The future prospects for renewable energy in South Australia

A report for the
Sustainability and Climate Change Division of the
Department of Premier and Cabinet of South Australia

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1. Introduction

The Sustainability and Climate Change Division of the South Australian Department of Premier and Cabinet engaged the National Institute of Economic and Industry Research to provide independent advice on setting Renewable Energy Targets in South Australia.

Under Section 5 of the *SA Climate Change and Greenhouse Reduction Act, 2007*, it states in Part 2 – Targets:

> *"(1) The principal target under this Act is to reduce by 31 December 2050 greenhouse gas emissions within this State by at least 60% to an amount that is equal to or less than 40% of 1990 levels.*
>
> *(2) Two related targets under this Act are –*
>
> > *(a) to increase the proportion of renewable electricity generated so that it comprises at least 20% of electricity generated in the State by 31 December 2014;*
> >
> > *(b) to increase the proportion of renewable electricity consumed so that it comprises at least 20% of electricity consumed in the State by 31 December 2014."*

The South Australian Government is now considering the setting of renewable electricity targets out to 2020 and the analysis of the situation by NIEIR was undertaken in this context.

With respect to Section 5(4), as we stated in our tender, we believe we have the capacity, knowledge and experience to undertake the tasks to be undertaken in the study.

At the outset in reviewing and assessing renewable electricity generation implementation issues and providing advice and assurance to meet legislative requirements under section 5 of the Act, it is instructive to outline how the term 'renewable energy potential' may be interpreted.

Renewable electricity (RE), that is renewable energy not including thermal (mainly solar hot water) and liquid fuel energy from renewable sources, potential may be classified in three ways.

1. Technical potential

Potential of the resource to deliver energy with only technical constraints.

For example, 10,000 MW of wind capacity at a capacity factor of 25 per cent or better.

2. Economic potential

Application of economic criteria (for example, a sent out or delivered cost of $120/MWh). The 10,000 MW technical potential of wind may reduce to 7,000 MW on applying this criterion.

3. Commercial potential

Application of commercial criteria (for example, availability and cost of financing, other market constraints). The 7,000 MW of economic potential may reduce to 5,000 MW when commercial criteria are applied.

In setting targets for renewable energy all three potential definitions are important as:

(a) some technical potential may convert to economic potential if technology improvements improve the economics of some technical potential and the economic environment may change to improve some RE economics, for example, through increases in costs of fossil based electricity which is now at a lower cost than RE;

(b) economic potential, now not commercially attractive due to current commercial criteria and constraints (availability of finance, interest rates) may in the future become commercially attractive to investors; and

(c) commercial potential, that is potential that is attractive to investors, is the potential which will ultimately result in greater proportions of RE entering the South Australian system. Commercial viability of potential may be enhanced by changes in private sector investment criteria and strategies but particularly by favourable government policies. For example, most current investments in RE would not be commercially viable in the absence of the Mandated Renewable Electricity Target (MRET).

The outlook for commercial viability of RE to meet targets will determine whether targets are, realistically, likely to be attained. However, as indicated above, the current outlook for commercial viability of RE can be changed by future government initiatives favouring RE, by technology advancements relative to RE competitors and by changes in commercial investment criteria.

This study focuses on the 2010-2020 period, but in the period beyond the prospects for renewable energy in South Australia is likely to be even more favourable in the world and Australia because, at this time, it seems very probable there will be a significant move to a low carbon future.

2. Outlook for renewable electricity (RE) generation and consumption in South Australia

The major influences on renewable electricity generation and consumption in South Australia are:

(i) assessments of the Renewable Electricity (RE) resources in South Australia;

(ii) levels and design of the expanded Mandated Renewable Electricity Target (MRET), now generally referred to as the RET;

(iii) the outlook for Green Power (voluntary) in a Carbon Pollution Reduction Scheme (CPRS) world;

(iv) the Federal commitment, separate to RET, of the current aspirational target of 20 per cent of Australian electricity consumption to come from renewable **electricity** (that is, excluding MRET eligible solar hot water);

(v) the impact of the **final** design of the Carbon Pollution Reduction Scheme (CPRS), still subject to uncertainty, which will significantly determine future gas and fossil-based electricity prices and demands, and hence the competitiveness of RE; and

(vi) future RE costs, in particular the long run marginal cost (LRMC) of RE sources, needed to meet the demands for RE.

2.1 RE resources in South Australia

To develop estimates of the South Australian RE resource, we used the independent data base of Carbon Market Economics Pty Ltd (CME) which we have used in previous work and as input to this study. **Appendix A** presents the CME database for South Australian Renewable Electricity projects as of March 2009.

2.2 Expanded Renewable Energy Target (RET) design

The expanded RET design, as accepted at the COAG meeting on 30 April 2009, includes two very important elements for assessing the future commercial potential for renewable electricity. They are as follows.

1. The continued eligibility of solar hot water (SHW), including heat pumps, which is taking a greater share of the current RET market (SHW is not eligible for Green Power acquittals). In 2008 SHW accounted for about 40 per cent of created RECs[1], according to CME interrogation of the Office of the Renewable Energy Regulator (ORER) database, under the influence of State and Federal rebates for SHW, State regulation favouring SHW (likely to extend nationally), the eligibility of SHW for REC creation and the high price of RECs (currently $45 – $50/MWh). SHW trends are likely to continue and our estimate is that 25-30 per cent of RECs (about 12,000,000) could come from SHW in 2020.

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[1] RECs = Renewable Energy Certificates, denominated in $/MWh, are the currency for acquitting electricity retailer liabilities under RET.

2. The eligibility over 2009-10, 2010-11 and 2011-12 for an REC multiplier of 5 times deemed RECs for photovoltaic (PV) electricity systems, falling to 1 by 2015-16. This will continue to drive the installations of PVs (particularly those ≤ 1.5 kW) a trend now apparent under the current rebate program (terminating on 30 June 2009) in South Australia and other regions. Post 2011-12 when the REC multiplier reduces the installation of PVs will depend on REC prices and the extent to which the gross cost (net of incentives) of PV systems drops.

   PV installations will contribute to attainment of South Australian RE targets but, together with SHW trends, reduces the market for larger (>1 MW) renewable electricity plants.

Both SHW and PV RECs under MRET are deemed, that is their impact is estimated over their life at the time of installation.

The future roles of SHW and small scale PV in the expanded MRET could significantly affect the costs and prices of Renewable Energy Certificates (RECs). Our early May 2009 views on evolution of the REC market are presented in **Appendix B**.

2.3 Green Power outlook

In 2008 the demand for Green Power (GP) in Australia was about 2,000 GWhs. This expands the market for renewable electricity (SHW not eligible for Green Power) as GP RECs are additional to RET RECs. That is, they must be acquitted under RET **or** GP. However, in the future, out to 2020, it is likely that Green Power (GP) demand (voluntary) will decline due to general economic conditions, higher electricity prices (although offset to many households under the proposed CPRS design) and perceptions that the expanded MRET will reduce the need for voluntary purchases of Green Power.

Nevertheless, the possibility of Green Power to continue increasing the demand for RE needs to be considered.

2.4 Commitment to a separate renewable electricity target

If commitment to a separate renewable electricity (RE) target were backed up by incentives to attain the target, the demand for renewable electricity could expand significantly as SHW would be excluded (we project up to 12,000 GWhs of SHW RECs by 2020), thereby aiding attainment of higher RE targets.

However as there is currently (May 2009) no policy position on this issue has been taken and hence it has been excluded from our analysis.

2.5 Impacts of the Carbon Pollution Reduction Scheme (CPRS)

Under the CPRS fossil fuel electricity prices will rise, the extent depending on the final design. Currently, in the absence of a global agreement, it is proposed to reduce emissions by 5 percent below 2000 emissions by 2020. This is the CPRS -5 scenario. Lower emissions caps, for example under a CPRS-25 (25 per cent below 2000 emissions) scenario which might emerge after 2015 but more likely post 2020, would enhance the competitiveness of RE sources and enable higher RE targets to be attained. The extent will depend on marginal RE costs.

2.6 RE costs

We estimate that the marginal costs (LRMCs) of RE to meet greater amounts of RE requirements will be about $110/MWh (2008 dollars) for an additional (to 1996 RE generation) cumulative generation of 30,000 GWh of RE, $115/MWh for 35,000 GWh and $125/MWh for 45,000 GWh. A fossil generation electricity price (wholesale) of around $125/MWh could, under CPRS-25, eventuate by about 2020 but under CPRS-5 the price may be about $90/MWh.

3. Mix of RE sources to attain the expanded RET from eligible sources by 2020

3.1 RET sources: 2010-2020

The main renewable energy sources eligible and likely to create RECs for RET attainments over the period to 2020 are as follows.

(i) **Solar hot water (SHW)** which, besides RECs, also benefits from direct incentives (rebates) from the Federal and several State Governments (Western Australia, Victoria, Queensland) and also from regulations that favour SHW (for example the South Australian, New South Wales and Victorian residential building standards).

This SHW support makes SHW a relatively low cost source of RECs and hence constrains the RET market for renewable electricity RECs.

(ii) **Biomass**, covering the production of renewable electricity from sources such as landfill gas (methane from anaerobic decomposition of organic wastes), wood wastes (from forest industries) and bagasse (sugar cane wastes). Costs of renewable electricity from biomass sources vary widely and generally the plants have a relatively low capacity (<50 MW), but they can operate at high capacity factors (CFs), that is, for up to 80 per cent of the year.

(iii) **Wind** (wind energy conversion systems, WECs), which since MRET began in 2001, has been the fastest growing source of renewable **electricity** RECs. Costs of wind RE depend mainly on the wind regime where they are located and the size of the individual turbines (now up to 5 MW) and the costs of connecting the plants to electricity grids (networks).

Capacities of wind farms (collection of turbines at one location) range from about 50-500 MWs but capacity factors at 25-45 per cent (averaging in South Australia about 32 per cent) constrain output and the output is intermittent and therefore difficult to accurately predict.

(iv) **Solar power** covering photovoltaic (direct conversion of sunlight into electricity) and solar thermal (solar production of heat to drive turbines) is still a relatively high cost source of RE (particularly from photovoltaics) but technology advances are reducing solar RE costs. Large scale solar plants (PV, thermal) are being directly supported by Australian governments on a cost shared basis and small scale PV is also significantly supported. Like wind, solar is also an intermittent source of RE with variable (but generally low, <35 per cent) capacity factors.

Storage of electricity from intermittent sources can increase practical system capacity factors but adds to costs and is unlikely to be commercially viable until after 2020.

(v) **Geothermal energy** sourced from subterranean heat sources, although used extensively in some countries (for example, New Zealand, Iceland, Italy) requires specialised techniques to successfully produce RE from the substantial Australian hot dry rock (HDR) sources (see discussion below on South Australian geothermal potential.

Geothermal plants (up to 1,000 MW) can operate at high capacity factors (up to 95 per cent) and thus operate in base load mode.

(vi) **Hydro**. Most hydro electricity potential in Australia was developed prior to 1990 but some has since been developed and some small scale (<10 MW) potential remains. Output from hydro plants is currently constrained by drought conditions. Hydro RE from **new** plants will not be a significant source of RECs post 2010.

(vii) **Other sources** (tidal, wave, etc.) have the potential to become substantial sources of RE in Australia but are unlikely to be a significant source by 2020. But they could become important post-2020.

(viii) **Baseline plant sources of RECS**

Renewable electricity plants which were operating before 1 January 1997 (mainly hydro but some biomass plants) are eligible to create RECs above a baseline output of MWhs determined by the MRET Regulator (Office of the Renewable Energy Regulator). In the early years of MRET, RECs from baseline plants were substantial but they have declined since 2005 mainly due to the drought conditions affecting hydro-electricity output.

Contribution of baseline plant RECs is estimated by NIEIR to be low (<5 per cent) over 2010-2020.

3.2 Estimation of the renewable energy mix to attain the Renewable Electricity Target (RET) of 45,000 GWhs by 2020

This estimation is very important for determining the future prospects for renewable electricity in South Australia as:

(i) without RET little RE will be commercially viable by 2020 even taking into account the impact (albeit uncertain) of the CPRS; and

(ii) South Australian RE sources have the potential to be a major contributor to RET, given South Australia's good wind regime and substantial geothermal potential.

Of the potential RET sources outlined above, the geothermal contribution is, however, probably the most difficult to predict given its very early stage of technical and commercial development.

Our preliminary analysis of the contribution of each RET eligible source by 2020 is shown in **Table 1** below.

Table 1	Estimated RET mix by 2020			
		GWhs	**Per cent**	**Comment**
1.	Solar hot water	12,000	26.7	Driven by RECs, direct incentives and regulation. 40 per cent of RECs created in 2008. South Australian SHW penetration significant.
2.	Biomass	8,000	17.7	Proven technologies available, reasonable resource delineation, costs reasonably predictable. 12 per cent of RECs created in 2008. South Australian potential (resource, costs) not significant (but depends on forest industry development, for example Penola mill).
3.	Wind	19,000	42.2	Proven technology, good resource delineation, costs reasonably predictable. 34 per cent of RECs created in 2008. South Australian potential (resource, costs) substantial.
4.	Solar	2,600	5.7	Some proven technologies but substantial further technology development required and underway. Support from Australian Governments for demonstration project funds. Penetration of small scale (<10 kW) PV increasing. 4 per cent of RECs created in 2008. South Australian potential significant.
5.	Geothermal	1,000 (to 10,000)	2.2 (to 22.2)	Technology applicable to Australian geothermal potential (HDR/HFR) not commercially proven. 0 per cent of RECs created in 2008. South Australian potential (resource) substantial. Cost of grid connection a major issue.
6.	Hydro	1,400	3.4	Proven technology but remaining potential low. 1 per cent of RECs in 2008. South Australian potential insignificant.
7.	Other sources	<400	<1	Technologies (tidal, wave, ocean) in demonstration phase. Some estimates of technical potential in Australia available but little cost data available. 0 per cent of RECs in 2008. South Australian potential being delineated.
8.	Baseline plants	500	1.1	Mainly from hydro plants (some biomass) affected by drought. Potential for increased output limited. 9 per cent of RECs in 2008. South Australian potential insignificant.

At the low estimate for geothermal the above percentage contributions add to about 100 per cent. But as discussed below (Section 4.2.5) the geothermal contribution is important for South Australia as currently South Australia is the most prominent geothermal potential State. The RE contribution of this source is very difficult to estimate given that there is, as yet, in mid-2009, no operating geothermal plant in Australia.

3.3 Other RE influences, 2010-2020

Banking of RECs

Banking of RECs (that is, holdings of non-acquitted RECs) is important. From data taken from the Office of the Renewable Energy Regulator (ORER) it appears that by the end of 2008 a substantial number of RECs (perhaps up to 7,000,000) were banked. This banked amount could be up to 65 per cent of the total REC requirement (MRET, Green Power, Victorian Renewable Energy Target – VRET) requirements in 2009.

Expectation of higher future REC prices (tighter markets) contributes to banking. Lower expected future REC prices would induce holders of banked RECs to sell some of them into the market. But this selling could lead to lower REC prices as supply grows relative to demand.

Overall, as banked RECs increase relative to future requirements, there is a likelihood that REC prices will drop, thereby inducing some selling.

REC prices

Expectation of lower REC prices could render some renewable electricity (RE) projects non-viable, depending on the differential between marginal RE project costs and wholesale electricity prices, that is the inferred REC price. An important RE cost caveat, however, is the extent to which RE plants will bear the costs of network expansions required by new RE plants.

CPRS

Under the proposed CPRS design in the White Paper caps out to 2014 are high, indicating relatively little abatement would be required until 2015 and hence impacts on electricity prices would be low. And the 4 May 2009 announcement of the CPRS commencement delay until 1 July 2011 at a fixed CO_2e price of $10/tonne until 1 July 2012, with market trading at given caps thereafter, may further delay significant electricity price increases. Also it may be possible for emitters to purchase lower priced overseas credits from the Clean Development Mechanism (CDM) and from the Joint Implementation (JI) as allowed without any limits under the proposed CPRS design.

Final CPRS design, its implementation and costs of domestic and overseas eligible Greenhouse Gas Abatement (GHGA) activities are crucial to forecasting wholesale electricity and REC prices and thus the viability of RE projects in Australia.

Green Power

Green Power source accredited under the National Greenhouse Accreditation Program (NGAP) cannot be acquitted against MRET liabilities and so adds to the market for RE. However, the future of Green Power under a CPRS continues to be uncertain, although the 4 May announcement indicated Green Power would be taken into account in setting CPRS emission caps.

3.4 Analysis of potential targets

Targets in Section 5 of the Climate Change and Greenhouse Emissions Reduction Act

Note that there are two related RE targets under the Act.

"(a) to increase the proportion of renewable electricity generated so that it comprises at least 20% of electricity generated in the State by 31 December 2014;

(b) to increase the proportion of renewable electricity consumed so that it comprises at least 20% of electricity consumed in the State by 31 December 2014."

The 2014 targets acknowledge electricity flows through inter connections with other NEM regions.

Inter connector trade will, for a given level of state renewable electricity (RE) generation, change the proportions of RE electricity to total State electricity generation, and to electricity consumed in the State

Generation Basis

Physical RE generation in the State is expressed as a proportion of total electricity generated in the State.

Consumption Basis

Physical RE generation in the State, not contracted RE consumption (through fulfilment of MRET and Green Power Requirements) is based on the premise that what is generated in the State is consumed in the State. Electricity consumed in the State is defined not just as customer sales but as Native Energy which is defined as customer sales plus transmission and distribution losses incurred in delivering the electricity to the customers. Defined in this way it is consumption in the sense that it is all electricity consumed (or dissipated) by the State's electricity consumers. It is their end-use consumption plus electricity dissipated from distribution and transmission losses (some of which maybe losses from inter-regional deliveries) from the delivery of generation sent out to customers.

The Electricity Supply Industry Planning Council (ESIPC) June 2008 Annual Planning Report defines Native Energy (page 32 Table 2-12) as customer sales plus network losses and generator houses loads. For example for 2017-18 in the ESIPC base case customer sales are projected to be 15,428 GWhs, network losses and generator house needs at 1,275 GWhs for a Native Energy total of 16,703 GWhs or 8.26 percent higher than customer sales.

Imports and exports[2]

South Australia is connected to the rest of the National Electricity Market (NEM) via the Heywood and Murray Link connectors.

Historically, South Australia was a net importer of electricity from the eastern States. Since late 2006 the wholesale price in the State has fallen below that in Victoria and there has, on average, been a flow of electricity to Victoria from South Australia. The total imports into South Australia in 2007-08 were the lowest on record and the total exports from the State the highest on record (net imports of 22 GWhs). The drought, continued growth in demand and increasing output from wind farms in South Australia have been significant contributing factors to this situation.

The changing nature of the South Australian export-import situation is illustrated below in Tables 3-14 and 3-15 from the ESIPC, Annual Planning Report, 2008 (page 83).

The future export-import situation depends on supply availability and costs of imports and internal South Australian generation, amounts which cannot be reliably forecast. Future interconnections and the impact of the CPRS will be the major determinants of future electricity targets. Due to uncertainty regarding these factors, we have assumed no net trade through to 2020. This issue is discussed further in **Section 4.3** below.

ESIPC estimate (2008 Annual Planning Report) that without any further new generation post 2009-10 to meet estimated 2017-18 requirements another 396 MW of capacity (mix not stated) would be required (page 92). Committed projects are included in the generation mix estimates.

Table 3-14 Historic Murraylink interconnector flow

Year	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)
2002-03	210	12	87	2
2003-04	217	60	46	27
2004-05	305	38	46	22
2005-06	270	31	41	20
2006-07	87	156	30	33
2007-08[1]	40	169	20	29
2007-08 pro-rata	41	174	20	29

Note: 1. This figure is for the period 1 July 2007 to 20 June 2008.
Source: ESIPC Annual Planning Report, 2008.

2 Sourced from Electricity Supply Industry Planning Council (ESIPC), June 2008, Annual Planning Report.

Table 3-15 Historic Heywood interconnector flow

Year	Total imports (GWh)	Total exports (GWh)	Import average (MW)	Export average (MW)
1999-00	3,574	1	408	63
2000-01	2,472	18	291	69
2001-02	1,442	156	97	40
2002-03	2,046	78	130	48
2003-04	2,553	31	305	74
2004-05	2,214	59	272	95
2005-06	2,374	35	312	83
2006-07	1,245	235	203	102
2007-08[1]	650	503	141	129
2007-08 pro-rata	668	517	141	129

Note: 1. This figure is for the period 1 July 2007 to 20 June 2008.
Source: ESIPC Annual Planning Report, 2008.

2020 Target Basis

As the focus of the target analysis over the period to 2020 is on renewable electricity generation and how it relates to South Australia's total electricity generation system, it is suggested that the 2020 target should be set on a generation basis only.

Target Analysis

Energy (customer sales) forecast

Based on ESIPC 2007-08 customer energy forecasts and assuming the Olympic Dam Expansion (ODX) proceeds, but not the pulp mill, in the forecast period. **Base case** customer sales reached 13,530 GWhs in 2014, extrapolated by NIEIR to19,000 GWhs at the end of 2020.

2014 situation (no ODX by end of 2014)

Targets 20 per cent of generation and electricity consumption by 31 December 2014.

Generation

On the assumption that:

Generation = **Native Energy** (no net trade)
= customer sales plus generator house loads, transmission and distribution losses of 8.26 percent.

Consumption (end-use) at end of 2014 (ESIPC estimate) = 13,530 GWhs.

Generation in SA = Native Energy (no net trade) =13,530 x1.0826 = 14,648 GWhs.

South Australian Renewable Electricity generation at beginning of 2010

= 2,433 GWhs from 868 MW (ESIPC, 2008) of wind at an estimated (CME) 32 per cent capacity factor plus approximately 75 GWhs of other (PV at 15 GWhs, and 60 GWhs from biomass).

Hence, in 2010 about 2,508 GWhs would be generated from RE sources. If no further RE were generated this would be 17.1 per cent of 2014 generation. Twenty per cent would require 2,930 (14,648 x 0.2) GWhs or another 422 GWhs which could come from another 151 MW of wind (at 32 per cent CF).

On this basis the 2014 generation target would be achieved.

Consumption target

As consumption is defined as Native Energy which on a no net trade basis is the same amount as generation, the consumption target would also be achieved.

4. 2020 targets: what could probably be achieved?

4.1 2020 generation

NIEIR's estimates of total SA generation out to 2020 are based on no net trade and estimates of end-use consumption, network losses and in-plant use.

As more RE enters the system in-plant losses would reduce but network losses (more remote locations) are likely to increase. In the absence of detailed information we have again used the 8.26 per cent ESIPC estimate of generation above end-use consumption.

Based on extrapolation of ESIPC forecasts and including ODX, NIEIR's estimate of end-use consumption at end of 2020 equals 19,000 GWhs.

Assuming no net trade (South Australia by 2020 **could** be a net electricity exporter and thus generation would be higher than that based on South Australian consumption) and generation 8.26 per cent above consumption.

South Australian generation in 2020 would be:

19,000 x 1.0826 = 20,569 GWhs

This is NIEIR's **base case** estimate of total South Australian 2020 generation.

RE generation required for 20, 30, 40 and 50 per cent targets in South Australia in 2020

	Target: per cent RE of total generation			
	20 per cent	**30 per cent**	**40 per cent**	**50 per cent**
Generation (total)	20,569 GWhs	20,569 GWhs	20,569 GWhs	20,569 GWhs
RE requirement	4,114 GWhs	6,171 GWhs	8,228 GWhs	10,285 GWhs

Analysis of South Australian RE mix in 2020

Preliminary estimate

Wind 1,942 MW at 31 per cent CF (CME database and CF dropping as less favourable wind sites developed) = 5,274 GWhs
(Source: CME database for operating, under construction, planned and advanced planning wind plants)

Geothermal 700 MW at 80 per cent CF = 4,906 GWhs
(70 per cent of total capacity estimation of MMA for Australian Geothermal Energy Association, August 2008: NIEIR assumes South Australia has the best State/Territory geothermal potential. NIEIR estimate of likely CF).

Other

Biomass	100 MW at 65 per cent CF = 570 GWhs (Depends on forestry and pulp mill project developments and technology developments in converting organic wastes to energy.)
Large scale solar	100 MW at an average of 30 per cent CF = 263 GWh (supported on cost-shared basis by the Federal Renewable Energy Development Fund, REDF)
PV	130 MW (100,000 installations at an average of 1.3 kW each) at 19 per cent CF = 216 GWhs
TOTAL by 2021 of all plants operating by end of 2020	11,229 GWhs, which if achieved would permit about a 50 per cent target to be achieved.

4.2 Constraints on achieving the above RE outputs in 2020

4.2.1 Solar hot water (SHW) and small scale photovoltaics (PV)

The eligibility of solar hot water (SHW) for RET is likely to significantly constrain renewable electricity generation from wind and other sources. We estimate that in 2020, through eligibility for REC creation, State and Federal rebates and regulations (for new housing and system replacement), SHW (thermal, heat pumps) units sold nationally in 2020 could reach 400,000 units in the residential and commercial sectors. At a REC per unit installation averaging 30 RECs, the RECs created in 2020 would be 12,000,000, or 27.7 per cent of RECs required under RET in 2020.

(South Australia contributed about 165,000 SHW RECs in 2008 from the installation of about 5,000 SHW units.)

Attainment of these SHW sales by 2021, and if SHW remains eligible for RECs, as scheduled in the proposed RET Regulations, SHW will significantly constrain the market for RE plants in all States and Territories out to 2020.

Small (<2 kW) scale PV systems could also contribute significant RECs over the period to 2020 thereby constraining the market for larger RE plants. The potential role of PV installations is discussed in **Appendix B**.

In Australia, overall, these small scale PV plants (<20 kW, mainly <2 kW) could contribute up to 14 million RECs (CME projection, Foresight No. 3, February 2008) in 2020 which, together with CME's projection of 11 million RECs from SHW in 2020, would only leave a 20 million REC market in 2020 for large scale RE plants. The future small scale PV market is very uncertain and we take a more conservative view of PV penetration (<1 million RECs in 2020). Nevertheless, small scale PVs could constrain the REC market for large scale wind and geothermal RE.

RECs for SHW and PV are **deemed**. That is, the RECs are not based on annual output (displacement in the case of SHW) as for other eligible sources but on what output they are **deemed** to produce (displace) over a fixed period: about 10 years for SHW and up to 15 years for PV.

For example, at an annual displacement of 3 MWhs for a specific SHW installation, the deemed RECs would be 30 over 10 years. These deemed RECs can enter the REC market once the installation has been accredited.

4.2.2 Financing

Global economic conditions which are affecting Australian capital markets will have an impact on the ability of RE project proponents to raise capital to finance projects.

Conditions should ease post 2010-11 but this constraint could force postponement or abandonment of some projects.

4.2.3 Competition from RE in other States/Territories

Victoria, for which we have reasonable data on RE potential, costs and projects, has a significant wind resource of similar magnitude to South Australia and some geothermal potential across the State. Also significant large scale solar and wave power projects are likely to attract demonstration project funding under the Federal Solar Flagships Program to which $1.5 billion has been committed. Two large scale solar projects in Victoria are being financially supported by the Victorian and Federal governments.

We estimate that demonstration projects in Victoria could produce 788 GWhs.

Biomass renewable electricity (RE) from landfill gas, anaerobic conversion of municipal organic solid wastes and agricultural and forest wastes could, in Victoria, contribute over 100 MW at an average capacity factor of 65 per cent (about 600 GWhs).

Overall Victorian contribution to the RET by 2020, exclusive of SHW and small scale PV, could comprise:

2,000 MW of **wind** at 32 per cent CF (1,016 MW by 2010)	5606 GWhs
50 MW of **geothermal** at 80 per cent CF	350 GWhs
300 MW of **large scale solar/wave** at 30 per cent CF	788 GWhs
50 MW of **biomass** at 65 per cent CF	285 GWhs
Total	**7029 GWhs**

The rest of Australia could contribute about:

2,000 MW of wind at 35 per cent CF (higher CFs in Tasmania)	6,130 GWhs
400 MW of biomass at 60 per cent CF	2,100 GWhs
100 MW of geothermal (New South Wales) at 80 per cent CF	700 GWhs
100 MW of other (mainly large solar) at 30 per cent CF	260 GWhs
Total	**9,190 GWhs**

These estimates, albeit uncertain at this time, give a total of 16,219 GWhs which, in itself, would not constrain the contribution of South Australian RE to RET.

Costs of other States' sources have not been estimated, but as stated above we estimate an RE LRMC of about $115/MWh would give about 30,000 GWhs of additional renewable electricity.

Of greater importance is the likely crowding out of renewable electricity by solar hot water and *within* renewable electricity the competition to "large" (1 MW to 500 MW) of small scale photovoltaics (see discussion in Appendix B).

4.2.4 Network constraints

Network constraints have two aspects:

(i) the cost of providing network connection to renewable electricity plants (the total cost and the sharing of these costs); and

(ii) limits on RE output to maintain system integrity.

Additional network costs have not been estimated but could be substantial, particularly for geothermal.

Who will pay the additional costs is far from settled: any contributions from RE plants could significantly affect their economics.

Limitations on wind power output to ensure South Australian grid stability is estimated to be associated with about a 20 per cent limit on wind capacity.

This could limit capacity to about 1,200-1,400 MW depending on evolution of the South Australian system capacity including interconnections. In our most probable (0.5p) case we have assumed 1,400 MW which, at a capacity factor of 32 per cent, would produce an output of 3,925 GWhs. This estimate, we feel, is a reasonable estimate of wind power limits by 2020. But we note that higher limits than 20 per cent may be feasible as wind plant and grid management technology improves, interconnections are augmented and as South Australian base load capacity increases.[3]

The wind power resource does not appear to be a constraint. Thus the CME database lists wind plants with a total of 4,601 MW of capacity in the operating, under construction, planning, advanced and prospective categories (see **Appendix A** for a listing of these projects).

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[3] In a December 2008 report titled *Wind General Licencing – Draft Proposals*, the Essential Services Commission of South Australia (ESCOSA), proposes to "Require that all future wind generation must be classified as **semi-scheduled** under the National Electricity Rules".

If accepted this proposal would mean all new wind plants would be required to provide wind forecasting and temperature data and would probably need to integrate their output with quick response generators (essentially gas generators) or electricity storage facilities (expensive).

These requirements could significantly constrain wind generation below our Base case estimate, perhaps to about 1,200 MW by 2020.

4.2.5 Development potential for geothermal by 2020[4]

Currently, although geothermal energy plants operate overseas, there is no experience with establishing and operating geothermal plants in Australia. As geothermal potential is substantial and as there is an expectation that geothermal energy will make a substantial contribution to RE generation in South Australia, it is necessary to critically assess how much geothermal energy might be successfully deployed over the next 10-20 years.

The ESIPC 2008 Annual Report, from which most of the discussion below is excerpted, indicates that there are five main geothermal energy sources recognised around the world:

- **Hydrothermal** – where either water or steam is trapped in fractured or porous rocks; these can be found from a hundred metres to several kilometres below the earth's surface;

- **Geopressured** – a type of geothermal resource occurring in deep basins in which the pore fluid is under very high pressure;

- **Magma** – associated with active volcanic areas;

- **Hot Dry Rock (HDR)** – a geothermal energy resource that consists of high temperature, impermeable, crystalline rock above 150^{o}C that may be fractured and have little or no pore water; and

- **Hot Fractured Rock (HFR)** – a separate category where naturally fractured hot rock is fluid-saturated.

There is approximately 10,000 MW of electricity generation capacity in the world that is based on conventional steam from geothermal and hot water hydrothermal generation. The potential yield of the later two categories can be increased by fracturing of the rock by physical or chemical techniques. Enhanced Geothermal Systems (EGS) based on Hot Dry Rock (HDR) and Hot Fractured Rock (HFR) represent emerging technologies where the heat stored underground is recovered or "mined" and the resulting hot geothermal fluid is used to generate electricity. EGS system at this stage do not figure significantly in the installed geothermal capacity world-wide. Analysis, research and development of these systems is being undertaken in Australia as part of a significant worldwide push to utilise the vast amounts of the earth's stored thermal energy.

The extraction of energy from Hot Dry Rock has been under investigation across the world for many years. It has recently received more prominence in South Australia, where significant potential has been delineated as a result of modifications to the *Petroleum Act 2000* introducing Geothermal Exploration Licences (GELs). Since that time 236 GELs have been issued to 23 companies covering some 110,358 square kilometres. There is also potential in Victoria, New South Wales and Western Australia.

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[4] For good summaries of geothermal potential and constraints to realising this potential see the *ESIPC Annual Report, 2008*, Chapter 3.5 and *Carbon Market Economics Foresight Report*, Issue 2, Fourth Quarter, November 2008.

The significant South Australian potential is attracting many private sector firms (Geodynamics, Petratherm, etc.). The Carbon Market Economics database reports for HDR/HFR in South Australia.

0 MW	operating
1 MW	under construction
37.5 MW	planned
1,530 MW	prospective

MMA in an August 2008 report for the Australian Geothermal Energy Association (AGEA) estimated that over 2,000 MW of commercial geothermal capacity could be operating by 2020 and likely at least 1,000 MW most of which would be in South Australia.

The MMA report for the AGEA (August 2008) estimated costs for a pilot plant (<10 MW) of \$150/MWh; \$90-135/MWh for demonstration projects (10-50 MW) and \$80-120/MWh for commercial plants (50 to >300 MW) and conclude (page 3):

> "*it is difficult to predict the viable installed capacity in 2020. However, if we assume that half the study respondents that provided data will deliver electricity at the lower part of the cost range then an effective installed capacity of 1,000 MW will be achieved by those companies*".

Most of this capacity would be based in the Cooper Basin in South Australia. This resource is generally accepted to be available but there is less certainty surrounding the maintenance of long term generation from the resource.

The potential of geothermal energy to supply significant quantities of base load generation capacity at capacity factors of up to 95 per cent has attracted Commonwealth interest and specific support for geothermal energy development is allocated \$50 million (on a cost-shared basis with private investors) under the Clean Energy Initiative. This support should accelerate assessment of the feasibility (technical, commercial) of substantial geothermal electricity generation in Australia.

The 2008 Annual Report of ESIPC estimated that the cost of geothermal electricity would be in the range of \$92-118/MWh for a 50 MW plant and Geodynamics estimate (in a submission to the Garnaut Review) the long run marginal cost of generation in the Cooper-Eromonga Basin would be \$72/MWh, **excluding transmission costs** (all values in 2008 dollars). Building a 50 MW plant at a cost of around \$6 million, setting aside transmission issues which may constitute the major barrier to realising geothermal potential, faces financing barriers due to technical risks, according to Geodynamics. However, support from the Federal Government over the next two years could contribute to overcoming this barrier. If such a 50 MW project were successful it could lead to larger scale developments post-2015 if transmission issues could be resolved in such a way that geothermal energy would be commercially viable.

If costs to connect a Cooper Basin geothermal plant to the grid had to be borne by the generator, it is very unlikely that a 50 MW demonstration plant would be built. Government support will likely be required to bring about the required transmission investment, but as yet there are no support guarantees. Geodynamics estimate a full transmission cost of \$14/MWh for the connection of a Cooper Basin geothermal plant to the grid via a 600 km. 1000 MWh 800kv DC transmission line.

In this regard Geodynamics' submission to the Garnaut Review stated that the:

> "*most cost effective option in the long term would be to build a foundation transmission network that is able to commence operation with low output from the region but can be scaled up incrementally to be fully utilised over time (i.e. start with 50 MW but be able to ramp up on the same infrastructure to 1,000 MW at minimal additional cost). This could be designed to address the emerging need to strengthen the already overloaded interconnections into the east coast electricity grid between South Australia and Victoria and New South Wales/Queensland. Such strengthening will be needed to facilitate the transfer of increasing amounts of wind power generation arising from the expanded MRET scheme that will mainly be located in South Australia and southern Victoria.*"

On the basis of the above discussion we recommend a cautious approach to estimating the contribution geothermal RE could make to South Australian RE by 2020 until experience with the technology builds.

If geothermal energy capacity is not significant in South Australia by 2020, and if network stability constraints are not eased and continue to limit wind to 20 per cent of generation, it is likely that the assumed contribution of geothermal by 2020 will not be filled by other RE sources.

Based on the above review of geothermal potential and constraints, we suggest that 500 MW of geothermal RE operating at an 80 per cent CF could be used as the most probable (0.5p) estimate for geothermal in South Australia by 2021.

> 400 MW at 80 per cent CF = 2,803 GWhs

(Up to 95 per cent CF is quoted but until evidence of successful geothermal energy plant operation in Australia eventuates we suggest a lower CF should be used.)

4.2.6 Impacts of constraints on other RE sources

Biomass (landfill gas (LFG), other forest, etc. waste conversions to electricity)

> 30 MW at 65 per cent CF = 170 GWhs

Large scale solar demonstration

> 30 MW at 35 per cent CF = 92 GWhs

Small scale PV

> 100 MW at 19 per cent CF = 166 GWh

These outcomes are further discussed below in **Section 4.4, Sensitivity and probability analysis**.

4.3 South Australian RE contribution by 2021 based on the above analysis

Based on the constraints analysis in **Section 4.2** above we downgraded the **Section 4.1** estimates to the following levels.

Wind	3,925 GWhs
Geothermal	2,803 GWhs
Other large scale (biomass, solar)	262 GWhs
Small scale PV	166 GWhs (see discussion below)
Total	**7,156 GWhs**

Targets

2020 generation basis

Generation (as estimated above)	**20,569 GWhs**
RE Proportion	**34.8 per cent**

The future RE generation contribution in South Australia will depend on the factors discussed above. Fossil fuel based generation in the State, out to 2020 and beyond, will depend mainly on the CPRS design and its implementation schedule), but also on South Australian demands (impacted by the CPRS and other factors), fuel prices (particularly gas), wholesale electricity prices in other NEM regions and interconnections between NEM regions.

Accordingly the South Australian generation estimated above may differ significantly from that used as the basis for our target analysis. NIEIR estimates are based on recent trends and current views on the CPRS and its likely impact on South Australian and other NEM electricity generation, demands and net trade. In the period to 2020 fossil generation under the CPRS will shift further towards gas in South Australia and other NEM regions with the proportion of fossil generation from coal declining, particularly in Victoria.

To amplify, in South Australia the two coal generators (Northern and Playford B) are at risk under the CPRS due to their high (particularly Playford B) greenhouse gas intensities (GHGIs) measured into CO_2e/ MWh, just as coal stations are in other NEM regions. Particularly at risk are Victoria's brown coal generators which are likely to have much of their current generation displaced by combined cycle gas turbines (CCGT), three of which are proposed for installation in Victoria. New South Wales black coal generators though of lower GHGIs than Playford B and Victorian brown coal generators will also face diminished generation under CPRS. In Queensland there are some low GHGI coal generators (Milmerran and Kogan Creek) and substantial coal seam methane (CSM) gas resources capable of producing relatively low GHGI electricity. Subject to interconnector transmission and high transmission losses Queensland could export into other NEM regions. Tasmania with a predominantly hydro generation subject to drought constrictions and high cost gas is unlikely to be a significant net exporter

Furthermore in the 2008 Treasury modelling of the CPRS over the period to 2020, South Australia has the lowest wholesale electricity price increase due mainly to access to gas from the Otway and Cooper basins. This suggests that SA generation could become more competitive over the period.

On this basis, albeit not a detailed analysis, NEM inter-regional trade patterns may not change significantly from current patterns and thus the no net-trade assumption seems reasonable at this time. Only more certainty on CPRS design and fuel prices and detailed modelling of the NEM would clarify the situation. It should be noted that as yet no public information is available on any modelling which may have been undertaken on PM Rudd's 4 May 2009 announcement of CPRS design changes.

Demands for electricity may also differ from those projected above depending again on CPRS impacts and the impacts of global economic conditions, energy efficiency improvements (EEIs) and fuel switching (SHW, etc.). However, the NIEIR demand estimates based on ESIPC projections do take the most recent views on these trends into account.

Overall, we believe that the South Australian RE and fossil based generation estimates presented above are reasonable given the current state of analysis in an uncertain environment. However, we also believe that they should be subjected to sensitivity and probability analysis which is presented below.

4.4 Sensitivity and probability analysis

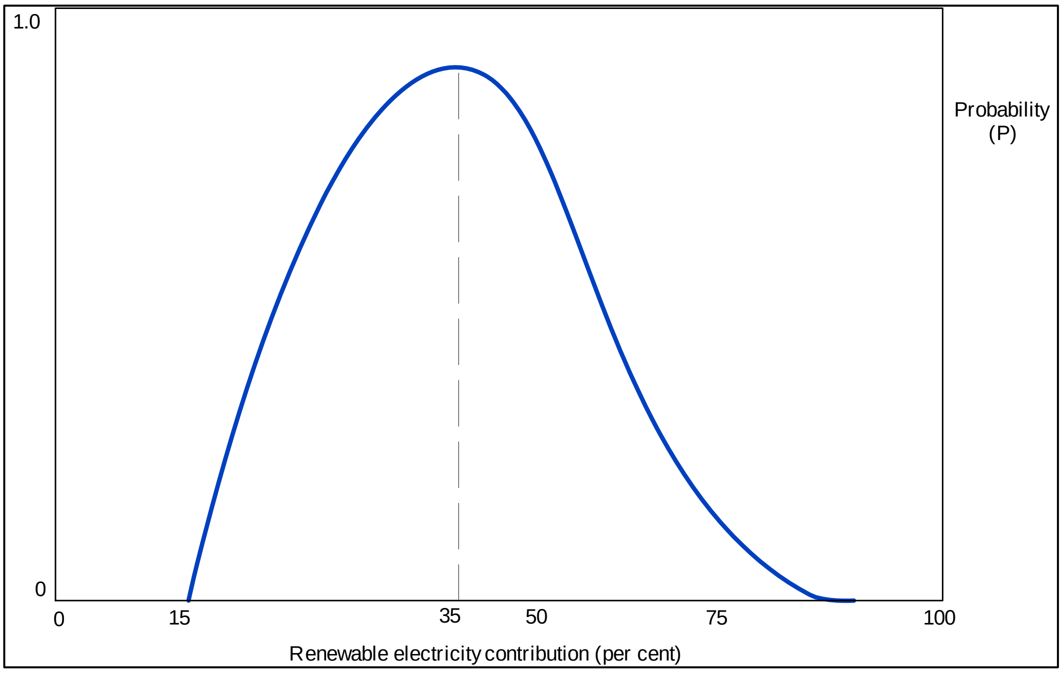
Given the uncertainties surrounding South Australian electricity generation and consumption, we think it prudent to conduct a probability analysis of the potential out to 2021 for renewable electricity in South Australia.

The underlying assumption for the probability analysis continues to be that the Renewable Energy Target (RET) will operate over 2010-2020 and will have the design put forward at the COAG meeting on 30 April 2009. This measure essentially sets the overall market for renewable energy sources, covering renewable electricity sources and solar hot water over the period. Without the RET and direct support (through rebates and R, D, D & C support) few renewable sources would be commercially viable in the period. However, renewable electricity commercial viability in the period will also depend on the design and timing of a Carbon Pollution Reduction Scheme (CPRS), now (4 May 2009) scheduled for 1 July 2011, with a fixed price of \$10/t CO_2e in 2011-12, and full market trading from 1 July 2012. The CPRS **might**, post 2012, increase the prices of fossil fuel energy sources to such an extent that some renewable sources become competitive without government support through RET, rebates, etc. And technological advances (for example scale economies, storage) for renewable energy sources could also improve their competitiveness.

RET, direct support, the CPRS and technology advances set an overall market penetration limit or constraint on renewables penetration in South Australia and other parts of Australia. However, there are other constraints particularly (but not only) related to South Australia: limits on the ability of the electricity system to reliably manage (absorb) large amounts of intermittent generation relative to overall system capacity (will depend on energy demand and interconnections) growth, South Australian generation competitiveness, the reliable technical development of the substantial potential for geothermal energy and costs of network expansions to connect renewable electricity sources.

It is in this context that the analysis presented below was undertaken: now some certainty with respect to RET but uncertainty with respect to other factors affecting future prospects of renewable electricity in South Australia.

An approach to this uncertainty is to assess each renewable energy source (including solar hot water as this will constrain renewable electricity under RET) and develop minimum, mean and maximum contributions (to which probabilities would be attached) for each. Based on this analysis scenarios could be developed ranging from a minimum renewable contribution (comprising the lowest probabilities) to a maximum contribution (all high probabilities) of renewable electricity to total generation in South Australia. A contribution distribution profile could be developed as set out schematically below.



In advance of detailed analysis the shape and levels of the distribution are hypothetical.

For each renewable energy source a probability profile could be developed. For example, in the case of wind by 2021: 0.1p, 10,000 GWhs; 0.4p, 8,000 GWhs; 0.6p, 6,000 GWhs; 0.9p, 3,000 GWhs.

4.4.1 Probability analysis of each South Australian renewable electricity source

The analysis was conducted by considering for each renewable electricity (RE) source (wind, geothermal, biomass, large scale solar and small scale PVs) the economic, technical and overall potential and constraint outlook.

The review of each source was conducted by NIEIR in association with Carbon Market Economics (CME). For each source **four cases** were developed from a low contribution (very conservative minimum) to a high contribution (optimistic towards maximum), each having an 0.1p of eventuating. Two intermediate cases were developed with respectively 0.3p and 0.5p of eventuating which are more probable cases. We feel that at this time of economic and environmental (climate change particularly) uncertainty it is not prudent to attempt development of higher probability (<0.5p) cases.

From these cases a probabilistic generation by 2021 (that is, for plants operating by the end of 2020) can be and was determined.

It is very important to note that the probabilities attached to each case by the reports' authors (particularly from NIEIR) rather by a group of knowledgeable persons in the area (a Delphi Group). This would be desirable but, given the study's constraints, was not feasible.

Wind

By the end of 2009 ESIPC estimate there will be about 868 MW of wind capacity, and CME a similar amount, installed in South Australia.

At an **average** capacity factor of 32 per cent (NIEIR/CME capacity factor estimates are based on plant outputs) wind generation with no further expansion of capacity would be 2,509 GWhs. If none of this capacity were withdrawn and only another 132 MW were installed (1,000 MW at 32 per cent by 2020) this would set the 2020 lower limit to South Australian wind generation by 2020 (**Case 1**).

Case 1

1,000 MW at 32 per cent capacity factor (CF) = 2,803 GWhs (0.1p).

Probabilities of higher wind capacities and outputs by 2020 are set out below.

Case 2

1,200 MW at 32 per cent CF, giving wind generation of 3,364 GWhs representing a potential but somewhat conservative limit on wind capacity (0.3p) based mainly on current network constraint limits.

Case 3

1,400 MW at 32 per cent CF, giving wind generation of 3,924 GWhs (0.5p).

This case is based on our assessment of the economic outlook to 2020 and improved ability to reliably control wind intermittency impacts on the electricity system.

Case 4

1,942 MW at 32 per cent CF based on CME database for operating, under construction, planned and advanced planning equals 5,444 GWhs.

As this capacity would exceed the 20 per cent limit on wind capacity (of about 1,200 MW) of total generation capacity, we examined the probability of South Australia's total generation capacity increasing and probabilities of interconnection augmentation increasing the permissible South Australian wind generation capacity.

On consideration of potential resource developments by 2020 as the global economy recovers, then grows significantly, and as the CPRS and the NEM regions' electricity demands increase significantly, there is some (but at current outlooks a low) probability that this could eventuate. The contribution of solar hot water (SHW) to RET also imposes a constraint on this level of wind generation being achieved.

We assign a 0.1p to this outcome.

Although higher wind capacity outcomes could be achieved given CME's project database, this outcome would essentially set the upper limit of South Australian wind generation by 2020.

Based on these probability estimates wind generation by plants operating at the end of 2020 would be as follows.

	GWhs	Probability	Generation
Case 1	2,803	0.1	280
Case 2	3,364	0.3	1,009
Case 3	3,924	0.5	1,962
Case 4	5,444	0.1	544
Probabilistic generation		**1.0**	**3,795**

Geothermal

As distinct from wind, South Australian geothermal generation by 2020 will be determined mainly by resolution of technical issues, the scale of geothermal plants and grid (network) connection costs.

Case 1

Given that in mid-2009 there is still not an operating pilot plant, technology deployment issues have not been resolved and that costs of interconnection issues have not been resolved, generation capacity may reach only 100 MW by 2021.

100 MW at 80 per cent CF would give generation of 701 GWhs. We assign a low probability of 0.1p to this outcome as substantial resources by governments and the private sector are being devoted to overcoming the geothermal energy development challenges.

Case 2

In this case there is some improvement in successfully addressing the challenges confronting geothermal energy development in South Australia.

200 MW at 80 per cent CF = 1,402 GWhs by 2021 (0.3p).

Case 3

As discussed in **Section 4.2.5** above, our review of geothermal potential in South Australia indicates that there is a reasonable probability (0.5p) that 400 MW of geothermal capacity generation might be achieved by 2021.

400 MW at 80 per cent CF = 2,803 GWhs by 2021 (0.5p).

Case 4

Given the significant (over 1,000 MW) advanced and prospective geothermal plants in the CME database, and the resources being applied to the challenges, there is some probability that up to 700 MW could be operating by the end of 2020. However, only a low probability (0.1p) is attached to this outcome as at this time (mid-2009) a range of technical, economic and commercial issues surrounding successful development of geothermal energy in South Australia remain unresolved.

700 MW at 80 per cent CF = 4,906 GWhs by 2021.

Based on these cases the probabilistic generation for geothermal energy in South Australia by 2021 would be as set out below.

It should be noted that these estimates may be regarded as conservative and could be exceeded, but we think they are reasonable given current geothermal development uncertainties.

	GWhs	Probability	Generation
Case 1	701	0.1	70
Case 2	1,402	0.3	421
Case 3	2,803	0.5	1,402
Case 4	4,906	0.1	491
Probabilistic generation, 2020		**1.0**	**2,384**

Biomass

Biomass, currently a minor source of RE in South Australia could increase significantly by 2020 through development of other landfill gas (LFG) sites, pulp, paper and other forestry industry developments and technological developments in converting organic wastes to methane for electricity production.

In 2010 about 60 GWh of electricity was produced from about 11 MW of LFG sites operating at an average 65 per cent CF.

2020 cases

Case 1

Some expansion of LFG generation: 15 MW at 65 per cent CF, 85 GWhs (0.1p).

Cases 2, 3 and 4 foresee increasing expansions in generation from wastes (municipal, forest industries).

Case 2

30 MW at 65 per cent CF, 171 GWhs (0.3p).

Case 3

60 MW at 65 per cent CF, 342 GWhs (0.5p).

Case 4

100 MW at 65 per cent CF, 570 GWhs (0.1p).

Probability outcome

	GWhs	Probability	Probabilistic generation GWhs
Case 1	85	0.1	9
Case 2	171	0.3	51
Case 3	342	0.5	171
Case 4	570	0.1	57
Probabilistic generation by 2021		**1.0**	**288**

Large scale solar

Large scale solar generation plants are of two main types: PV based/concentrating sunlight on PV direct conversion to electricity and solar thermal which heat a fluid which is used to drive a turbine to produce electricity. Several of these systems are in operation in the world (Spain, United States, etc.), and although currently the electricity produced is higher cost than biomass, wind and geothermal, they are attracting considerable technology development support. In Australia several plants may be funded under the Federal Solar Flagships Program including two now planned in Victoria (one concentrating PV and one solar thermal). With South Australia’s excellent solar regime it is probable that a demonstration plant will be located in the State.

Average capacity factor is estimated to be 30 per cent (depends on actual plant design). On this basis we have again developed four cases for plants operating by the end of 2020, from 0 MW (Case 1) to 100 MW (Case 4).

Cases 2, 3 and 4 are based on increasing funding from public and private sources of large scale solar demonstration plants.

Case 1

0 MW, 0 GWhs (0.1p).

Case 2

30 MW at 30 per cent CF, 79 GWhs (0.3p).

Case 3

60 MW at 30 per cent CF, 158 GWhs (0.5p).

Case 4

100 MW at 30 per cent CF, 263 GWhs (0.1p).

Probabilistic outcome

	GWhs	Probability	Probabilistic generation GWhs
Case 1	0	0.1	0
Case 2	79	0.3	24
Case 3	158	0.5	79
Case 4	263	0.1	26
Probabilistic generation by 2021		**1.0**	**129**

Small sale (<10 kW) photovoltaics (PVs)

These systems are:

(i) achieving increasing penetration in Australia under direct Federal grants/rebates and MRET;

(ii) after 1 July 2009 will receive support under RET (reducing until 2012-13) and are now receiving support from a preferential feed-in-tariff (FIT) in South Australia; and

(iii) benefiting from cost reductions through technology and manufacturing scale developments.

The Department of the Environment, Water, Heritage and the Arts, report that to February 2009 5,295 PV systems were grid connected and 245 PV systems were off-grid in South Australia. The total is only slightly lower than New South Wales, but South Australia has significantly more grid connected systems.

NIEIR estimates that by 2010 on installation and policy there will be about 10 MW of these systems installed in South Australia and about 23 MW by 2015.

Given the change in Federal support for PVs, the uncertain impact of the FIT, CPRS impacts and PV cost decreases, there is a wide range of views on the future uptake of these PV systems.

Again, we have developed four cases, as set out below, for these systems operating by the end of 2020. The cases are based on our estimates and estimates from other sources such as Carbon Market Economics Pty Ltd.

Case 1

30 MW at 18 per cent CF, 47 GWhs (0.1p).

Case 2

50 MW at 18 per cent CF, 79 GWhs (0.3p).

Case 3

100 MW at 19 per cent CF (CF increasing through technology improvements), 166 GWhs (0.5p).

Case 4

250 MW at 19 per cent CF, 416 GWhs (0.1p).

Probabilistic outcome

	GWhs	Probability	Probabilistic generation GWhs
Case 1	47	0.1	5
Case 2	79	0.3	24
Case 3	166	0.5	83
Case 4	416	0.1	42
Probabilistic generation by 2021		**1.0**	**154**

4.4.2 South Australian renewable energy generation to 2021 based on probability analysis

The probabilistic generation (in GWhs) for each RE source are set out below in order of increasing generation from left to right.

Table 2 Probabilistic South Australian RE generation for each probability case

RE source	0.1p	0.3p	0.5p	0.1p	Probabilistic total 1.0
Wind	280	1,009	1,962	544	3,795
Geothermal	70	421	1,402	491	2,384
Biomass	9	51	171	57	288
Large scale solar	0	24	79	26	129
Small scale solar PV	5	24	83	42	154
Totals	**364**	**1,529**	**3,697**	**1,160**	**6,750**

Table 2 above presents data on the probabilistic generation for each case and total for each source.

In **Table 3** below the generation (undiscounted by probabilities) for each case and each source is presented. This data gives a range of total RE generation for the low (estimated minimum) case, the two intermediate cases and the high (estimated maximum) case.

These case totals can then be compared with estimated South Australian generation in 2020 (as set out below) to present the range of targets which could be set for RE generation in South Australia.

Table 3 Generation ranges estimated for each source

RE source	Case 1	Case 2	Case 3	Case 4	Probabilistic generation
Wind	2,803	3,364	3,924	5,444	3,795
Geothermal	701	1,402	2,803	4,906	3,384
Biomass	85	171	342	570	288
Large scale solar	0	79	158	263	129
Small scale solar PV	47	79	166	416	154
Totals	**3,636**	**5,095**	**7,393**	**11,599**	**6,750**
Percentage of 2020 **total** South Australian generation (20,125 GWhs: see below)	18.1	25.3	36.7	57.6	33.5

4.4.3 Generation estimates

Generation in South Australia in 2020 will depend on the economic conditions (including CPRS impacts) prevailing over the period to 2020, the competitive situation of South Australian generation and interconnection capacity.

As with renewable electricity generation, we have developed a probabilistic estimate of total electricity generation in South Australia in 2020.

NIEIR generation cases

		Case probabilities	Probabilistic outcome
Base case	20,569 GWhs	0.6	12,341 GWhs
High case	26,523 GWhs	0.1	2,652 GWhs
Low case	17,105 GWhs	0.3	5,132 GWhs
2020 probabilistic generation			**20,125 GWhs**

4.4.4 Renewable electricity target (percentage of total generation) estimate

Target based on probability analysis (33.5 per cent or about one-third of projected total South Australian generation in 2020).

This estimate is slightly lower than the estimated level (35.4 per cent) presented in **Section 4.3** above which, however, did not take into account the range of potential cases and their probabilities of their achievement.

A stretch target of 40 per cent may be attainable but we consider that given the uncertainty surrounding future South Australian total and renewable electricity generation a target of 33.3 per cent would be prudent and appropriate. **Note** that as some RE generation units may only begin operating in 2020 their **annual** generation would only be achieved in 2021.

Appendix A: South Australian renewable electricity plants out to 2020: Carbon Market Economics Pty Ltd (CME) database, February 2009

Name	CME status[1]	Plant type	Planned installation date	MW 2020
Pedler Creek	1. Operating	Biomass		2.9
Highbury	1. Operating	Biomass		1.0
Tea Tree Gully	1. Operating	Biomass		1.0
Wingfield I, II & III Landfill site	1. Operating	Biomass		6.0
Radius Power Station	1. Operating	Biomass		<1.0
Ernabella PV	1. Operating	Solar		0.2
Wilpena Pound	1. Operating	Solar		0.2
PC Power	1. Operating	Solar		0.2
Lavina June	1. Operating	Solar		0.2
Ernabella	1. Operating	Solar		0.2
SA Solar PV plants	1. Operating	Solar PV		220
Lake Bonney - Stage I	1. Operating	Wind		80.5
Mount Millar, Eyre Peninsula	1. Operating	Wind		30.0
Hallet S1 Brown Hill	1. Operating	Wind		94.5
Starfish Hill	1. Operating	Wind		34.5
Lake Bonney Stage II	1. Operating	Wind		160.0
Canunda Wind Farm (Lake Bonney Central)	1. Operating	Wind		46.0
Cathedral Rocks (Eyre)	1. Operating	Wind		63.0
Wattle Point	1. Operating	Wind		90.8
Snowtown S1	1. Operating	Wind		99.0
Innamincka Pilot	2. Construction	Geothermal	2008	1.0
Hallett S2 Hill Wind (Barunga)	2. Construction	Wind	2010	71.0
Clements Gap	2. Construction	Wind	2011	57.0
Willogoleche	3. Planned	Wind	2012	52.0
Mount Bold Mini Hydro	3. Planned	Hydro	2009	1.0
Coober Pedy	3. Planned	Solar	2009	0.9
Innamincka I	4. Advanced	Geothermal	2013	50.0
Myponga, Sellicks Beach	4. Advanced	Wind	2011	40.0
Vincent North	4. Advanced	Wind	2012	59.0
Elliston Stage 1 Tungketta Hill	4. Advanced	Wind	2014	16.0
Waterloo	4. Advanced	Wind	2016	117.0
Barn Hill (Red Hill)	4. Advanced	Wind	2016	125.0
Elliston Stage 2	4. Advanced	Wind	2013	65.0
Mount Hill	4. Advanced	Wind	2015	80.0
Hallett Wind S4	4. Advanced	Wind	2016	189.0
Mount Bryan Hallett S3	4. Advanced	Wind	2013	98.0
Snowtown S2	4. Advanced	Wind	2012	175.0
The Bluff Range Hallet S5	4. Advanced	Wind	2016	50.0
Kuplara S2	4. Advanced	Wind	2016	50.0
Paralana Pilot	5. Advanced	Geothermal	2009	7.5
Paralana Demonstration	5. Advanced	Geothermal	2014	30.0
Tarpeena	5. Prospective	Biomass	2012	60.0

Name	CME status[1]	Plant type	Planned installation date	MW 2020
Beatrice Hill	5. Prospective	Biomass	2009	0.4
Innamincka II	5. Prospective	Geothermal	2016	450.0
7 TBA Geothermal	5. Prospective	Geothermal	2017	20.0
Millicent	5. Prospective	Geothermal	2013	50.0
Great Artesian Basin	5. Prospective	Geothermal	2017	200.0
Handorf	5. Prospective	Hydro	2016	1.0
Whyalla	5. Prospective	Solar	2010	24.0
Port Paterson	5. Prospective	Solar	2010	50.0
Green Point	5. Prospective	Wind	2014	54.0
Troubridge	5. Prospective	Wind	2013	25.0
Mount Benson	5. Prospective	Wind	2017	130.0
Kongorong	5. Prospective	Wind	2014	30.0
Lake Hamilton/Sheringa	5. Prospective	Wind	2016	110.0
Uley Basin	5. Prospective	Wind	2016	150.0
Lake George	5. Prospective	Wind	2017	120.0
Sheringa	5. Prospective	Wind	2014	100.0
Collaby Hill	5. Prospective	Wind	2016	96.0
Lincoln Gap	5. Prospective	Wind	2015	120.0
Allendale	5. Prospective	Wind	2017	150.0
Kulpara	5. Prospective	Wind	2016	85.0
Laslett	5. Prospective	Wind	2017	150.0
South Eastern	5. Prospective	Wind	2016	80.0
Tungketta Hill II Wind	5. Prospective	Wind	2016	65.0
Vincent North Wind	5. Prospective	Wind	2014	59.4
Waokwine	5. Prospective	Wind	2013	100.0
Weymouth (Hill)	5. Prospective	Wind	2016	20.0
World's End	5. Prospective	Wind	2015	180.0
Kuplara S1	5. Prospective	Wind	2016	60.0
Gulnare	5. Prospective	Wind	2016	175.0
SA Wind Project	5. Prospective	Wind	2017	450.0
Australia Plain Eudunda	5. Prospective	Wind	2017	150.0
Blanche No1	6. Prospective	Geothermal	2018	50.0
Lime Coast 1	6. Prospective	Geothermal	2018	500.0
Lime Coast 2	6. Prospective	Geothermal	2021	
Paralana 1	6. Prospective	Geothermal	2017	260.0
Paralana 2	6. Prospective	Geothermal	2021	

Notes: 1. Definitions of CME status classification:

Operating plants – Renewable electricity plants that were operational in 2008.
Under construction – Plants that had commenced construction in 2008.
Planned – Plants that had received planning approval. Judgement in respect to South Australia was based on information published by ESIPC in 2008 and information gathered by CME.
Advanced – Defined as proposed plants that where available information indicated that the plant had a strong prospect of proceeding to the planned stage. Information on wind plants was based on published data by ESIPC.
Prospective – Plants that had been publicly announced by developers or another interested party in the renewable electricity generation plant. At the time the classification was determined CME did not have any additional information on these plants.

2. **Planned installation dates**: these are indicative, particularly for the prospective plants. In our experience installation dates projected tend to be optimistic compared with actual installation dates and some projects never proceed in the projection period.

Appendix B: Renewable Energy Certificate (REC) market analysis

RE contributions in 2020 will depend significantly on REC prices under the expanded MRET. Accordingly, an analysis of the forward REC market is presented below

A major constraint on renewable electricity (large scale) will be the SHW contribution to MRET, the PV contribution to MRET and their impact on REC prices (currently $46-$50/MWh).

Our analysis of REC requirements, REC creation and REC prices to 2020 is set out below as of February 2009.

Our analysis of the REC market over 2008-2020 indicates that under the assumptions applied the REC market tightens over 2008-12 as REC requirements increase and RE plant investment does not keep up with the increasing demands. RECs created are less than REC requirements, hence banked REC numbers decline.

In this market REC prices increase peaking in 2011 and 2012 even though the inferred REC price (marginal RE cost – wholesale electricity price) is less than the market REC price.

REC creation from solar hot water and PVs (x5 multiplier impact and lower costs) is strong.

Post-2012 new RE plant investment and output is stronger, and despite increasing requirements, this source of RECs together with continued growth in solar hot water (SHW) and PV increases the banked REC levels until they reach unsustainable (to holders) levels in 2015 as RECs created begin to significantly exceed REC requirements.

Sale of banked RECs causes REC prices to fall below viable RE plant cost levels and investment stalls but SHW RECs continue to increase.

Post-2016 REC prices increase to sustainable levels to meet REC price requirements for new RE plants and RE plant investment resumes but probably not quickly enough to cause a spike in REC prices in 2018 and 2019. By 2020 the market is about in balance. Prices reduce towards inferred REC price levels.

Post-2020 out to 2030 there are no increases in REC requirements of an additional (to 1996 RE) 45,000 GWhs but there may be some RE plant capacity/output increases to assure market balance. REC prices decline as inferred prices decline under the influence of the CPRS and probably reach zero between 2022 and 2030 as inferred prices tend to zero. (The CPRS increases electricity prices to levels where RE required to meet MRET is competitive with fossil electricity.) REC creation ceases once it is apparent that held RECs are worthless. Some (perhaps many) banked REC holders lose money.

Investment in MET eligible activities and hence REC creation and REC prices is very difficult to predict in the 2013-2023 period. REC requirements climb rapidly to a peak of around 46,000,000 in 2020 and remain there till 2030.

We project that SHW RECs will increase steadily through the period because of other incentives, more competitive pricing (heat pump and collector systems). PV installations are difficult to predict but will probably increase after 2016 as system costs reduce but they and new renewable electricity plants will require REC price support to justify investments, even though wholesale electricity prices rise due to the CPRS.

The major issue is how will the peak REC requirement be met with a likely surplus of RECs post the early 2020s?

New renewable electricity plants will require an assurance that their returns will be adequate before they are competitive with fossil fuel generation.

Thus, in the Base scenario **market REC prices** remain above the **inferred REC prices** to such an extent that near zero REC prices can be tolerated for commercial viability when potential REC creation is well above REC requirements.

Another possibility is that in the 2017-2022 period the shortfall charge is paid by retailers in the absence of sufficient RECs from REC creators.

Critical assumptions in the analysis are:

- baseline plant output declines;
- continued growth in SHW;
- moderate declines in Green Power (now guaranteed consideration under the CPRS);
- PV trends to 2013 and beyond;
- RE marginal prices, and wholesale electricity prices; and
- strategies, outlooks and constraints of potential investors in new renewable electricity plants.

A **HIGHER** REC price scenario would result from lower SHW and PV installations, higher marginal RE prices, lower wholesale electricity prices and significant lags in new RE plant investments.

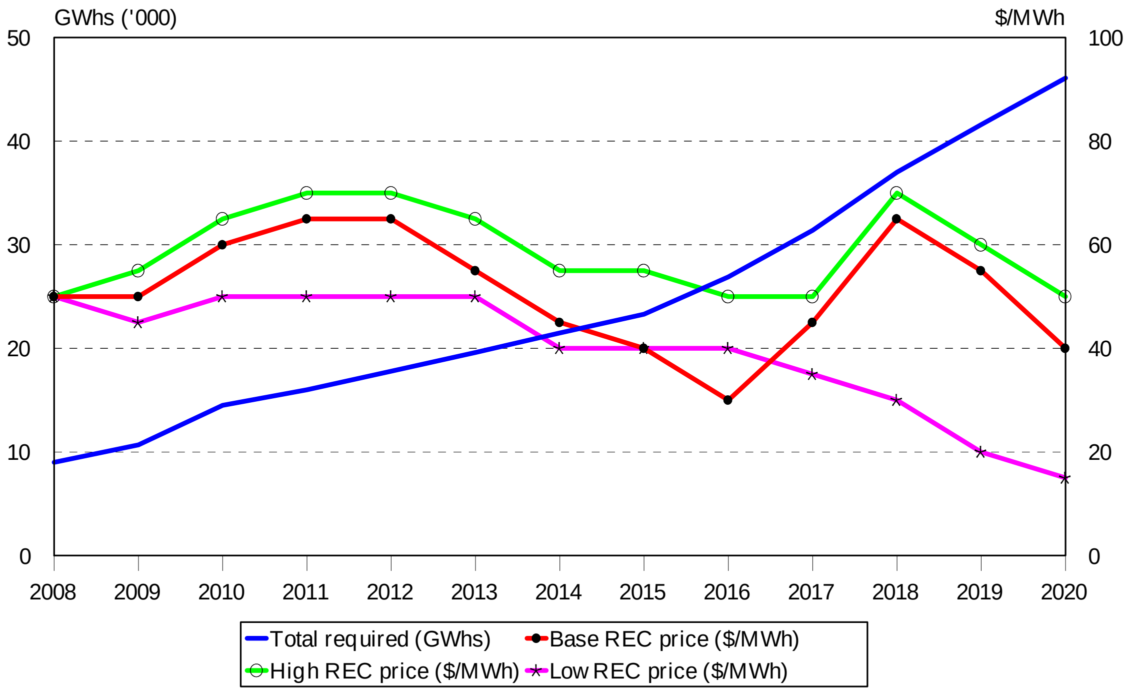
A **LOWER** REC price scenario would result from higher baseline plant outputs, higher SHW (and PV installations depending on the REC price to make them viable) and higher and consistent investments in new RE plants. Increased investment in new RE plants could come from lower viable sent out prices from these plants, an easing of tightness in finance markets and higher wholesale electricity prices.

Average REC prices, 2010-2020

Base scenario	$51.4
High scenario	$60.0
Low scenario	$38.2

Results of the analysis are summarised in **Table B.1**.

Figure 1:



Probability analysis of average REC prices, 2010-2020

By attaching probabilities to each of the Base, High and Low scenarios eventuating, a probabilistic average REC price can be estimated. Ideally a Delphi approach would be used by asking each of a panel of knowledgeable persons on the REC market to nominate probabilities of each scenario eventuating.

The report author's probability analysis is presented below.

	Average REC price	Probability of scenario eventuating	Probabilistic contribution of each scenario
Base scenario	$51.4	0.65	33.09
High scenario	$60.0	0.20	12.00
Low scenario	$38.2	0.15	5.73

Probabilistic REC price over 2010-2020 $50.82

This approach and the values resulting could be refined by other persons nominating probabilities and averaging the probability determined REC prices.

Table B.1 Quantitative analysis results

	Year					
	2008	**2009**	**2010**	**2011**	**2012**	**2013**
Banked 1 January in year	4,000,000	2,650,000	2,100,000	1,000,000	1,300,000	2,250,000
RECs created in year						
Baseline plants	800,000	700,000	650,000	650,000	650,000	600,000
Solar hot water	3,000,000	3,750,000	4,500,000	5,250,000	6,000,000	6,750,000
Photovoltaics	150,000	1,500,000	2,250,000	2,400,000	1,920,000	1,170,000
New (post-1997) plants	3,700,000	4,200,000	6,000,000	8,000,000	10,000,000	12,000,000
TOTAL created	**7,650,000**	**10,150,000**	**13,400,000**	**16,300,000**	**18,750,000**	**20,520,000**
TOTAL available for acquittal	11,650,000	12,800,000	15,500,000	17,300,000	20,050,000	22,770,000
TOTAL required	9,000,000	10,700,000	14,500,000	16,000,000	17,800,000	19,600,000
Banked 1 January next year	2,650,000	2,100,000	1,000,000	1,300,000	2,250,000	3,170,000
Marginal RE cost ($/MWh)	100	100	100	102	104	106
Wholesale electricity price ($/MWh)	50	50	52	54	56	58
Inferred RE price ($/MWh)	50	50	48	48	48	48
BASE REC price scenario	50	50	60	65	65	55
HIGH REC price scenario	50	55	65	70	70	65
LOW REC price scenario	50	45	50	50	50	50
BASE REC price scenario influences	Created RECs < required, market tightening	Created RECs < required, market tightening	Created RECs < required, market tightening	Created RECs ≅ required, market tight	Created RECs > required, but market tight	Created RECs > required, market easing

Table B.1 Quantitative analysis results (continued)

	Year						
	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Banked 1 January in year	3,170,000	5,360,000	7,190,000	5,940,000	1,470,000	(1,280,000)	–
RECs created in year							
Baseline plants	600,000	550,000	500,000	500,000	500,000	500,000	500,000
Solar hot water	7,500,000	8,250,000	9,000,000	9,750,000	10,500,000	11,250,000	12,000,000
Photovoltaics	790,000	330,000	150,000	180,000	210,000	240,000	270,000
					(PV cost declining)		
New (post-1997) plants	14,800,000	16,000,000	16,000,000	16,500,000	23,000,000	31,000,000	34,000,000
TOTAL created	**23,690,000**	**25,130,000**	**25,650,000**	**26,930,000**	**34,210,000**	**42,990,000**	**46,770,000**
TOTAL available for acquittal	26,860,000	30,490,000	32,840,000	32,870,000	35,680,000	41,710,000	46,770,000
TOTAL required	21,500,000	23,300,000	26,900,000	31,400,000	37,000,000 (GP 1,200,000)	41,600,000	46,000,000 (GP 1,100,000)
Banked 1 January next year	5,360,000	7,190,000	5,940,000	1,470,000	(1,280,000)*		
Marginal RE cost ($/MWh)	106	108	110	112	112	114	115
Wholesale electricity price ($/MWh)	62	64	68	75	80	84	90
Inferred RE price ($/MWh)	44	44	42	37	32	30	25
BASE REC price scenario	45	40	30	45	65	55	40
HIGH REC price scenario	55	55	50	50	70	60	50
LOW REC price scenario	40	40	40	35	30	20	15
BASE REC price scenario influences	Created RECs > required and REC price decline	Large REC surplus, new plant investment unsustainable	Price collapse, investment stalls	Investment stalls	Price spike as market goes into REC deficit	Output from new investment restores balance	Balance probably restored. New plant investment reaches peak

Note: * In 2018 and 2019 a deficit suggests payments of shortfall charge but market may balance as in 2017 the deficit may be anticipated bringing on greater investment in REC sources.

In the above analysis of the REC market the future projections of the PV contribution is probably the most difficult to estimate of recent PV trends and potential PV trends.

Accordingly, we have outlined, in **Appendix C**, the potential for small scale (<2-20 kW) photovoltaic system installations.

Appendix C: Photovoltaics: small scale (<2 kW)

Analysis

Predictions of the growth of these photovoltaic installations over the period to 2020 are very variable. At the end of 2008 about 20,000 such systems were installed in Australia. Growth in PV installations will add to RE output in South Australia and other States and the RECs available from them will affect the REC market and hence other REC sources.

RECs (deemed) from PVs reached about 350,000 in 2008 up from 6,400 in 2003 (ORER) under the influence of Federal rebates, REC values, decreasing system costs and very recently feed-in tariffs (FITs – which guarantee a price for PV power produced – gross, **or** fed-into the grid – net). Future PV growth will depend on similar influences.

2009 is an important year for PVs as by year end a range of FITs and from 1 July 2009 a new incentive regime will be operating.

In South Australia a net (guaranteed prices for exports to the grid) feed in tariff of $440/MWh until 2028. At an estimated export to the grid of about 0.6 MWh/year, the value to the household (HH) is approximately $265 per year (plus the value of the energy saved: for an average South Australian household using 5 MWh/a and in-house use of 1.4 MWh at $200/MWh = $280/a: total of $445/a from the installation).

In-house use is estimated to be about 1.4 MWh/year, about 28 per cent of average South Australian domestic customer use.

Up to 1 July 2009 **Federal rebates** are available for households (HHs) with annual incomes of <$100,000 per year of up to $8,000 for 1.5 kW systems will be operating. These installations are also eligible to receive RECs. In 2009-10, 2010-11 and 2011-12 system RECs will have a multiplier of 5; in 2012-13 a multiplier of 4; in 2013-14 a multiplier of 3; in 2014-15 a multiplier of 2; and from 2015-16 reverting to the system REC amount.

Above 1.5 kW systems the REC multiplier RECs will be at levels for a 1.5 kW system.

Under this regime REC "subsidies" are less than under the current rebate program. For example, in Adelaide, Zone 3, the incentive for a 1.5 kW system drops from $8,000 (rebate) plus $1,555 (RECs at $50) = $9,555 to about 30 x 5 (multiplier) x $50 (assumed REC price) = $7,750 in 2010-11, 2011-12, 2012-13 reducing to $1,550 in 2015-16.

The actual rebate in any year will depend on location, system size and REC price.

REC "rebates" will not be means tested and together with falling gross PV system costs will offset to some extent the lower "rebate".

Future installations will depend on customer reactions to the REC "rebate" after 1 July 2009 given their financial situations and other calls on their financial resources, and the returns from PV installation which will depend on FITs and electricity prices in their jurisdiction and net costs of PV installation.

By the end of 2009 data for the analysis of the post-30 June PV regime will be becoming available.

Currently an **installed** PV system of 1 kW costs about $13,000: comprised of $2,000 installation cost, about $6,500 for the PV cell modules, leaving balance of system (BOS) costs (inverter, etc.) at about $4,500. **Net** costs (installed) for 1 kW systems are quoted as low as $2,000 when the rebate, RECs bulk purchasing and installation are taken into account.

Australian installed costs are now about US$10/watt, well above the current European and North American costs of about US$5/watt. Cost reductions projected are about US$4/watt in 2010 and perhaps US$3/watt by 2020.

Hence, there is potential for Australian installed costs for a 1 kW system to reduce by 50 per cent, the rate depending on import and local manufacturing (proposal by Spark Solar) costs, BOS costs and economies of scale/bulk purchasing and installation of systems. (Some bulk purchasing and installation is now occurring).

Estimates of PV economics (1 kW system) are outlined below under several system costs, REC prices, FITs and electricity prices, for South Australia. Costs, prices in 2008 $'s. Outputs, exports, own use data from ETSA.

System cost (gross)	System cost (net)	Output (MWh/a)	Export (MWh/a)	Own use (MWh/a)
$13,000 (2008)	$4,000	1.5	0.6	0.9
$12,000 (2010)	$7,000 (x5 multiplier, $50/REC)	1.5	0.6	0.9
$910,000 (2015)	$6,000 (x3, $50/REC)	1.5	0.6	0.9
$6,000 (2020)	$5,000 (x1, $40/REC)	1.5	0.6	0.9

		Savings		
Customer economics	**Net system cost**	**Net FIT**	**Own use**	**Total**
2008	$4,000	$261	$180	$444
2010	$8,000	$440/MWh $264 (0.6 x 440)	$200/MWh $180 (0.9 x 200)	 $444
2015	$6,000	$440/MWh $264	$220/MWh (CPRS) $198	 $462
2020	$5,000	$440/MWh $264	$240/MWh (CPRS) $216	 $480
Paybacks				
2008	9.1 years			
2010	15.8 years			
2015	15 years			
2020	10.4 years			

The paybacks do not look attractive in any of the above cases. However, net consumer costs for a 1 kW system of $2,000 – $3,000 are quoted for the first half of 2009, giving a current payback as low as 4.5 years.

Data is obviously variable and consumer choices may not be **economically** rational given the long paybacks. The results of our PV analysis entered into **Table B.1** above is regarded as far too conservative by Green Energy markets (GEM) and Carbon Market Economics (CME) who respectively estimate about 3.7 x 10^6 and 14.0 x 10^6 RECs from PVs in 2020 compared with our 0.27 x 10^6 RECs in 2020.

Relevance of analysis for SADPC

1. The mix in 2020 for attaining the MRET may change but the total RE amounts and REC prices are not likely to change significantly as:

    - REC prices would be similar as the REC prices to bring on the SHW and PV amounts would be of similar magnitude; and

    - PV **RECs** could displace significant large scale RE plant investments (SHW REC amounts remaining similar).

Out of this analysis and review of the situation we recommend:

(i) inclusion of PVs in the RE contributing to the 2020 target; and

(ii) close surveillance of the unfolding REC and RE market.