Centre for Energy and Environmental Markets

Assessing “Gas Transition” pathways to low carbon electricity

by

Dr Jenny Riesz*, Dr Peerapat Vithayasrichareon, Assoc. Prof Iain MacGill

Centre for Energy and Environmental Markets
University of NSW

CEEM Working Paper

June 2014

*Corresponding author: Centre for Energy and Environmental Markets,
The University of New South Wales, Sydney, NSW2052, Australia.
Tel.: +61 411 042 502, E-mail: j.riesz@unsw.edu.au

THE UNIVERSITY OF NEW SOUTH WALES
SYDNEY • AUSTRALIA

About CEEM and this discussion paper

The UNSW Centre for Energy and Environmental Markets (CEEM) undertakes interdisciplinary research in the design, analysis and performance monitoring of energy and environmental markets and their associated policy frameworks. CEEM brings together UNSW researchers from the Australian School of Business, the Faculty of Engineering, the Institute of Environmental Studies, and the Faculty of Arts and Social Sciences and the Faculty of Law, working alongside a growing number of international partners. Its research areas include the design of spot, ancillary and forward electricity markets, market-based environmental regulation, the integration of stochastic renewable energy technologies into the electricity network, and the broader policy context in which all these markets operate.

This is an area of ongoing work for CEEM and we are actively seeking feedback and comments on this discussion paper, and on related work. The corresponding author for this paper is:

Dr Jenny Riesz
Centre for Energy and Environmental Markets,
The University of New South Wales, Sydney, NSW2052, Australia.
Tel.: +61 411 042 502
E-mail: j.riesz@unsw.edu.au

www.ceem.unsw.edu.au

UNSW THE UNIVERSITY OF NEW SOUTH WALES SYDNEY • AUSTRALIA
Centre for Energy and Environmental Markets

Abstract

Generation portfolios including varying quantities of gas-fired and renewable generation were compared on the basis of expected costs, cost risk and greenhouse gas emissions. A Monte-Carlo based generation portfolio modelling tool was applied to take into account the effects of highly uncertain future gas prices, carbon pricing policy and electricity demand. The Australian National Electricity Market (NEM) was used as a case study. Input assumptions were based upon widely accepted future technology cost estimates, electricity demand, fuel costs, carbon prices and their associated uncertainties. Hourly wind and photovoltaic generation profiles were used to account for generation variability. Outcomes were modelled for 396 possible generating portfolios in 2030 and 66 possible generating portfolios in 2050, each with 10,000 simulations of possible fuel prices, carbon prices and electricity demands.

Results indicate that portfolios sourcing significant quantities of energy from gas-fired generation in 2030 and 2050 are found to be significantly higher cost and significantly higher risk than the other alternatives considered. High gas portfolios also cannot achieve the greenhouse gas (GHG) emissions reductions levels recommended. For example, portfolios that source 95% of energy from gas-fired generation in 2050 experience expected generation costs that are $65/MWh (40%) higher than portfolios that source only 20% of energy from gas-fired generation. These high gas portfolios also exhibit a cost risk (standard deviation in cost) that is three times higher. The lowest cost portfolios in 2050 source less than 20% of energy from gas with the remaining energy sourced from renewables.

Even in the absence of a carbon price, the lowest cost portfolio in 2050 sources only 30% of energy from gas-fired generation, with the remaining 70% of energy being sourced from renewable technologies. Approximately half of the installed gas-fired capacity in this portfolio is peaking OCGT plant, providing firm capacity without significant quantities of energy. This indicates that investment in gas-fired plant is high cost and high risk, even in the absence of any expectation of a carbon price.

Results suggest the optimal strategy for minimising costs, minimising cost risk and reducing GHG emission levels in the NEM involves minimising energy sourced from gas, and increasing renewable generation towards levels around 60% of energy by 2030 and 80-100% by 2050. In the lowest cost and lowest risk portfolios, firm capacity is provided primarily by the transition of existing coal-fired plant into a peaking role, and later by further investment in peaking open cycle gas turbine plant. These results are found to be robust to a wide range of assumptions around future carbon prices.

Contents

1. Introduction

Recent work by the International Energy Agency (IEA, 2014a) and Intergovernmental Panel for Climate Change (IPCC, 2014) has highlighted the increasingly urgent need for large, rapid and sustained global emission reductions, and the key role that the electricity industry will need to play in this transition.

Almost all nations face major challenges in achieving such emission reductions from their electricity industry at the speed and scale that appears required to avoid dangerous global warming. Australia faces the particular challenge of having amongst the highest per-capita greenhouse emissions (Garnaut, 2011) and highest emissions intensity electricity industry in the world (Stock, 2014). However, it also has the significant advantages of major and diverse renewable energy resources and considerable gas reserves (BREE, 2013). As such it provides an interesting case study of possible transition pathways towards future low-carbon electricity industries.

There is ongoing debate about the best way to reduce the emissions intensity of Australia's electricity supply. While there are some nuclear proponents, recent setbacks for the global industry (IEA, 2014b), the current absence of any local nuclear generation in Australia and considerable local opposition (nuclear generation is currently illegal) all raise questions about its future role in Australia. Australian State and Federal Governments have all advocated a key role for carbon capture and storage, but the poor progress seen in over the past decade in demonstrating the technology within the electricity industry has also raised concerns about its future role. Given the urgent need to deploy low-carbon generation, renewables and gas-fired generation have been seen as the key immediate options. Some stakeholders argue that investment should focus on renewable generation given its falling costs and zero operating emissions. Others propose (King, 2011) that a transition pathway focussed on gas-fired electricity would be preferable as Combined Cycle Gas Turbines are a mature and flexible generation option that offers high dispatchability by comparison with variable and somewhat unpredictable wind and solar, yet have an emissions intensity a half to a third of current coal-fired generation. This approach could be termed a "gas transition" to low carbon electricity, with gas playing a significant role in delivering large quantities of energy in future power systems.

Most previous studies of the Australian electricity sector have focused on a small number of generation portfolios, modelled under a small number of scenarios. For example, in 2011 the Australian Government modelled optimal future low-carbon generation mixes for 2050 that delivered emission reductions through a mix of renewables, gas-fired generation and CCS. The actual mix varied with the strength of the emission reduction target (core and higher carbon price scenarios) and gas price (Australian Federal Treasury, 2011). Molyneaux et al. modelled the costs and GHG emissions of two generation portfolios in 2035 (exploring investment in primarily gas-fired generation or renewable generation respectively) (Molyneaux, Froome, Wagner, & Foster, 2012). The Australian Energy Market Operator (AEMO) annually undertakes a National Transmission Network Development Plan (NTNDP) which explores a small number of scenarios (two were modelled in the 2012 NTNDP) (AEMO, 2012a). A number of studies have also explored the potential for 100% renewable energy (RE) in the Australian NEM (Elliston, MacGill, & and Diesendorf, 2014), (AEMO, 2013). While such efforts can have considerable value, these studies consider only a very small subset of the possible generating portfolios that might eventuate over time, and sample only a few of the possible market conditions under which those portfolios may need to operate. Inevitably, such approaches inadequately account for the high degree of uncertainty over important driving factors such as gas and carbon prices. As such, they do not provide a detailed analysis of the future risks associated with particular portfolio choices.

There are number of studies applying generation portfolio analysis concepts based on the Mean Variance Portfolio (MVP) technique, some of which examine the role of renewable energy in generation portfolios. For example, analysis has been conducted for electricity industries including Japan (Bhattacharya & Kojima, 2012), Brazil (Losekann, Marrero, Ramos-Real, & and de Almeida, 2013), Taiwan (Huang & and Wu, 2008), Spain (Muñoz, Nieta, A.A., & and Bernal-Agustín, 2009) and Ireland (Doherty, Outhred, & and O'Malley, 2006). However the majority of these studies only model low to moderate levels of renewable generation, and do not explore the potential implications of high renewable penetrations.

This study is intended to explore possible pathways towards decarbonisation of emissions intensive electricity sectors, using the Australian NEM as a case study. The focus is particularly on comparing the merits and risks in decarbonisation predominantly via a "gas transition", as compared with a direct shift to renewable energy, where gas is used for peaking generation only. Analysis is conducted for the year 2050, 36 years in the future. Policies implemented now could be expected to affect investment decisions in the coming decade (and beyond), and the developers installing this plant are likely to have an expectation of continuing to operate that plant in 2050. Therefore, analysis of the optimal power system in 2050 should directly influence policy decisions that affect current electricity sector investment. Analysis for the year 2030 is also included, to provide an intermediate point on the transition pathway.

A Monte-Carlo based generation portfolio modelling tool is employed. This tool was first developed in (Vithayasrichareon & and MacGill, 2012) to assess different possible future generation portfolios in the NEM by considering different investment scenarios involving gas and renewable generation for 2030 and 2050. The study adopts a long-term overall societal perspective focusing of overall generation costs, associated costs risks and GHG emissions of future generation portfolios without considering issues associated with privately undertaken generation investment.

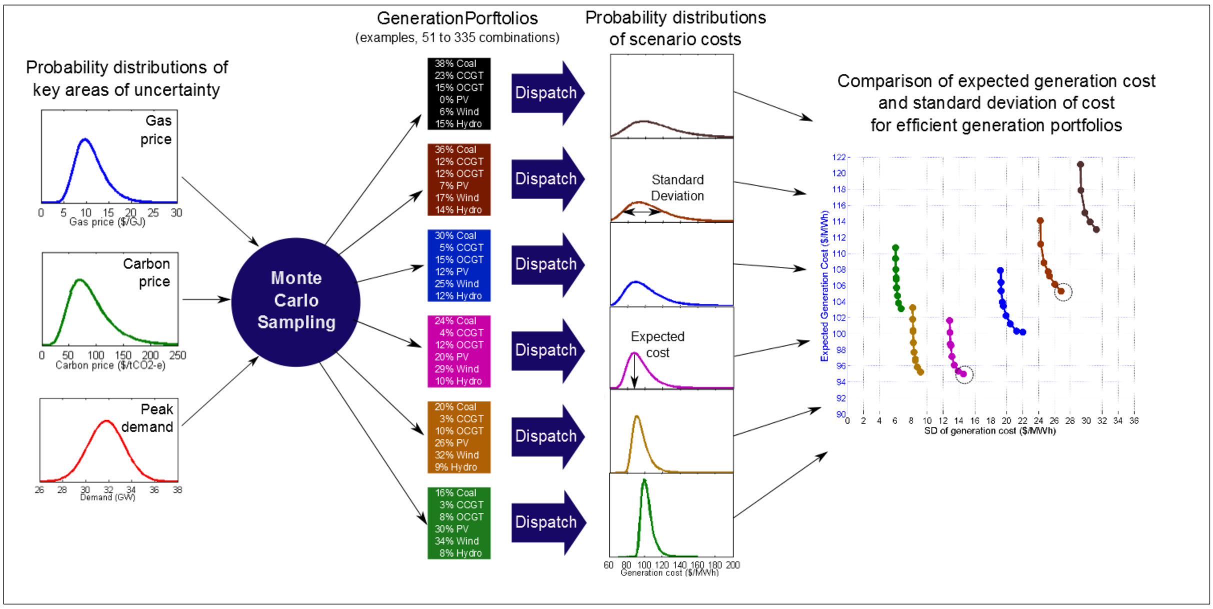
This paper is structured as follows. Section 2 provides an overview of the model applied for this analysis. Section 3 outlines the manner in which the considerable uncertainty in key input variables has been managed in the model. Section 4 describes the other input assumptions used in the model. Section 5 presents the findings of the modelling, with discussion of modelling limitations included in section 6. Significant conclusions and their policy implications are summarised in section 7.

2. The Model

The modelling tool employed in this study extends the commonly applied residual load duration curve (RLDC) based optimal generation mix techniques by using Monte Carlo Simulation (MCS) to formally incorporate key uncertainties which directly impact overall generation costs and other outcomes into the assessment. Outputs from the modelling tool consist of many thousands of simulations of generation costs and GHG emissions for each of the different possible future generation portfolios. These outputs are, therefore, a series of probability distributions that, for relatively simple distributions, can be described as an expected future value of annualised generation costs and GHG emissions, and the standard deviation (SD) in these (cost and emissions uncertainty or risk) for each portfolio.

The tool then applies financial portfolio methods to determine an Efficient Frontier (EF) of expected (i.e. mean) costs and the associated cost uncertainty (i.e. SD) for each of the different generation portfolios. EF techniques provide a basis for explicitly analysing cost and risk trade-offs among different generation technology portfolios. In particular, the EF is made up of those generation portfolios which offer the lowest expected cost for some level of cost uncertainty. A graphical description of the operation of the modelling tool is shown in Figure 1.

Figure 1 - Methodology Monte Carlo based modelling tool.



Since the tool applies MCS techniques, it can support more sophisticated risk assessments of different generation portfolios such as downside economic risks, value at risk (VAR) and other risk-weighted uncertainty measures. It also does not rely upon the use of a normal distribution to model input uncertainties – any probability distributions can be used. These uncertainties can also be correlated – for example, future gas and carbon prices.

The methodology and mathematical formulation of this modelling tool are described in detail in (Vithayasrichareon & and MacGill, 2012). The model has previously been applied to portfolio analysis with wind generation in the context of the NEM (Vithayasrichareon & MacGill, 2013).

3. Handling of uncertainties in the modelling formulation

3.1. Electricity demand

Estimated hourly electricity demand for 2029-2030 and 2049-2050 were obtained from AEMO's 100% renewable energy study in the case of moderate growth, which corresponds to a 50% 'probability of exceedance' (POE) case (AEMO, 2013). The demand profiles provided by AEMO were based on the historical 2009-10 demand pattern.

Demand uncertainty

Electricity demand uncertainty was modelled by assuming a normal distribution of residual peak demand in the RLDC in each RE penetration scenario. AEMO's forecast 50% POE peak demand was applied as the mean peak demand. The SD of peak demand was determined based the difference between AEMO's 10% POE and 50% POE peak demand estimates. The SD was approximated as 5% of the central projection. To create the RLDC used in each simulation, the reference RLDC (central projection) for each renewable penetration scenario was then adjusted by scaling the whole net RLDC as required to match the desired peak demand for the particular simulation. The uncertainty in the RLDC was therefore modelled as vertical shifts in the reference RLDC, thus maintaining the same shape. The peak demand projections for 10% and 50% POE cases and SD for 2030 and 2050 are shown in Table 1.

There were some instances in which the simulated residual peak demands exceeded the installed conventional generation capacity, resulting in unserved energy. Unserved energy was valued at $12,900/MWh, which was the market price cap in the NEM in 2012-13[1]. The cost of unserved energy was included in the overall cost in each Monte Carlo run.

Table 1. Peak demand projections and standard deviation for 2030 and 2050.

Year	Peak demand (GW)		SD of peak demand	
	10% POE	50% POE	%	Absolute
2030	40.8	38.3	5%	1.9
2050	45	42.2	5%	2.1

3.2. Fuel and carbon prices

Lognormal distributions were applied to future fuel and carbon prices to reflect the asymmetric downside risks associated with their future value. As for normal distributions, lognormal distributions can be characterised by their mean (expected value) and SD.

[1] The market price cap increases each year; for the 2013-2014 financial year it is $13,100/MWh, and on 1 July 2014 it will increase to $13,500/MWh.

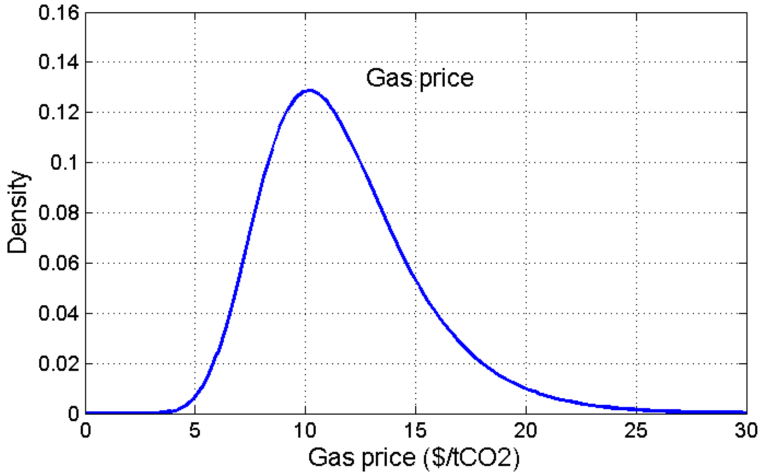
Fuel prices

Fuel prices were based upon an average of NEM regions. The mean and SD of fuel prices were determined from the 2030 and 2050 fuel cost estimates provided in the 2012 AETA report, which also provides projections for low, medium and high price scenarios (BREE, 2012a). The central projection of fuel costs was applied as the mean, while the SD was approximated based on the spread between the low and high case scenarios. The SDs obtained were approximately equal to percentage of absolute uncertainty provided in the AETA report. Fuel prices in the low, medium and high scenarios as well their SDs are shown in Table 2. Note that the fuel price estimates are the same for 2030 and 2050. The resulting gas price probability distribution applied in the model is illustrated in Figure 2.

Table 2. Fuel price estimates for 2030 and 2050.

Fuel	Fuel price ($/GJ)			SD of fuel prices	
	Low	Medium	High	%	Absolute
Black coal	1.78	1.86	1.99	6%	0.1
Natural gas	8.81	11.65	15.83	30%	3.5

Figure 2 - Gas price probability density distribution assumed in the model for 2030 and 2050.



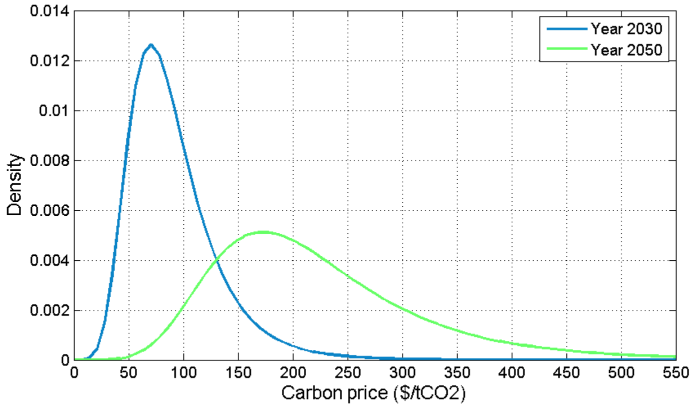
Carbon prices

For carbon prices, mean and SDs were obtained from Australian Treasury Modelling of carbon prices in Australia in 2030 (Australian Treasury, 2011). This modelling included two scenarios: a low carbon price case (corresponding to a 5% reduction in emissions by 2020) and a high carbon price case (corresponding to a 25% reduction in emissions by 2030). For this modelling, the mean carbon price was based upon a scaling between these two scenarios (adjusted by CPI to March 2013 dollars). The SD was obtained using the same approach as the fuel prices. Table 3 shows the assumed carbon prices in the low, medium and high scenarios as well as the SDs. The resulting carbon price probability distribution applied in the modelling for 2030 and 2050 is illustrated in Figure 3.

Table 3. Carbon price estimates for 2030 and 2050.

Year	Carbon price ($/t$CO_2$)			SD of carbon price	
	Low	Medium	High	%	Absolute
2030	54	91	115	40%	36
2050	135	224	284	40%	67

Figure 3 - Carbon price probability density distributions assumed in the model for 2030 and 2050



Correlations

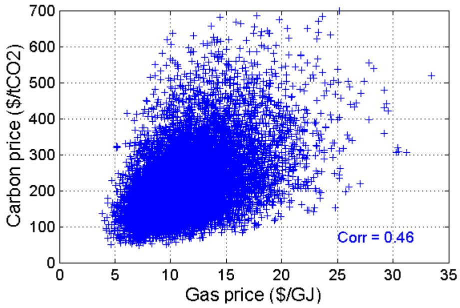
Correlations between fuel and carbon prices are also accounted for when modelling these uncertainties, given that their movements have exhibited a considerable historical correlation in the EU and UK markets (Roques, Nuttall, Newbery, & Neufville, 2005). For example ambitious climate policies might involve high carbon prices that would increase the use and hence cost of lower emission gas in relation to coal while also resulting in higher electricity prices (Green, 2008). Such correlations may have a significant influence by either moderating or exacerbating the impact of uncertainty. Neglecting them, therefore, can impact overall industry costs and associated cost risks, and subsequently affect the choice of future generation portfolios (Awerbuch & Yang, 2008). Correlations used in the modelling were estimated based upon historical trends in OECD countries and are shown in Table 4.

Table 4. Correlation coefficients between fuel and carbon prices.

Correlation Coefficient ($\rho_{i,j}$)	Coal price (ρ_{coal})	Gas price (ρ_{gas})	Carbon price (ρ_{carbon})
Black coal price ($\rho_{bl\ coal}$)	1	0.6	-0.35
Gas price (ρ_{gas})	0.6	1	0.45
Carbon price (ρ_{carbon})	-0.35	0.45	1

Correlated samples of coal, gas and carbon prices are generated from their marginal lognormal distributions using a multivariate Monte Carlo simulation technique described in (Vithayasrichareon & and MacGill, 2012). The scatter plot of 10,000 simulated gas and carbon price simulations in 2050 illustrating their correlation is shown in Figure 4.

Figure 4 - Scatter plot of 10,000 simulated gas and carbon prices for 2050 showing their positive correlation.



4. Portfolio options

396 possible generating portfolios in 2030 and 66 possible generating portfolios in 2050 were constructed from a selection of existing generation and four new generation investment options: wind (on shore), utility scale solar PV (single axis tracking), combined cycle gas turbines (CCGT) and open cycle gas turbines (OCGT).

Existing generation

All existing generation capacity was assumed to be retired by 2050, except for hydro generation. For 2030, all existing brown (lignite) coal generation was assumed to be retired, and black coal capacity was varied between the portfolios (ranging from no retirements to full retirement of all black coal capacity). This provides "best case" portfolios with regards to GHG emissions; if lower emissions intensity black coal were to retire in place of brown coal, outcomes could be expected to be similar but with higher overall GHG emissions. All existing gas, distillate, cogeneration, photovoltaic (PV) and wind generating capacity were assumed to continue operating in 2030. Investment costs of the existing capacity of each technology were considered 'sunk' and therefore were not included in the calculation of annualised (capital and operating) industry generation costs. These assumptions are summarised in Table 5.

Table 5. Existing generation capacity included in 2030 and 2050 portfolios

Technology	Existing capacity in 2013 (MW)[a]	Remaining capacity (MW)	
		In 2030	In 2050
Black coal	19,814	Varies from 0 to 19,814	0
Brown coal	7,294	0	0
CCGT	2,758	2,758	0
OCGT	7,415	7,415	0
Hydro	7,654	7,654	7,654
Distillate	586	586	0
Cogeneration	171	171	0
PV (rooftop)	2,800	2,800	0
Wind	3,000	3,000	0

[a] includes committed capacity

Renewable Energy (RE)

Portfolios for 2030 and 2050 include varying quantities of new investment in on-shore wind, and utility scale solar PV with single axis tracking. More expensive emerging RE technologies, such as concentrating solar thermal, geothermal, biomass and wave were excluded from consideration, but could be considered in future studies. Investment in new hydro generation was also excluded from consideration due to strong environmental opposition to new hydro development in Australia.

Portfolios considered ranged from no new investment in RE technologies, to portfolios targeting 40% of energy from PV and 50% of energy from wind, as listed in Table 6. The actual RE penetrations were determined based upon hourly generation output from the merit order dispatch, taking into account spilling in some periods, as described further below.

Table 6. RE Penetration Scenarios

		RE Penetration Scenarios					
	Targeted energy from PV	0%	5%	10%	20%	30%	40%
	Targeted energy from wind	0%	10%	20%	30%	40%	50%
2030	**2030 Scenario Name**	15% RE	30% RE	45% RE	60% RE	75% RE	85% RE
	Spilled PV and Wind	0%	0%	1%	3%	10%	22%
	Achieved Renewable Penetration	15%	30%	44%	62%	75%	83%
	Energy from non-renewables	85%	70%	56%	38%	25%	17%
2050	**2050 Scenario Name**	95% Gas	80% Gas	65% Gas	45% Gas	30% Gas	20% Gas
	Spilled PV and Wind	0%	0%	0%	0%	5%	17%
	Achieved Renewable Penetration	5%	20%	35%	55%	70%	78%
	Energy from non-renewables	95%	80%	65%	45%	30%	22%

Capacity factors of 34% for PV and 41% for wind were applied for both 2030 and 2050, assuming technology improvement over time (AEMO, 2013). These capacity factors were used to determine the capacity of PV and wind that would need to be installed to reach the targeted levels of energy penetration, as listed in Table 7.

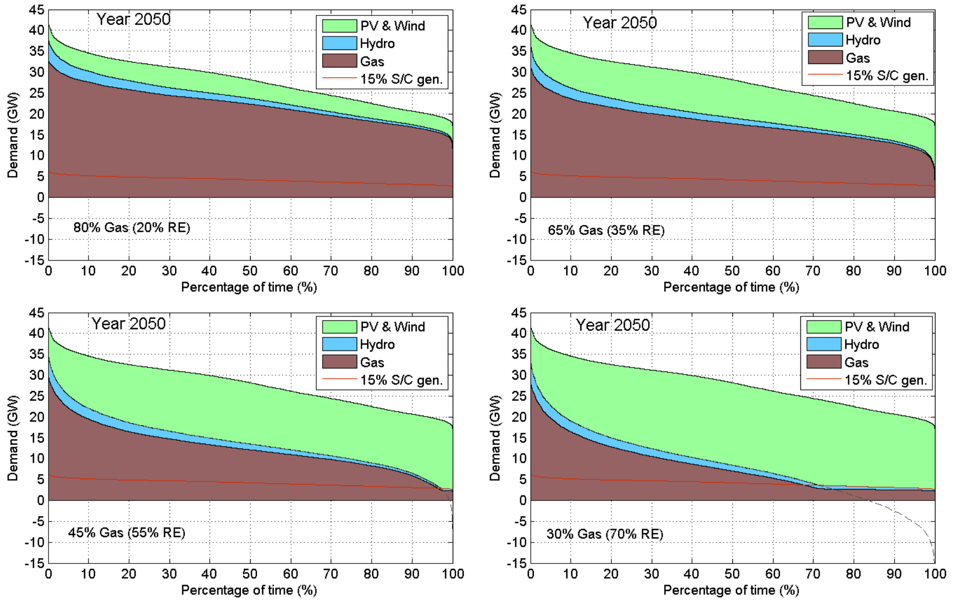
Hourly wind and solar output profiles in 2030 and 2050 for each RE penetration scenario were simulated based on historical hourly traces of 1-MW on-shore wind and solar PV (single axis tracking) generation in different locations across the NEM provided by AEMO (AEMO, 2013). Data from the year 2009-10 was used as a reference year to ensure consistency with the demand profile (based upon the same year). Hourly PV and wind generation was scaled up to the desired penetration level.

Variable renewable generation (wind and PV) was incorporated into the model through the use of a residual load duration curve (RLDC) technique. Hourly renewable generation outputs in the time-sequential domain were subtracted from demand over the same time period. This assumes that renewable are given first priority in merit order dispatch due to their low operating costs by comparison with conventional generation technologies. The resulting residual (net) demand after accounting for renewable generation is then rearranged in descending order of magnitude to obtain a RLDC. It is this curve which has to be met by conventional technologies in the portfolio.

Hydro was also treated as exogenous to the dispatch, and hence modelled through a RLDC technique. A hydro duration curve was constructed from actual hourly hydro generation output obtained from AEMO using 2009-10 as the reference year (AEMO, 2012c). The aggregate hydro duration curve (rearranged in order of magnitude) was subtracted from the RLDC in each renewable penetration scenario. With this approach, historical hydro generation patterns are re-mapped onto the new net demand curve, better accounting for the fact that the future generation mix will likely be very different from that currently in use, and adjusting hydro dispatch accordingly. Energy constraints are also maintained at levels considered realistic for future operation (AEMO, 2013), and the method accounts for environmental and other operational constraints that may apply.

Residual load duration curves for a selection of the RE penetration scenarios modelled are illustrated in Figure 5. To ensure realistic dispatch outcomes, the modelling assumes a hypothetical minimum of 15% synchronous generation in any one hour period. Previous studies have used this assumption in the NEM, to ensure sufficient system inertia to maintain a stable frequency and satisfy other important system security concerns (such as fault detection) (AEMO, 2013). Synchronous generation is provided by conventional generating plants, which are coal, CCGT, OCGT, hydro, distillate and cogeneration. This represents the minimum amount to which aggregate conventional generators can be turned down. Hence, PV and wind generation are 'capped' at 85% of demand in each dispatch interval. For high renewable scenarios, there are periods during which combined PV and wind outputs were greater than total demand. In such cases, energy from PV and wind was spilled. PV was given priority over wind in the dispatch due to the lower variable operating and maintenance costs for PV. With this dispatch provision, it is possible that actual PV and wind energy penetration is less than the desired penetration due to energy spillage, particularly in the high renewable scenarios.

Figure 5 - Residual load duration curve for different RE penetration scenarios



A probabilistic approach was applied to ensure that each portfolio included sufficient firm capacity to meet the expected demand for at least 99.998% of the time during the year, consistent with the current NEM reliability standard of 0.002% of unserved energy per year, measured over the long term. Table 7 shows the installed capacity of firm generation calculated to be required to meet the reliability standard for each renewable investment scenario for 2030 and 2050. Note that the installed capacity of PV and wind shown in the table includes both new and existing capacity.

Table 7. Installed generation capacity and residual peak demand for different RE penetration scenarios in 2030 and 2050.

RE penetration scenario		2030				2050			
		Residual peak demand (GW)	Installed capacity (GW)			Residual peak demand (GW)	Installed capacity (GW)		
New PV	New Wind		PV	Wind	Additional firm capacity required		PV	Wind	Additional firm capacity required
0%	0%	30	3	3	44	37	0	0	51
5%	10%	29	5	8	42	34	4	7	48
10%	20%	27	8	15	40	33	8	14	46
20%	30%	26	16	21	39	32	17	20	45
30%	40%	25	25	28	38	31	25	27	44
40%	50%	24	31	34	36	30	31	34	42

Remarks: Installed PV and wind capacity includes existing and new capacity

Fossil Fuels

For each RE penetration scenario, different possible permutations of existing black coal, CCGT (existing and new) and OCGT (existing and new) generation portfolios were considered by varying the share of each in 10% intervals of the additional firm capacity required (as listed in Table 7). This resulted in 66 generation portfolio combinations for 2050, and 396 generation portfolio combinations in 2030.

The modelling assumed that there will be no new investment in coal-fired generation. There appears to be growing consensus on this given its high emissions and high capital investment risk (Bloomberg New Energy Finance, 2013). Furthermore, costs of renewables are becoming increasingly competitive with coal (Bazilian, et al., 2012; Bhavnagri, 2013), particularly with a carbon price in place. The modelling also assumed no new investment in distillate and cogeneration.

Nuclear generation

Nuclear generation was not included as an investment option. There is no nuclear generation in Australia at present, and there is strong public opposition to the development of this technology in Australia.

Dispatch and cost calculation

For each generation portfolio constructed, the dispatch in each hourly period was calculated so that the total annual cost of the portfolio could be determined. When spilling occurred, PV was given priority in the dispatch order due to lower assumed short run marginal costs (SRMC). The dispatch of each fossil fuel technology in each period in the RLDC was determined using merit order dispatch based on short run marginal costs (SRMC) of each technology in 2030 and 2050, as listed in Table 8.

Existing plant parameters were obtained from the AEMO NTNDP, calculated as the average for all of the existing plant for each technology type (AEMO, 2012a). New entrant generation parameters for each technology were based on the 2030 cost estimates averaged over all NEM regions from (BREE, 2012a). It is assumed that any existing fuel contracts will have expired by 2030, such that existing generators will be purchasing fuel at the same prices as new generators. Annualized capital costs were calculated using a weighted average cost of capital (WACC) of 10%. Expected fuel prices were also based upon an average of NEM regions for the "medium" projection case from (BREE, 2012a). For OCGTs, an uplift of 20% was applied to the gas price in any investment scenario, accounting for their lower purchasing power given smaller generation volumes. The parameters for new generators are shown in Table 8.

Table 8. Generator parameters for existing and new-entry plants.

Parameters	Existing Generators								New Generators			
	Coal	*CCGT*	*OCGT*	*Hydro*	*PV*	*Wind*	*Distillate*	*Cogen*	*CCGT*	*OCGT*	*Wind*	*PV*
Plant life (years)	N/A								30	30	30	30
Overnight capital cost ($kW) – 2030	SUNK								1,113	751	1,816	2,197
Overnight capital cost ($kW) – 2050	N/A								1,159	782	1,866	1,571
Fixed O&M cost ($/MW/yr)	55,651	32,307	17,355	55,988	25,000	23,459	14,000	26,922	10,000	4,000	40,000	38,000
Variable O&M cost ($/MWh)	1.3	1.7	8.8	6.9	0	2.7	10.2	2.1	4	10	12	0
Thermal efficiency (%)	34	46	28	N/A	N/A	N/A	27	70	50	35	N/A	N/A
Heat Rate (GJ/MWh)	10.6	7.8	12.9	N/A	N/A	N/A	13.2	9.1	7.27	10.29	N/A	N/A
Emission Factor (tCO_2/MWh)	0.96	0.4	0.67	N/A	0	N/A	0.91	0.47	0.37	0.52	0	0
Expected fuel price ($/GJ)	1.9	11.65	14	N/A	0	N/A	32.3	3.8	11.65	14	0	0

Remarks: Note parameters for existing PV plants are based on non-tracking while those for new PV plants are based on single-axis tracking

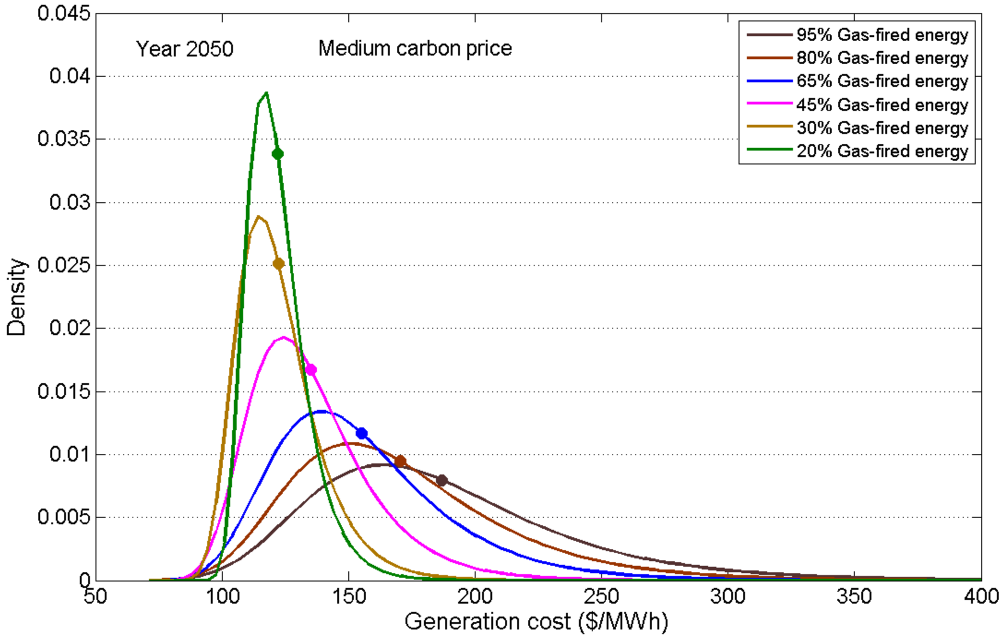
5. Results

Results for the year 2050 are examined first, providing an indication of the "end point" which is likely to be optimal some 35 years into the future. Results for the year 2030 are then examined to suggest low cost possible transition pathways to that point.

In 2050, all portfolios are composed entirely of varying combinations of gas and renewable technologies. All existing generation is assumed to be retired, and only gas and renewable technologies were available to the model as new investment options. Therefore, each RE penetration scenario implies directly the level of energy from gas-fired generation. In the following charts (Figure 6, Figure 7 and Figure 8), different colours are used to represent the different proportions of energy derived from gas and renewables, ranging from 95% of energy from gas and 5% renewable generation (in dark brown) to 20% of energy from gas and 80% renewable generation (in green).

The generation portfolios with the lowest expected (mean) cost at each level of gas-fired generation (or, equivalently, RE penetration scenario) was determined from the 2050 modelling results. The probability density distribution for generation costs for each of these lowest cost generating portfolios is illustrated in Figure 6. Portfolios with a high proportion of energy from gas-fired generation exhibit a wide cost distribution, as well as higher expected costs (represented by the solid marker on each curve). Reducing reliance upon gas-fired generation by adding renewable generation is found to reduce expected costs, and reduce the width of the cost distribution.

Figure 6 - Probability density distribution of the generation cost for the lowest cost portfolio for each level of gas-fired generation considered. The markers on each curve show the expected (average) cost for the distribution. Since lognormal distributions have been applied for the various input assumptions, the expected cost lies to the right of the peak density.



The cost outcomes for the scenarios at the ends of the investment spectrum are compared in Table 9. It is apparent that heavy reliance upon gas-fired generation increases expected costs by $65/MWh or around 40%. For a typical Australian household with four people (using 7400 kWh per annum) this equates to an additional cost per household of $481 per annum (ACIL Tasman, 2011). Heavy reliance upon gas-fired generation also increases the cost risk by a factor of more than three. Gas-fired generation is exposed to significant price uncertainty through uncertain gas prices, and also through uncertainty about carbon pricing policy.

Table 9. Cost and cost risk outcomes for 2050

	% of energy from renewables	% of energy from gas-fired generation	Expected generation cost ($/MWh)	Cost risk (SD of cost) ($/MWh)
Gas Investment	5%	95%	187	1
Renewables Investment	80%	20%	122	12

Figure 7 illustrates the cumulative probability distribution for generation costs for each of these portfolios. The least cost portfolio with 20% gas-fired energy has a 90% probability of wholesale costs remaining below $138/MWh. By contrast, the lowest cost portfolio with 95% gas-fired energy has a 10% probability of wholesale costs exceeding $254/MWh. This equates to a typical Australian household being exposed to an additional cost of as much as $814 per annum, with a 10% probability of exceedance.

Figure 7 - Cumulative probability of the lowest cost portfolio at each level of gas-fired generation. The markers on each curve show the expected (average) cost for the distribution.

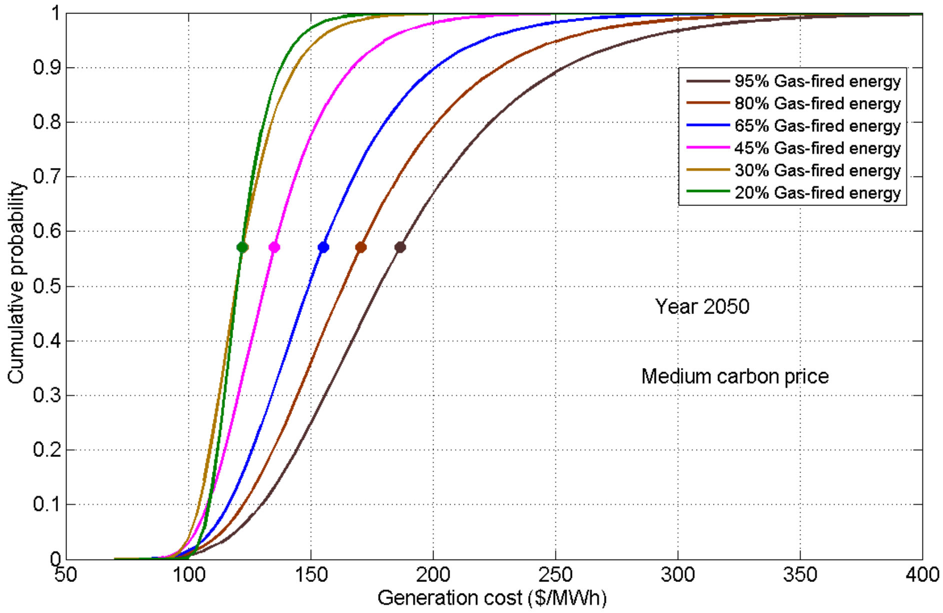
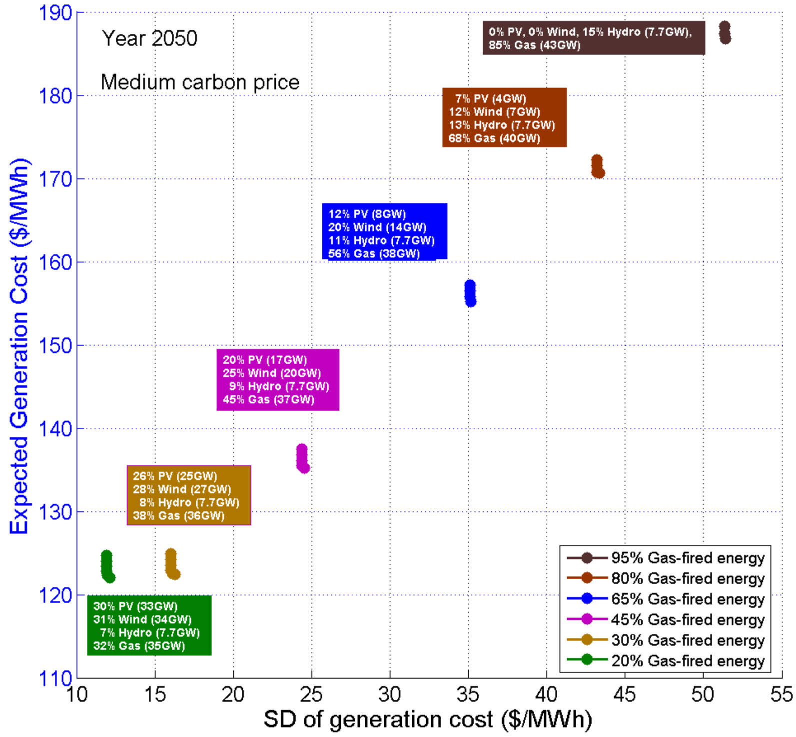


Figure 8 illustrates the modelling outcomes for a wider selection of the generation portfolios considered in 2050. Each dot represents a single generation portfolio, plotting that portfolio's expected cost (against the vertical axis) and the expected cost risk (SD of cost, plotted against the horizontal axis), calculated over 10,000 simulations of uncertain fuel prices, carbon prices and electricity demands.

Only generation portfolios that lie on the "efficient frontier" for each gas generation level have been included on the graph. Generation portfolios on the efficient frontier represent the most optimal options in terms of cost and cost risk (SD of cost) for each gas generation level. This means that any portfolio that is not on the efficient frontier is necessarily suboptimal (by the measures calculated in this study). However, there remains an important trade-off between portfolios that lie on the efficient frontier; decision makers will need to determine their preferred trade-off between cost and cost risk (for example, by moving along the efficient frontier cost risk can be reduced, but only by increasing expected costs).

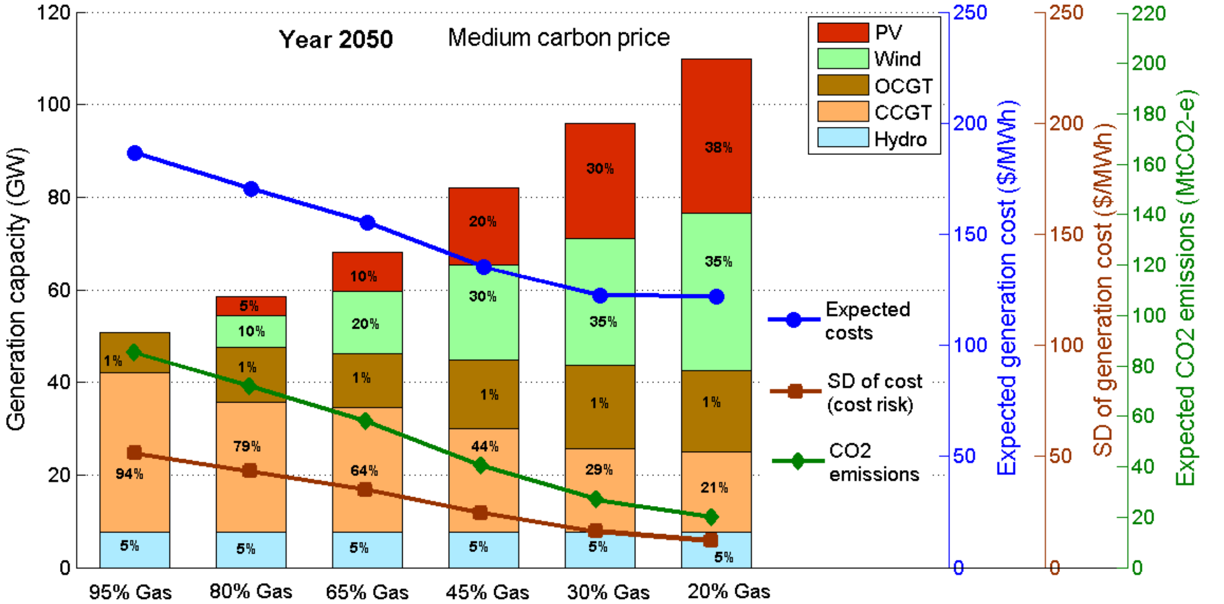
Figure 8 - Efficient frontiers for each renewable scenario for 2050



As illustrated in the previous charts, Figure 8 shows that the expected generation cost is minimised in the scenario with the lowest amount of energy from gas-fired generation, and therefore the highest renewable penetration (20% gas-fired energy, 80% RE). This low level of energy from gas-fired generation also minimises the cost risk (standard deviation in cost). Figure 8 also shows that markers of the same colour cluster together tightly, meaning that changing the proportion of CCGT to OCGT generation does not change the cost risk significantly, and has only a minimal impact upon the expected generation cost. However, the introduction of RE and corresponding reduction of energy from gas-fired generation does significantly reduce costs and cost risk (markers of different colours are widely dispersed from each other).

The least cost generation portfolios for each level of gas-fired generation are compared in more detail in Figure 9. In addition to expected cost and cost risk increasing as the amount of energy sourced from gas-fired generation increases, GHG emissions are also found to increase. Figure 9 also illustrates the changing role of gas-fired generation in the least cost portfolios as more renewable generation is added. The total capacity of gas-fired generation remains relatively constant as the proportion of renewable energy increases, declining only marginally from 43 GW (with 5% renewables) to 35 GW (with 80% renewables). This indicates that variable renewables such as wind and PV have limited ability to displace firm generating capacity, while maintaining the necessary reliability standard. However, as the proportion of renewable generation increases, the proportion of CCGT capacity in the least cost portfolio declines markedly (from 34 GW to 17 GW), while the proportion of OCGT capacity increases (from 9 GW to 17 GW). Furthermore, the CCGT capacity installed operates at lower capacity factors in the higher renewable scenarios, decreasing from 0.79 with 5% of energy from renewables, to 0.34 with 80% of energy from renewables. This indicates that the lowest cost scenarios use gas-fired generation only for peaking capacity, and source most of their energy from renewable generation. Portfolios that use gas-fired generation primarily in a peaking role (rather than for "baseload" electricity generation) also exhibit around 80% lower cost risk, and around 80% lower greenhouse gas emissions. This suggests that gas-fired generation should play a role in future portfolios as peaking units, providing firm capacity without significant quantities of energy. It also highlightesthat gas-fired peaking units can effectively partner with variable renewables (which provide low cost and low risk energy, but do not provide large quantities of firm capacity).

Figure 9 – The least cost portfolio in each RE penetration scenario for 2050. Percentages indicate the percentage of energy sourced from that technology.



5.1. Analysis in the absence of a carbon price

This modelling has assumed a significant probability of a meaningful carbon price in 2050, as illustrated in Figure 3. In theory, the economically efficient carbon price is that at which the marginal 'control' cost of an additional tCO2e abatement equals the marginal social 'damage' cost of an additional tCO2e emitted. In practice, the marginal social cost of carbon is a highly challenging concept with intra-generational and inter-generational complexities. Instead, most future carbon price estimates are derived from the 'control' costs required to achieve particular emission targets in economic models. In this sense, a carbon price can be considered as a form of Pigouvian tax, such that the taxation revenue is returned fully to consumers (through alleviated taxation in other areas, or Government expenditure on public infrastructure, for example). Therefore it is also useful to compare the costs of various portfolios in the absence of the carbon price itself contributing to those costs and cost risks.

To allow direct comparison between the generation costs of different portfolios, without the influence of the carbon price itself dominating the costs of emissions intensive scenarios, the modelling described above was repeated with a zero carbon price applied, as illustrated in Figure 10. The authors do not consider this to be representative of a likely future, given the likelihood of mounting pressure to price the externality of greenhouse emissions, but it allows direct comparison of the other scenario costs and factors contributing to cost risk (in this case, the gas price and demand uncertainties).

Figure 10 – The least cost portfolio in each RE penetration scenario for 2050, in the absence of a carbon price. Percentages indicate the percentage of energy sourced from that technology.

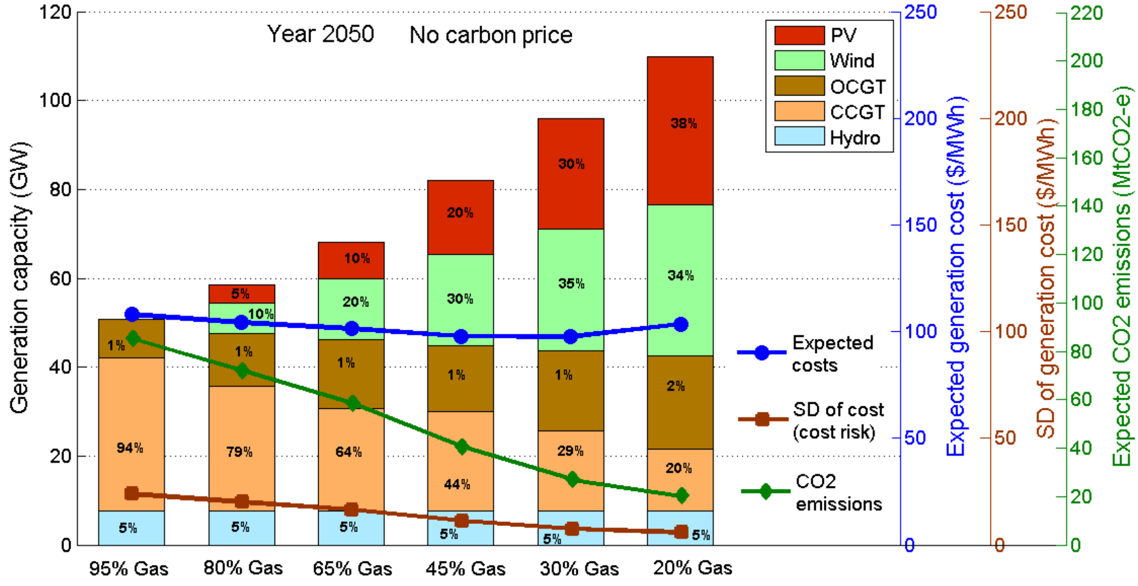


Figure 10 indicates that even in the absence of a carbon price, the lowest cost portfolio in 2050 sources only 30% of energy from gas-fired generation, with the remaining 70% of energy being sourced from renewable technologies. Approximately half of the installed gas-fired capacity in this portfolio is peaking OCGT plant, providing firm capacity without significant quantities of energy. Cost risk and GHG emissions can be reduced further by increasing the proportion of energy sourced from renewables (and therefore decreasing the proportion of energy sourced from gas-fired generation), with an increase in expected cost of $5/MWh (5%). This indicates that investment in gas-fired plant is high cost and high risk, even in the absence of any expectation of a carbon price.

5.2. The least cost options in achieving emissions reduction targets

The data produced from modelling these 66 generation portfolios under 10,000 combinations of uncertain gas price, carbon price and demand can be visualised in another way that provides further insight into the merits and risks of decarbonisation via different kinds of gas transitions. The portfolios modelled were arranged into groups based upon their levels of greenhouse emissions. The lowest cost portfolio achieving each greenhouse emissions level was selected, as illustrated in Figure 11. When determining the emission ranges, the number of generation portfolios was taken into account to ensure that generation portfolios were not heavily concentrated in certain emission ranges.

Figure 11 - The least cost generation portfolios for each emission range for 2050 in the case without a carbon price. Dotted lines indicate the costs and cost risk for these portfolios if the carbon price distribution is applied. Percentages indicate the percentage of energy sourced from that technology.

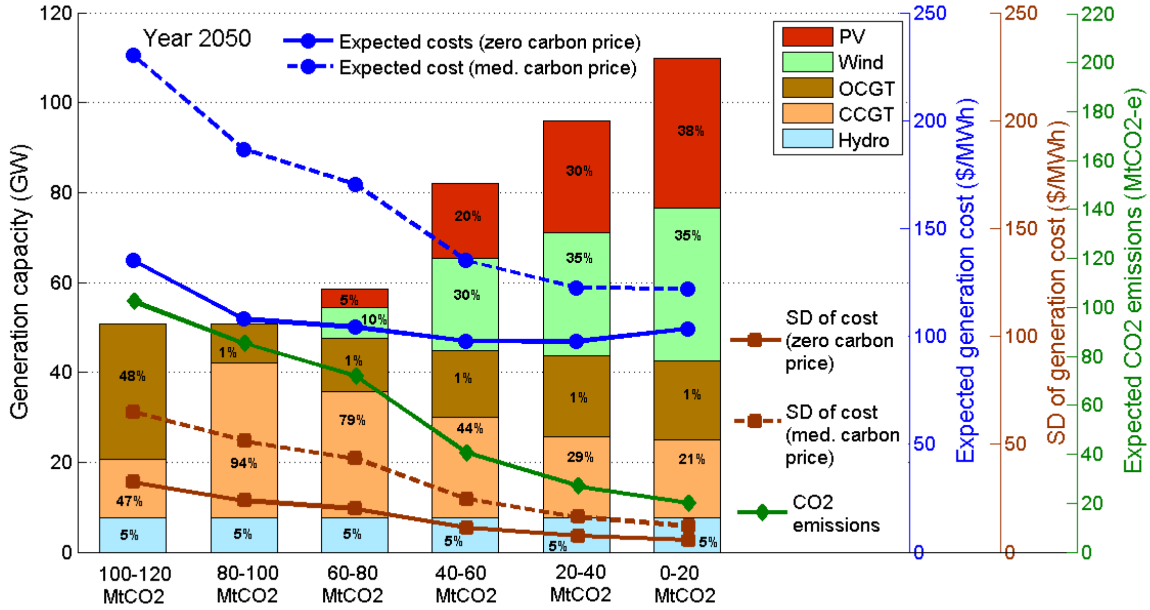


Figure 11 illustrates that portfolios composed entirely of gas-fired generation achieve greenhouse emissions levels approximately 30-50% lower than present (GHG emissions from the NEM were 167 $MtCO_2$-e in 2012) (AEMO, 2014). Portfolios with CCGT plant providing the majority of energy provide GHG emissions at the lower end of this range, and also have lower expected generation costs and cost risk due to more efficient use of the gas fuel.

To lower emissions below 80 MtCO2-e, the addition of renewable generation is required. In 2050, the lowest cost portfolio in the absence of a carbon price achieves GHG emissions in the range 20-40$MtCO_2$-e, sourcing 75% of energy from renewables. If the carbon price probability is included, the lowest cost portfolio has emissions in the range 0-20 $MtCO_2$-e, and sources the maximum amount of energy from renewables.

Australia has a legislated target of an 80% reduction in GHG emissions from 2000 levels by 2050. If this were applied as a direct proportion in the NEM, this would require emissions of no more than around 32 $MtCO_2$-e by 2050. The two lowest gas portfolios modelled in this study, sourcing 20-30% of energy from gas, and 70-80% of energy from renewables would be in this range. Portfolios with higher proportions of energy from gas-fired generation do not meet this legislated target.

The Australian Government's Climate Change Authority has recently recommended carbon budgets and targets that would require GHG emissions close to zero by 2050 (with the precise level depending upon the degree of action in earlier decades) (CCA, 2014). In the absence of carbon capture and storage technology, this will require zero use of gas-fired generation in 2050.

In practice, it is likely that the electricity sector will be required to achieve emissions reductions below national targets (IPCC, 2014). There are a range of commercially available, cost effective alternatives for electricity generation that do not produce GHG emissions. By comparison, other sectors, such as land use and agriculture, aviation and various industrial processes do not yet have ready low GHG alternatives. A lack of emissions reductions in other sectors will require stronger and faster action in the electricity sector in order to meet the required emissions levels on a national scale. This would mean that the NEM could be expected to reach zero emissions prior to 2050. Portfolios that achieve these levels were not modelled in this study, since the model used is not yet suited to modelling portfolios with 100% renewable energy. This is identified as an area for future investigation.

5.3. Achieving near-term emissions reductions: Results for 2030

In addition to exploring the lowest cost generation portfolios for emissions reductions over the long term, it is also worth considering emissions reductions in the near term, to begin to establish a transition pathway for the NEM. Therefore, modelling was also conducted for the year 2030. Since 2030 is only 16 years from the present, a significant proportion of the present generation fleet may remain in operation. Therefore, existing coal-fired plant was included in portfolios (with varying levels of retirements), as well as existing wind, PV, OCGT and CCGT generation. The capital costs of this existing generation were considered "sunk", such that the only costs of including this generation in the portfolio were related to fixed operations and maintenance, variable operations and maintenance, fuel costs and carbon costs.

The least cost generation portfolio for each of the emission ranges for 2030 are shown in Figure 12. Since there are a large number of portfolios in the 10 - 60 $MtCO_2$-e emission range, the resolution of emission ranges is greater than that of 60 -180 $MtCO_2$-e.

Figure 12 - The least cost generation portfolios for each emission range for 2030 in the case without a carbon price. Dotted lines indicate the costs and cost risk of these portfolios if the carbon pricing probability distribution is applied. Percentages indicate the percentage of energy sourced from that technology.

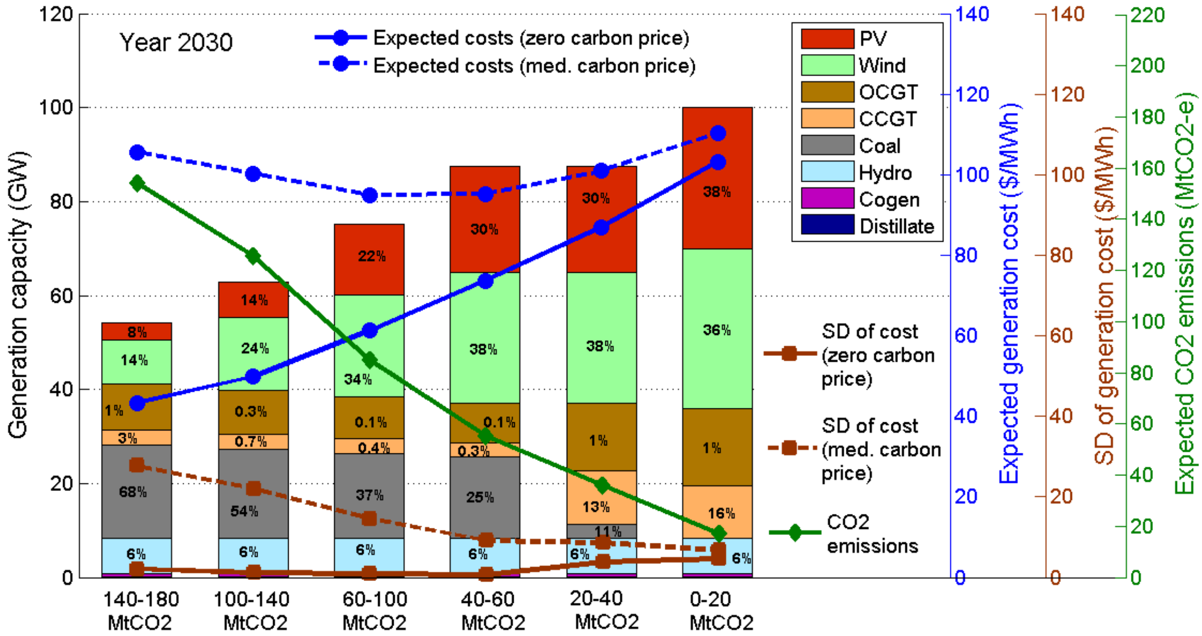


Figure 12 shows that none of the least cost portfolios for achieving any level of emissions reductions in 2030 include significant quantities of energy being sourced from gas-fired generation. Only the portfolios that need to achieve the very lowest emissions ranges include any significant quantity of gas-fired generation, and this remains significantly less than the quantity of energy sourced from renewables (75% to 80%). This suggests that baseload gas-fired generation does not have a significant role to play in the NEM's future, if the aim is to minimise costs, minimise cost risk, and achieve emissions reductions.

If emissions in the range 140-180 MtCO2 are considered acceptable in 2030, and the cost of carbon is ignored, this can be achieved at lowest cost by continuing to operate existing coal-fired power stations in conjunction with 30% of energy from renewables, with OCGT gas peaking plant providing firm capacity. Only around 3% of energy is provided by gas in this portfolio.

The Australian Government Climate Change Authority has recommended 2030 GHG reductions in the range 40-60% from 2000 levels. If this were applied to the NEM as a direct proportion, this would imply 2030 emissions from the NEM in the range 60-100 $MtCO_2$-e. The lowest cost portfolio that achieves this level of GHG emissions also sources only around 3% of energy from gas-fired generation. Emissions reductions are achieved by adding significantly more renewable energy (to reach 60% of energy sourced from renewables). Existing coal-fired plant are then operated at significantly lower capacity factors (reduced from 0.9 to 0.55). 8GW of peaking gas-fired generation provides firm capacity, without contributing significant generation.

Achieving more significant emissions reductions below 40 $MtCO_2$-e at lowest cost requires closure of the existing coal-fired generation, and replacement with gas-fired generation. Even in these scenarios, the bulk of energy (75-85%) is supplied by renewable generation, with gas-fired generation only supplying 10-15% of energy. Portfolios involving proportions of renewable energy higher than 85% were not modelled in this study, but may offer lower cost and lower risk and avoid the necessity of investing in gas-fired generation to achieve these very low GHG emissions levels.

5.4. Transition pathways for the NEM

Figure 13 illustrates the historical GHG emissions levels from the NEM, with a range of trajectories for the future based upon the recommendations by the Australian Government Climate Change Authority (CCA, 2014). The CCA recommends a GHG budget for the period to 2050, such that higher emissions earlier would necessitate lower emissions later. For 2030, the CCA recommended range of 40-60% reductions from 2000 levels by 2030 is illustrated. For 2050, the upper bound is provided by the legislated 80% reduction target from 2000 levels, and the lower range is the zero emissions level indicated by many of the CCA recommended trajectories.

The lowest cost portfolios for 2030 and 2050 (including the assumed probability of a carbon price) are illustrated in Figure 13. These portfolios which minimise cost and cost risk also achieve the required emissions reduction ranges. The emissions associated with these portfolios are indicated by the blue dotted line in Figure 13.

For 2050, this modelling indicates that portfolios that maximise the proportion of energy from renewables minimise expected costs, minimise cost risk, and minimise GHG emissions. The illustrated portfolio sources 80% of energy from renewables, being the lowest proportion of energy from gas-fired generation of those considered. Portfolios with higher proportions of RE were not modelled, but may offer lower costs and lower cost risk.

Figure 13 - GHG emissions trajectories for the Australian NEM in the proportions of national targets recommended for Australia by the Climate Change Authority, with lowest cost portfolios that meet the targets in 2030 and 2050. Percentages indicate the % of energy supplied by each technology.

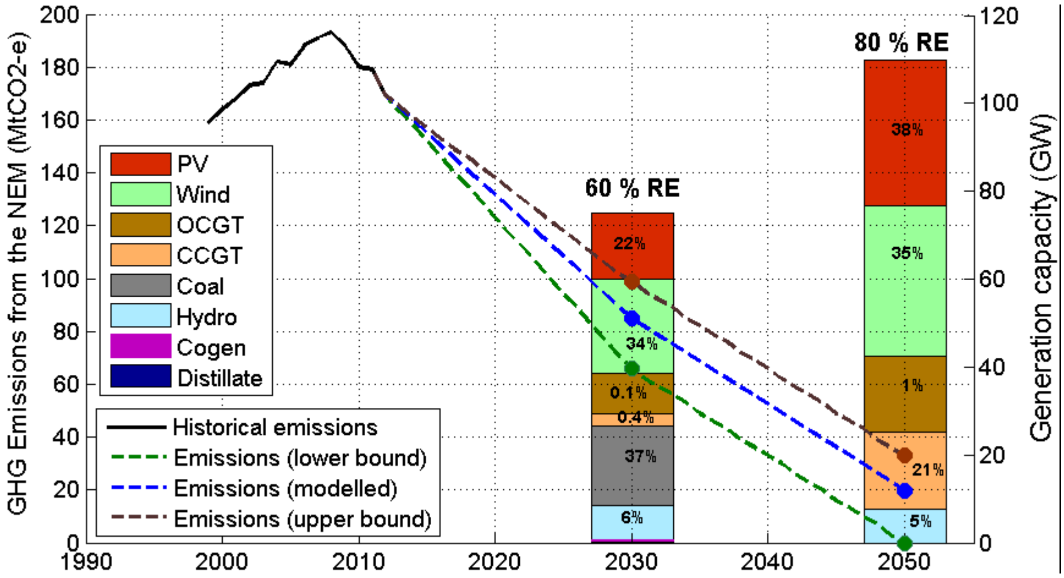


Figure 13 indicates an optimal transition pathway for the NEM that does not involve baseload gas-fired generation, either in the near term, or the long term. In order to minimise costs and cost risk, the NEM should continue to operate a selection of existing coal-fired plant with reduced capacity factors (in a peaking role), supporting the operation of a significant quantity of renewable energy (supplying 60% of energy). This portfolio includes very minimal investment in CCGT gas-fired plant. By 2050, assuming all existing coal-fired generating capacity will be retired, maximising the proportion of energy sourced from renewable technologies (and therefore minimising the proportion of energy sourced from gas-fired generation) minimises costs and cost risks, and is also important for achieving the required emissions reductions. This finding is robust to varying assumptions around carbon pricing. Even in the complete absence of a carbon price, the lowest cost and lowest cost risk portfolios do not involve significant amounts of energy supplied by gas-fired generation.

6. Modelling limitations

As with other modelling exercises, these findings need to be considered with suitable caution since the modelling outcomes are highly dependent on input assumptions, and the modelling tool has a range of inherent limitations. The modelling is static since it only assesses the performance of future generation portfolios in 2030 and 2050 without taking into account the dynamic and multi-stage process of generation planning and investment. System costs have been calculated based upon capital investment costs for each technology projected for the year 2030 and 2050; in reality investment will progress over time, and the generation capacity installed earlier will have higher costs. Previous assessments have suggested that the additional cost from this "investment trajectory" could be on the order of 10-20% for the move to a 100% renewable power system by 2030 (Riesz et al., 2013).

The costs of building new or upgrading existing transmission facilities to access new renewable generation is not included in these simulations. However, the costs of transmission are estimated to be relatively minor compared with the capital cost of generation in a move to a high renewable system (AEMO, 2013a).

Operation of the power system with very high proportions of renewables has not been considered in detail, beyond a relatively simple balancing of demand and supply in each modelling period, and the application of a 15% minimum of synchronous generation in each period to account for operational constraints around fault feed in levels and system inertia. The operation of the electricity market was also not considered in detail; for example, no potential for exercise of market power was included in the modelling.

The modelling is not time sequential, and therefore did not include explicit consideration of operational limitations such as ramp rates. Furthermore, the ability of coal-fired plant to operate at low capacity factors was not explicitly examined, either from a technical perspective, or an economic perspective. Adjustments to the electricity market and augmentation of these units may be required to facilitate this behaviour.

7. Conclusions and Policy Implications

The findings of this study suggest that the best strategy for reducing GHG emissions in the NEM at the speed and scale that appears required for effective climate change mitigation is unlikely to be via baseload (CCGT) gas-fired generation. Portfolios that source significant quantities of energy from gas-fired generation are found to be high cost, high risk, and not able to provide the necessary emissions reductions. This is found to be robust to a wide range of assumptions on future carbon prices. In contrast, this modelling suggests that the optimal investment approach is likely to involve increasing renewable generation towards levels around 60-75% of energy by 2030 and 80-100% by 2050. Firm capacity can be provided primarily by OCGT plant operating at low capacity factors, and in the near term by continued operation of existing coal-fired plant in a peaking role.

This modelling suggests that the Australian Government should not implement policies to promote the development of baseload (CCGT) gas-fired plant in the NEM. If the gas price probability distributions applied in this modelling are accurate, generation developers are unlikely to be able to secure long term gas supply contracts to support the financing of baseload gas-fired plant. This means that existing market dynamics should appropriately prevent investment in baseload gas-fired plant.

However, the Government may need to consider other types of market intervention, to promote investment in renewable generation, to support the development of peaking gas-fired generation in an increasingly strained energy-only market, and in smoothing the transition of coal-fired plant from baseload to a peaking role.

Ongoing growth in renewable generation could be achieved via an expansion and strengthening of the existing Renewable Energy Target scheme, or via a suitably high carbon price (of the levels modelled in this study). Government intervention of this nature is likely to be required to achieve the levels of renewable energy indicated to be optimal in this analysis. Renewables cannot compete at present wholesale electricity prices in the absence of subsidies; gas prices and carbon prices will need to rise to the anticipated levels before a rational investor would bring a renewable project to market. However, electricity infrastructure has significant development lead times. Industry constraints such as the availability of appropriately skilled labour and installation equipment will mean that transforming the entire infrastructure base will take many years. If the goal is to achieve 60-75% renewable energy by 2030, most would agree that this is most likely to be achieved if development starts as soon as possible.

If the Australian Government does not implement mechanisms to support the managed growth of renewable generation in Australia, this modelling suggests that consumers could be exposed to extended periods of higher than necessary electricity prices while the industry "catches up" to the high gas and carbon prices that have eventuated. Gas-fired generators are likely to be able to pass these high costs through to consumers for an extended period.

The NEM's energy-only market signals the need for investment in peaking plant (or any type of firm capacity) via a very high market price cap of $13,100/MWh. With ongoing growth in renewable generation the energy-only market design may need further support to encourage appropriate levels of investment in firm capacity. Intervention in the fundamental market design may be required to ensure appropriate market signals for investment in peaking gas-fired generation (Riesz & MacGill, 2013). This is considered an important area for future research.

8. References

ACIL Tasman. (2011). *Electricity Bill Benchmarks for residential customers - Report for the Consumer Information Implementation Committee*. Retrieved from http://www.aer.gov.au/sites/default/files/ACIL%20Tasman%20-%20Electricity%20bill%20benchmarks%20for%20residential%20customers%20-%20December%202011_0.pdf

AEMO. (2012a). *National Transmission Network Development Plan*. (Australian Energy Market Operator) Retrieved from http://www.aemo.com.au/Electricity/Planning/National-Transmission-Network-Development-Plan

AEMO. (2012b). *National Electricity Forecasting Report for the National Electricity Market (NEM)*. (Australian Energy Market Operator) Retrieved from http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report-2012

AEMO. (2012c). *National Electricity Market (NEM) data*. (Australian Energy Market Operator) Retrieved from http://www.aemo.com.au/data/market_data.html

AEMO. (2013). *100 per cent Renewables Study - Modelling Outcomes*. (Australian Energy Market Operator) Retrieved from http://www.climatechange.gov.au/sites/climatechange/files/documents/08_2013/100-percent-renewables-study-modelling-outcomes-report.pdf

AEMO. (2014, May 28). *Carbon Dioxide Equivalent Intensity Index*. Retrieved from Australian Energy Market Operator: http://www.aemo.com.au/Electricity/Settlements/Carbon-Dioxide-Equivalent-Intensity-Index

Australian Federal Treasury. (2011). *Strong Growth, Low Pollution - Modelling a carbon price*. Commonwealth of Australia.

Australian Treasury. (2011). *Strong Growth, Low Pollution: Modelling a carbon price*. Canberra: Australian Government.

Awerbuch, S., & Yang, S. (2008). Efficient Electricity Generating Portfolio for Europe: Maximising Energy Security and Climate Change Mitigation. In *Analytical Methods for Energy Diversity and Security: A tribute to Shimon Awerbuch* (pp. 87-115). London: Elsevier.

Bazilian, M., Onyeji, I., Liebreich, M., MacGill, I., Chase, J., Shah, J., . . . D., a. Z. (2012). *Reconsidering the Economics of Photovoltaic Power*. Bloomberg New Energy Finance.

Bhattacharya, A., & Kojima, S. (2012). Power sector investment risk and renewable energy: A Japanese case study using portfolio risk optimization method. *Energy Policy, 40*, 69-80.

Bhavnagri, K. (2013). Uncertainty: The new certainty. *Clean Energy Week Conference, Bloomberg New Energy Finance*.

BREE. (2012a). *Australian Energy Technology Assessment*. (Australian Government, Bureau of Resources and Energy Economics) Retrieved from http://bree.gov.au/documents/publications/Australian_Energy_Technology_Assessment.pdf

BREE. (2012b). *Gas Market Report.* Australian Government, Bureau of Resources and Energy Economics.

BREE. (2013). *Energy in Australia.* Australian Government, Bureau of Resources and Energy Economics.

CCA. (2014). *Reducing Australia's Greenhouse Gas Emissions - Targets and Progress Review - Final Report.* Australian Government - Climate Change Authority.

Doherty, R., Outhred, H., & and O'Malley, M. (2006). Establishing the Role That Wind Generation May Have in Future Generation Portfolios. *IEEE Transactions on Power Systems, 21*, 1415-1422.

Elliston, B., MacGill, I., & and Diesendorf, M. (2014). Least cost 100% renewable electricity scenarios in the Australian National Electricity Market. *Energy Policy (in press)*.

Finance, B. N. (2013). *Renewable energy now cheaper than new fossil fuels in Australia.* Bloomberg New Energy Finance.

Garnaut, R. (2011). *The Garnaut Review 2011 - Australia in the Global Response to Climate Change*. Cambridge University Press.

Green, R. (2008). Carbon tax or carbon permits:The impact on generators' risks. *The Energy Journal, 29*, 67-89.

Huang, Y.-H., & and Wu, J.-H. (2008). A portfolio risk analysis on electricity supply planning. *Energy Policy, 36*, 627-641.

IEA. (2014a). *Energy Technology Perspectives - Harnessing Electricity's Potential.* International Energy Agency.

IEA. (2014b). *Tracking Clean Energy Progress 2014 - Energy Technology Perspectives 2014 Excerpt - IEA Input to the Clean Energy Ministerial.* International Energy Agency.

IPCC. (2014). *Fifth Assessment Report AR5.* Intergovernmental Panel on Climate Change.

King, G. (2011). The rise of unconventional gas - Origin Energy. *Speech to American Chamber of Commerce in Australia.*

Losekann, L., Marrero, G., Ramos-Real, F., & and de Almeida, E. (2013). Efficient power generating portfolio in Brazil: Conciliating cost, emissions and risk. *Energy Policy, 62*, 301-314.

Markowitz, H. (1052). Portfolio Selection. *The Journal of Finance, 7*, 77-91.

Mason, I., Page, S., & Williamson, A. (2010). A 100% renewable electricity generation system for New Zealand utilising hydro, wind, geothermal and biomass resources. *Energy Policy, 38*, 3973-3984.

Molyneaux, L., Froome, C., Wagner, L., & Foster, J. (2012). Australian Power: Can renewable technologies change the dominant industry view? *Energy Economics and Management Group Working Papers, School of Economics, University of Queensland, Australia*.

Muñoz, J., Nieta, S. d., A.A., C. J., & and Bernal-Agustín, J. (2009). Optimal investment portfolio in renewable energy: The Spanish case. *Energy Policy, 37*, 5273-5284.
Nelson, T., Nelson, J., Ariyaratnam, J., & Camroux, S. (2013). An analysis of Australia's large scale renewable energy target: Restoring market confidence. *Energy Policy, 62*, 386-400.
Riesz, J., & MacGill, I. (2013). 100% renewables in Australia - will a capacity market be required? *Proceedings of the 3rd International Workshop on the Integration of Solar Power into Power Systems.* London.
Riesz, J., & Tourneboeuf, E. (2012). *Delivering energy price security in an age of uncertainty.* AECOM Australia.
Roques, F., Nuttall, W., Newbery, D., & Neufville, R. (2005). *Nuclear Power: A Hedge Against Uncertain Gas and Carbon Prices.*
Stock, A. (2014). *Australia's Electricity Sector - Ageing, inefficient and unprepared.* Climate Council of Australia Ltd.
Vithayasrichareon, P., & and MacGill, I. (2012). A Monte Carlo based decision-support tool for assessing generation portfolios in future carbon constrained electricity industries. *Energy Policy, 41*, 374-392.
Vithayasrichareon, P., & MacGill, I. (2013). Assessing the value of wind generation in future carbon constrained electricity industries. *Energy Policy, 53*, 400-412.

Acknowledgments

This work is supported in part by funding from the CSIRO Future Grid project, and the Australian Renewable Energy Agency (ARENA).