedures, and infrastructure investment specifically targeting these items."*

The simple cost analysis presented here demonstrates that the renewable electricity system simulated by EDM-2011 cannot meet these requirements at anywhere near the cost of a conventional system.

Conclusions

I have reviewed and critiqued "*Simulations of Scenarios with 100% Renewable Electricity in the Australian National Electricity Market*" by Elliston *et al.* (2011a). That paper does not analyse costs, so I have also made a crude estimate of the cost of the scenario simulated and three variants of it. I conclude:

The costs for the simulated 100% renewable electricity system are estimated to be \$568 billion capital cost, \$336/MWh cost of electricity and \$290/tonne CO2 abatement cost. That is, electricity would cost seven times more than now, and CO2 abatement cost would exceed current carbon prices by 13 times the starting price for the Australian carbon tax and 30 times the European carbon price (at time of writing).

The electricity supply would be unreliable.

Any largely renewable electricity system for the NEM would be high cost, as demonstrated here. The changes made to the assumptions make little difference to the estimated capital cost, cost of electricity and CO2 abatement cost.

Recommendations

I recommended the simulation be rerun with the following changes:

1. Use natural gas instead of biofuel

2. Increase the gas generation capacity so there is sufficient capacity in the system to meet all peak demand and ensure 20% capacity reserve.

3. Check that the system can meet demand at the 5 minute time scale, not just the average demand over 1 hour.

4. Introduce constraints on hydro generation, pumped hydro energy storage rate, times of day for pumping and for generating and minimum number of continuous hours of pumping that match the actual constraints on the actual plants in the NEM.

5. Reduce the capacity of transmission lines from the wind farms to a percentage of their rated power output and reduce the maximum output of the wind farms accordingly; optimise (roughly) the transmission line capacity and generating capacity to achieve the least overall cost of electricity from the system.

6. Limit the peak output of the PV generators at a percentage of their peak power output to fit within the constraints of the distribution system; optimise (roughly) to achieve the least overall cost of electricity from the system.

7. Limit the capacity of the interstate transmission interconnectors (this would reduce the output of the renewable energy generators at some times and reduce the pumped hydro storage rate).

8. Do a loss of load probability (LOLP) analysis to check that the system being simulated meets the Australian Energy Regulator's reliability requirements.

9. Do a simulation with a nuclear power scenario to provide an objective comparison of the cost for an alternative way to provide a low-emission electricity supply.

Estimate the costs of all scenarios and compare them on the basis of:

1. CO_2 emissions intensity

2. capital cost

3. cost of electricity

4. CO_2 abatement cost

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I would like to thank Professor Barry Brook, Dr. Jani-Petri Martikainen Dr John Morgan, Dr Ian Nalder, Martin Nicholson, Graham Palmer, Dr. Gene Preston, Dr. Ted Trainer and two others in the electricity industry whom I cannot name, for their input and assistance with this analysis and reviewing this document.

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Appendix 1 – Basis of estimates for capital costs, LCOE and CO2 abatement costs

This appendix provides the basis of the costs estimates for the four scenarios.

Scenario 1 – Baseline, gas turbines running on biofuels and Scenario 2 – Baseline, gas turbines running on natural gas

Table A1-1: Scenario 1 & 2 - Capacity, capacity factor, generation & share

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Generation Capacity	GW	4.9	2.2	14.6	23.2	15.6	24.0	**84.5**
Capacity factor		21%	20%	16%	30%	60%	13.37%	
Annual generation	GWh	9,014	3,854	20,463	60,970	81,994	28,099	**204,394**
Share		4%	2%	10%	30%	40%	14%	**100%**

Scenario 1 – Baseline (i.e. gas turbines running on biofuels)

Table A1-1-2: Scenario 1, Capital Cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Capital cost rate	$/kW			$4,650	$2,744	$13,362	$5,051	
Capital Cost	$bn			$68	$64	$208	$121	**$461**
Capital cost for 'Copper-Plate' transmission additions								**$107**
Total capital cost	$bn							**$568**

Table A1-1-3: Scenario 1, Levelised Cost of Electricity (LCOE)

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Technology LCOE	$/MWh	$50	$300	$394	$130	$286	$563	
System LCOE	$/MWh	$2	$6	$39	$39	$115	$77	**$278**
Add LCOE for the 'Copper-Plate' Transmission additions								$58
Total LCOE	$/MWh							**$336**

Table A1-1-4: Scenario 1, CO2 abatement cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
System LCOE	$/MWh							$336
NEM 'LCOE' equiv.	$/MWh							$45[2]
LCOE difference	$/MWh							$290
CO2 emissions factor for NEM (t/MWh)								1.0[3]
CO2 emissions factor per technology (t/MWh)							0.0[4]	
CO2 emissions factor for the system (t/MWh)							0.0	0.0
CO2 emissions factor difference (t/MWh)								1.0
CO2 abatement cost ($/t CO2)								**$290**

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[2] 2009-10 Weighted average wholesale price of electricity in the NEM = $45.40 DRET (2011), p22,

[3] Weighted average of the NEM states' emissions factor (Table 5, DCCEE (2010), NGA Factors
Weighted average using generation per state in 2009-10 (BREE Australian energy statistics – Energy update 2011

[4] Emissions factor: = 0 t/CO2/MWh for gas turbines running on biofuels

Scenario 2 - Baseline with gas turbines running on natural gas

Table A1-2-2: Scenario 2, Capital Cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Capital cost rate	$/kW			$4,650	$2,744	$13,362	$995	
Capital Cost	$bn			$68	$64	$208	$24	**$364**
Capital cost for 'Copper-Plate' transmission additions								**$107**
Total capital cost	$bn							**$471**

Table A1-2-3: Scenario 2, Levelised Cost of Electricity (LCOE)

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Technology LCOE	$/MWh	$50	$300	$394	$130	$286	$159	
System LCOE	$/MWh	$2	$6	$39	$39	$115	$22	**$223**
Add LCOE for the 'Copper-Plate' Transmission additions								$58
Total LCOE	$/MWh							**$280**

Table A1-2-4: Scenario 2, CO2 abatement cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
System LCOE	$/MWh							$280
NEM 'LCOE' equiv.	$/MWh							$45
LCOE difference	$/MWh							$235
CO2 emissions factor for NEM (t/MWh)								1.0
CO2 emissions factor per technology (t/MWh)							0.622	
CO2 emissions factor for the system (t/MWh)							0.09	0.09
CO2 emissions factor difference (t/MWh)								0.91
CO2 abatement cost ($/t CO2)								**$257**

Scenario 3 - Less RE + more gas to improve reliability

Table A1-3-1: Scenario 3 - Capacity, capacity factor, generation and share

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Generation Capacity	GW	6.6	0.9	14.6	23.2	15.6	33.0	**93.5**
Capacity factor		21%	10%	10%	23%	50%	25.6%	
Annual generation	GWh	12,141	770	12,790	46,743	68,328	73,860	**214,632**
Share		6%	0.4%	6%	22%	32%	34%	**100%**

Table A1-3-2: Scenario 3, Capital Cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Capital cost rate	$/kW			$4,650	$2,744	$13,362	$995	
Capital Cost	$bn			$68	$64	$208	$33	**$373**
Capital cost for 'Copper-Plate' transmission additions								**$107**
Total capital cost	$bn							**$480**

Table A1-3-3: Scenario 3, Levelised Cost of Electricity (LCOE)

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Technology LCOE	$/MWh	$50	$300	$631	$169	$351	$111	
System LCOE	$/MWh	$3	$1	$38	$37	$112	$38	**$228**
Add LCOE for the 'Copper-Plate' Transmission additions								$58
Total LCOE	$/MWh							**$286**

Table A1-3-4: Scenario 3, CO2 abatement cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
System LCOE	$/MWh							$286
NEM 'LCOE' equiv.	$/MWh							$45
LCOE difference	$/MWh							$240
CO2 emissions factor for NEM (t/MWh)								1.0
CO2 emissions factor per technology (t/MWh)							0.622	
CO2 emissions factor for the system (t/MWh)							0.21	0.21
CO2 emissions factor difference (t/MWh)								0.79
CO2 abatement cost ($/t CO2)								**$306**

Scenario 4 - Less transmissions capacity + more gas

Table A1-4-1: Scenario 4 - Capacity, capacity factor, generation & share

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Generation Capacity	GW	6.6	0.9	14.6	23.2	15.6	33.0	**93.5**
Capacity factor		21%	7%	10%	18%	40%	33.9%	
Annual generation	GWh	12,141	539	12,790	36,582	54,662	97,911	**214,626**
Share		6%	0.3%	6%	17%	25%	46%	**100%**

Table A1-4-2: Scenario 4, Capital Cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Capital cost rate	$/kW			$4,650	$2,744	$13.362	$995	
Capital Cost	$bn			$68	$64	$208	$33	**$373**
Capital cost for 'Copper-Plate' transmission additions								**$67**
Total capital cost	$bn							**$439**

Table A1-4-3: Scenario 4, Levelised Cost of Electricity (LCOE)

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
Technology LCOE	$/MWh	$50	$300	$631	$169	$351	$99	
System LCOE	$/MWh	$3	$1	$38	$37	$112	$34	**$224**
Add LCOE for the 'Copper-Plate' Transmission additions								$37
Total LCOE	$/MWh							**$261**

Table A1-4-4: Scenario 4, CO2 abatement cost

	Units	Hydro	PHES	PV	Wind	CST	OCGT	Total
System LCOE	$/MWh							$261
NEM 'LCOE' equiv.	$/MWh							$45
LCOE difference	$/MWh							$215
CO2 emissions factor for NEM (t/MWh)								1
CO2 emissions factor per technology (t/MWh)							0.622	
CO2 emissions factor for the system (t/MWh)							0.28	0.28
CO2 emissions factor difference (t/MWh)								0.72
CO2 abatement cost ($/t CO2)								**$301**

Appendix 2 – Transmission system additions and cost estimates

'Copperplate' assumptions

The simulation assumes a 'copper-plate' transmission and distribution system ("*power can flow unconstrained from any generation site to any demand site*"). The simulation does not allow for additional energy losses in the 'copper-plate' transmission system.

Assumptions for the cost estimate for the 'copperplate' transmission system are:

1. To minimise gas generation (whether biofuel or natural gas), the renewable energy power must be fully utilised in winter (up to the demand), and especially at times of winter peak demand. This means that every renewable energy generator must be able to transmit its nameplate generating capacity to anywhere and everywhere on the grid. This is because we do not know which solar plants will be under widespread cloud and which wind farms becalmed, so any generator has to be able to transmit its full power when it is working and others are producing little output.

2. The transmission line from each CST to the nearest capital city, or to an entry point to the nearest trunk power line, is sized to carry the full capacity of the CST plant.

3. The transmission line from each wind farm to the nearest capital city, or to an entry point to the nearest trunk power line, is sized to carry the full capacity of the wind farm. Assume average length is 300 km.

4. The interstate interconnector lines are sized to transmit the lesser of the winter peak demand at the receiver end or peak generation minus demand at the sender end. Tasmania's peak demand and renewable energy generating capacity is added to Victoria's when deciding the capacity of other interstate transmission lines to and from Melbourne. Likewise, Queensland's peak demand and renewable energy generating capacity is added to NSW when deciding the capacity of other interstate transmission lines to and from Sydney

5. The capacity estimates are crude; there is no way of assessing the capacity needed without access to the simulation data and ideally, an accompanying LOLP analysis, so these estimates are put forward as a "Straw-man" approach, i.e., propose something that seems reasonable given the size and variability of demand and supply, present it as a 'straw-man' and let others improve on it.

6. Scenarios 3 and 4 include 5% energy losses in the transmission system. Therefore, the total demand (204.4 TWh) is increased by 5% (to 214.6 TWh).

7. The capital cost of the enhancements to the distribution system is assumed to be equivalent to 20% of the asset value of the existing distribution system. The O&M costs of the enhancements to the distribution system are assumed to be 20% of the O&M costs of the NEM distribution systems[1].

Table A2-1: Winter peak demand and EDM-2011 renewable energy capacity assumptions by technology and state (GW)

State	Winter peak demand[2]	Total RE capacity	Renewable energy capacity [3 4]			
			PV	CST	Wind	Hydro
SA	2.5	18.6	1.3	5.2	12.1	0.0
VIC	8.0	11.6	4.5		6.4	0.7
TAS	1.7	4.0			2.0	2.0
NSW	13.2	17.0	5.5	5.2	2.5	3.8
QLD	7.3	9.3	3.3	5.2	0.2	0.6
NEM		60.5	14.6	15.6	23.2	7.1

The following table shows how the capacities for the interstate interconnector lines were selected (for the 'Copper-plate scenario)'. Lines from Melbourne to Sydney and Melbourne to Adelaide include the Tasmanian peak winter demand and Tasmanian renewable energy generating capacity minus winter peak demand. Lines from Sydney to Adelaide and Sydney to Melbourne include the Queensland peak winter demand and Queensland renewable energy generating capacity minus winter peak demand. For the 'reduced Copper-plate' scenario (Scenario 4) the capacities of the lines from the wind farms and the interstate interconnectors were arbitrarily half the capacities assumed in the 'Copper-plate' transmission system.

Table A2-2: 'Copperplate' transmission additions and estimated capital cost

From	to	Capacity (GW)	Length (km)[5]	MW * km	Unit Cost[6] ($/MW.km)	Capital Cost
Woomera	Adelaide	2.6	518	1,346,800	$1,500	$2,020,200,000
Nullarbor	Adelaide	2.6	1,196	3,109,600	$1,500	$4,664,400,000
White Cliffs	Hay	2.6	485	1,261,000	$1,500	$1,891,500,000
Roma	Brisbane	2.6	477	1,240,200	$1,500	$1,860,300,000
Longreach	Brisbane	2.6	1,177	3,060,200	$1,500	$4,590,300,000
Tibooburra	Mildura	2.6	630	1,638,000	$1,500	$2,457,000,000
Wind		23.2	300	6,960,000	$1,500	$10,440,000,000
Adelaide	Melbourne	9.7	729	7,053,367	$1,500	$10,580,049,900
Adelaide	Sydney	16.1	1,408	22,695,750	$1,500	$34,043,625,486
Hobart	Melbourne	2.3	800	1,865,663	$3,000	$5,596,988,931
Melbourne	Sydney	5.9	909	5,387,103	$1,500	$8,080,654,436
Sydney	Brisbane	7.3	1,000	7,312,830	$1,500	$10,969,245,000
Brisbane	Cairns	0.3	1,707	512,100	$1,500	$768,150,000
						$97,962,413,753

Table A2-3: LCOE of 'Copperplate' additions to transmission system

Capital cost		$97,962,413,753
Capacity	MW	33,758
Capital cost unit rate	$/kW	$2,902
Book life	years	40
Energy transmitted	MWh	204,400,000
Load Factor		69%
LCOE (capital component only)	$/MWh	$50
LCOE (O&M component)	$/MWh	$1
LCOE, total for transmission additions	$/MWh	$51

Table A2-4: LCOE of 'Copperplate' additions to distribution system

Capital cost	$ bn	$8,815,800,000
LCOE (capital component)	$/MWh	$5
LCOE (O&M component)	$/MWh	$2
LCOE, Distribution upgrades	$/MWh	$7

Table A2-5: Capital cost and LCOE of the 'Copperplate' additions to transmission and distribution system

Capital cost, Transmission & distribution	$ bn	**$107**
LCOE, Transmission & distribution	$/MWh	**$58**

'Book end' the cost of additions to the transmission system

The cost of the transmission system additions depends on the assumptions about renewable energy generators and the limits placed by the capacity of the transmission lines on their peak power output. To better understand this, consider two ends of a spectrum and an intermediate position.

1. If there are no renewable energy generators and all the capacity is provided by gas generators, there would be negligible new transmission required.

2. At the other extreme, with the 'baseline' system, which assumes a 'copperplate' transmission system, the transmission system must have sufficient capacity to transfer the maximum power output of each renewable energy generator to all capital cities. The transmission capacity must be sufficient to transmit the lesser of the peak demand at the receiver end or peak generation minus demand at the sender's end. This must be done without energy loss, or the generators must supply higher power to compensate for the losses.

3. Between these two limits, is reduced transmission capacity. Reducing the transmission capacity would mean the peak power output that can be delivered by the renewable energy generators would be reduced; therefore, the average capacity factor of the renewable energy generators would be reduced. This means the LCOE of the renewable energy generators would be increased.

4. The capacity and/or capacity factor of the gas generators will have to be increased to compensate.

5. As an example, using hypothetical figures to illustrate, we may reduce the cost of the transmission system by 50% while reducing the output of the renewable energy generators by say 10% and adding x% capacity factor to the gas generators to compensate. As Figure 7 shows, this would save about $38 billion in capital cost and $19/MWh in cost of electricity.

6. The estimate below for reduced transmission capacity assumes the capacity of the transmission lines from the wind farms and the interstate interconnectors is reduced by 50% compared with the 'Copperplate' assumptions. There is no change to the capacity of the lines from the CST plants and no change to the assumptions about the upgrading of the distribution system.

Capital cost and LCOE - Reduced 'Copper-plate' transmission capacity

Table A2-6: Reduced 'Copperplate' transmission capacity - transmission additions and estimated capital cost

From	to	Capacity (GW)	Length (km)	MW * km	Unit Cost ($/MW.km)	Capital Cost
Woomera	Adelaide	2.6	518	1,346,800	$1,500	$2,020,200,000
Nullarbor	Adelaide	2.6	1,196	3,109,600	$1,500	$4,664,400,000
White Cliffs	Hay	2.6	485	1,261,000	$1,500	$1,891,500,000
Roma	Brisbane	2.6	477	1,240,200	$1,500	$1,860,300,000
Longreach	Brisbane	2.6	1,177	3,060,200	$1,500	$4,590,300,000
Tibooburra	Mildura	2.6	630	1,638,000	$1,500	$2,457,000,000
Wind		11.6	300	3,480,000	$1,500	$5,220,000,000
Adelaide	Melbourne	4.8	729	3,526,683	$1,500	$5,290,024,950
Adelaide	Sydney	8.1	1,408	11,347,875	$1,500	$17,021,812,743
Hobart	Melbourne	1.2	800	932,831	$3,000	$2,798,494,466
Melbourne	Sydney	3.0	909	2,693,551	$1,500	$4,040,327,218
Sydney	Brisbane	3.7	1,000	3,656,415	$1,500	$5,484,622,500
Brisbane	Cairns	0.2	1,707	256,050	$1,500	$384,075,000
						$57,723,056,877

Table A2-7: LCOE of reduced additions to transmission system

Capital cost		$57,723,056,877
Capacity	MW	33,758
Capital cost unit rate	$/kW	$1,710
Book life	years	40
Energy transmitted	MWh	204,400,000
Load Factor		69%
LCOE (capital component)	$/MWh	$29
LCOE (O&M component)	$/MWh	$1
LCOE, Total for transmission additions	$/MWh	$30

Table A2-8: LCOE of additions to distribution system

Capital cost		$8,815,800,000
LCOE (capital component only)	$/MWh	$5
LCOE (O&M component)	$/MWh	$2
LCOE, Distribution upgrades	$/MWh	$7

Table A2-9: Capital cost and LCOE of the reduced additions to transmission system and additions to the distribution system

Capital cost, Transmission & distribution	$ bn	**$67**
LCOE, Transmission & distribution	$/MWh	**$37**

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