CSIRO

Australian electricity market analysis report to 2020 and 2030

Final Draft

Thomas S. Brinsmead, Jenny Hayward and Paul Graham
EP141067
May 2014

For the International Geothermal Expert Group

Citation

Brinsmead T.S., J. Hayward and P. Graham (2014) *Australian Electricity Market Analysis report to 2020 and 2030*, CSIRO Report No. EP141067.

Copyright and disclaimer

Important disclaimer

Contents

Figures

Tables

Acknowledgments

Executive summary

The Board of the Australian Renewable Energy Agency (ARENA) is seeking advice on the barriers to, and opportunities for, the development and deployment of geothermal energy in Australia. To this end, ARENA has established an International Geothermal Expert Group (IGEG) to assess Australia's geothermal prospects and present its findings in the form of a written report and briefing to the ARENA Board and a report for public dissemination.

This report provides an overview of the Australian Energy Market along with projections for future electricity demand and wholesale electricity prices in Australia's major electricity markets out to 2020 and to 2030, to provide context to the IGEG's consideration of the prospects for geothermal energy. The report does not seek to employ new methodologies and analysis but rather summarises the most relevant and recent information on Australia's electricity industry, including regional markets, projected demand, generation costs and transmission infrastructure requirements.

Demand

With respect to electricity demand (consumption) the projected range of outlooks are shown in Figure 1. The annual growth rate is between 0 and 2.5 percent over the period with a declining rate of growth over time reflecting slowing population growth, efficiency improvements and structural change. There are two possible ways of characterising the demand growth rate projections. The first is to note there is significant uncertainty in projected demand. This reflects the fact that analysts are still seeking to understand the unprecedented decline in demand since 2009-10 and are therefore uncertain as to how to project future demand. The key uncertainties are

- the exchange rate and its impact on the competitiveness of Australian manufacturing,
- whether households adopt more energy conservation and efficiency measures in response to higher electricity prices and
- the relative balance of centralised, on-site and off-site electricity generation.

The second interpretation is that in general consumption growth will be below 2 per cent per annum (closer to and possibly even below 1 per cent) which is uncharacteristically below the projected rate of growth in the economy. As such, there is a general consensus view that electricity demand growth has shifted to a sustained lower rate.

Prices

A summary of the potential range of wholesale electricity market prices is shown in Figure 2.

The projections indicate that there will be a continuing weakness in the wholesale electricity price owing to the current excess supply of generation capacity that is both a function of the recent decline in electricity consumption, and additional capacity to meet the Renewable Energy Target. Given the consensus of demand projections is for only a modest recovery in the rate of growth in demand, these market conditions are expected to continue into the 2020s. Under a no carbon price scenario, wholesale electricity prices could be in the range of $40-80/MWh. The Future Grid Forum (2013) projections are the most pessimistic during this period.
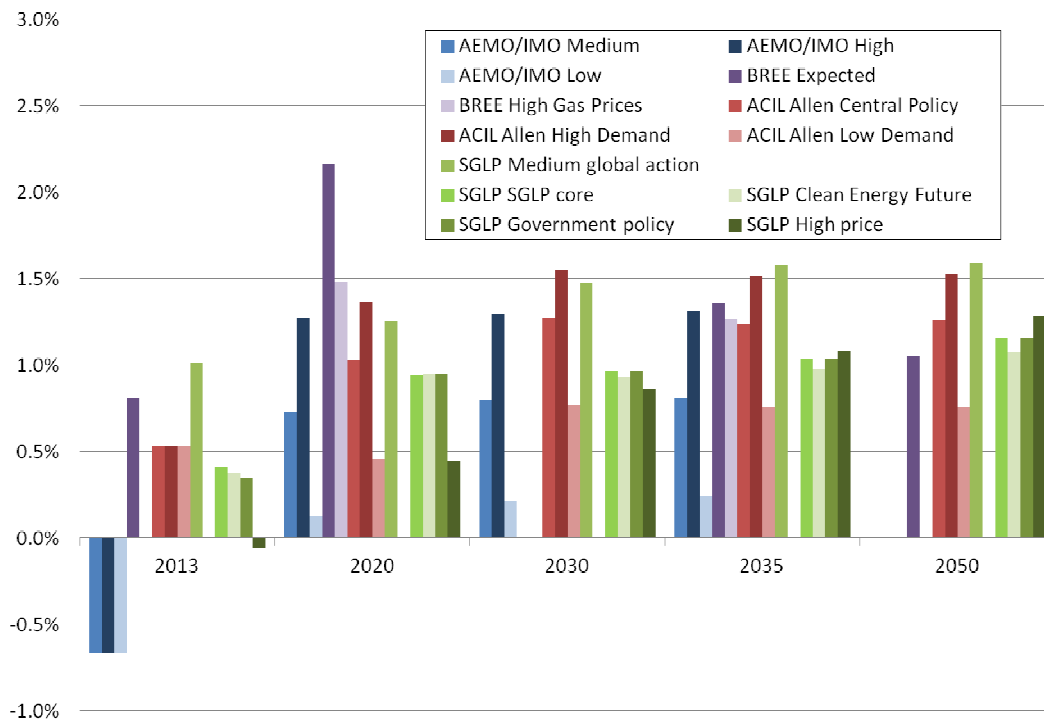
Figure 1: Rate of growth in consumption by source of demand projection (annual rate of growth expressed as from the year 2009)
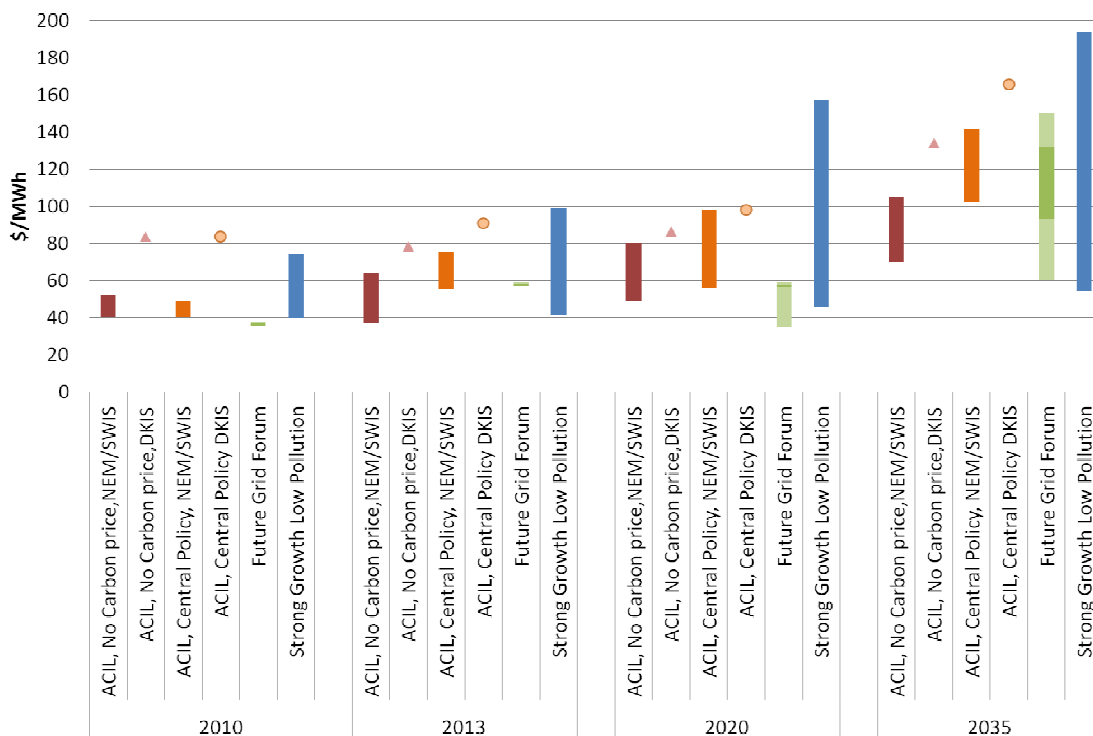
Figure 2: Projected average wholesale electricity prices various sources (ACIL Allen, CSIRO, Treasury)

However, assuming there is some emission reduction policy mechanism, the upper ranges of the Future Grid Forum and SGLP and the ACIL central policy "with carbon" price projections are the most relevant. These indicate the potential range of compensation that might be available to low emission technologies, even if a carbon price is not the preferred policy mechanism[1]. In these projections there appears to be a general consensus region around $100-140/MWh by 2035.

The Darwin-Katherine Interconnected System projections indicate the premium potentially available in more remote regions. However, the trade-off for access to these higher prices is a significantly smaller market.

Costs

The projected levelised costs for the key fossil and renewable electricity generation technologies with and without a carbon price for 2030 are shown in Figure 3.
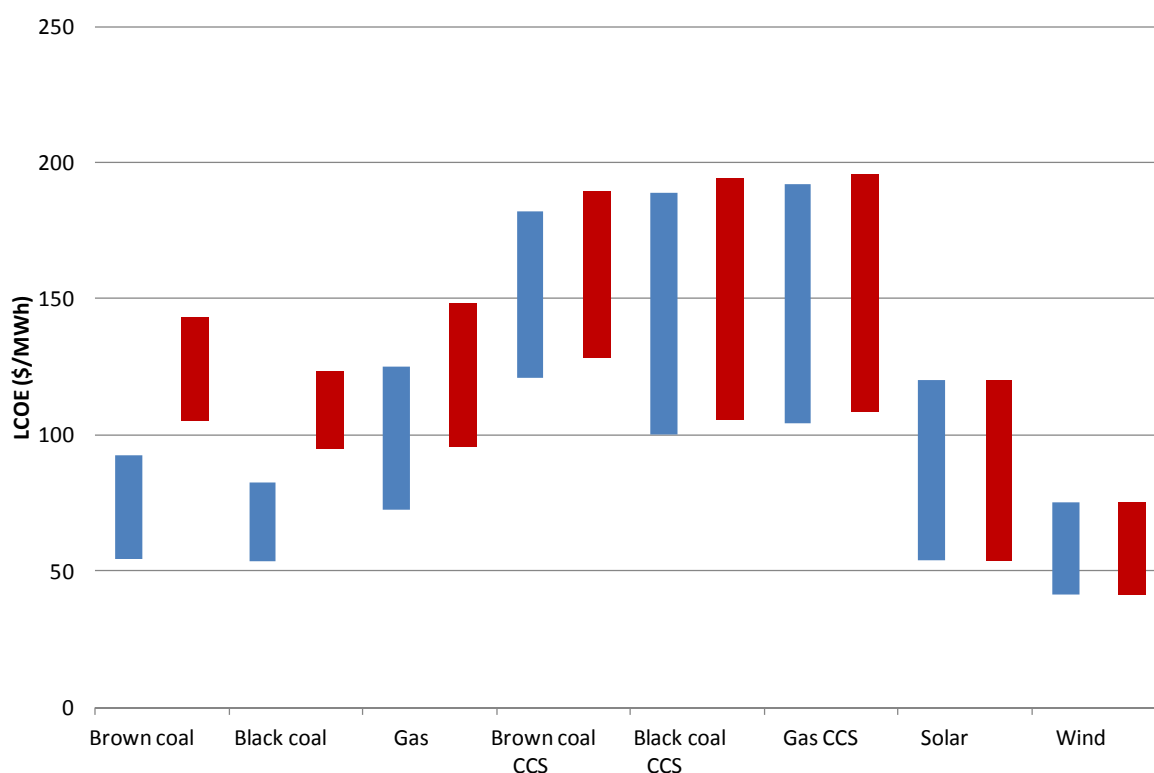
Figure 3: Projected 2030 Levelised Cost of Electricity with (red) and without (blue) a carbon price

The data assumptions underlying the LCOE projections were sourced from BREE (2012) and CSIRO (2012). The Bureau of Resources and Energy Economics (BREE) has updated its projections in December 2013, lowering the projected operating and maintenance costs of some wind and solar technologies.

The projections indicate that by 2030, wind power is the most competitive. Solar is also very competitive against fossil fuels with CCS and is close to being on par with non-CCS technologies with no carbon price.

---

[1] The government has indicated it will be shifting to an alternative emission reduction policy. In this case, the "with carbon price" wholesale price projections are still indicative of the level of compensation that will need to be provided to low emission technologies via an alternative mechanism in order for investors to deploy low emission technologies.

However, this comparison has been made difficult by the differences in performance of the technologies. The variability of solar and wind output means that at some times and in some regions there may be additional costs to managing their output which are borne by the electricity system as a whole. Levelised costs of electricity should not therefore be used as an absolute measure of the least cost generation mix.

For enhanced geothermal technologies seeking to compete against these technologies, transmission costs are a consideration as these are not included in LCOE calculations. Transmission line costs per unit distance are subject to significant economies of scale by capacity, so that larger capacity geothermal power stations will tend to have much lower transmission investment costs per unit delivered energy. Table 1 provides some crude upper and lower bounds on transmission line investment costs for distances of 800-1200km and capacities of 50-1000MW, which would be suitable for accessing geothermal resources in the Cooper Basin.

Assuming that power is generated at 0.8 capacity factor, this permits a calculation of transmission capital costs on a MWh/year basis. This can then be converted to a capital charge at 7.5% rate of return and a 30 year amortisation life (capital charge factor 8.5%). Because there are few savings to be achieved with lower capacity transmission, the transmission costs per MWh are significantly larger for small scale plant.

Note that for all of the technologies, some part of their cost range is competitive within the $100-140/MWh consensus price range discussed earlier indicating some consistency between projected costs and prices, as would be expected in a competitive market framework.

Scale	Transmission Capital Charge $/ MWH		Transmission Capital Costs $ / MWH/year		Transmission Capital Costs $M	
MW	Lower Bound	Upper Bound	Lower Bound	Upper Bound	Lower Bound	Upper Bound
50	77.3	148.4	913	1752	320	614
100	38.7	74.2	457	876	320	614
150	25.8	49.5	304	584	320	614
200	33.8	37.1	400	438	560	614
250	27.1	29.7	320	350	560	614
300	22.6	34.0	266	401	560	843
350	19.3	29.1	228	344	560	843
400	16.9	25.5	200	301	560	843
500	13.5		160		560	
1000	7.2		86		600	

Table 1: Costs of transmission from the Cooper Basin to East NSW (800-1200km)

1 Introduction

1.3 Background

The Board of the Australian Renewable Energy Agency (ARENA) is seeking advice on the barriers to, and opportunities for, the development and deployment of geothermal energy in Australia.

To this end, ARENA has established an International Geothermal Expert Group (IGEG) to assess Australia's geothermal prospects and present its findings in the form of a written report and briefing to the ARENA Board and a report for public dissemination.

This report provides an overview of the Australian Energy Market along with projections for future electricity demand, wholesale electricity prices and levelised costs of electricity in Australia's major electricity markets out to 2020 and to 2030.

2 Australian Electricity Market Overview

2.1 Electricity Networks in Australia

The two largest electricity networks in Australia are the National Electricity Market (NEM) and the South-West Interconnected System (SWIS). The NEM, services the eastern states, including Tasmania and South Australia, and accounts for approximately 85% of the Australian electricity market. The SWIS in Western Australia accounts for approximately 10%. The remote ("off-grid") market accounts for the remaining 5% of the market (AECOM, 2013), including both remote industrial and remote community networks. See Table 2 and Figure 4.

Table 2: Australian electricity markets overview

NETWORK	CAPACITY (GW)	CONSUMPTION (TWH)
NEM	45.0	199
SWIS	5.9	17.7
Off-grid remote Industrial Market	3.5	12.4*
Off-grid remote Community Market	1.0	3.4*
Total	55.4	232.5

* Excluding NSW, ACT, Vic and external territories

 [Source: AECOM, 2013]
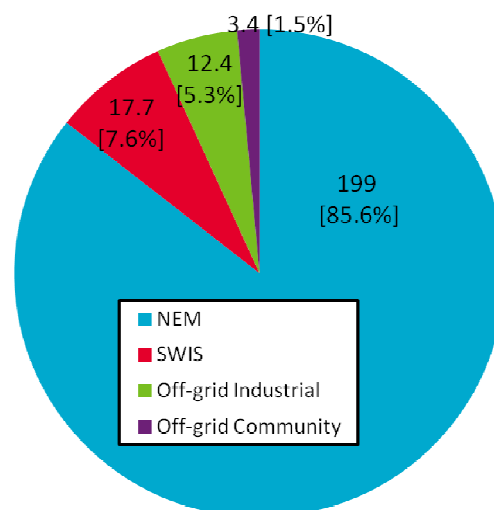
Figure 4: Electricity market share (TWh) by grid

In Western Australian there are almost 40 non-interconnected networks (Horizon Power website, 2014[2]) serviced by the state owned power corporation, Horizon Power, including the North-West

---

[2] http://www.horizonpower.com.au/about_us.html

Interconnected System (NWIS), which is less than a tenth the scale of the SWIS. The major electricity network in the Northern Territory (NT) is the Darwin Katherine Interconnected System (DKIS). Data on these networks is shown in Table 3 and Figure 5 and note that data on off-grid markets in NSW, ACT and Victoria is not included.

Table 3: Australia's regional electricity networks (2011-12)

| NETWORK | CAPACITY (MW) | CONSUMPTION (GWH) | | | |
		Total	Residential, commercial & community	Energy & resources	Other
NWIS Pilbara region	993	**2467**	493	1973	-
Rest of Off-grid Western Australia	2169	**6414**	506	5860	48
DKIS region	451	**1530**	1408	105	17
Rest of Off-grid Northern Territory	481	**1744**	519	1136	89
Mt Isa region	454	**2239**	223	2016	-
Rest of Off-grid Queensland region	237	**1160**	155	919	86
Off-grid South Australia	76	**236**	40	193	3
Off-grid Tasmania region	12	**22**	22	-	<1
Rest of off-grid Australia	18	**35**			
Total	**4891**	**15847**	3366*	12202*	243*

*Excluding rest of off-grid Australia [Source: BREE, 2013a]
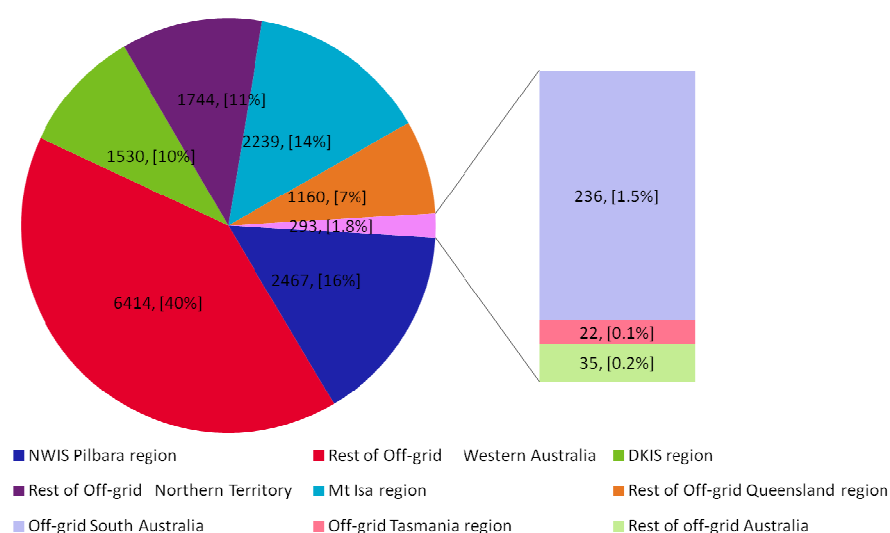
Figure 5: Electricity market share off-grid (TWh) [Source: BREE, 2013a]

2.2 Policy context

Energy industries in Australia, including the oil and gas industry, transport fuels, and the electricity industry are governed by policies with a principal focus on economic efficiency and development. The focus on economic efficiency has resulted in significant industry reforms since the early 1990s (Department of Industry website, 2014[3]) aimed primarily at opening up markets to competition in line with the National Competition Policy. Australian states and territories have agreements in place to implement a national energy market. This is called the Australian Energy Market Agreement (Ministerial Council on Energy website, 2014[4]), which is currently overseen by the Standing Council on Energy and Resources (SCER). The rules of the Australian Energy Market have been developed by the Australian Energy Market Commission (AEMC), and enforced by the Australian Energy Regulator (AER), which is a body of the Australian Competition and Consumer Commission (ACCC).

In the eastern states and territories (comprising Queensland, NSW, the ACT, Victoria, Tasmania and SA), the electricity market (NEM) is managed by the Australian Energy Market Operator (AEMO). In Western Australia, the electricity market (Wholesale Electricity Market, WEM) is managed by the Independent Market Operator (IMO).

Goals of energy policy in the electricity market complementary to economic efficiency include energy security, safety and customer service, greenhouse gas emissions management, energy efficiency and support for renewables.

- Energy Security – concerned with emergency supplies of gas and electricity, overseen by a working group.
- Safety – technical safety standards that apply to the electricity industry in addition to occupational health and safety standards.
- Customer service – customer protection under the National Energy Customer Framework.
- Greenhouse gas emissions management – current government policy is the repeal of carbon pricing legislation and implementation of Direct Action from 2014-15. At the time of writing this report a Green paper on the proposed emission reduction fund (Commonwealth of Australia, 2013) indicated there was still significant detail yet to be determined for how this scheme may operate[5].
- Energy efficiency – National Framework for Energy Efficiency (NFEE).
- Renewables – the major element is the Large scale Renewable Energy Target.
- Various state policies mostly relating to energy efficiency improvement schemes and arrangements for solar feed-in tariffs.

2.3 Market operations

In the eastern states, the NEM is a wholesale electricity market that operates across an electrical network that covers Queensland, NSW, the ACT, Victoria, Tasmania and South Australia, from Port Douglas in Queensland to Port Lincoln in South Australia. Covering a distance of some 5000 km, it is the world's longest interconnected power system (AEMO, 2010).

---

[3] http://www.industry.gov.au/Energy/Pages/default.aspx
[4] http://www.mce.gov.au/
[5] http://www.environment.gov.au/topics/cleaner-environment/clean-air/emissions-reduction-fund/green-paper

Physically, the NEM comprises connected transmission and distribution grids in each of five regional areas (one corresponding to each state, with NSW and the ACT comprising a single region), with the regions connected by a small number of high voltage interconnectors. The high voltage interconnectors permit inter-regional trade up to their physical capacity limit, so that wholesale market prices may vary among regions. The rules of the NEM specify that wholesale market prices do not vary within each region.

AEMO monitors total generation capacity in the network and identifies projected shortfalls in an *Electricity Statement of Opportunities* publication that is updated annually (e.g., AEMO, 2012, 2013a). However, the market for energy is relied upon to motivate the construction of adequate generation capacity:

> *Wholesale trading in electricity is conducted as a spot market where supply and demand are instantaneously matched in real-time through a centrally-coordinated dispatch process. Generators offer to supply the market with specific amounts of electricity at particular prices. Offers are submitted every five minutes of every day. From all offers submitted, AEMO determines the generators required to produce electricity based on the principle of meeting prevailing demand in the most cost-efficient way. AEMO then dispatches these generators into production (*AEMO, *2010).*

Wholesale prices are set each half-hour according to a reverse auction process with supply offers (bids) provided by each generation unit. Bid prices may vary from negative up to a maximum spot price (Market price cap, previously known as the "Value of Lost Load" – VoLL). This description is intended to suggest that the price stands as a proxy for the marginal economic costs to customers resulting from the loss of supply. This price cap is specified by the National Electricity Market rules to be indexed to the Consumer Price Index, and for the 2013-2014 financial year is valued at $13,100 AUD/MWh. AEMO also manages six other markets at shorter time scales to manage variation in supply and demand that are more rapid than half-hourly (Three hundred, Sixty and Six second raises and lowers), which are known as Frequency Control Ancillary Services (FCAS, see Power Exchange Operations, 2010). To date, the markets in ancillary services involve significantly less revenue than the wholesale energy market, although under existing market rules an increase in the penetration of intermittent generators such as some renewable sources of electricity may result in an increased importance of these services.

The SWIS covers an area including Perth from Kalbarri to Albany, plus Kalgoorlie, a distance of some 1000 km. The WEM is managed by the Independent Market Operator (IMO). In the SWIS, unlike the NEM, customers are required to procure generation capacity as well as energy, so the WEM includes a trading mechanism for reserve generation capacity as well as for energy. Generation capacity is tracked and shortfall estimates are published in the annual *IMO Electricity Statement of Opportunities* (e.g. IMO, 2013).

Both the NEM wholesale market and the WEM allow for bilateral contracts to be made between electricity generators and customers, with the balance setting the wholesale spot market price (IMO, 2012).

3 Electricity Demand

3.1 Australian Electricity Market Recent Trends

In the NEM, the consumption of centrally generated electricity has consistently increased for many decades up to 2009-2010, corresponding to population and economic growth. Since 2009-2010 however, consumption has declined in absolute terms, and is expected to continue to do so until 2013-14. This decline in total consumption has been driven by declining consumption in the industrial sector owing to the high Australian dollar and global economic conditions, and a reduction in per-capita electricity consumption in the residential sector partly as a consequence of rising prices and government energy efficiency mandates (AEMO, 2013b,c)

Over the next ten years, however, consumption is projected by AEMO to grow moderately. Projected increases in consumption are driven primarily by population growth in the east and south-east of Australia (AEMO, 2013b), slowing of the increase in residential electricity prices and three large liquefied natural gas (LNG) projects in Queensland expected to come on-line in 2013-14. The uptake of electric vehicles may also provide a modest increase in electricity consumption over the next several decades but with significant uncertainty as to the rate and timing of adoption (Graham and Smart, 2011). Moderating these projected increases is increased energy efficiency as a result of building and appliance standards. Increases in electricity generation from small-scale solar photovoltaic (PV) installations is further expected to reduce the need for electricity generated by large scale, centralised plant (AEMO, 2013b,c).

In the SWIS, electricity consumption had also historically grown consistently:

> *Up until 2008, electricity consumption grew consistently at rates broadly aligned with economic growth. For more than a decade, peak demand grew at an even faster rate. However, recent electricity consumption data in the SWIS has demonstrated a material dislocation between economic growth in Western Australia and the growth in underlying electricity demand.* (Independent Market Operator, 2013)

Although the consumption in the 2012-2013 period was less than that for the previous year, the IMO is projecting a continuation of the historical growth in consumption into the foreseeable future.

3.2 Demand Projections 2020 and 2030

AEMO uses income projections and weather forecasts to model the electricity demand per capita (Frontier Economics, 2013), moderated by separate projections for the impacts of energy efficiency and small scale photovoltaic generators. The nature of their operations also requires them to make forward estimates of electrical power losses incurred during transmission across the network, and the auxiliary loads consumed by large generators themselves. This results in annual demand projections out to 20 years for each region in the NEM, published annually in their *National Electricity Forecasting Report* (NEFR). The IMO also project annual demand published in the *Electricity Statement of Opportunities* (IMO, 2013). Both AEMO and IMO provide upper and lower estimates of demand.

Combining the projections of AEMO and IMO with an estimate of off-grid demand projected by extrapolating demand in 2011-2012 (BREE, 2013a) with the same projected growth rate as the SWIS, provides a total national demand (sent out, see Box*: What is Demand?*) estimate as shown in Figure 6 (with extrapolation beyond 2033 to 2035). This projection by region is based on the central scenario estimate of AEMO and IMO. Upper and lower estimates of total national consumption based on the upper and lower estimates of AEMO and IMO are shown in Figure 7.
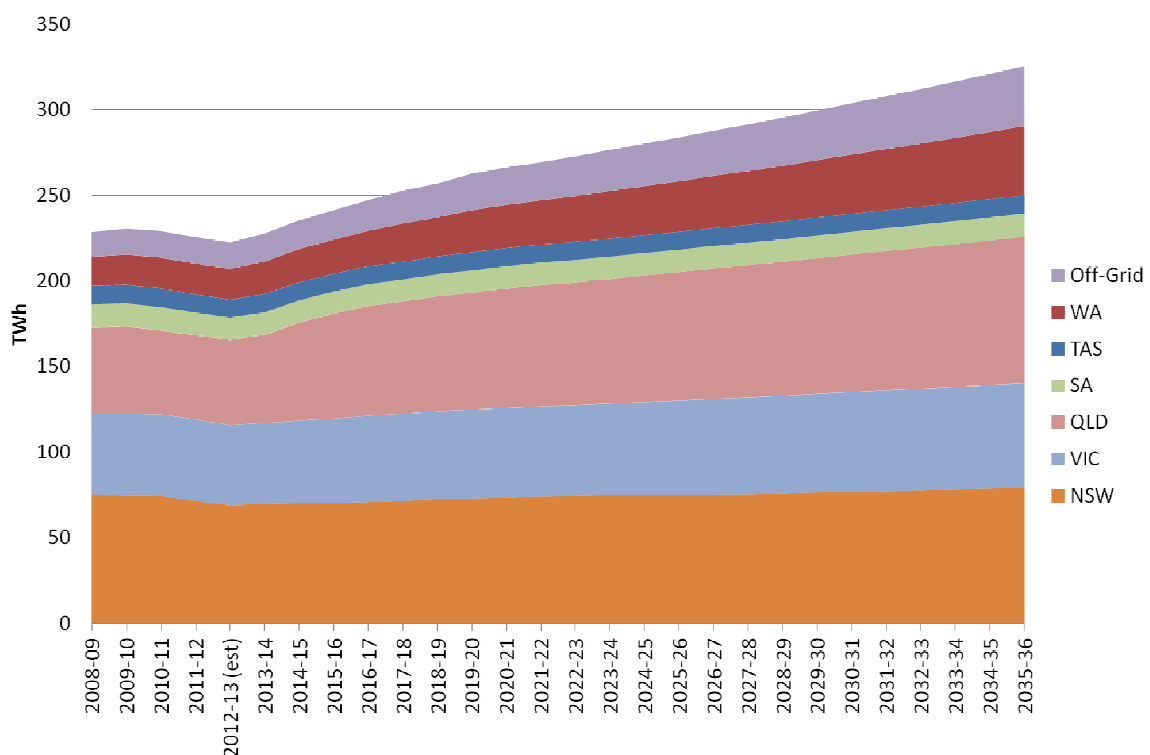
Figure 6: Electricity market share by region (Sources: AEMO 2013b,c, IMO 2013, BREE 2013a, CSIRO)

What is Demand?

Various definitions of electricity "demand" are used for different purposes. The main forecasts for the NEM produced by AEMO in the NEFR are for "Native" demand, also called "sent-out" generation. This includes electricity delivered to the electricity network by large scale centralised generators and small-scale, non-scheduled generators (below 30 MW). It does not include electricity generated on-site and used by a customer or electricity generated by small-scale solar photovoltaic panels. Native demand includes within its total any energy losses that occur on the network during transmission from the generators to customers. It does not include "auxiliary" generation which is produced by large generators, and consumed by them within the "plant gate".

The electricity demand projections reported by the BREE are for levels of consumption, consistent with the National Greenhouse and Energy reporting scheme. This definition also includes electricity generated by small-scale and non-scheduled generators and electricity generated on-site by customers, including small-scale solar photovoltaic panels. However, it also includes off-grid consumption, not accounted for by the NEM (or SWIS). These figures include energy lost during transmission (consumption by Network Service Providers), and auxiliary generation (consumption by large generators). These figures are therefore larger than AEMO's "Native" demand.

The main differences are that the BREE consumption figures include auxiliary generation by large generators, customer generated electricity including small scale photovoltaic generation, and off-grid consumption.
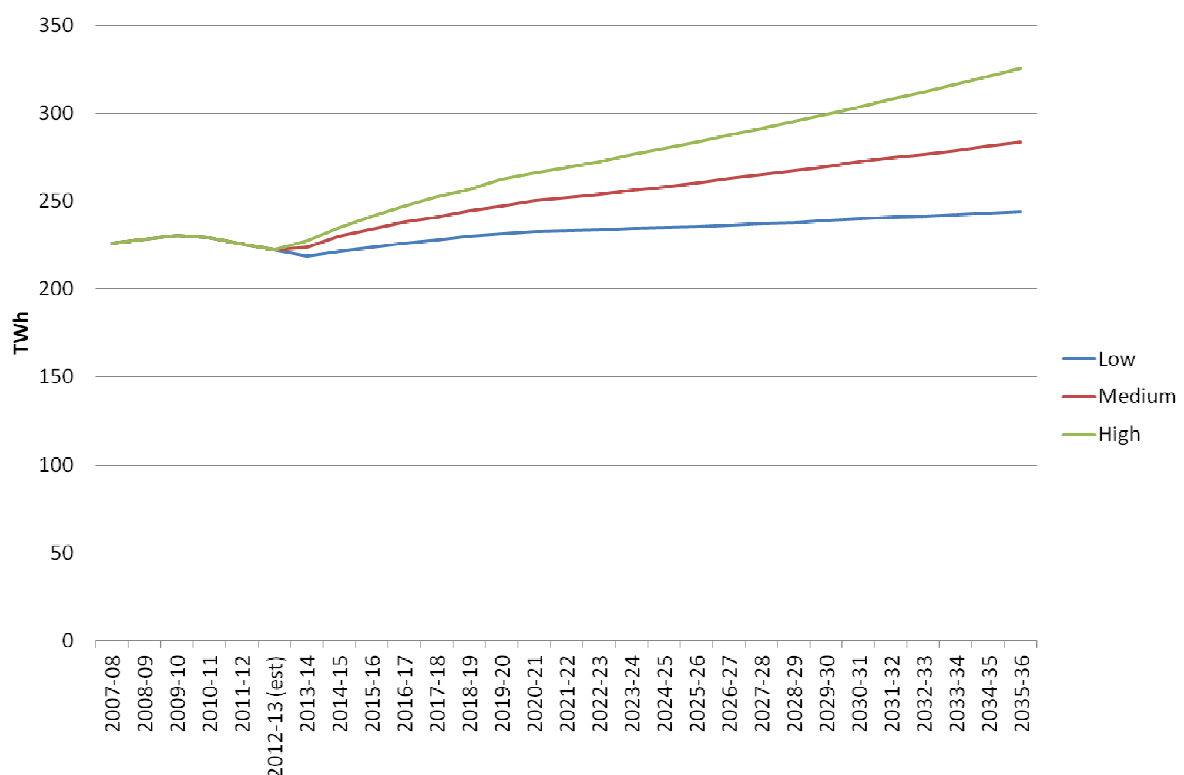
Figure 7: Australian electricity consumption projection range: Delivered (Sources AEMO 2013b,c, IMO 2013, BREE 2013a, CSIRO)

BREE also provide projections of future electricity demand in their reports *Australian Energy Projections to 2034-35* (BREE, 2011) and *Australian Energy Projections to 2049-50* (Syed, 2012). BREE (2011) includes demand scenarios under high gas prices. These electricity demand projections by BREE include auxiliary generation of large scale grid-connected generators and small-scale solar photovoltaic generation and off-grid generation (see Box: *What is Demand?*). This could explain why BREE estimates are higher than that obtained from AEMO and IMO estimates, even before considering differences in assumptions about future economic growth and energy intensity. Figure 8 shows projections by BREE for selected years, disaggregated by generation type.
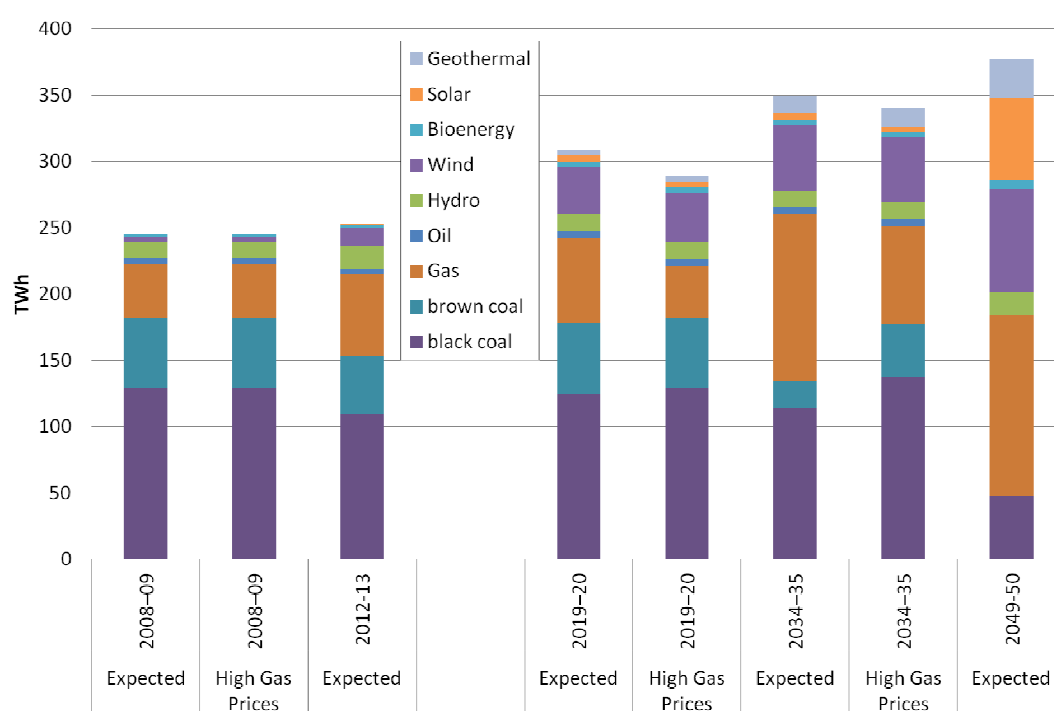
Figure 8: Australian electricity demand projections: Sent Out (Data Source BREE 2011, Syed 2012)

By way of historical comparison, Figure 9 shows national sent-out electricity demand projections from a Treasury report (Commonwealth of Australia, 2011). In Figure 10 are projections from ACIL Allen Consulting (2013) that are being used in the Department of Climate Change *Targets and Progress Review* of emissions targets for Australia.[6] This shows that forecasts of electricity demand were higher in the past than they are at present.

---

[6] http://climatechangeauthority.gov.au/caps
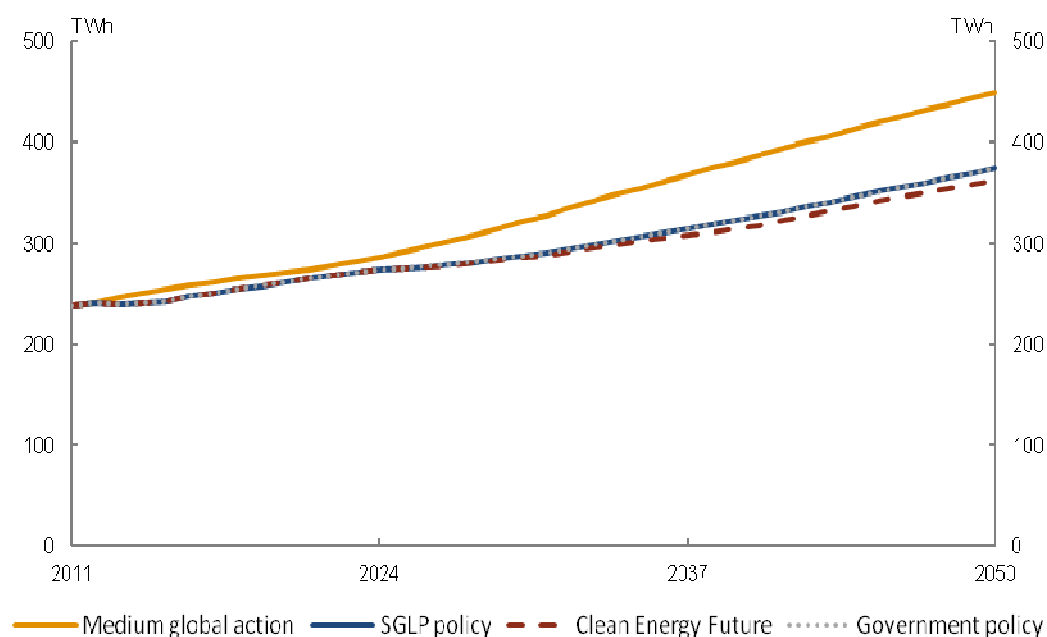
Figure 9: Australian electricity demand projections: Sent Out (Treasury 2011, reproduced under Creative Commons Attribution Licence, original data sources: Treasury estimates from MMRF, SKM MMA and ROAM)
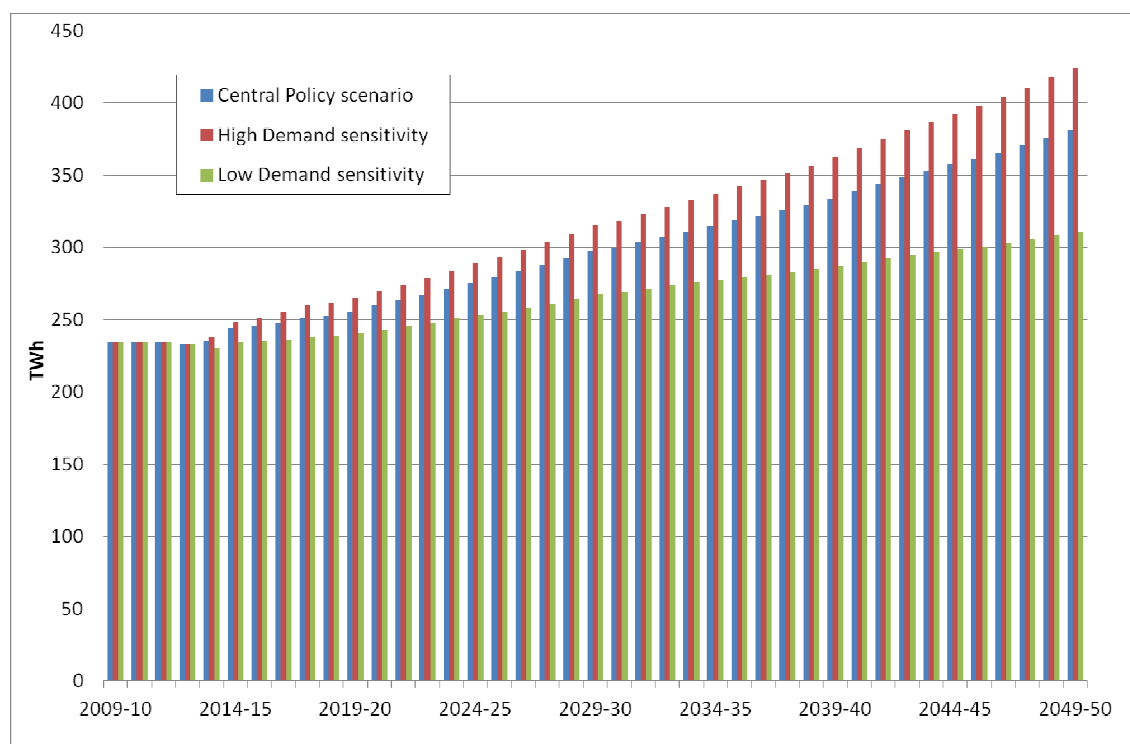
Figure 10: Australian electricity demand projections: Sent out (ACIL Allen Consulting, 2013)

3.3   Recent changes in Demand Projections

Future electricity demand projected by AEMO has been reduced recently. For example, between the 2012 and 2013 National Electricity Forecasting Reports, there was a reduction of 2.4% in the electricity demand projected for 2013-2014. Many of the factors resulting in this demand reduction are expected to be ongoing, and so have resulted in lower projected growth rates over the period to 2030. Some of these factors include improvements in energy efficiency from new regulations for buildings and growth in the installation of solar photovoltaics in the residential sector.

In addition, a decline in projected industrial demand has resulted from activities of large customers, reflected in the closure of an aluminium smelter (Kurri Kurri) in NSW, a decrease in projected consumption in a desalination plant (Wonthaggi) in Victoria, and deferral of plans by resources company BHP Billiton to develop Olympic Dam in South Australia. Factors contributing to an increase in industrial demand forecasts include LNG projects in Queensland and aluminium and paper plants in Tasmania. AEMO projections of industrial demand are fairly flat beyond a few years for each of their medium, low and high growth scenarios.

3.4   Demand Projections: Summary

Figure 11 summarises the demand projection data from these various sources. Blue markers show sent out electricity as projected by the market operators, purple markers shows BREE estimates, and red and green markers show current and historical estimates used by the Climate Change Authority (CCA). Figure 12 shows the same information with more detail, with the market operator estimates disaggregated by region, and the BREE estimates disaggregated by either region or generation type.

Scenarios considered by the Future Grid Forum (2013) suggest that there are a number of technological options that allow, and economic forces that may motivate, the realisation of the lower end of AEMO and IMO demand projections. These include

- the decreasing costs of solar PV, and other on-site generation technologies,
- the prospects for increasing wholesale electricity prices owing to higher gas prices, and
- energy efficiency options (including awareness of cogeneration) that are beyond the projections estimated in AEMO (2013c,d).

Factors that could increase electricity demand include a faster than expected uptake of electric vehicles, which at this stage is projected to have greater impact beyond the 2030 time horizon, and increases in industrial demand depending on global economic conditions and the value of the Australian dollar.
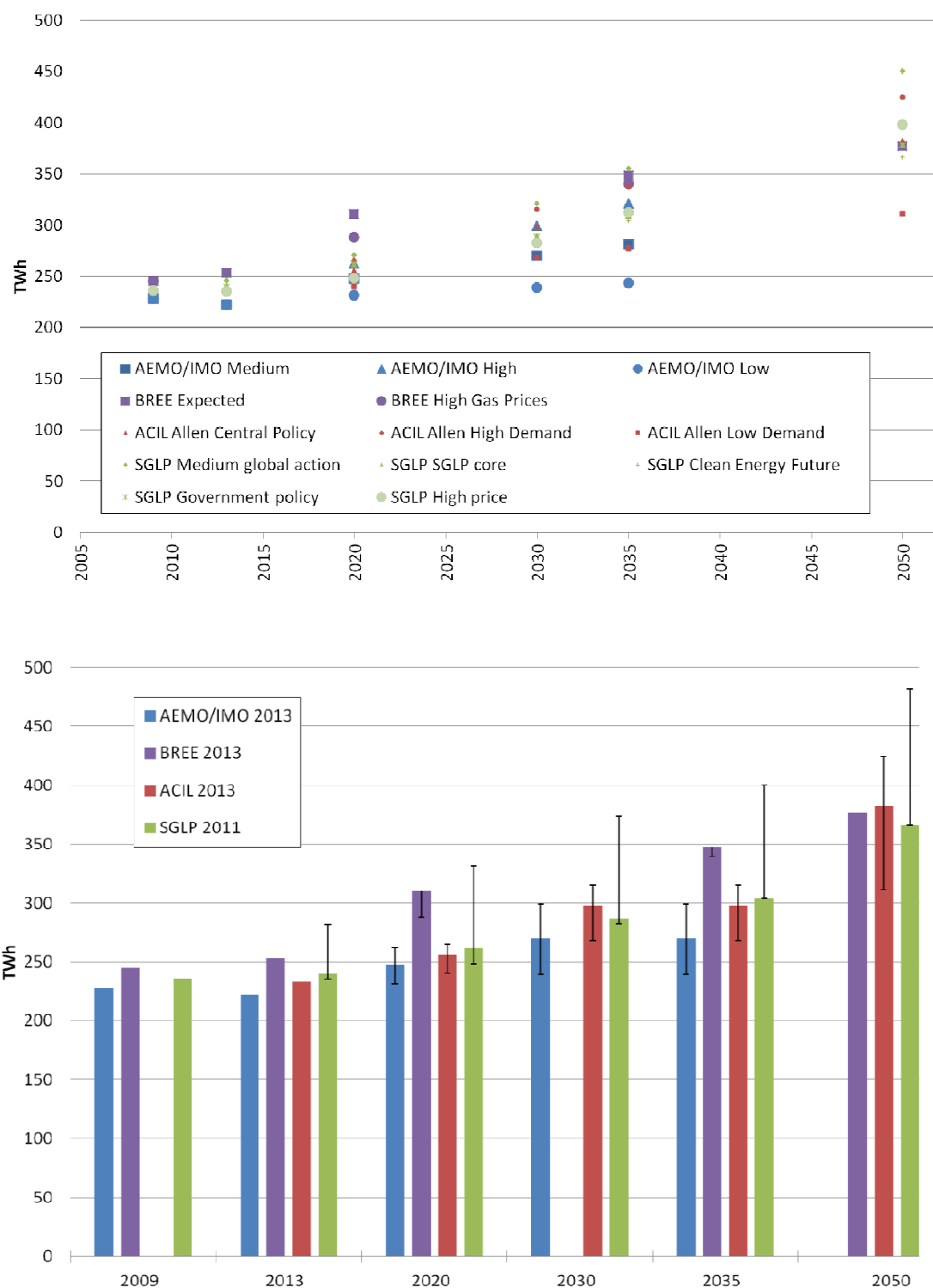
Figure 11: Australian Electricity Demand Projections: point estimate and range perspectives, various sources summary (AEMO 2013bc, IMO 2012, BREE 2013a, 2011, Syed 2012, CSIRO, ACIL Allen Consulting 2013, CoA 2011, *Strong Growth Low Pollution*)
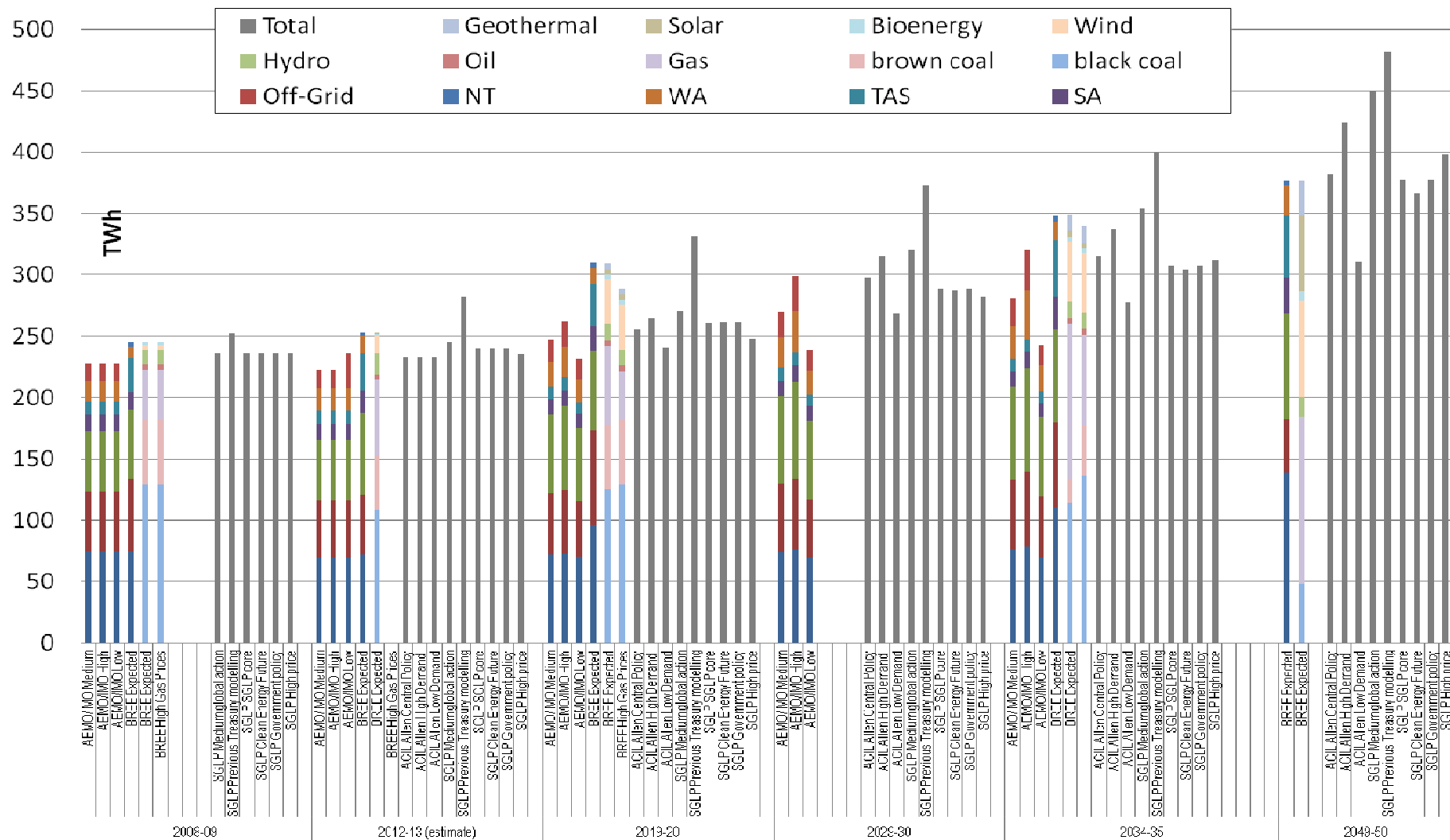
Figure 12: Australian electricity demand projections, various sources detail (AEMO 2013bc, IMO 2012, BREE 2013a, 2011, Syed 2012, CSIRO, ACIL Allen Consulting 2013, CoA 2011). Source: Australian Energy Market Operator (AEMO, 2013), National Electricity Forecast Report 2013

4 Electricity Prices to 2020 and 2030

This section provides wholesale electricity price projections from existing studies. Almost all of the wholesale electricity price projections include a carbon price. This is because a carbon price was the planned, and then legislated, policy mechanism for reducing electricity sector greenhouse gas emissions at the time that all of the source material was developed. However, as was noted in Section 2.2, it is the intent of the present government to take a different approach.

Nevertheless, the carbon price modelled price projections remain relevant for understanding future revenue available to electricity generation projects. This is because these price projections still indicate the compensation that must be provided for investment in low emission generation technologies. So long as the intent remains to reduce electricity emissions via introduction of low-emission technologies this level of compensation will be required in some form.

The exact compensation scheme was not firmly decided in Commonwealth of Australia (2013). It could be provided in the form of a subsidy to the prevailing no-carbon price electricity price. For example the reverse auction mechanism included in the proposed Emission Reduction Fund effectively provides a payment to those that can provide reductions in greenhouse gas emissions. Alternatively the "safe guarding" mechanism also discussed in Commonwealth of Australia (2013) may impose emission standards on new investment that progressively rule out high emission intensive technologies. As existing capacity is retired and new capacity is introduced to meet demand, normal market mechanisms would eventually raise the wholesale electricity price to the point where a new low-emission entrant can enter. The carbon price-inclusive electricity price projections provide an indication of those potential price/subsidy levels.

4.1 Electricity prices under alternative demand and Renewable Energy policy settings

In this section we consider two alternative renewable energy target (RET) schemes, which impacts the prices received by renewable energy technologies[7]. At the time of writing this report the present legislated renewable energy target has a fixed target of 41 TWh for large scale renewable energy generation. This is additional to the expected 4 TWh small scale (mainly rooftop solar PV) and the 15 TWh of pre-existing generation. This legislated target is likely to overshoot its original intent of achieving a 20% renewable share by 2020. Due to lower than previously expected growth in electricity demand renewable generation could reach a share of around 27% of electricity generated by 2020, under the "Low Generation" scenario.

The alternative renewable energy target modelled is a flexible renewable target that only reaches 20% for any realised level of total demand, including small scale and pre-existing renewable generation (see Box: *Fixed versus Flexible Targets*). The carbon price assumed is the composite of recent changes to the forward outlook for carbon prices announced with the May 2013 budget and the Government policy scenario published in Commonwealth of Australia (2011).

---

[7] A review of the existing RET policy was announced in February 2014:
http://www.environment.gov.au/minister/hunt/2014/pubs/mr20140217.pdf

Fixed versus Flexible Targets

At present, the national renewable energy targets (RET) is specified in terms of absolute quantities of electricity that are generated from large scale renewable resources that are additional to a 15 TWh baseline, in a trajectory that increases from year to year, to a maximum in 2020.

At the time that these targets were developed, they were based on 2007 projections that Australia's energy demand would be close to 300 TWh. Given existing renewable energy generation of 15 TWh, this required an additional 45 TWh to bring the total of renewable energy to 20% of projected demand.

Following an unexpected uptake of small scale solar PV panels, the renewable energy target was split in 2010 into a *Small scale Renewable Energy Scheme* (uncapped, but expected to be about 4 TWh) and a *Large scale Renewable Energy Target* (LRET) at 41 TWh. This change assisted in stabilising the market for large-scale renewable generation in the face of uncertain uptake of small scale renewables.

Since then, the projections of Australian electricity demand in 2020 have been revised downward. The consequence of this is that tracking to the currently existing fixed targets is projected to result in a renewable energy percentage in 2020 of around 27% (although significant uncertainty about demand remains)

A flexible RET, designed to achieve a specified percentage of electricity generation, rather than an absolute level of supply, would therefore vary depending on the demand in 2020 (See Figure 13). If future demand is less than 300 TWh, the fixed target is more stringent than a flexible target, in terms of the amount of renewable capacity and generation required. If demand in 2020 is greater than 300 TWh, the flexible target would be more stringent. (See also CCA 2012, Chapter 4). However, none of the AEMO/IMO projections consider such a high demand case.
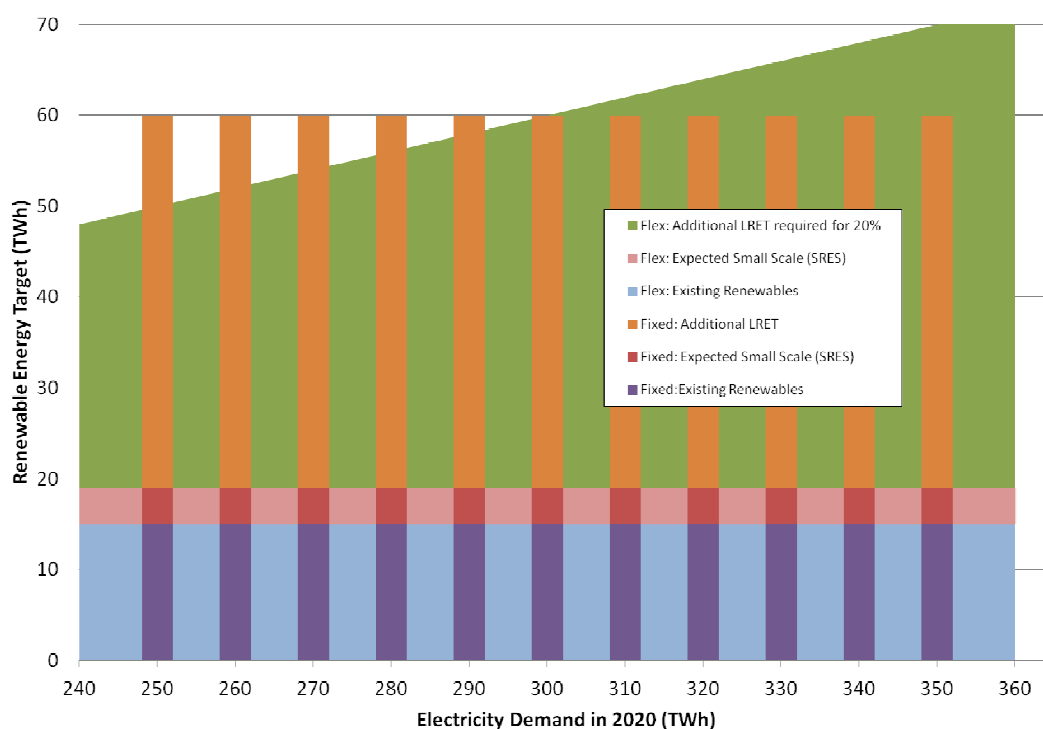
Figure 13: Fixed (column) versus Flexible (area) Renewable Energy Target

Figure 14 below shows projected wholesale prices from CSIRO's Energy Sector Model (ESM) under different demand and RET policy scenarios (line colours denote the demand scenario, with solid lines denoting the fixed RET case, while dotted lines denotes the flexible RET case).

Given that the most recent AEMO/IMO projections are for demand to be lower than the prior forecast of 300 TWh in 2020 under which the fixed RET was developed, the flexible RET scenario requires less renewables to be deployed in all three (lower, medium and high) demand cases. Given renewables are more expensive than other generation sources one might have expected a flexible RET to result in projected lower wholesale electricity prices. However, this is not the case. Projected wholesale electricity prices are consistently higher for the less stringent "flexible" RET than under the tighter "fixed" target. The difference is around 10$AUD/MWh in 2025 but only 2-3$AUD/MWh in 2030. The likely reason is that the generation market is starting from a position of excess supply and subsequently depressed wholesale prices. The reduction in the amount of renewable capacity deployed in the flexible case shortens the period in which the market remains in excess supply by between 2 to 7 years depending on the demand case. This removal of supply leads to projected sharp price rises through the mid to late 2020s.

These higher prices are closer to what would be required for new investment in a market where demand and supply are more closely balanced.
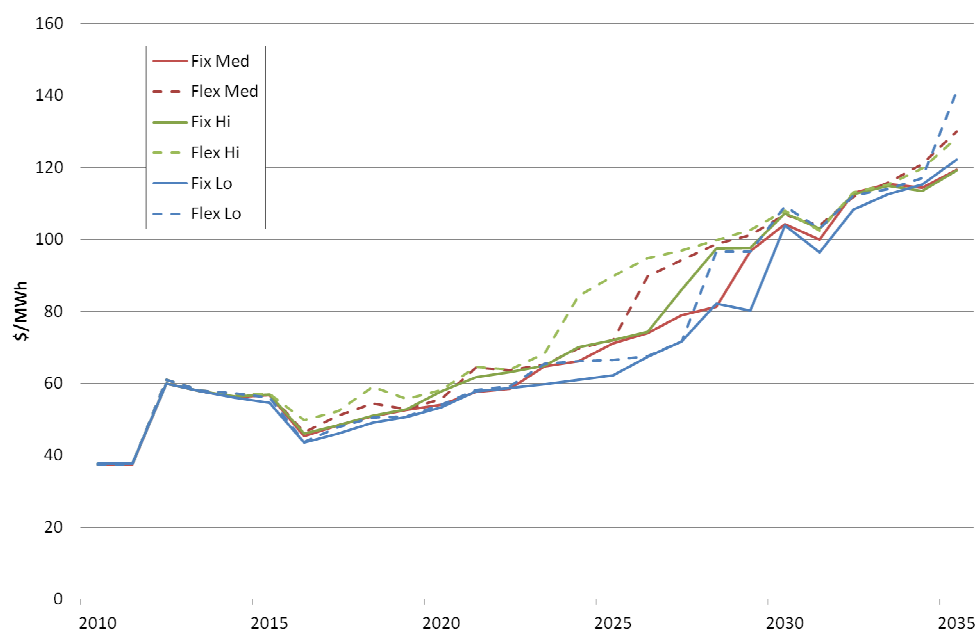
Figure 14: Projected wholesale prices by demand scenario and renewable energy target under a carbon price

4.2 Comparison of price projections

This section shows projected electricity prices from a number of earlier studies, all of which were made under the assumption of the existing policy of a fixed RET. Figure 15 shows projected prices for selected years by region for the caps and targets review (ACIL Allen Consulting, 2013) for two alternative policy scenarios, one with a carbon price (stars) and one with no carbon price (solid diamonds). Note that the variation in prices within the NEM and SWIS regions is relatively small, but the average prices in the Darwin-Katherine Interconnected System (DKIS) are consistently significantly higher.
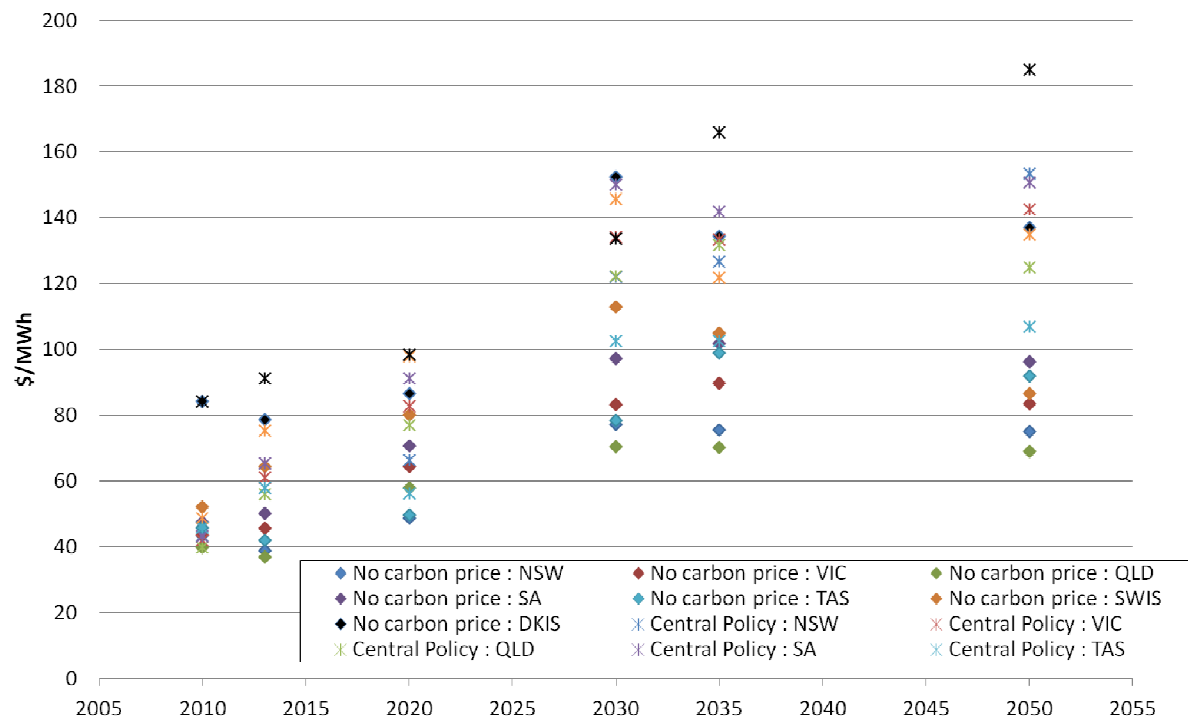
Figure 15: Projected wholesale prices by region (Caps and Targets Review, ACIL Allen Consulting)

Figure 16 shows a range of projected average Australian wholesale electricity prices determined for the recent Future Grid Forum (CSIRO and ROAM Consulting, 2013), under a range of alternative scenarios. Price variation with a high carbon price (plus symbol), and no carbon price (solid circle) is moderate in 2020 but quite large in 2035. The case with a high gas price (solid diamond) is also of interest, but the absolute impact is less than that of the carbon price for the range of parameter values considered.
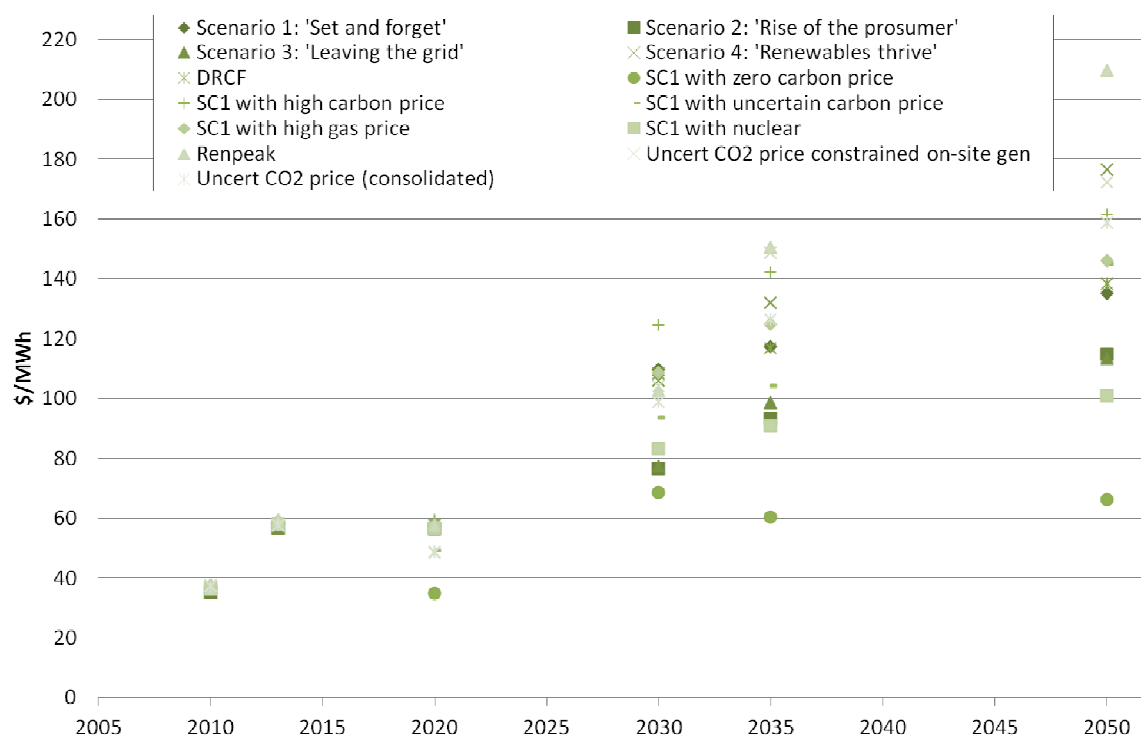
Figure 16: Projected average wholesale prices by scenario (CSIRO and ROAM Consulting, 2013)

Figure 17 shows a wide range of price projections for selected years in the *Strong Growth, Low Pollution* report (Commonwealth of Australia, 2011) under different scenarios, with again most of the observed variation shown due to differing carbon price assumptions.
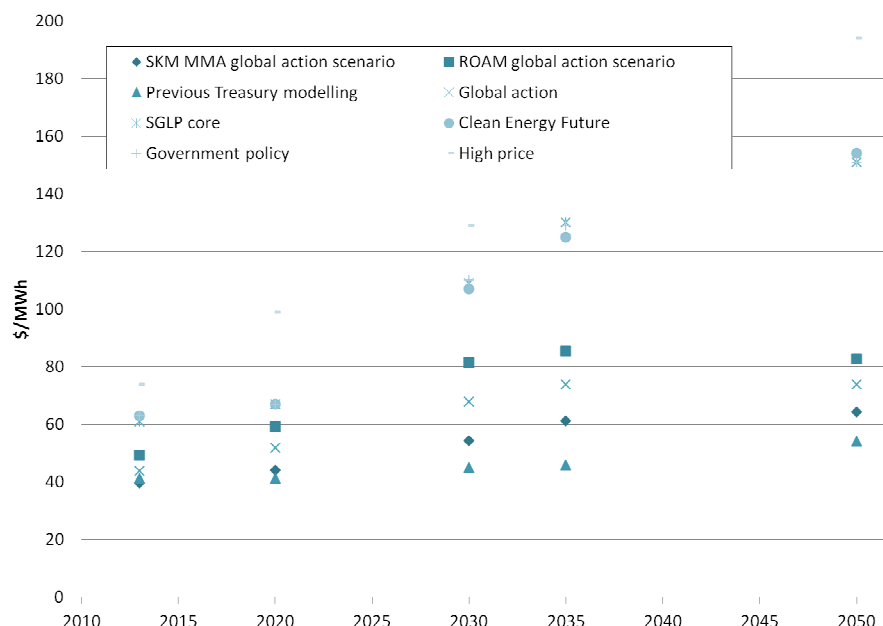
Figure 17: Projected average wholesale prices by scenario (Strong Growth Low Pollution, CoA 2011)

All these price projection ranges are shown in Figure 18 for the selected years – again showing a significant range.
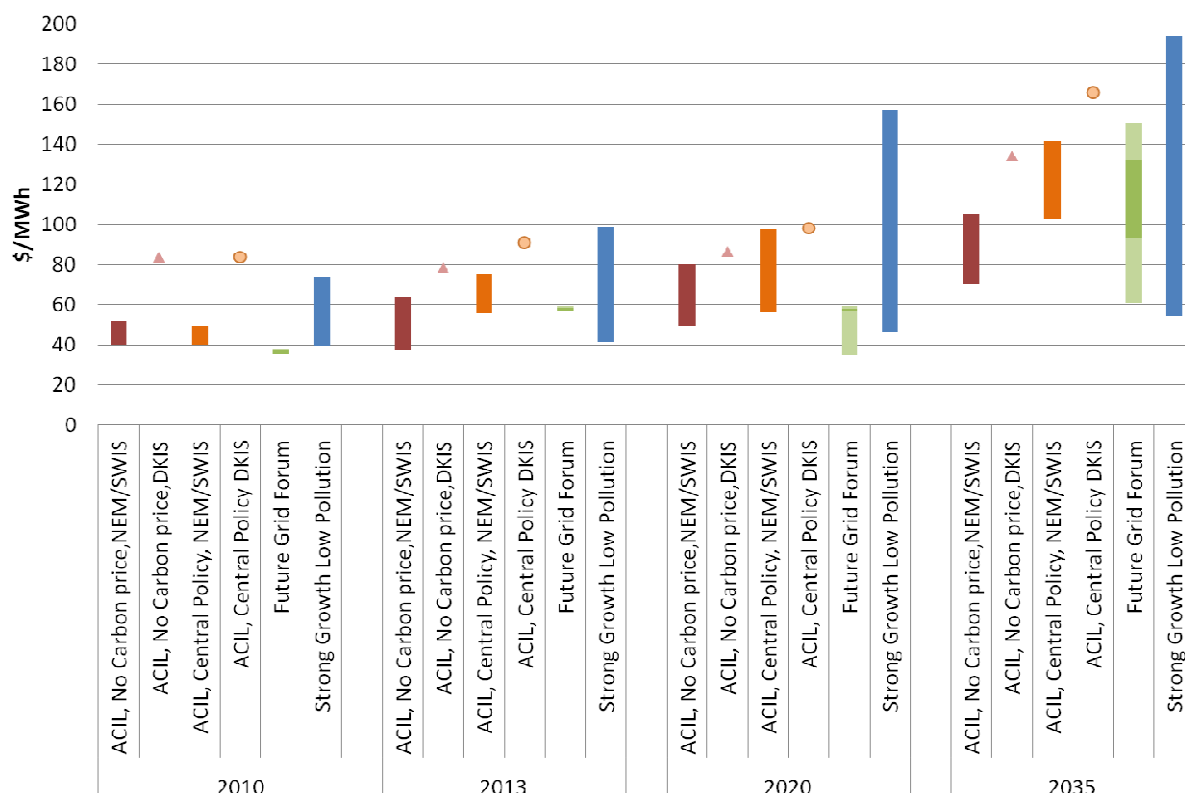
Figure 18: Projected average wholesale prices various sources (ACIL Allen Consulting, CSIRO, CoA 2011)

One further source of price projections is shown in the three charts of Figure 19 which provide a sensitivity analysis of a number of parameters over an exhaustive range of more than one thousand scenarios (Graham, Brinsmead and Marendy, 2013). The parameter assumptions are broadly consistent with those in Future Grid Forum (2013). The first chart shows the variation in wholesale price (both in 2020 and in 2030) due solely to variation in demand assumptions is quite small (10-15 AUD/MWh in 2020 and only 5-10 AUD/MWh in 2030) compared to those from all other sources (75-115 AUD/MWh in 2030). Lower demand reduces the need for additional capacity and energy resources but additional resources and capacity are not significantly more costly that this should lead to a large change in electricity prices.

The second chart in the series shows that assumptions about technology capital costs also makes a reasonably small difference to wholesale prices (approximately 2-5 AUD/MWh). This is largely because gas technologies tend to set the marginal costs of supply regardless of the capital costs of other technologies and there is only expected to be minor variation in their capital costs (fuel is the largest component), given their technological maturity.

Variation in fuel (that is, including gas) costs appears to make a much more substantial difference of 10-20 AUD/MWh, as can be seen in the third chart of Figure 19. This is consistent with the observation that gas generation is an important determinant of wholesale electricity prices and gas is a large proportion of generation costs.
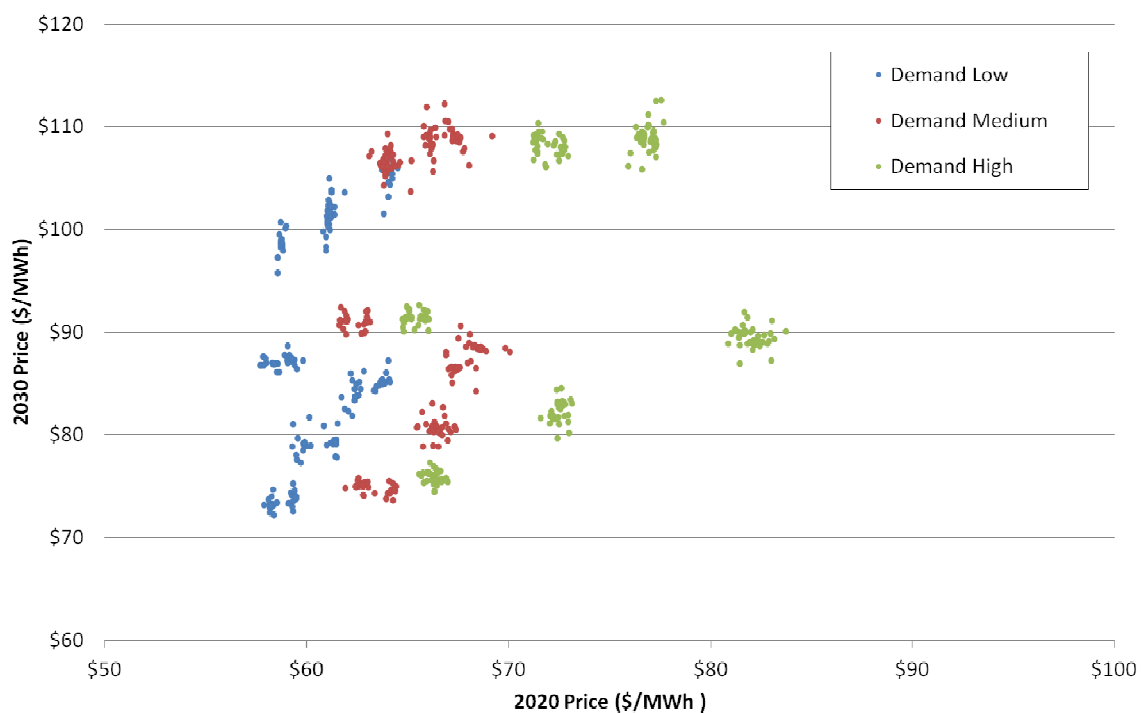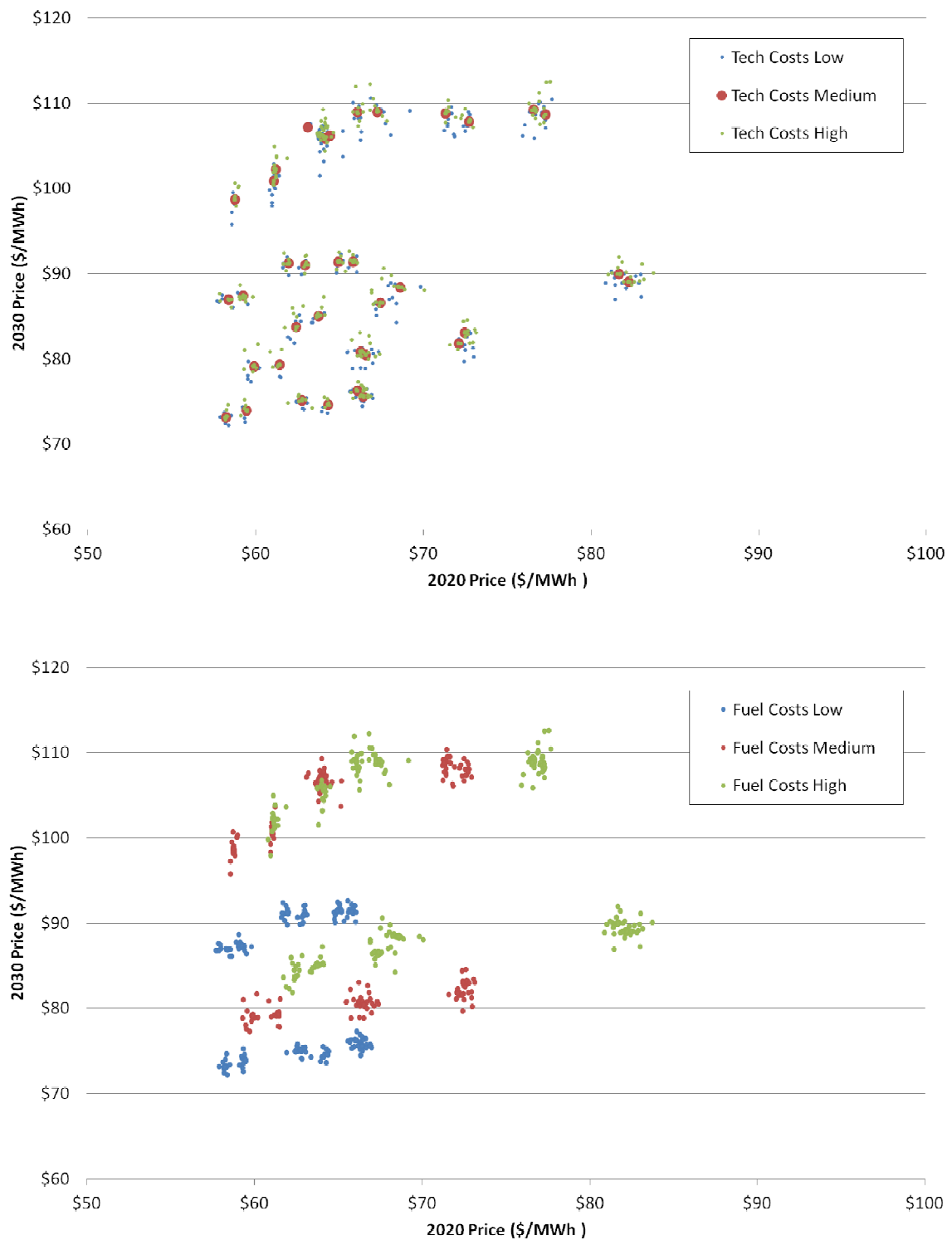
Figure 19: eFuture Sensitivity Analysis: demand, technology and fuel perspectives

4.3 Off-Grid generation costs

Off-grid generation is subject to significant economies of scale. Estimates of generating electricity with diesel generators are of the order of $600-900/MWh at single household scale (see Tables 2 and 3) down to $350-450/MWh at the scale of several thousand households. In some circumstances (IT Power Australia 2013, see also Table 5), hybridisation of solar PV with a diesel generator can lead to slightly lower net costs (**bolded** entries indicate source of value in minimum cost column.)

Table 4: Levelised cost of off-grid diesel generator electricity

DIESEL GENERATOR CAPACITY (KW)	PRODUCTION AT 60% CAPACITY (KWH/DAY)	CAPITAL ($/KW)	O & M ($/MWH)	LCOE ($/MWH)
1- 10	14-144	1890 – 3030	500 – 650	575 – 680
10- 100	144-1440	450 – 1890	380 – 500	425 – 560
100-500	1440-7200	300 – 450	330 – 380	365 – 410

[Source: IT Power Australia (2013), Table 3 from a secondary 1999 source: inflated to Sep 2013 from Sep 1999 based on ABS Catalogue 6401.0]

Table 5: Levelised cost of off-grid electricity, Diesel-Solar hybrid systems

DIESEL CAPACITY*	KWH/ DAY	MINIMUM COST ($/MWH)		DIESEL WITH PV & BATTERY	DIESEL ONLY	DIESEL & BATTERY	PV WITH DIESEL & BATTERY
3.5	50	**890**	PVD	1360	1346	942	**890**
7.0	100	**751**	PVD	1262	1253	869	**751**
20	300	**749**	PVD	839	839	771	**749**
70	1000	**541**	DPV	**541**	557	569	726
350	5000	**512**	DPV	**512**	522	515	673
700	10000	**461**	DPV	**461**	472	469	651
3500	50000	**428**	DPV	**428**	439	447	585

* Capacity required for daily energy production target, assuming a 60% capacity factor

[Source: IT Power Australia (2013), Table 7]

5 Levelised Cost of Electricity in 2020 and 2030

The levelised cost of electricity (LCOE) has been projected for the years 2020 and 2030, with and without a carbon price, for baseload coal and gas technologies and lowest capital cost solar and wind. The main source of data for these projections was the *Australian Energy Technology Assessment* (AETA), undertaken by the Bureau of Resources and Energy Economics in 2012 with an update in December 2013 (BREE, 2013b; 2012). The assessment is a comprehensive overview of the current costs and operating assumptions of 40 electricity generation technologies in Australia, with projections out to the year 2050. The update included changes to operations and maintenance (O&M) costs for solar and wind, which have been included in this report.

Some of CSIRO's modified AETA projections which are used to examine higher emission abatement pathways were also included in this analysis. Accordingly, we provide a brief outline of some elements of CSIRO's projection methodology in Appendix A.

5.1 Assumptions

5.1.1 SCOPE

LCOEs consist of the costs of production of electricity only. They do not include profit and may include taxes and depreciation. The major costs in an LCOE are the capital cost, operations and maintenance (O&M) costs, fuel costs, carbon permit costs and CO_2 storage costs. However, many of the specific cost components depend on the technology (for example, solar does not have fuel costs). Because of the variability in the inclusions within an LCOE calculation, as well as the variability in assumptions about various parameter values (such as discount rate, capacity factor), it is inadvisable to directly compare LCOEs from one study to another without understanding both the calculation methods and the underlying assumptions. See CSIRO (2011) for more information on comparing LCOEs.

The LCOE was generally calculated on a plant gate basis, i.e. all costs incurred within the plant gate are included. However, in the case of Carbon Capture and Storage (CCS) an additional CO_2 storage cost was included whether storage were to occur on-site. Electrical transmission costs were not included for any technology. Transmission costs may be significant, depending on the distance of any new generation asset from the existing grid. However, as they are site specific they cannot reasonably be included in a general LCOE calculation. Given the remote location of Australia's Enhanced Geothermal System (EGS) resources, the transmission costs will be high. However, there may be opportunities to use the power locally, for example, replacing imported diesel currently used in off-grid mines.

Costs of managing the intermittency of wind and solar, which could require battery storage and/or gas peaking plant, were also excluded. The use of these back-up forms of generation depends on many factors such as the period of intermittency, other forms of generation (e.g. spinning reserve), or correlation between solar and wind which may cancel or exacerbate intermittency. As the management of intermittency depends on many site-specific factors, it cannot be included in a general LCOE calculation.

5.1.2 UPPER AND LOWER RANGES

In order to provide upper and lower estimates of the LCOE, a range of capital costs were sourced. Alternative capital cost projections for wind and solar were taken from the recently completed Future Grid Forum (FGF) (Graham et al., 2013). These values were projected under an assumed fast rate of technological development and deployment of renewable technologies (Hayward and Graham, 2013). The FGF fossil fuel capital costs were the same as those of AETA (see Table 6). Therefore, to provide a range of capital costs for the LCOE calculations for coal and gas technologies, those of both standard and Carbon Capture and Storage (CCS)-based technologies have been used. However, this was only possible for the year 2030 as CCS is considered to be unavailable in 2020 (BREE, 2013b; 2012).

Table 6: Projected capital costs in $/kW. CCS = carbon capture and storage (BREE, 2012; Graham et al., 2013)

YEAR	2020	2030
Brown coal	3783	3768
Brown coal with CCS	NA	6130
Black coal	2954	2947
Black coal with CCS	NA	4453
Gas	1097	1113
Gas with CCS	NA	2232
Solar (alternative)	2042	1637
Solar (AETA)	2434	2138
Wind (alternative)	1507	1433
Wind (AETA)	1771	1799

5.1.3 OTHER (NON-CAPITAL) TECHNOLOGY ASSUMPTIONS

Capacity factors, thermal efficiency (higher heating value (HHV)), and O&M costs are shown in Table 7 by technology and year. Only one data point was provided for each of these factors in AETA. Fuel prices vary between the NEM and WA for natural gas and black coal (brown coal is not used in WA), as can be seen in

Table 8. An upper, lower and a mid-range value were provided in AETA for fuel costs. The NEM value is an average across the region.

5.1.4 AMORTISATION APPROACH

Capital costs not including interest during construction (IDC) were amortised over a 30 year amortisation period that begins when construction is completed. This is in contrast to AETA (2012) where the amortisation period was such that when added to the construction period the total is 30 years. For example, over a reported 30 year amortisation period in AETA (2012), if the construction period were 3 years the capital costs not including IDC were amortised over a 27 year period to the date of finalisation of construction. This latter treatment has the effect of reducing the period of

time permitted for the amortisation of initial capital costs, and increasing the derived LCOE, an impact that is greater for technologies with longer construction times. Further explanation can be found in AETA 2013 (p19).

A range of real discount rates were used: 5%, 7.5% and 10% to provide low, mid and high values respectively.

Table 7: Technology specific data used to calculate the LCOE (BREE, 2012)

TECHNOLOGY	CAPACITY FACTOR (%)		EFFICIENCY (HHV) (%)		VARIABLE O&M ($/MWH)		FIXED O&M ($/MW/YR)		CONSTRUCT PERIOD (YRS)
	2020	2030	2020	2030	2020	2030	2020	2030	
Brown coal, pf	83	83	34.7	37.7	9	10	68063	75625	3
Brown coal w. CCS	NA	83	NA	26.6	NA	19	NA	115900	3
Black coal, pf	83	83	44.3	47.3	8	9	57714	64929	3
Black coal with CCS	NA	83	NA	37.1	NA	15	NA	91500	3
Gas combined cycle	83	83	52.3	55.8	5	5	12500	12500	1
Gas with CCS	NA	83	NA	50.3	NA	11	NA	20778	3
Solar	24	24	NA	NA	0	0	33263	24194	1
Wind	38	38	NA	NA	11	11	35000	37500	1

Table 8: Projected fossil fuel prices (BREE, 2012)

FUEL ($/GJ)		NEM			WA		
	YEAR	LOW	MEDIUM	HIGH	LOW	MEDIUM	HIGH
Gas	**2020**	6.99	8.64	11.94	11.37	13.38	14.71
	2030	8.81	11.65	15.83	8.85	11.8	14.71
Black coal	**2020**	1.87	1.92	2.07	2.3	2.75	3.5
	2030	1.78	1.86	1.99	2.3	2.75	3.5
Brown coal	**2020**	0.49	0.65	0.87	NA	NA	NA
	2030	0.48	0.64	0.85	NA	NA	NA

5.1.5 CARBON PRICES, STORAGE AND EMISSION FACTORS

Carbon prices were taken from the FGF, based on those of the Australian government's Clean Energy Future (CEF) policy (Commonwealth of Australia, 2012; Graham et al., 2013). The year 2020 carbon price was an adjustment of the CEF carbon price, adjusted downwards due to the weakening of international carbon permits (Graham et al., 2013). The values used were $28.40/tCO$_2$ in 2020 and $56.60/tCO$_2$ in 2030.

In order to calculate carbon permit costs for the fossil fuel technologies, the emission factors of the fuels were needed, as shown in Table 9.

Table 9: GHG emission factors of fuels used. Includes direct and indirect emissions
(Commonwealth of Australia, 2012)

GHG EMISSION FACTORS (KGCO2/GJ)	
Brown coal	93.6
Black coal	95.29
Gas	62.9

Table 10 shows CO_2 storage costs, as determined in AETA (2013), were found to vary by state and fuel. In the LCOE calculations, the lower and upper CO_2 storage cost of each fuel was used to provide a range. Therefore, the NSW coal and gas values were used as the upper limit and the WA values as the lower limit. The VIC cost was used for brown coal with CCS. The capture rate was assumed to be 90% in all states and for all coal with CCS and 85% for gas with CCS (BREE, 2013a; 2012).

Table 10: Costs of CO_2 storage by fuel and region (BREE, 2013a; 2012)

REGION	COAL ($/MWH)	GAS ($/MWH)
NSW	67	24
QLD	21	8
VIC (Brown coal only)	31	7
WA (SWIS)	13	5

5.2 Method

The LCOE was calculated according to CSIRO (2011) in $/MWh as:

$$LCOE = KC + O\&M_{fix} + O\&M_{var} + FC + SC + PC \qquad (1)$$

Where KC is the capital cost, $O\&M_{fix}$ and $O\&M_{var}$ are the fixed and variable O&M costs respectively, FC is the fuel cost, SC the CO_2 storage cost and PC the permit cost in the case when a carbon price is applied.

$$KC = KC(\$/kW) \times \frac{r(1+r)^L}{(1+r)^L-1} \times \frac{1000}{cap \times 8760} + IDC \qquad (2)$$

The capital cost component is calculated as shown in the equation above, where KC is provided in $/kW, r is the discount rate, L is the amortisation period and cap is the capacity factor. 8760 is the number of hours in a year. IDC is the interest during construction.

$$O\&M_{fix} = O\&M_{fix}(\$/MWyr) \times \frac{r(1+r)^L}{(1+r)^L-1} \times \frac{1}{cap \times 8760} \qquad (3)$$

$O\&M_{fix}$ is calculated on the same basis as the capital cost, as it is given as an annual cost, as shown in the equation above. $O\&M_{var}$ is given in $/MWh and so it is inserted directly into Equation 1.

$$FC = FC(\$/GJ) \times 3.6 \div eff \qquad (4)$$

The fuel cost needs to be converted from $/GJ and then is divided by eff, the fuel conversion efficiency, to determine FC.

$$PC = emiss \div eff \div 1000 \times 3.6 \times carbprice \qquad (5)$$

The permit price PC is calculated when a carbon price is in place. *Emiss* is the fuel emission factor and *carbprice* the carbon price.

5.3 Results

The LCOEs calculated for the year 2020 with and without a carbon price are shown in Figure 20. Wind is the lowest cost technology. Without a carbon price the fossil fuel technologies are lower cost than solar. With a carbon price wind and solar can be less expensive than the fossil fuel technologies.
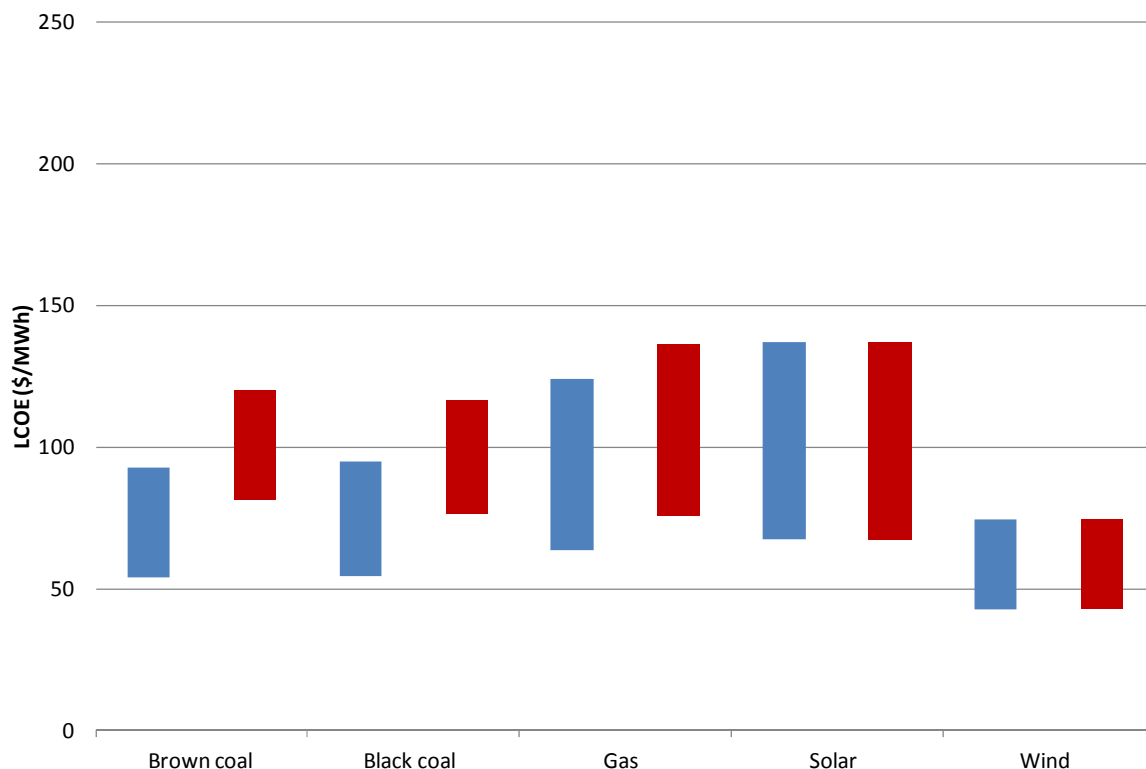
Figure 20: Projected 2020 LCOEs with (red bars) and without (blue bars) a carbon price

The year 2030 LCOEs are shown in Figure 21. The addition of a carbon price sees a dramatic difference in the cost of black and brown coal technologies, with their cost more than doubling under a carbon price. The CCS technologies have the highest LCOE, both with and without a carbon price. The LCOEs of technologies with CCS under a carbon price only increase marginally as 90% of emissions are captured and therefore not subject to permits.

Under both carbon price scenarios wind is typically the lowest cost option. Without a carbon price both black and brown coal technologies have an LCOE similar to that of solar. With the carbon price, solar and wind are lower cost than all fossil fuel technologies.

There is little change in wind costs between 2020 and 2030. Solar costs decrease by around 15 $/MWh, which is explained by the projected reduction in capital cost over that period. There is also little change to the non-CCS fossil fuel LCOEs between 2020 and 2030 without a carbon price. These are mature technologies and their costs are not expected to change significantly.
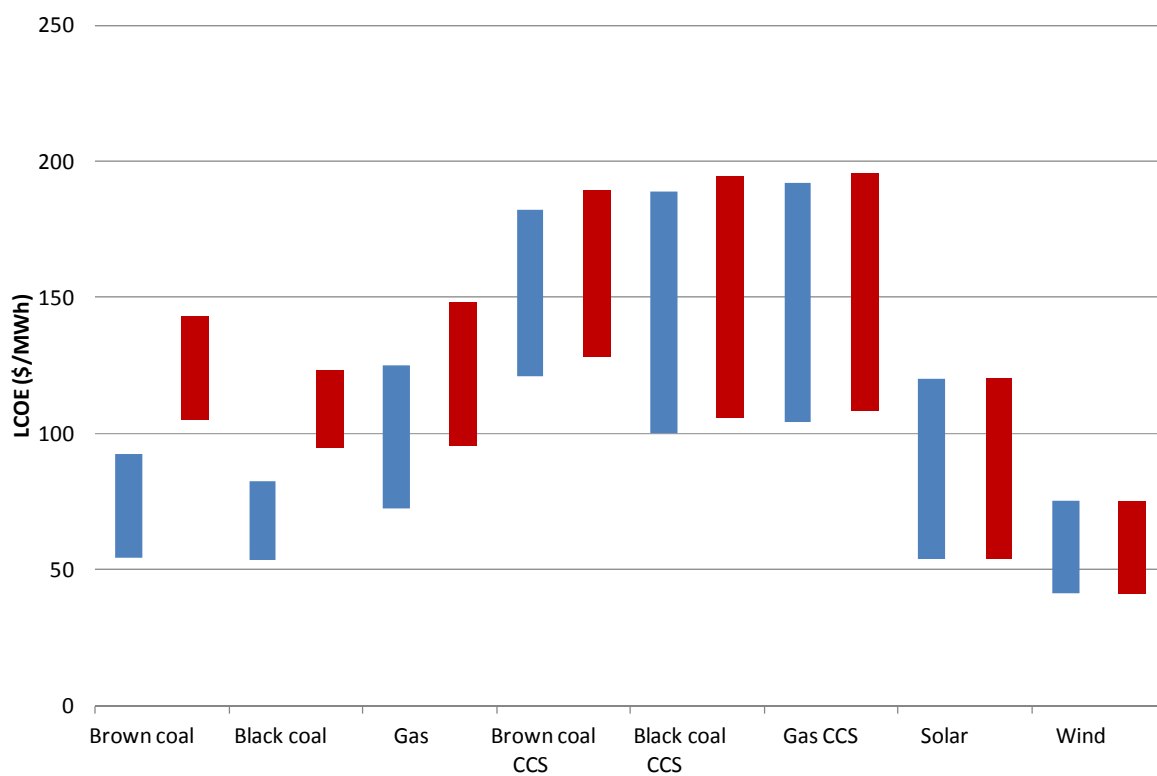
Figure 21: Projected 2030 LCOEs with (red bars) and without (blue bars) a carbon price

The mid-point values are provided in Table 11.

Table 11: Projected medium LCOEs in $/MWh

	2020		2030	
	No CO$_2$ price	CO$_2$ price	No CO$_2$ price	CO$_2$ price
Brown coal	73.1	100.8	73.3	124.0
Black coal	74.5	96.5	68.0	109.1
Gas	93.8	106.1	98.8	121.8
Black coal CCS	NA	NA	144.6	150.0
Gas CCS	NA	NA	148.2	152.0
Solar	102.1	102.1	86.9	86.9
Wind	58.4	58.4	58.2	58.2

5.4 Enhanced geothermal systems relative to other technologies

Enhanced Geothermal System (EGS) generation technology is quite different from the technologies discussed previously in this section. It is a renewable technology, like wind and solar, however it can provide baseload electricity, its output can be reasonably well controlled to provide a constant rate of power output. Due to the costs and transmission infrastructure required, it will need to be built at a large scale, similar to CCS plant. EGS is also an emerging technology; it is not commercial yet, also similar to CCS.

Solar and wind continue to be installed, which drives down their costs via learning-by-doing and economies of scale. Delays in deployment of EGS mean that solar and wind become even lower cost, and thus harder for EGS to compete against. However, cost reductions in wind will start to slow as it becomes mature, as can be seen by comparing wind LCOEs from 2020 and 2030. Given that the solar market is less mature than wind, the modules will continue to have a high learning rate for some time (Wilson and Grübler, 2011). Local solar installation costs have been found to reduce more slowly than module costs. This can be due to many factors – such as shortage of skilled labour and resource constraints. Furthermore, module costs will always reduce more quickly as they are sourced globally, whereas installation is local, and thus is a smaller market.

Market size may be an issue for geothermal in Australia. Drilling comprises the largest part of the cost of EGS. Even though drilling has a high learning rate (20%, same as photovoltaic modules), large cost reductions are not expected as the local market is small thus limiting the uptake of this technology. Further exploration to find the best drilling locations and advances in drilling technologies would be needed achieve significant cost reductions.

The balance of plant (BOP) such as the generation equipment, is used globally in all types of geothermal generation plant, but is a more mature (intermediate) technology with a lower learning rate (8%).

EGS has the advantage of being dispatchable, which should make it attractive to network operators. It can also provide some diversity of supply in terms of backing up more intermittent technologies like wind and solar. At the moment, hydro is the only form of renewable backup for intermittent forms of generation.

Being remote from the grid may work in the favour of EGS, at least for the short term. Mines in regions with good EGS resources rely on diesel for their energy needs, which is expensive. This could provide a niche opportunity for early deployment of EGS without having to build costly transmission lines.

For further discussion of learning-by-doing and opportunities for EGS see Appendix A.

6 Investment in Transmission Infrastructure

6.1 Existing transmission investment plans

AEMO has developed three versions of its *National Transmission Network Development Plan* (NTNDP) for the NEM (AEMO 2013d, 2012b, 2011) outlining plans for transmission network infrastructure upgrades required over the next 25 years. Committed and proposed transmission upgrades are listed by spatially specific NTNDP zones in the two most recent plans (AEMO 2013d, 2012b), which also provide cost estimates. These are based on the annual planning reports by the transmission network providers in each NEM region.

However, not all transmission infrastructure investment is relevant to the development of geothermal power. To narrow down transmission investment of potential interest to the geothermal industry we identify NTNDP zones with reasonable geothermal resources. The 2012 NTNDP (AEMO 2012b) identifies a number of potential opportunities for geothermal development up to 2030. Under their "planning" scenario, AEMO (2012b) identified potential in the Latrobe Valley (LV) and the Northern South Australia (NSA) zones. Under their alternative "slow rate of change" scenario, the Central Queensland (CQ) and Central NSW (NCEN) zones are identified as potentially seeing the development of geothermal resources. Although the inaugural network planning document (AEMO 2011), does not list transmission investments in detail, a number of scenarios are described qualitatively. Figures 7-11 and 7-17 identify zones of geothermal potential. It finds that:

> *Delaying geothermal expansion in South Australia will lower the generation support from South Australia to Victoria, deferring the need to augment the Victoria-South Australia (Heywood) interconnector, which proceeds under the FC-H scenario. (*AEMO, 2011, p7-19*)*

In addition to the NSA, the LV and NCEN under only the high carbon price scenario, it finds geothermal potential in South-East South Australia (SESA) and Country Victoria (CVIC) under both scenarios considered, and South-West Queensland (SWQ) under a scenario with high gas prices and rapid change. ElectraNet (2009), considering South Australian energy resources development, identifies the Murraylink between the Northern South Australia node and NSW and the Heywood interconnector from the South East South Australia node as relevant to the development of geothermal resources in South Australia.

The economic case for transmission investment to access geothermal resources was also considered by MMA (2009), again focussing on the same NTNDP zones, considering specifically transmission between Innamincka to Olympic Dam at some 600 km, and between Paralana and Olympic Dam at some 400 km. AEMO (2013d) forecasts that geothermal resources will not be developed within the NEM within the twenty year planning horizon considered.

Given that transmission investment relevant to the geothermal industry are likely to be within the NTNDP zones identified in the above studies, Table 12 shows the committed investment within the zones CQ, SWQ (Queensland), NCEN (NSW), LV, CVIC, (Victoria) and SESA, NSA (South Australia). Table 13 shows upgrades that AEMO modelling shows may be needed to meet customer demand, again with the geothermal NTNDP zones. Table 14 shows potential investment in NEM transmission that may be justified on economic grounds. Finally, Table 15 shows major transmission network investments that have been identified by the regional transmission network providers in their annual planning reports (in the selected zones). Some of these potential upgrades have not been identified as warranted under AEMO (2013d) modelling assumptions. AEMO has produced a consolidated summary of all the Annual Planning report investment proposals (AEMO, 2013d).

Table 12: Committed transmission investment in selected NTNDP zones (AEMO 2013d, 2012b)

REFERENCE	REGION	ZONE	PROJECT	TIMING	COST ESTIMATE ($MILL)
C-Q1	Queensland	SWQ	The Columboola–Wandoan South line operating at 275 kV (currently energised at 132 kV).	Winter 2014	90
C-Q2	Queensland	SWQ	The Columboola–Western Downs 275 kV line.	Winter 2014	145
C-S1	South Australia	NSA	Cultana 275 kV and 132 kV network augmentation.	2014	72
C-VS1	Victoria and South Australia	MEL–SESA	The incremental augmentation of the Victoria to South Australia interconnector (Heywood):	2016	107.7

Table 13: Potentially needed transmission investment to overcome capacity constraints in meeting customer load in selected geothermal NTNDP zones (source, AEMO 2013d, 2012b)

REFERENCE	REGION	ZONE	PROJECT	TIMING	COST ESTIMATE ($MILL)
L-N1	New South Wales	NCEN	Overload of Sydney South–Beaconsfield West 330 kV line for outage of Sydney South–Haymarket 330 kV line.	2013–14 to 2017–18.	647
L-N2	New South Wales	NCEN	Overload of a Liddell–Tomago 330 kV line or a Liddell–Newcastle 330 kV line, for an outage of a parallel line.	2013–14 to 2017–18.	80
L-V3	Victoria	CVIC	Overload of Moorabool–Ballarat 220 kV No.1 circuit for an outage of Moorabool–Ballarat 220 kV No.2 circuit.	2013–14 to 2017–18.	126
L-V4	Victoria	CVIC	Overload of the Ballarat–Bendigo 220 kV circuit for an outage of the Bendigo–Shepparton 220 kV circuit.	2013–14 to 2017–18.	
L-S1	South Australia	NSA	Transmission limitation on Robertstown – North West Bend 132 kV line during peak load times in Riverland when Murraylink is not importing into South Australia.	2013–14 to 2017–18	
L-Q1a	Queensland	CQ	Overload of a Calvale–Wurdong 275 kV circuit for an outage of the Gladstone–Wurdong 275 kV circuit.	2012–13 to 2016–17.	

Table 14: Potentially economic transmission investment in selected geothermal NTNDP zones (source, AEMO 2013d)

REFERENCE	REGION	ZONE	PROJECT
M-V2	Victoria	CVIC	Transmission limitations on the Terang–Ballarat 220 kV line.
M-V3	Victoria	CVIC	Transmission limitations on the Ballarat–Waubra–Horsham 220 kV line.
M-V4	Victoria	CVIC	Transmission limitations on the Red Cliffs –Wemen–Kerang 220 kV line.
M-S1	South Australia	NSA	Transmission limitations on the 132 kV network in the lower Eyre Peninsula.
M-S2	South Australia	NSA	Transmission limitations on the network between NSA and ADE.
M-S3	South Australia	NSA	132 kV network in the Riveland area of South Australia.
M-S4	South Australia	SESA	Transmission limitations on the Tailem Bend -Tungkillo transmission corridor.

Table 15: Potential transmission investment in selected geothermal NTNDP zones from transmission network annual planning reports (source, AEMO 2013d, 2012b)

REFERENCE	REGION	ZONE	PROJECT &ANNUAL PLANNING REPORT	STATUS	TIMING
T-Q2	Queensland	CQ	CQ to SQ transient stability limit.	Proposed	Timing subject to generation commitment
T-Q3	Queensland	SWQ	Possible voltage stability limitations on the network supplying Surat Basin north west area.	Proposed	Summer 2016–17
T-N4	New South Wales	NCEN	The 132 kV network supplying the Tomerong/Nowra area.	Proposed	Within 5 years.
T-N5	New South Wales	NCEN	The 330 kV lines between Bannaby and Marulan and Sydney and the South Coast.	Proposed	Not within 5 years.
T-N6	New South Wales	NCEN	The 330 kV network supplying southern Sydney from the west.	Proposed	Not within 5 years
T-N7	New South Wales	NCEN	Thermal and voltage limits on the injection of power into the Sydney Metropolitan area.	Proposed	Within 5 years
T-N8	New South Wales	NCEN	The two 330 kV transmission lines between the Hunter Valley and the Newcastle Area.	Proposed	Not within 5 years
T-N9	New South Wales	NCEN	330 kV line connecting the Munmorah and Vales Point Power Stations.	Proposed	Not within 5 years
T-V8	Victoria	CVIC	Ballarat–Bendigo and Ballarat– Moorabool No.1 220 kV lines.	Current RI T-T in progress.	2016–17
T-V9	Victoria	CVIC	Inadequate reactive power support around Bendigo in Regional Victoria	Proposed	Deferred until 2019 or later
T-V10	Victoria	CVIC	Geelong–Moorabool 220 kV line.	Proposed	NCIPAP project timing 2015/16.
T-S1	South Australia	NSA	132 kV network on the lower Eyre Peninsula.	Proposed	Timing subject to connection appl.
T-S2	South Australia	NSA	Transmission network between NSA and ADE.	Proposed	Not stated
T-S3	South Australia	NSA	Robertstown – North West Bend 132 kV line.	Proposed	Not stated

6.2 Transmission investment costs for geothermal resources: case studies

A number of studies have investigated the cost of investment in transmission infrastructure for the purposes of accessing renewable energy resources (primarily wind and geothermal) in South Australia. In order to provide an indication of the scale of costs required to access geothermal resources, the figures from some of these studies are reported below. The scope of the studies is for essentially greenfield transmission to connect to the grid, where the distances covered can be up to approximately 600km. The infrastructure would be used exclusively by energy generated by the new resources. There is a wide variation in the reported costs whether normalised by distance (some 700-2400 M$/km) or by both distance and capacity (some 1250-3000 M$/GW-km).

Table 16 details cost estimates from ElectraNet (2012) for smaller scale transmission reinforcement in the Eyre Peninsula near existing and potential wind resources in South Australia, motivated by expected increases in load. Table 17 details transmission investment amounts from MMA (2009), motivated solely by South Australian geothermal resources. Table 18 considers transmission investment amounts from Baker & McKenzie et al. (2010), required to unlock primarily wind resources in a similar location, whereby access to additional geothermal resources becomes convenient.

Table 16: Potential transmission investment for reinforcing the SA Eyre Peninsula (ElectraNet 2012)

CAPACITY (MW)	DISTANCE	TRANSMISSION	SOURCE	DESTINATION	COST (INCLUDING SUBSTATIONS)
600 MVA	140 km	275 kV Double	Cultana	Yadnari	$335 M
1000 MVA	140 km	275 kV Double	Cultana	Yadnari	$375 M
600 MVA	90 km	275 kV Double	Yadnari	Port Lincoln North	$260 M (in aggregate)
200 MVA	40 km	132 kV Double	Port Lincoln North	Port Lincoln	
600 MVA	85 km	275 kV Double (single strung)	Yadnari	Wudinna East	$180 M (in aggregate)
NA	35 km	132 kV	Wudinna East	Wudinna	

The figures reported by de Silva and Robbie (2009, Table 19) are for reinforcement of existing capacity between South Australia and NSW, where the distances required to be covered are approximately 1000km (see also : the transmission line between Davenport and Mt Piper) . There is again a wide variation in the estimated costs, at about 600-1900 M$/km by distance and $170-2200 $M/GW-km by distance and capacity.

Table 17: Potential transmission investment to access South Australian geothermal resources (MMA 2009)

CAPACITY (MW)	DISTANCE	275 KV TRANSMISSION	SOURCE	DESTINATION	CAPITAL COST ($2008)
400 MW	575 km	Double circuit	Innamincka	Olympic Dam	$404 M
NA	375 km	Double circuit	Paralana	Olympic Dam	$265 M
NA	200 km	Double circuit	Innamincka	Paralana	$265 M
250 MW	375 km	Single circuit	Paralana	Olympic Dam	$192 M
250 MW	365 km	Single circuit	Paralana	Davenport	$206 M
NA	265km	Single circuit	Olympic Dam	Davenport	$180 M
NA	200km	Single circuit	Innamincka	Paralana	$190 M

Table 18: Potential transmission investment for accessing South Australian wind resources (Backer & McKenzie et al. 2010)

CAPACITY (MW)	DISTANCE	500 KV TRANSMISSION	SOURCE	DESTINATION	CAPITAL COST	OPERATION & MAINTENANCE
2000	225 km	Double circuit	Davenport	Central Region (Cleve)	$625M Including substations	$ 11.7M pa
	165 km	Single circuit	Central Region (Cleve)	Western Region (Elliston)		
1000	145 km		Port Lincoln	Central Region (Cleve)	300M	$ 6,6M pa
1000	~100 km		Davenport	Northern		
4000 (source)-1300 (destination)	~1000 km	HVDC	Davenport	Mt Piper	$1 855	$37 pa

Table 19: Potential transmission investment options for reinforcing capacity between Innamincka (South Australia), and Sydney (NSW, de Silva and Robbie, 2009)

	AC OPTIONS			HVDC OPTIONS		
	INN-ADL-MEL-SYD	**INN-MEL-SYD**	**INN-WSD-SYD**	**INN-ADL-MEL-SYD**	**INN-MEL-SYD**	**INN-WSD-SYD**
Stage 1 500MW	950km 500kV double circuit	1250km 500kV double circuit (strung 1 circuit)	1000km 500kV double circuit (strung 1 circuit)	850km 500MW +/- 500kV bipole	1250km 60MW - 500 kV monopole	1000km 600MW - 500 kV monopole
Dest.	Adelaide via Broken Hill switch station	Melbourne	Western Downs	Adelaide	Melbourne	Western Downs
	900 – 1400	1000 – 1500	800 – 1200	300 – 500	700 – 1000	600 – 900
Stage 2 2000MW	Extend 500kV double circuit line plus series compensation	Upgrade by stringing 2nd 500kV circuit & series comp.		1250km 2400MW +/- 500kV bipole to Melbourne	Make a 2400MW bipole	
	750km from Broken Hill switching station to Melbourne				Add 600MW -500kV half pole in parallel and 1200MW +500kV	
	2100 – 3200	1700 – 2700	1400 – 2200	1500 – 2200	1200 –1700	1000 – 1500
Stage 3 5000 MW	1100km 765kV 2-ble cct line w. series comp.			1100km 4000MW +/- 800kV bipole		
Dest.	Sydney					
	3900 – 6100	3600 – 5600	3300 – 5100	2800 – 4000	2500 – 3500	2300 – 3300

6.3 Transmission investment costs for geothermal resources: extrapolations

The AEMO (2013e) study included an assessment of the prospects of geothermal energy (see pg 26-27 and Figure 8). The study concluded that it was feasible to include exploitation of geothermal resources (in polygons 11, 13, 14, 32, 38) where polygons 13 and 14 are in the Cooper Basin. Polygon 14 (Cooper Queensland) is of particular interest given potential for concentrating solar thermal (CST) and photovoltaic (PV, see Figure 4 and pg 19). The study also calculated the costs of transmission capacity between the Cooper Basin and East NSW as being (Table 25) $7107 million for 6240 MW capacity of High voltage direct current (HVDC, Scenario 1, in the year 2030) and $9513 million for 9350 MW capacity (Scenario 1, in the year 2050).

The following provides an estimate of transmission investment costs for 50-1000MW of geothermal power in the Cooper Basin, a distance of 800-1200km to the Central NSW NTNDP zone. Scaling down transmission cost estimates from 6000MW HVDC to 50MW of capacity presents some challenges, since transmission capacity costs are subject to significant economies of scale, as evidenced by Tables 1 and 8 of Appendix 2 of AEMO 2013e (Transmission Cost assumptions, some data reproduced as Table 20 here). For these lower capacity transmission lines, high voltage alternating current (HVAC) lines are likely to be lower cost.

Specification	MVA	$M/km
132 kV single circuit transmission line (Capacity per circuit 75-175 MVA)	75 - 175	0.4
132 kV double circuit transmission line (Capacity per circuit 100- 250 MVA)	200 - 500	0.7
220 kV double circuit transmission line (Capacity per circuit 500 MVA)	1000	0.75
220 kV, 275 kV or 330 kV single circuit transmission line (Capacity per circuit 800- 1300 MVA)	800 - 1300	0.7
220 kV, 275 kV or 330 kV double circuit transmission line (Capacity per circuit 800- 1300 MVA)	1600 - 2600	1.1
500 kV single circuit transmission line (Capacity per circuit 2500 MVA - 3500 MVA)	2500 - 3500	1.4
500 kV double circuit transmission line (Capacity per circuit 2500 MVA - 3500 MVA)	5000 - 7000	1.8

Table 20: Costs of HVAC transmission assumptions (Extracted from Table 1, appendix 2, 100% Renewables)

The relative costs of transmission line versus converter stations are typically greater for HVAC (comparable at about 10-20km) than HVDC (comparable at about 100-200km), but in any case over the distances of interest they are less significant than transmission line costs, so it is reasonable to approximate the relative costs of fully installed transmission line as related to the costs of the line alone.

Table 8 of Appendix 2 of AEMO (2013) has the costs of 1253MW of HVDC transmission capacity at 2.18 $million/km, which means that 6240MW of capacity would be no more than 10.8 $ million/km.

This suggests that scaling back to 75-175MVA capacity at $0.4 million/km would reduce total transmission line costs by no more than a factor of 27, that is the minimum cost of a 75-175MVA transmission line for the Cooper Basin is 7107/27=$260 million. On the other hand 6240MW of HVDC capacity must cost at least as much as 1253MW at 2.18 $million/km, so that scaling back to 75-175MVA capacity at $0.4 million/km would reduce total transmission line costs by at least a factor of 5.5, so that the maximum cost of a 75-175MVA transmission line is 7107/5.5= $1292 million. Unfortunately the range $260- 1292 million for 75-175MVA of transmission capacity is a rather wide range.

A better lower estimate can be obtained from Table 1 of Appendix 2 which indicates that high voltage AC transmission with capacity between 75-175 MVA is approximately the same cost per km at 0.4 $million/km, with 200-500MVA costing 0.7 $million/km and up to 1000MVA costing 0.75 $million/km. Note that this is the cost of the line only, not including transformer substations etc., so that at a minimum transmission distance of 800km, it is possible to calculate a lower bound on transmission line costs for 50-400MW (See Table 21 below) as between $320 and $600 million.

Table 17 indicates suggests that a completed transmission line with up to 250MW capacity (Paralana to Davenport) could be available for 0.56 $million/km, and up to 400MW capacity (Innamincka to Olympic Dam) for 1.01 $million/MW. At a maximum transmission distance of 1200km this corresponds to an upper estimate of costs at $614 million and $843 million respectively.

Assuming that power is generated at 0.8 capacity factor, this permits a calculation of transmission capital costs on a MWh/year basis. This can then be converted to a capital charge at 7.5% rate of return and a 30 year amortisation life (capital charge factor 8.5%). Note that because there are few savings to be achieved with lower capacity transmission, the transmission costs per MWh are significantly larger for small scale plant.

Scale	Transmission Capital Charge $/ MWH		Transmission Capital Costs $ / MWH/year		Transmission Capital Costs $M	
MW	Lower Bound	Upper Bound	Lower Bound	Upper Bound	Lower Bound	Upper Bound
50	77.3	148.4	913	1752	320	614
100	38.7	74.2	457	876	320	614
150	25.8	49.5	304	584	320	614
200	33.8	37.1	400	438	560	614
250	27.1	29.7	320	350	560	614
300	22.6	34.0	266	401	560	843
350	19.3	29.1	228	344	560	843
400	16.9	25.5	200	301	560	843
500	13.5		160		560	
1000	7.2		86		600	

Table 21: Costs of transmission from the Cooper Basin to East NSW (800-1200km)

Similar methods were used to estimate transmission costs for a 375km distance, using Table 20 for the minimum costs and data from Table 17 to estimate an upper cost (based on a Paralana case study in MMA2009).

		Upper Bound		Upper Bound		Upper Bound
50	36.2	49.8	428	588	150	206
100	18.1	24.9	214	294	150	206
150	12.1	16.6	143	196	150	206
200	15.8	12.4	107	147	150	206
250	9.1	10.0	86	118	150	206
300	7.2	10.7	125	126	262	265
350	9.0	9.1	107	108	262	265
400	7.9	8.0	93	95	262	265
500	6.3		75		262	
1000	3.4		40		280	

Table 22: Costs of transmission 375km

Finally, costs for a number of selected capacities for distances of 140km and 200km were selected from Table 16 and Table 17, based on South Australian studies.

Scale MW	Transmission Capital Charge $/ MWH	Transmission Capital Costs $ / MWH/year	Transmission Capital Costs $M
250	9.2	108	190
400	8.0	95	265
600	6.7	80	335
1000	4.5	54	375

Table 23: Costs of transmission 140-200km

6.4 Regulations regarding responsibility for transmission investment

Investment in transmission infrastructure typically enjoys significant economies of scale in transmission capacity. Thus the cost of capacity additional to that required to service some minimum guaranteed scale of generation is relatively small, and so investment may be justified where the additional generation capacity is likely, but not guaranteed, to be further developed. Under previous energy market regulations, transmission extensions and upgrades could only be realised by a transmission network provider if they passed a "Regulatory Investment Test for Transmission" (Baker & McKenzie et al., 2010). This test was based on an extended economic cost-benefit analysis, set by the Australian Energy Regulator, which would allow the costs of the transmission infrastructure development to be recovered from customers via price regulated charges. An alternative to provision by a regulated transmission network provider is investment by a generator.

Recent changes to the regulations (AEMC 2011a, 2011b) have been made to encourage "Scale Efficient Network Extensions". These are transmission extensions that are of sufficient capacity to serve multiple potential generation developments within a similar geographical area. It may be the case that not all of the potential generation developments are firm proposals, so that a larger capacity extension may fail a Regulatory Investment Test for Transmission even while private interests may be willing to partially contribute to the investment costs in return for service access guarantees that are not currently provided for by the market rules. These recent changes require the Transmission Network Service Provider (TNSP) to undertake, and to make publically available, studies to consider the opportunities for scale efficient network extensions (SENE) which can then provide an informational basis for the extension to be funded by private interests, on terms negotiated with the TNSP.

A more recent transmission frameworks review (AEMC, 2013) resulted in the recommendation of the implementation of a package of market arrangements to further encourage investment in both generation and transmission assets to be driven by joint economic impacts. These recommendations provide an alternative for generators to purchase rights to guaranteed access to transmission services capacity from a TNSP. This alternative allows generators to make a partial contribution to transmission network extensions without a requirement to fully fund the extension.

7 Appendix: Technology learning and learning curves

In the general literature "learning rates" often means the rate of change in costs over time. However, this popular use of the term is different to its original meaning in the academic literature. Learning curves refer to the observed phenomenon that the costs of new technologies tend to reduce with the cumulative production of the technology – that is, "learning-by-doing", rather than learning by time. Technology costs have been observed to reduce by an approximately constant factor for each doubling of cumulative production (Wright, 1936; Arrow, 1962; Grübler et al., 1999). This observation allows for the ability to create cost projections based on projections of the future uptake of a technology. Projections can be created from a transparent mathematical equation as follows:

$$IC_t = IC_0 \times \left(\frac{CC_t}{CC_0}\right)^{-b} \qquad (5)$$

where IC is the investment cost of a technology at CC cumulative capacity at a given future point in time t, IC_0 is the investment cost at given starting period and/or capacity CC_0, and b is the learning index. The learning index is related to the learning rate LR by: LR = 100 x $(1 - 2^{-b})$, where LR is represented as a percentage.

Any mathematical equation or model is only as good as the data it applies. For technologies that have already been deployed the learning rate can be observed. For new technologies not yet deployed, no historical learning rate can be calculated. In this case assumed values, based on learning rates of similar previously emerging technologies, are often applied. Component learning can be used, where technologies are broken down into their components. When components are shared between different technologies (e.g. steam turbines), the cost reductions are shared among the technologies that use the same component (IEA, 2000; Ferioli et al., 2009).

Projections of the global and local uptake of a technology need to be generated to project costs. However, uptake depends itself on projected costs. Hence, to resolve this interdependency, models like CSIRO's Global and Local Learning Model (GALLM) are applied to simultaneously project cost and uptake in a single step (Hayward et al., 2013).

The main advantage of the learning curve approach is that it provides an objective and transparent methodology for assigning a timeline to technology cost improvements. It also simultaneously provides a projection of the global technology mix at each point in time.

The disadvantage of the learning curve approach is that it cannot provide any guidance to exactly what processes or material components changed to arrive at the future cost level. It is unable to identify breakthroughs in technological development or bottlenecks that need to be addressed. If not constrained in some way, the learning curve approach can lead to unrealistically low costs. However, this can be addressed by implementing a lower limit (informed by engineering and science estimates of the maximum potential of a technology) or reducing the learning rate over time based on the experience of other technologies.

7.1 Challenges for the learning curve approach

The price of a technology does not always decrease at a steady rate with an increase in the number of units produced. Various factors can have an influence on the price and thus on the actual slope of a learning curve:

- Technology structural changes, which result in a dramatic improvement in the technology accompanied by a sharp increase in the learning rate and decrease in cost. This may happen, for example, in the case of hot fractured rocks, if the promise of plasma drilling techniques are realised.
- Market forces, which can have a large influence when price instead of cost data is used to construct the learning curves. When there is high demand for a product and few suppliers, the price can remain high or increase, leading to a perceived decrease in the learning rate. This has been the case in recent years, for example, for wind turbines and photovoltaic panels.
- Government policy and research and development (R&D) spending, which can help push some technologies down the learning curve when they are given government support for demonstration projects, for example. This type of support is especially important for emerging and early stage technologies which need to move beyond the demonstration phase.
- Compound or component learning, where technologies are a combination of different parts which have different rates of learning. This can result in learning being saturated in one component for example, and as a consequence the learning rate for the technology as a whole reduces.
- The country or region/s in which the learning has occurred can also have an effect as local rates of learning differ from global rates, since uptake of the technology is on a different scale.

7.2 Local versus global learning

It is important to distinguish between local and global learning. For example, wind turbines are developed and sold in a global market however, installation happens on a local/regional scale. The data and fitted curves for wind turbines and installation in the developed world are shown in Figure 22 (Hayward et al., 2013). The data for turbines ranges from 1998–2007 and for installations from 2000–2007. Each marker shown on the curves represents the average over one year. The learning rate determined from the turbine data is 4.3%.This means that for every doubling in the cumulative number of wind turbines installed globally, the cost of turbines should reduce by 4.3%.

It can be seen from Figure 22 that there is a deviation in the data from the experience curves beginning in the year 2004. This is the result of market forces having an influence on the price of wind. There were increasing costs for the manufacturers in input materials and labour shortages however, demand for wind turbines was extremely high, which gave manufacturers the freedom to charge higher prices and increase their profit margins (Milborrow, 2008).
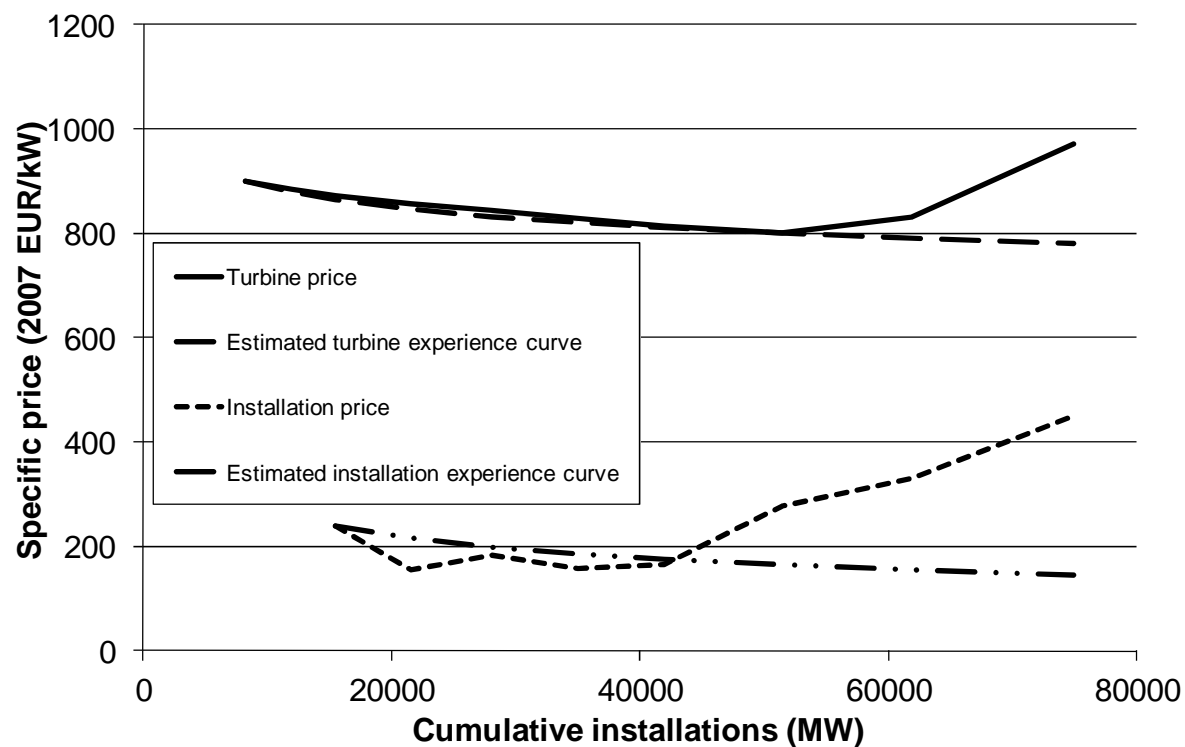
Figure 22: Global turbine experience curve and installation experience curve in developed countries (source IEA data)

7.3 Dealing with market forces

Not only were higher prices observed during that period for wind, other electricity generation technologies were and are still affected. If the price increases are temporary (i.e. price not cost increase), then it is important to have a methodology for including this effect in cost projections of electricity generation technologies, otherwise the price of the technology may be over-estimated in the longer term as can be seen in Figure 23.

Figure 23: Options for addressing 'price bubbles'

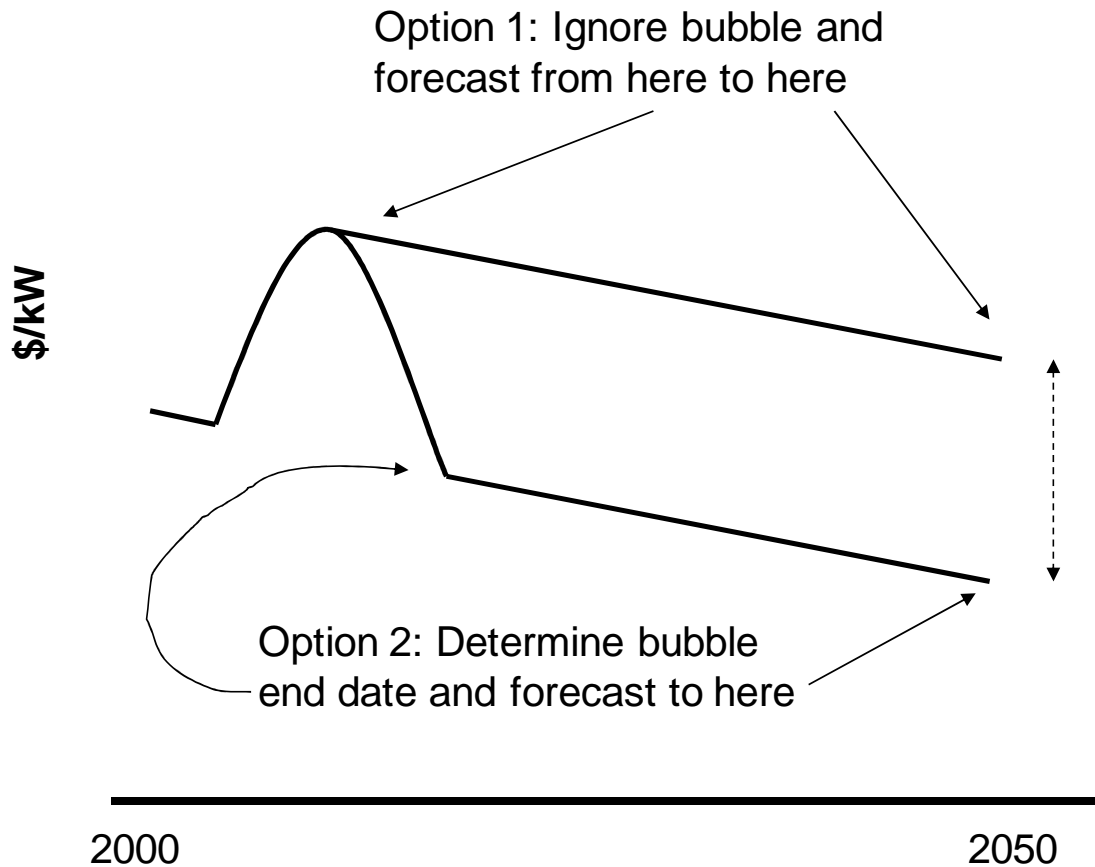GALLM includes a so-called "penalty constraint" as a simple methodology for handling these market forces. Basically, if demand for a technology in any one year is high, the cost of that technology increases by a percentage in the model. The penalty constraint has been effective in reducing demand for any single technology (and thus avoiding the problem of technology lock-in), while not preventing rapid expansion of some technologies, particularly in the short-term when it is more cost-effective to pay more for a low-emissions technology that is more mature (e.g. wind) than a technology which is still emerging and expensive (e.g. wave energy).

7.4   Technologies in early stages of learning

The Grubb curve is a concept that says the costs of a new technology initially rise as the challenges are better understood and then fall as the challenges are overcome with learning. Emerging technologies are in the early stages of learning and are those situated on the left-hand side of the Grubb curve. The costs of emerging technologies are not well known and in the majority of cases have had few installations. A learning curve based on historical data cannot be constructed if there has been no deployment of the technology. Other technologies in the early stages of learning are those which have been deployed, but are still commercialising and expanding rapidly globally. However, because deployment data is available learning rates can be formulated. The learning rates tend to be high for these technologies; a good example is photovoltaics. These technologies would be situated in the "Early" stage as shown in Figure 24 and the high slope of the curve indicates that technologies in this stage tend to have a high learning rate.
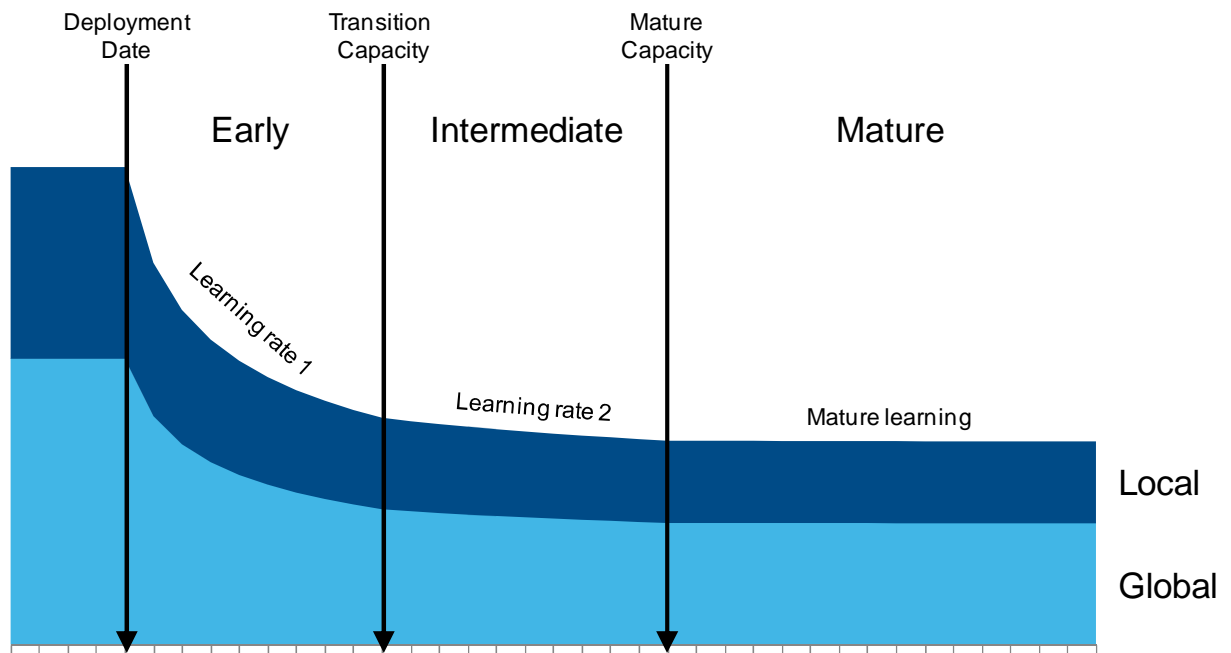
Figure 24: Schematic of changes in the learning rate as a technology progresses through its development stages after commercialisation

The high rate of learning observed in these early-stage technologies does not continue indefinitely. Several rates of learning can be observed for the same technology over its lifespan, and the rate depends on the stage of development of the technology. Typically, the learning rate reduces as the technology matures. For example, during the early commercialisation stages, learning rates may be around 20 per cent. During the pervasive diffusion stage or intermediate stage as shown in Figure 24, learning rates may be around 10 per cent. When the technology is mature, little or no learning may be observed (Grübler et al., 1999).

Only the technology components, not labour components, have a second reduced rate of learning. Experience, particularly from the oil and gas industry, has shown that labour rates of learning tend to remain high even once the technology has become pervasive (Brett and Millheim, 1986; Schrattenholzer and McDonald, 2001). Labour costs are included in the local component of plant costs.

7.5   Enhanced geothermal systems

The costs associated with developing any type of geothermal power plant can be broken into two components: the drilling cost and the balance of plant (BOP). The cost of drilling can be as much as 80% of the capital cost of the plant for EGS and approximately 60% for conventional geothermal but the cost varies considerably for different conventional geothermal sites depending on how deep the resource is. Another major source of variation in drilling cost is the price of oil, because the drilling rigs are used for oil and gas wells as well as geothermal plants.
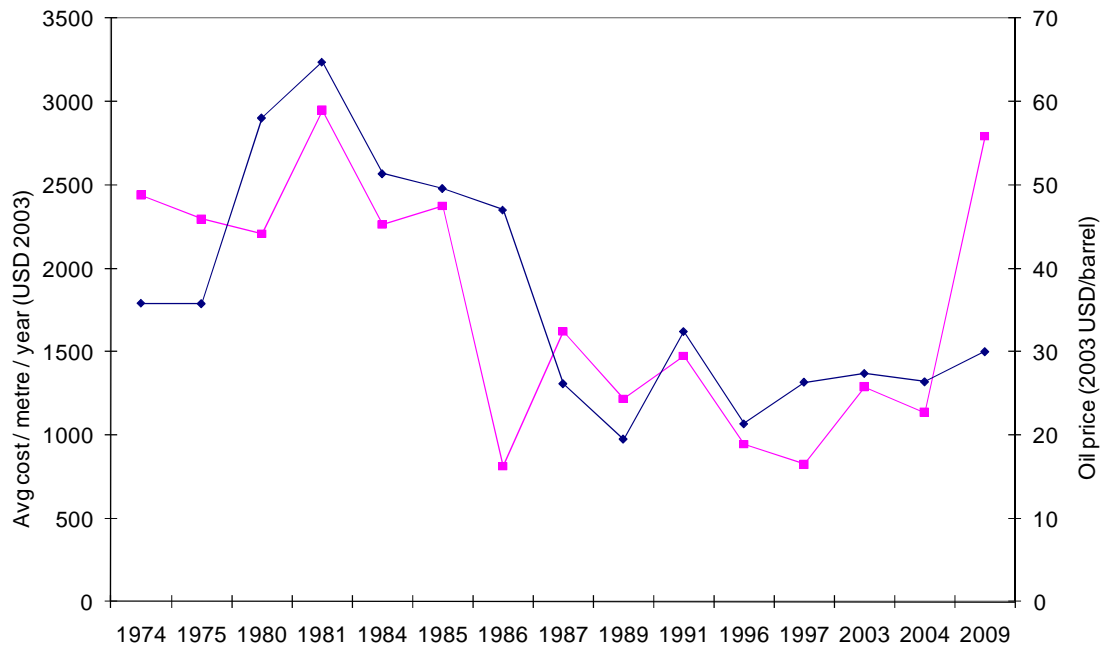
Figure 25: Geothermal well drill cost per metre (blue) and oil price over time (pink). Note that data was not available for some years.

In the US in particular, when the price of oil is high, drilling rigs for geothermal wells are scarcer as they are used to drill for oil which pushes up the rig price. The correlation between cost of drilling for geothermal and the price of oil can be seen in Figure 25. The data for the drilling cost are based on wells deeper than 2 km as the cost per metre for drilling deeper wells is higher than for shallower wells (Chad et al., 2006).

In Australia, the situation may be a little different as there is not as much drilling activity. However, because of lower demand there are very few drilling rigs and experienced crew. In Australia, the correlation of the drilling price with the oil price has not been imposed.

To counterbalance the high drilling cost, a high degree of learning occurs when drilling at one site especially when the same rig and crew are used (Williamson, 2010; Brett and Millheim, 1986; Pinto et al., 2004). And more than one well is required for any geothermal plant. Therefore, for subsequent wells drilled at any one site a learning rate has been applied to the cost of drilling. The learning rate is based on the cumulative number of wells per site, rather than cumulative capacity. The rate is quite high – 20% and this is based on general estimates from onshore oil drilling rigs (Brett and Millheim, 1986). We assume that for a conventional geothermal plant 15 wells are required to produce 50 MW and the drill depth is 1500 m. For an EGS power plant 18 wells are required to produce 50 MW and the drill depth is 4000 m (Cosgrove and Young, 2009; Geodynamics, 2009; Di Pippo, 2008).

The BOP for both types of geothermal plants is essentially the same. Therefore, there is one global experience curve for geothermal BOP and the learning is shared between EGS and conventional geothermal (Energy Information Administration, 2009). The learning rate for this component is 8%, based on experience with global geothermal plants.

Abbreviations and Acronyms

ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
AEMC	Australian Energy Market Commission
AEMO	The Australian Energy Market Operator
AER	Australian Energy Regulator
AETA	Australian Energy Technology Assessment
ARENA	Australian Renewable Energy Agency
AUD	Australian dollars
BOP	Balance of Plant
BREE	Bureau of Resources and Energy Economics
CCA	Climate Change Authority
CCS	Carbon capture and storage
CEF	Clean Energy Future
CO$_2$	Carbon Dioxide
CoA	Commonwealth of Australia
CQ	Central Queensland region
CSIRO	Commonwealth Scientific and Industrial Research Organisation
CVIC	Country Victoria
DKIS	Darwin Katherine Interconnected System
EGS	Enhanced Geothermal System
FGF	Future Grid Forum
GALLM	Global and Local Learning Model
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt-hours
HHV	Higher Heating Value
HVDC	High Voltage Direct Current
IGEG	International Geothermal Expert Group
IMO	Independent Market Operator
km	Kilometre
kV	Kilovolt
kW	Kilowatt

LCOE	Levelised cost of electricity
LNG	Liquefied Natural Gas
LV	Latrobe Valley region
MVA	Megavolt ampere
MW	Megawatt
MWh	Megawatt-hour
NA	Not applicable or Not available
NCEN	NSW Central region
NEFR	National Electricity Forecasting Report
NEM	National Electricity Market
NFEE	National framework for Energy Efficiency
NT	Northern Territory
NTNDP	National Transmission Network Development Plan
NSA	Northern South Australia region
NSP	Network Service Provider
NSW	New South Wales
NWIS	North-West Interconnected System
O&M	Operations and maintenance
PV	Photovoltaic
RET	Renewable Energy Target
RIT-T	Regulatory Investment Test - Transmission
SCER	Standing Council on Energy and Resources
SGLP	Strong Growth Low Pollution (Commonwealth of Australia, 2011)
SENE	Scale Efficient Network Extension
SESA	South-East South Australia
SWIS	South-West Interconnected System
SWQ	South-West Queensland
TNSP	Transmission Network Service Provider
TWh	Terawatt-hours
VIC	Victoria
WA	Western Australia
WEM	Wholesale Electricity Market

References

ABS Catalogue 6401.0, Consumer Price Index, Australia, Dec 2013,
http://www.abs.gov.au/ausstats/abs@.nsf/mf/6401.0

ACIL Allen Consulting, 2013, *Modelling of the Australian Electricity Generation Sector: Electricity Sector Emissions*, report to the Department of Innovation, Industry, Climate Change, Science, Research and Tertiary Education, 4 September, available at http://climatechangeauthority.gov.au/sites/climatechangeauthority.gov.au/files/files/Target-Progress-Review/Electricity-Sector-Emission-to-2050/Electricty%20sector%20emissions.pdf [accessed 8 Jan 2014]

AECOM, 2013, *Australian Remote Renewables: Opportunities for Investment,* Report to the Australian Trade Commission (Austrade), available at http://www.austrade.gov.au/ArticleDocuments/2786/Australian-Remote-Renewables-Opportunities-for-Investment.pdf.aspx [accessed 8 Jan 2014]

Australian Energy Market Commission (AEMC), 2011a, *Scale Efficient Network Extensions Final Rule Determination Information Sheet*, available at http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Scale-Efficient-Network-Extensions.html [accessed 20 Jan 2014]

Australian Energy Market Commission (AEMC), 2011b, *Scale Efficient Network Extensions Rule Determination 30 June 2011*, available at http://www.aemc.gov.au/Electricity/Rule-changes/Completed/Scale-Efficient-Network-Extensions.html [accessed 20 Jan 2014]

Australian Energy Market Commission (AEMC), 2013, *Transmission Frameworks Review*, Final Report, 11 April 2013, Sydney, available at http://www.aemc.gov.au/market-reviews/completed/transmission-frameworks-review.html [accessed 20 Jan 2014]

Arrow, K.J., 1962, The economic implications of learning by doing. *The Review of Economic Studies*, 29, 155-173.

Australian Energy Market Operator (AEMO), 2013a, *Electricity Statement of Opportunities for the National Electricity Market 2013,* available at http://www.aemo.com.au/Electricity/Planning/Electricity-Statement-of-Opportunities [accessed 5 Feb 2014]

Australian Energy Market Operator (AEMO), 2013b, *2013 National Electricity Forecasting Report Update for the National Electricity Market*, November, available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013 [accessed 8 Jan 2014]

Australian Energy Market Operator (AEMO), 2013c, 2013 *National Electricity Forecasting Report Update*, available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013 [accessed 8 Jan 2014]

Australian Energy Market Operator (AEMO), 2013d, *National Transmission Network Development Plan for the National Electricity Market 2013*, available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan [accessed 8 Jan 2014]

Australian Energy Market Operator (AEMO), 2013e, *100 per cent renewables study – Modelling outcomes*, June http://www.climatechange.gov.au/reducing-carbon/aemo-report-100-renewable-electricity-scenarios [accessed 7 April 2014]

Australian Energy Market Operator (AEMO), 2012a, *Assessing Reserve Adequacy in the NEM 2012*, available at http://www.aemo.com.au/Electricity/Planning/Related-Information/Assessing-Reserve-Adequacy [accessed 20 Jan 2014]

Australian Energy Market Operator (AEMO), 2012b, *National Transmission Network Development Plan for the National Electricity Market 2012*, ISSN: 1838-6628 (Online), available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan [accessed 20 Jan 2014]

Australian Energy Market Operator (AEMO), 2011, *National Transmission Network Development Plan for the National Electricity Market*, ISSN: 1838-6628 (Online), available at http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan [accessed 20 Jan 2014]

Australian Energy Market Operator (AEMO), 2010, *An Introduction to Australia's National Electricity Market*, July http://www.aemo.com.au/About-the-Industry/Energy-Markets/National-Electricity-Market [accessed 20 Jan 2014]

Baker & McKenzie, Worley Parsons, Macquarie Capital Advisors, 2010, *Green Grid: Unlocking Renewable Energy Resources in South Australia*, available at http://www.renewablessa.sa.gov.au/investor-information/green-grid- [accessed 5 March 2014]

Brett, J.F. and K.K. Millheim, 1986, The drilling performance curve: a yardstick for judging drilling performance. *61st Annual Technical Conference and Exhibition of the Society of Petroleum Engineers.* New Orleans LA, Society of Petroleum Engineers.

Bureau of Resource and Energy Economics (BREE), 2013a, *Beyond the NEM and the SWIS: 2011-12 Regional and Remote Electricity in Australia*, October, available at http://www.bree.gov.au/publications/beyond-nem-and-swis-2011%E2%80%9312-regional-and-remote-electricity-australia [accessed 8 Jan 2014]

Bureau of Resources and Energy Economics (BREE), 2013b, *Australian Energy Technology Assessment 2013 Model Update*. Available at: http://www.bree.gov.au/publications/australian-energy-technology-assessments [accessed 14 March 2014]

Bureau of Resources and Energy Economics (BREE), 2012, *Australian Energy Technology Assessment*, available at http://www.bree.gov.au/publications/australian-energy-technology-assessments [accessed 8 Jan 2014]

Bureau of Resources and Energy Economics (BREE), 2011, *Australian Energy Projections to 2034–35*, BREE report prepared for the Department of Resources, Energy and Tourism, Canberra, December. ISBN 978-1-921812-78-1(online), available at http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%9350 [accessed 8 Jan 2014]

Chad, A., J.W. Tester, B.J. Anderson, S. Petty and B. Livesay, 2006, A comparison of geothermal with oil and gas well drilling costs. *Thirty-first Workshop on Geothermal Reservoir Engineering, January 30-February 1.* Stanford University, Stanford, California.

Climate Change Authority (CCA), 2012, *Renewable Energy Target Review*, available at http://climatechangeauthority.gov.au/ret [accessed 14 March 2014]

Climate Change Authority (CCA), 2014, *Reducing Australia's Greenhouse Gas Emissions— Targets and Progress Review final Report*, available at http://climatechangeauthority.gov.au/caps [accessed 14 March 2014]

Commonwealth of Australia (CoA), 2011, *Strong Growth, Low Pollution Modelling a Carbon Price Update*, ISBN 978-0-642-74737-2, available at http://carbonpricemodelling.treasury.gov.au/carbonpricemodelling/content/default.asp [accessed 8 Jan 2014]

Commonwealth of Australia (CoA), 2012, *Australian National Greenhouse Accounts*. Department of Climate Change and Energy Efficiency, available at: http://www.climatechange.gov.au/sites/climatechange/files/documents/03_2013/nga-factors.pdf [accessed 8 Jan 2014]

Commonwealth of Australia (CoA), 2013, *Emissions Reduction Fund Green Paper*, Department of the Environment, available at http://www.environment.gov.au/topics/cleaner-environment/clean-air/emissions-reduction-fund/green-paper [accessed 3 March 2014]

Cosgrove, J. and J. Young, 2009, *Geothermal Energy in Australia: Two Geothermal Systems under Development*. Wilson HTM Investment Group.

CSIRO, 2011, *Unlocking Australia's Energy Potential,* available at: http://www.csiro.au/Organisation-Structure/Flagships/Energy-Flagship/unlocking-Aust-energy-potential.aspx [accessed 8 Jan 2014]

CSIRO and ROAM Consulting, 2013, *Modelling the Future Grid Forum Scenarios*, December, available at http://www.csiro.au/Organisation-Structure/Flagships/Energy-Flagship/Future-Grid-Forum-brochure.aspx [accessed 8 Jan 2014]

de Silva, R. and A. Robbie, 2009, *Network Extensions to Remote Areas: Part 2 – Innamincka Case Study*, Power Systems Consultants Australia Pty Ltd, available at http://www.aemo.com.au/Electricity/Policies-and-Procedures/Planning/~/media/Files/Other/planning/0400-0005.pdf.ashx [accessed 26 Feb 2014]

Department of Industry website, 2014, *Energy Markets,* http://www.industry.gov.au/Energy/EnergyMarkets/Pages/default.aspx [accessed 21 Jan 2014]

Di Pippo, R., 2008, *Geothermal Power Plants: Principles, Applications, Case Studies and Environmental Impact*, Oxford, Butterworth-Heinemann.

ElectraNet, 2009, *Future Electricity Infrastructure Requirements of South Australia's Resources Industry Information Paper*, November http://www.pir.sa.gov.au/__data/assets/pdf_file/0003/125184/Future_Electricity_Infrastructure_Requirements_Information_Paper_-_Final_Draft_25Nov2009.pdf [accessed 5 March 2014]

ElectraNet, 2012, *Lower Eyre Peninsula Reinforcement, RIT-T: Project Specification Consultation Report*, available from http://www.electranet.com.au/assets/RIT-T/Eyre-Peninsula-Reinforcement-Project/11201-EyrePeninsulaReinforcement-PSCR-Feb2012.pdf [accessed 5 March 2014]

Energy Information Administration, 2009, *Annual Energy Outlook 2009: With Projections to 2030.* Washington DC, United States Department of Energy.

Ferioli, F., K. Schoots and B.C.C. van der Zwaan, 2009, Use and limitations of learning curves for energy technology policy: A component-learning hypothesis. *Energy Policy,* 37, 2525-2535.

Frontier Economics, 2013, *Review of AEMO's 2013 National Electricity Forecasts: A Report Prepared for the Australian Energy Market Operator*, November, available at http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2013 [accessed 8 Jan 2014]

Future Grid Forum, 2013, *Change and Choice: The Future Grid Forum's Analysis of Australia's Potential Electricity Pathways to 2050*, available from http://www.csiro.au/Organisation-Structure/Flagships/Energy-Flagship/Future-Grid-Forum-brochure.aspx [accessed 8 Jan 2014]

Geodynamics, 2009, http://www.geodynamics.com.au. Accessed 2009.

Graham, P.W., T.S. Brinsmead and P. Marendy, 2013, *efuture sensitivity analysis 2013*, CSIRO, June, available from http://efuture.csiro.au/ [accessed 28 Jan 2014]

Graham P. and J. Hayward, 2012, *AEMO 100% Renewable Energy Study: Projection of Electricity Generation Technology Capital Costs for Scenario 1*, CSIRO, available at http://www.climatechange.gov.au/sites/climatechange/files/files/reducing-carbon/APPENDIX10-CSIRO-GALLM-gen-tech-capital-costs-scenario.pdf [accessed 5 Feb 2014]

Graham, P.W. and A. Smart, 2011, *Possible Futures: Scenario Modelling of Australian Alternative Transport Fuels to 2050*, A report for the Department of Resources, Energy and Tourism, available at http://www.innovation.gov.au/Energy/Documents/Energy-Security/transport-fuels/ScenarioModellingAustralianAlternativeTransportFuels2050.pdf [accessed 5 Mar 2014]

Grübler, A., N. Nakicenovic and D.G. Victor, 1999, Dynamics of energy technologies and global change. *Energy Policy,* 27**,** 247-280.

Hayward, J.A. and P.W. Graham, 2013, A global and local endogenous experience curve model for projecting future uptake and cost of electricity generation technologies. *Energy Economics*, 40, 537-548.

Horizon Power website, 2014, About Us, http://www.horizonpower.com.au/about_us.html [accessed 5 Feb 2014]

IT Power Australia, 2013, *Data Collection of Diesel Generators in South Australia*, Department of Manufacturing, Innovation, Trade, Resources and Energy, available at http://www.renewablessa.sa.gov.au/investor-information/diesel-generators-directory [accessed 19 Feb 2014]

Independent Market Operator (IMO), 2013, *Electricity Statement of Opportunities*, Perth WA, June, available at http://www.imowa.com.au/reserve-capacity/electricity-statement-of-opportunities-(soo) [accessed 8 Jan 2014]

Independent Market Operator (IMO), 2012, *Wholesale Electricity Market Design Summary*, October, available at http://www.imowa.com.au/docs/default-source/Electricity-Market/wem-design-summary-v1-4-24-october-2012.pdf [accessed 8 Jan 2014]

International Energy Agency (IEA), 2000, *Experience Curves for Energy Technology Policy*. Paris, OECD.

Milborrow, D., 2008, Dissecting wind turbine costs. *WindStats Newsletter*, 21, 3-5.

Ministerial Council on Energy website, http://www.mce.gov.au/quicklinks/agreements.html [accessed 21 Jan 2014]

MMA, 2009, *Preliminary Assessment of the Value of a new 275 kV Transmission line to connect Geothermal Resources to the NEM in South Australia*, Confidential report to the Australian Geothermal Association, September, available at http://www.agea.org.au/geothermal-energy/publications-reports/2009/preliminary-assessment-of-the-value-of-a-new-275-kv-transmission-line-to-connect-geothermal-resources-to-the-nem-in-sa/ [accessed 4 Feb 2014]

Pinto, C.J., J.L. Dick, L.A. Sinor, J. Oldham and B. Stauffer, 2004, Novel PDC bit achieves ultrafast drilling in the Gulf of Thailand. *Baker Hughes In Depth,* 10**,** 20-29.

Power Exchange Operations, 2010, *Guide to Ancillary Services in the National Electricity Market,* Document No 160-0056, available at http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services, [accessed 3 Feb 2014]

Schrattenholzer, L. and A. McDonald, 2001, Learning rates for energy technologies*. Energy Policy*, 29, 255-261.

Sinclair Knight Merz, 2010, *Feasibility Study Estimates for Transmission Network Extensions*, available from http://www.aemo.com.au/~/media/Files/Other/planning/0179-0176%20pdf.pdf [accessed 10 March]

Syed, A., 2012, *Australian Energy Projections to 2049-50*, Bureau of Resources and Energy Economics, available at http://www.bree.gov.au/publications/australian-energy-projections-2049%E2%80%9350 [accessed 8 Jan 2014]

Williamson, K.H., 2010, Geothermal power: the baseload renewable. In Sioshansi, F.P. (ed.) *Generating electricity in a carbon constrained world.* Burlington, MA, USA, Academic Press.

Wilson, C. and A. Grübler, 2011, Lessons from the history of technological change for clean energy scenarios and policies. *Nature Resources Forum*, 35, 165-184.

Wright, T.P., 1936, Factors affecting the cost of airplanes*. Journal of the Aeronautical Sciences*, 3, 122-138.